

PETROPOLITICS: PETROLEUM DEVELOPMENT, MARKETS AND REGULATIONS, ALBERTA AS AN ILLUSTRATIVE HISTORY

Alan J. MacFadyen and G. Campbell Watkins

ISBN 978-1-55238-769-6

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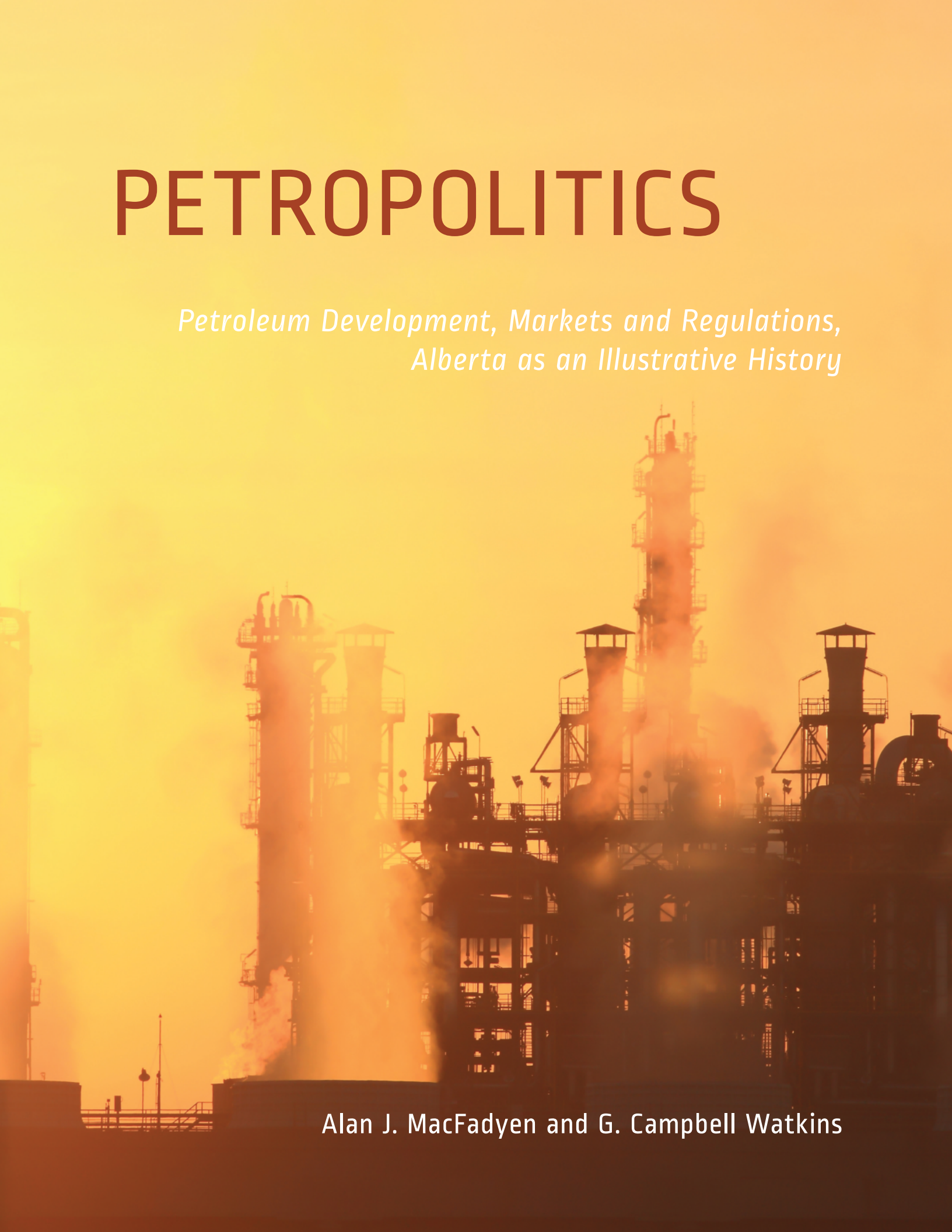
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ALAN J. MACFADYEN AND G. CAMPBELL WATKINS

Energy, Ecology, and the Environment Series
ISSN 1919-7144 (Print) ISSN 1925-2935 (Online)



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University of Calgary Press
2500 University Drive NW
Calgary, Alberta
Canada T2N 1N4
www.uofcpress.com

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Library and Archives Canada Cataloguing in Publication

MacFadyen, Alan J., author

Petropolitics : petroleum development, markets and regulations, Alberta as an illustrative history / Alan J. MacFadyen and G. Campbell Watkins.

(Energy, ecology, and the environment series ; no. 6)

Includes bibliographical references and index.

Issued in print and electronic formats.

ISBN 978-1-55238-540-1 (pbk.).—ISBN 978-1-55238-541-8 (pdf).—ISBN 978-1-55238-769-6 (open access pdf).—ISBN 978-1-55238-754-2 (epub).—ISBN 978-1-55238-755-9 (mobi)

1. Petroleum industry and trade—Alberta—History. 2. Petroleum industry and trade—Government policy—Alberta—History. 3. Petroleum industry and trade—Government policy—Canada—History. 4. Alberta—Economic policy—History. 5. Alberta—Economic conditions. I. Watkins, G. C. (Gordon Campbell), 1939–, author II. Title. III. Series: Energy, ecology, and the environment series ; no. 6

HD9574.C23A54 2014 338.2'7282097123 C2014-900035-9
C2014-900036-7

The University of Calgary Press acknowledges the support of the Government of Alberta through the Alberta Media Fund for our publications. We acknowledge the financial support of the Government of Canada through the Canada Book Fund for our publishing activities. We acknowledge the financial support of the Canada Council for the Arts for our publishing program.



Canada



Canada Council
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Cover design by Melina Cusano

Cover image: Colourbox #5501887

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To our children and, as always, to Heather

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ACKNOWLEDGMENTS

It is difficult when writing the acknowledgments for a jointly authored volume falls, of necessity, on one of the authors alone. At the time of Campbell's death, we had reasonably complete drafts of the first thirteen chapters of this book, and he had just provided his comments on the final chapter. Campbell was a pre-eminent Canadian petroleum economist, so his expertise, not to mention his energy and wit, were sorely missed during the lengthy updating, rewriting, and final editing. However, there can be no doubt that *Petropolitics* is truly a co-authored study.

Campbell first proposed this book many years ago. We were both trained as economists (Campbell going on to consult in energy economics, and I to join the Department of Economics, University of Calgary, as their first energy economist). So it is not surprising that we agreed that our discipline brought the most useful framework for understanding the functioning of the petroleum industry. While the subject matter might appear to be specific to the Alberta crude petroleum industry, it was agreed from the beginning that the book would be directed at a much wider audience than Alberta petroleum economists. This broader perspective has both professional and geographical dimensions: the oil industry has ramifications for society at large and for many professions beyond energy economics, and Alberta is far from alone in facing the opportunities and challenges of developing oil and natural gas resources.

Our intent in writing *Petropolitics* was to place the history of the development of Alberta's crude petroleum within the larger contexts of natural resource

economics and public policy formation. Framed in this way, the example of the Alberta experience can be applied anywhere petroleum is being developed. Consequently, this is a lengthy volume, which readers may wish to approach in a selective manner. For example, someone with training in economics may find little that is new in Chapter Four but require the description of industry activity found in Chapter One; conversely, someone employed by the oil industry may already be familiar with the material in the first chapter but have no familiarity with the tools of analysis used by economists as set out in the fourth chapter. Conscious of the difficulties involved in providing reasonably refined economic analysis and detailed descriptions of government regulations while maintaining narrative flow, we provide a brief "Readers' Guide" at the start of each chapter to aid in deciding which parts might prove of most interest. In addition, there are numerous summary and conclusion sections, should the fine technical detail be of less interest to any specific reader. It was also decided that if material was of interest it should be included in the main text rather than in lengthy appended footnotes as is common in many academic studies.

I would like to thank the University of Calgary Press for accepting such a mammoth manuscript and to John King, in particular, for his invaluable and meticulous editing. The anonymous reviewers the Press called on made many valuable comments that led to useful modifications in the text. Campbell would, I am sure, join me in extending a special note of appreciation to our many colleagues and students

over the years: anyone involved in the academic world knows it is impossible to overstate the importance of critical discussion in developing and refining any line of argument.

Finally, I would like to extend special thank to my wife, Heather. While she must have wondered when

this project would ever end, she has been endlessly supportive.

Canmore, Alberta
April 2013

UNITS AND ABBREVIATIONS

Units and Conversions

Oil

b (or bbl.)	barrel
b/d	barrels per day
m ³	cubic metre
1 b	= .159 m ³
1 m ³	= 6.293 b

Natural Gas

Mcf	thousand cubic feet
Tcf	trillion cubic feet
m ³	cubic metre
1 Mcf	= .028 m ³
1 m ³	= 35.5 Mcf

Numbers

10 ³	thousands
10 ⁶	millions
10 ⁹	billions
10 ¹²	trillions

Acronyms and Abbreviations

AGTL	Alberta Gas Trunk Limited
AIOC	Anglo-Iranian Oil Company
AOSTRA	Alberta Oil Sands Technology and Research Authority
API	American Petroleum Institute

APMC	Alberta Petroleum Marketing Commission
AUC	Alberta Utilities Commission
Btu	British thermal unit
CAPM	Capital asset pricing model
CAPP	Canadian Association of Petroleum Producers
CERI	Canadian Energy Research Institute
CCA	Capital consumption Allowance
CNRL	Consolidated Natural Resources Limited
COR	Canadian Ownership ratio (federal)
COSC	Canadian Ownership Special Charge
CPA	Canadian Petroleum Association
CPSG	Canadian Society of Petroleum Geologists
EIA	Energy Information Administration (of the U.S. Department of Energy)
EMR	Energy Mines and Resources (federal government department)
EOR	Enhanced oil recovery
EORV	East of the Ottawa River valley
ERCB	Energy and Resources Conservation Board (Alberta)
EUB	Energy and Utilities Board (Alberta)
FIRA	Foreign Investment Review Agency (federal)
FPC	Federal Power Commission (U.S.)
FTA	Free Trade Agreement (Canada and U.S.)
GATT	General Agreement on Tariffs and Trade
G&G	Geological and geophysical
GCOS	Great Canadian Oil Sands (company)
GPP	Good production practice
GSC	Geological Survey of Canada

ha	hectare	OPEC	Organization of Petroleum Exporting Countries
HFO	Heavy fuel oil	P&NG	Petroleum and Natural Gas
IEA	International Energy Agency	PCC	Petroleum Compensation Charge
IORT	Incremental Oil Revenue Tax (federal)	PGRT	Petroleum and Gas Revenue Tax
IPAC	Independent Petroleum Association of Canada	PIP	Petroleum Incentive Payment
IPL	InterProvincial Pipeline Company	PNGCB	Petroleum and Natural Gas Conservation Board (Alberta)
ISPG	Institute of Sedimentary and Petroleum Geology	PUB	Public Utilities Board (Alberta)
LDC	Local distribution company (natural gas)	R/P	Reserves/Production ratio
LNG	Liquified natural gas	RPP	Refined petroleum products
LPG	Liquified petroleum gases	RSSC	Resource stock supply curve
LTRC	Long term replacement cost	RTPC	Restrictive Trade Practices Commission (federal)
MBP	Market-based pricing (natural gas)	SAGD	Steam assisted gravity drainage (bitumen)
MPR	Maximum permissive rate	SCC	Special Compensation Charge
NAFTA	North American Free Trade Agreement (Canada, U.S. and Mexico)	SOOP	Special Old Oil Price
NARG	North American regional gas model	SPR	Strategic Petroleum Reserve
NEB	National Energy Board (federal)	STRC	Short term replacement cost
NEP	National Energy Program	TCPL	TransCanada Pipeline Company
NGGLT	Natural Gas and Natural Gas Liquids Tax	TOP	Take-or-Pay (natural gas)
NGL	Natural Gas Liquids	USOIQP	United States Oil Import Quota Program
NFFB	Net federal fiscal balance	VRIP	Value Related Incentive Price (natural gas)
NOC	National oil company	WCSB	Western Canadian Sedimentary Basin
NOP	National Oil Policy	WGML	Western Gas Marketing Ltd.
NORP	New Oil Reference Price	WORV	West of the Ottawa River valley
OEB	Ontario Energy Board	WTI	West Texas Intermediate
OGCB	Oil and Gas Conservation Board (Alberta)	WTO	World Trade Organization
OGSP	Official Government Selling Price (OPEC)		

Part One: Overview

In January, darkness covers the Canadian prairies by five o'clock in the afternoon. The landscape appears as it has for the past century. Lights of vehicles or farmhouses, and occasional small communities, dot the landscape. Otherwise, a wide expanse of snow-covered fields stretches out, marked only by the riverbeds and windbreaks of trees. Suddenly a blazing mass appears, myriad lights from a sprawling city: glowing skyscrapers; never-ending streams of headlights spreading from the city core; hectic shopping centres; endless banks of apartments and houses in which the evening's activities begin. A modern megalopolis in the once quiet prairie provides a tangible symbol for this book. Its light and warmth in the depth of winter's cold illustrate the possibilities opened by the low-cost energy of the Fossil Fuel Age. The very existence of active, wealthy cities in the Canadian prairies, so far removed from the longer-lived centres of world power, reflects the potential offered to a region by nature's bounty of energy resources.

We want to provide an 'economic history' of the petroleum industry in Alberta, from its beginning to the present. There are many ways in which the story could be told. A scientist might emphasize the physical history – how primitive life forms in shallow seas hundreds of millions of years ago can lead to an array of wells, pipelines, and refineries that provide the energy to fuel our industrialized world. The political scientist might highlight the management role of governments and detail the complex web of petroleum legislation and regulation that results from the political interplay of local farmers, regional entrepreneurs, multinational corporations, environmentalists,

government departments, and just plain taxpayers. A lawyer would trace the course of cases in civil and common law, and the judicial judgments, that give precise meaning to laws and regulations and stimulate new legislation. For the psychologist or biographer, the story might lie in a succession of determined and eccentric personalities relentlessly pursuing new ideas and opportunities. We do not dismiss the vibrancy of these approaches. However, our view is one of petroleum as an economic commodity, produced in competition with other energy products throughout the world. The history of the development of oil and gas in Alberta is in large measure an economic story. We hope that this perspective will prove valuable to readers of this book, even those who begin by thinking that energy is too important to be left to economists.

As economic commodities, oil and gas can be viewed from a purely 'private' perspective, as seen by companies and consumers. They can also be viewed from a 'social' perspective, as commodities to be utilized in the broad public interest. The importance of energy to the functioning of any economy has meant that energy is amongst the most regulated of commodities. What might appear to be purely private decisions are made within a complex and evolving web of government regulations. The title "Petropolitics" was chosen to acknowledge the importance of the legal and regulatory setting to the economics of the petroleum industry.

Our study deals with oil and natural gas in Alberta. It might, therefore, be viewed as a restricted study of narrow interest. However, the physical conditions that generated petroleum, the assorted tasks

performed by the petroleum industry, the operation of economic markets, and the regulatory issues that arise are common to oil- and gas-producing regions throughout the world. It is our hope that the analysis in this book will serve as a valuable exemplar for analysts and policy-makers studying the petroleum industry in other parts of the world.

Part One provides an overview, in four parts. Chapter One deals with oil and natural gas as physical products: what they are, what the petroleum industry does to/with them, and what these physical realities imply for an economic depiction of the industry. Chapter Two provides an initial perspective on the petroleum industry in Alberta, contrasting the operations of the industry in the late 1940s with the year 2010 and briefly reviewing some critical policy issues that arose over this period. Chapter Three sets the Alberta petroleum industry in a global context. Finally, Chapter Four reviews the formal concepts and constructs that economists utilize to help understand how economies and markets function.

Part Two looks at the Alberta crude oil industry from what we call a 'private' perspective: it is largely concerned with the evolution of the industry from the viewpoint of oil producers and consumers. In this part we look at the crude oil resource base, the evolution of crude oil markets (prices and production), the development of Alberta's non-conventional oil sands resources, and various 'models' that economists have built to help us understand this complicated industry.

Part Three examines the Alberta crude oil industry from a 'social' perspective: it deals with the government regulatory environment. Three important policy areas are covered: pricing and trade regulations;

production conservation regulations; and tax and royalty regulations.

Part Four includes three sections. First, it covers the history of Alberta natural gas, focusing on aspects that differ from crude oil. We discuss both natural gas markets and government regulations, with a particular emphasis on the restriction of gas exports to sales in excess of 'domestic requirements.' Next, the perspective is broadened from an emphasis on crude oil and natural gas markets to the role of the petroleum industry in the Alberta provincial economy. Finally, we conclude with lessons from the Alberta experience that may be of value to decision-makers elsewhere in the world.

While we have incorporated most of the economic issues of significance for the Alberta crude petroleum industry, we should alert readers to several exceptions. Our primary interest is with Alberta's abundant natural petroleum wealth. Hence we focus on the production and marketing of crude oil and natural gas. However, we do not examine in any detail natural gas liquids such as ethane, butane, and propane, or the sulphur often produced in conjunction with natural gas; nor do we delve deeply into the many issues associated with the subsequent shipment and processing of petroleum such as pipeline operation, oil refining, natural gas processing, or petrochemicals.

Finally, we do not engage in any detailed analysis of the environmental impacts of the industry. This is not because we think they are unimportant. However, this book is already very long, and the environmental questions involve scientific issues with which we have no expertise.

CHAPTER ONE

Petroleum and the Petroleum Industry: What Are They?

Readers' Guide: Chapter One is aimed at readers who have little familiarity with the petroleum industry. It describes the activities of the industry in terms of a number of different stages required to transform petroleum from a resource in nature to a product that consumers willingly purchase. Readers familiar with the industry may wish to move on to Section 3 of this chapter.

1. What Is Petroleum?

A dictionary will note that the word 'petroleum' is derived from Latin, meaning 'rock oil,' and is almost always used to refer to those mineral oils provided from below the earth's surface that consist mainly of mixtures of hydrogen and carbon molecules (i.e., hydrocarbons). Petroleum is, therefore, a natural resource. Sometimes the term has been broadened to include 'manufactured' hydrocarbons that are identical to the natural resource; this would include, for instance, liquid oil or natural gas derived from coal or biomass. However, such 'synthetic' products have not as yet been produced in large volumes. The term 'petroleum' is also applied to refined petroleum products like motor gasoline and fuel oil, which are derived from processing the natural resource.

Naturally occurring hydrocarbon deposits vary greatly in physical composition but are generally grouped into two broad classes, depending upon whether the main output is liquid (crude oil) or gaseous (natural gas). The greater is the proportion of

carbon to hydrogen in the deposit, the heavier and more viscous the petroleum. In extreme cases, such as the bitumen in oil sands deposits around Fort McMurray in Northern Alberta and kerogen in oil shale deposits in Colorado, the hydrocarbon is so viscous that it will not flow of its own accord beneath the surface. To date relatively little petroleum of this very heavy type – frequently labelled 'non-conventional oil' – has been produced, with production concentrated in Alberta and Venezuela. 'Conventional' crude oil refers to liquid hydrocarbons derived from natural underground deposits ('pools' or 'reservoirs') in which the liquid is fluid enough beneath the surface that some of it can be lifted readily through wells.

Conventional crude oil is a liquid mixture of paraffinic and other hydrocarbons spanning a wide range of molecular weights and containing varying amounts of sulphur, nitrogen, and other elements. It varies in specific gravity (relative to water) from about 0.8 to 1 (API gravity from 50° to nearly 10°). API stands for the American Petroleum Institute, which instituted the API degree scale in the late 1800s. If (sg) is the specific gravity of the oil, the API degree is given by the following formula:

$$\text{API} = (141.5/\text{sg}) - 131.5.$$

The lower the specific gravity (the lighter the oil), the higher the API degree number. Since water has a specific gravity of 1, oil as heavy as water would have an API degree number of 10. The bitumen found in the Alberta oil sands is heavier than water, with API values around 5. Natural gas is a gaseous mixture of normal paraffinic hydrocarbons, mainly methane

(CH₄), which is often contaminated with water vapour, nitrogen, carbon dioxide, and hydrogen sulphide.

The general belief is that crude oil and natural gas were formed millions of years ago from the remains of aquatic plant and animal life. For this reason oil and gas (as well as coal) are called fossil fuels. In the prevailing view, petroleum originated in sedimentary basins – areas where thick layers of sediment were deposited at the bottoms of shallow seas. Over time dead plant and animal matter settled with the sediment; eventually these overlying layers of mud and silt created great pressure and high temperatures. Finally, when these beds had sunk thousands of metres deep, the plant and animal matter became chemically converted to oil and natural gas.

As pressures on the original sedimentary rock intensified, and as the earth's crust shifted over time, the oil and gas 'migrated' through pores, cracks, and fissures where it became trapped in porous rock in underground structures. These petroleum yielding structures are known as reservoirs and consist of several types of 'traps' – the most typical being structural (or fault) traps, stratigraphic traps, and a combination of both types.

Structural traps are caused by local deformations that 'fold' or 'fault' the reservoir rock. Anticlines, resembling elongated arches, and domes, resembling inverted bowls, are the main types of folds that serve as traps for oil and gas. A fault is a fracture in the earth's crust along which movement has taken place; these shifts can bring non-porous rocks in contact with porous ones, thus forming a trap.

A stratigraphic trap is one in which the chief trap-forming element is some variation in the nature of the reservoir rock. These traps represent the most difficult oil and gas accumulations to find since there are no structural features associated with them. A common stratigraphic trap consists of a wedge-shaped sandstone formation squeezed between impervious rocks and lying at an inclined angle. Oil or gas becomes trapped where the sandstone 'pinches out' against the impervious rock.

The trap holds the oil and gas in place so that they cannot escape until released by drilling a well. In an oil pool, the three elements that are usually present – water, oil, and gas – occur largely in layers. Water is at the base and gas, when present, tends to the top. Oil lies between since it is of intermediate density. In most cases oil deposits contain some natural gas in solution, mixed with the oil and held there by the high pressure in the reservoir; natural gas in gaseous form is also found as a gas cap above an oil trap. Such gas

is called 'associated' since it is found in association with crude oil in the reservoir. Sometimes natural gas is discovered in a free state in a reservoir not in association with crude oil; this is called 'non-associated' gas. Frequently non-associated natural gas is relatively 'wet,' including hydrocarbons heavier than methane; that is, the molecules have more than a single carbon atom. These may be removed as natural gas liquids (NGLs), such as ethane (C₂), propane (C₃), butane (C₄), and pentanes plus (C₅₊). While water tends to lie beneath the oil in a reservoir, it is also common to have some water molecules adhering to the rock pore spaces in the portion of the reservoir holding oil.

Petroleum is of interest primarily for its energy content: the electromagnetic (chemical) bonds holding together the various atoms in the hydrocarbon compounds can be released quite easily (e.g., by application of heat) with an attendant release of energy (again, in the form of heat), which can be harnessed to do work. More than 90 per cent of the world's use of hydrocarbons is for their energy content. In the remaining instances petroleum is used for its matter; that is, the particular hydrocarbon compounds are desired, by petrochemical and plastics companies, fertilizer manufacturers, road pavers or others, for their structural or other physical features.

Scientists note that petroleum, as a physical product, is subject to various laws of nature including the first two laws of thermodynamics (Foley, 1976, chap. 4). In simplistic terms, the first law of thermodynamics is a conservation law that states that the energy content of petroleum can be neither created nor destroyed; instead it changes form on use. Expressed in quite different terms, the utilization of petroleum *necessarily* creates waste energy and matter. The second law of thermodynamics is the famous Entropy Law. It states, in essence, that the utilization of energy necessarily reduces it to a less usable or available form (i.e., increases entropy) so that, while it is possible to use energy more or less efficiently, it is not possible to recycle it. The entropy law, combined with the tremendously long time span involved in the generation of petroleum deposits, make petroleum in nature a non-renewable or exhaustible natural resource. How efficiently the economic system recognizes this non-renewability is a matter of widespread debate. For example, Georgescu-Roegan (1973) and Daly (1973) emphasize the critical importance of entropy; on the other hand, Adelman (1990) and Watkins (1992) question whether the concept of finite physical resource limitations is meaningful to economic analysis of the petroleum industry.

2. What Is the Petroleum Industry?

The petroleum industry consists of six main sectors: **exploration** for reservoirs of crude oil and natural gas; reservoir **development**; production or **lifting** of oil and gas; **transportation** or transmission; **refining** of crude oil into refined petroleum products; and the **marketing** (distribution) of these refined products and of natural gas. Exploration, development, and lifting (or extraction) are generally referred to as the 'upstream' activities of the petroleum industry (or the 'crude petroleum industry') while the refining and marketing of petroleum constitute 'downstream' operations. Transportation provides the link between the 'upstream' and 'downstream' segments; this book treats it as part of the industry's downstream activities.

In the material that follows, we shall refer to the production of oil; unless otherwise specified, similar factors hold for natural gas.

A. What Constitutes 'Upstream' Activity?

A formal definition of the 'upstream' segment of the petroleum industry is (Canada Petroleum Monitoring Agency, 1986): "activities and operations related to the search for, and development, production, extraction and recovery of crude oil, natural gas, natural gas liquids and sulphur, as well as the production of synthetic oil."

1. Exploration and Development

a. Geological and Geophysical Work and Land Acquisition

The search for underground accumulations of oil and natural gas begins with looking for the type of rock formations in which petroleum deposits are likely to be found. (Gow, 2005, provides a useful overview of the geological and technical dimensions of petroleum industry activity, with specific reference to Alberta.) This typically restricts the search to regions with deep overlays of sedimentary rock (i.e., a sedimentary basin), in which it is believed that adequate source and reservoir rock (geological formations) were laid down in the distant past. The first stage in the exploration effort is to select the regions in which effort will be expended. This depends on a mix of factors including the physical prospects for finding petroleum, accessibility, the economic and political climate of the region, and proximity to markets. Once a region is selected, a preliminary geological survey is undertaken. Visible rocks are examined for any clues

they may provide as to what type of formations lie beneath the area. Rock samples are taken to compare with samples from previously discovered hydrocarbon deposits. A detailed geological map is prepared, which provides information on the prospects for finding oil or gas in the area.

At this time the company will begin the process of acquiring 'land' in the region; more specifically, it must acquire 'mineral rights,' i.e., the property right that conveys the legal right to explore for and recover petroleum, if found, at particular locations. In Canada the majority of mineral rights are 'Crown'; that is owned by governments, mainly provincial governments. Petroleum exploration rights have been issued primarily through competitive bidding sales. Some mineral rights are 'freehold,' that is owned by private parties with whom the oil companies must negotiate. In addition to obtaining mineral rights for the subsurface petroleum resources, oil companies must negotiate with surface rights owners (e.g., farmers and ranchers) to obtain rights of use for the land needed for roads, drilling sites, etc. Before any oil can be produced, it is necessary to acquire production rights as well as exploration rights. Typically areas covered by exploration licences may be converted in whole or part into leases that allow petroleum extraction. In addition, primary landowners, like provincial governments on Crown land, often directly issue leases that permit exploration and production.

The next step is to investigate the underground rock structures. Geophysical surveying is the application of the principles of physics to the study of subsurface geology. Geophysical surveys measure the thickness of sediments and map the shape of structures within the sediments. The most common type of geophysical study is seismic, in which explosive charges are detonated at or near the ground's surface. The ensuing shock waves are recorded by geophones after they strike and rebound off underlying layers of rock. With this information geophysicists are able to locate structures that might contain oil or gas. Gravimetric and magnetic surveys are other methods employed by geophysicists to obtain subsurface data. Recent technological developments, like 3-D seismic mapping, and now 4-D seismic (with time as the fourth dimension) have expanded the role of seismic activities and have led to much re-evaluation of previously studied geological strata.

b. Exploratory Drilling

Geological and geophysical surveys undoubtedly improve the chances of finding oil or gas, but they

can at best map the underlying geological structures, not pinpoint the presence of petroleum. Since many potential petroleum-holding traps are dry, the only way to prove the existence of an underground reservoir where large accumulations of oil or gas occur is to drill a hole. Thus the next stage in the search for petroleum is exploratory 'wildcat' drilling. This is done on a site recommended by the geologist or geophysicist, predicated on the survey work done earlier.

On occasion the first hole that is drilled in a new territory will 'prove' oil or gas in quantities large enough to be exploited commercially. The normal occurrence, though, is the drilling of a number of dry holes, or holes suggesting only small (non-commercial) amounts of petroleum. The additional information obtained from these holes will lead to a final decision on whether to proceed with more exploration of the area.

When a successful exploratory well occurs, a series of appraisal ('stepout' or 'extension' or 'outpost') wells are typically drilled to determine the extent of the reservoir. Cylindrical samples of the formations penetrated (known as 'cores') are analyzed over the oil-bearing section of the rock so that its permeability, porosity, and oil content can be determined. In addition, samples of the oil are taken from the bottom of the well at full reservoir pressure so that the properties of the oil, as it exists in the reservoir, can be measured, including the unrestrained flow rate. Oil pools are heterogeneous: they vary tremendously in areal extent, depth, rock porosity, permeability, fluid content (oil, gas and water), quality of the hydrocarbons (light or heavy, etc.), and other salient characteristics.

c. Development Drilling

The drilling of development wells begins as soon as the information derived from appraisal drilling is sufficient to suggest that the oil or gas discovery is commercial and what would be the most suitable way to develop and produce the reservoir. This stage is often reached before the limits of the field have been fully delineated, and it is therefore not unusual for more stepout or outpost wells to be drilled at the same time as development wells are being sunk. (While stepout wells are commonly classified as part of the exploration process, they could just as well be considered development, since they occur after a reservoir has been found.)

The number of development wells, their spacing, and their depth will depend on the size and character of the field, as well as the land-tenure system under which the government establishes conditions about

mineral rights. For example, development wells, like apple trees in an orchard, may be spaced in a regular pattern or grid system. This type of spacing pattern may ensure that the oil off-take is evenly distributed over the whole reservoir. However, such patterns are only appropriate in the development of flattish structures with relatively homogeneous subsurface rock and reservoir conditions. On steeply dipping structures, a single line or ring of wells is more likely to be drilled. And the distance between the wells depends on the size of the area that can be effectively drained by each one. In addition, governments typically set regulations about the allowable development patterns, often in the form of a minimum required spacing for wells. Such regulations often reflect a concern by the government to protect the (subsurface) property rights of adjacent land owners. (Since oil and gas are fugacious, i.e., fluid, it is possible for a producer to capture petroleum from beneath a neighbouring property.)

Until recently, development wells were almost always entirely vertical, or, in exceptional circumstances, slanted at a constant angle for the entire well depth. A slant well would be appropriate, for example, if the land is particularly sensitive for environmental reasons directly above the part of the reservoir being drained, or if a large area of the pool is to be drained from wells that start from the same location, as an offshore production platform. Technological advances in recent years have encouraged the drilling of 'horizontal wells' in which the well bore turns markedly away from the vertical to the horizontal as the well enters the producing formation. A single horizontal well is in contact with a larger volume of reservoir rock than a single vertical well. In a reservoir that has relatively high permeability and is relatively homogeneous in character, horizontal wells allow faster recovery of oil. In a reservoir that has relatively poor permeability and/or is very heterogeneous in nature (with 'pockets' of better and worse producibility) horizontal wells may increase the 'sweep' area and allow greater total recovery of oil than would be possible with vertical wells only.

Development activities are multifaceted and highly specific to the particular characteristics of the pool to be drained. Wells may be all vertical or vertical and horizontal. Development wells may include some or all of the following: appraisal (outpost) wells that prove up new volumes of recoverable oil (new 'reserves'); infill wells, spaced among previously drilled ones, that allow faster recovery of the oil; water disposal wells, to pump connate water back

into underground formations; water or gas or other injection wells and associated oil-lifting wells, as part of an enhanced oil recovery (EOR) project to augment the natural productivity of the pool. The variety of physical production procedures combined with the heterogeneity of oil pools translates into an array of economic costs of producing petroleum.

2. Production (Lifting or Operation)

The rate at which oil can be extracted once wells are drilled depends largely on the permeability of the rock – the degree to which a rock will allow oil and gas to pass through it. If this is too low, the production obtained from an individual well might be insufficient to offset its cost so that the development of the reservoir would be ruled out on economic grounds. Generally the porosity – the number of spaces and openings that separate the individual rock grains – and permeability vary from place to place within the same reservoir rock. Sometimes these variations are so diverse that wells located in different parts of the reservoir may have markedly different production rates.

The reservoir crude can range from very heavy viscous (thick) oil under very low pressure containing little or no dissolved gas to extremely light straw-coloured crude under considerable pressure containing a large amount of dissolved gas. The viscosity of the oil depends largely on its specific gravity as well as on the quantity of gas that it holds in solution. The less viscous an oil, and the more gas it contains, the more readily it will flow through the crevices of the rock to gain entry to the well.

An oil or gas reservoir also typically contains some water in its pore spaces. This ‘connate’ or ‘interstitial’ water is believed to be water that was not displaced by the petroleum at the time of its accumulation and entrapment in the originally water-saturated reservoir. The connate water content may range from 5 to 40 per cent or more of the reservoir void space and plays an important role during the productive life of the reservoir.

a. Primary Production Methods

For oil to move through the pores of the reservoir rock and out into the bottom of a well, the pressure under which the oil exists in the reservoir must be greater than the pressure at the bottom of the well. As oil is removed from the rock, the pressure of the reservoir will decrease and the rate of production will decline. The rate at which the pressure decreases will affect the total amount of oil that can be removed from the

reservoir over a given period of time, if only because declining production brings the well closer to being uneconomic to operate.

The connate water found in the reservoir, associated gas, and the free gas in the gas cap are the main sources of energy that drive the crude oil to the bottom of the producing wells and thence up the pipe tubing to the surface or wellhead. The production mechanisms associated with these sources of energy are referred to as ‘water drive,’ ‘solution gas drive’ (or ‘depletion drive’), and ‘gas cap drive,’ respectively. ‘Water drive’ is normally the most efficient of the three displacement processes; ‘solution gas drive’ is the least efficient. Both gas cap and water drive reservoirs are often subject to more than one mechanism. Consequently, the terms ‘partial gas cap drive’ and ‘partial water drive’ may apply. Also a reservoir’s predominant drive mechanism may change over time, as for instance when gas from solution collects by gravity segregation to form a gas cap as reservoir pressure declines.

The oil obtained as a result of these natural production mechanisms, supplemented only by pumping and simple fracturing of reservoir rock, is referred to as ‘primary recovery.’ As will be discussed below, ‘enhanced oil recovery’ (EOR) techniques may allow recovery of even greater volumes of oil.

b. Recovery Factor

As the preceding discussion suggests, there is no known economic process by which all of the oil in porous rock may be recovered. There are six groups of factors that jointly determine the ‘recovery factor’; that is the fraction of the oil-in-place within a reservoir that can be brought to the surface. These are:

- reservoir rock properties, e.g., porosity, permeability, structural position, and thickness;
- reservoir fluid properties, e.g., viscosity, pressure, gas saturation;
- drive mechanism, e.g., solution, gravity drainage, water drive;
- method of production, e.g., well completion techniques (including EOR), spacing of wells, rate of withdrawal, utilization of EOR;
- economics, e.g., drilling and completion costs, production costs, prices of oil, gas, and by-products;
- government regulations including those relating to well-spacing and assorted ‘conservation’ practices, royalties, taxes.

In combination these factors determine the amount of oil or natural gas that can be recovered economically, or the 'reserves' in the pool. Applying the recovery factor to the quantity of oil in place generates an estimate of 'initial recoverable reserves' that is typically considerably less than the volume of petroleum in place. ('Remaining recoverable reserves' is an estimate of the amount of petroleum still waiting to be produced, so equals initial recoverable reserves minus cumulative production to date.)

Recovery factors vary markedly among reservoirs, but on average about 25 to 35 per cent of the oil initially in place in a conventional oil reservoir is recoverable, as is about 80 per cent of the gas in place in a non-associated natural gas reservoir. The recovery factor for oil is often improved by the introduction of enhanced recovery techniques in the extraction process. In Alberta, for instance, on average about 17 per cent of the oil in place is recovered by primary means and another 7 per cent by EOR (Alberta Energy Resources Conservation Board, 2013, *Reserves Report*, ST-98, p. 4-6). However, the recovery factor cannot be estimated reliably until the behaviour of the reservoir has been observed under actual producing conditions at commercial rates of off-take. Fields are generally put on production before delineation and development drilling has been completed. As a result, data on recoverable reserves are continually being revised as additional productive areas are drilled up. Typically more reserves additions are credited to 'extensions and revisions' in discovered pools than to 'new discoveries.' Expressed in other terms, the reserves in a petroleum pool typically 'appreciate' over time as development proceeds. An analysis by the Alberta Energy Resources Conservation Board in its 1969 *Reserves Report* of all except the smallest pools found an average appreciation factor of about nine times for oil pools and four times for non-associated gas pools. That is, the average pool in the province will ultimately yield nine times the amount of oil that was credited to the pool as reserves in its year of discovery. This average appreciation factor of nine for the Province masks a wide range of differences for individual oil pools.

c. Enhanced Oil Recovery (EOR) Processes

Some EOR methods, like primary recovery, rely on direct displacement with another fluid to force the oil out of the reservoir rock and are often called 'secondary' recovery techniques. Water flooding is one of the most successful and extensively used secondary recovery methods. Water is injected under pressure into the reservoir rock via injection wells and drives

the oil through the rock into adjacent producing wells. Where there is considerable variation in the permeability of the rock, the rate of injection must be carefully controlled to avoid trapping and leaving behind large quantities of oil. In the gas drive process, gas is injected into the reservoir via injection wells, which are usually located on or near the crest of the structure. The injected gas is driven downwards and sideways through the reservoir and displaces the oil into producing wells; over time the ratio of oil to gas recovered falls.

These techniques were originally developed to extract more oil out of reservoirs from which no more oil could be recovered by primary production. However, the current practice is to apply these processes much earlier in the producing life of the reservoir to forestall the decline in reservoir pressure. The application of secondary recovery techniques during the early stages of the primary production phase is referred to as 'pressure maintenance.'

In recent years, EOR processes have become more effective by the adoption of methods that improve the performance of the displacing fluids. These enhanced oil recovery methods can be broadly divided into solvent techniques and thermal techniques and are often called 'tertiary recovery techniques.'

In solvent techniques, the displacing fluid is treated with an additive to make it miscible with the reservoir oil and thus improve the efficiency with which it sweeps the oil out of the pores of the rock. For example, a 'miscible gas drive' is a process where the natural gas in a gas drive is rendered miscible with oil by the addition of a sufficient amount of liquefied petroleum gas (LPG). This process is most effective in light oil reservoirs; however, large amounts of LPG are required, which makes the process relatively expensive. Carbon dioxide is another injection fuel, the popularity of which may increase as concerns over global warming lead to policies that reward the capture and storage of CO₂.

The difficulty of recovering oil from reservoirs containing heavy viscous crude has led to the development of thermal techniques that increase the flow rate of the oil primarily by the addition of heat, as in steam injection.

Since natural gas moves so readily through pore spaces in the reservoir, EOR techniques have not been common in non-associated gas pools.

d. 'In Situ' Bitumen Recovery

Some oil deposits contain crude that is so viscous that primary production is not generally feasible. The crude in these reservoirs is generally called 'bitumen.'

In some cases it can be produced through wells, some amounts by primary pressure or water and solvent injection, but most by thermal processes, in which heat is applied to the reservoir to reduce the viscosity of the oil and make it easier to displace. The heating effect might be achieved by injecting steam or hot water or by burning, underground, some of the oil in the reservoir. In this latter process, which is referred to as ‘in situ combustion,’ air is injected to support combustion and to act as the displacing agent. Such processes are used to recover the crude bitumen at various sites in east-central Alberta, including Cold Lake where steam is injected into the reservoir in cycles of injection and production. More recent projects have usually used steam-assisted gravity drainage (SAGD), a technique developed with the encouragement of the Alberta Oil Sands Technology Research Authority (AOSTRA), a research facility created in 1974 by the Alberta government. (In 1994 AOSTRA was melded into the Ministry and Energy. Then, in 2000, it was terminated, with its projects transferred to the Alberta Energy Research Agency. At the start of 2010, a new Agency, Alberta Innovates, took over.) With SAGD, steam (most often created by burning natural gas) is injected through horizontal wells above the bitumen-bearing rock; bitumen is then gathered by horizontal wells within the oil-bearing rock (Deusch and McLennan, 2005; Engelhardt and Todirescu, 2005). Such output is called ‘in situ’ bitumen production, since the oil is treated in the reservoir to allow production.

e. Surface Mining of Oil Sands

The petroleum found in the oil sands in the vicinity of Fort McMurray, Alberta, is thick bitumen that is mixed with sand, clay, and water. Much of the bitumen-laden sands are sufficiently shallow that the sands can be strip-mined. Huge bucket-wheel excavators and dragline shovels are used to remove the overburden and mine the exposed sands. However, this method can only be used to a depth of about fifty metres. Centrifugal water flotation techniques are used to separate the sand and the bitumen, and the bitumen is then upgraded to light crude, often called ‘syncrude.’ As of 2012, there were only four commercial mining operations. The Suncor and Syncrude plants had been in operation for decades. The Albian sands project co-ordinated by Shell began operation in 2005, and Consolidated Natural Resources Limited (CNRL) commenced the Horizon project in 2008. At the end of 2012, the ERCB reported two new projects under construction, twelve others that had been approved and seven that had made application;

these numbers include expansions by the four current producers (ERCB, *Reserves Report*, ST-98, 2013, Table S3.2). The Imperial Oil and Exxon Mobil Kearn mining project began production in the spring of 2013, and is the first mining project to produce bitumen without upgrading it to synthetic crude oil.

Needless to say, these bitumen recovery methods are expensive and require prospective oil prices robust enough to warrant the high investment. Recent technological improvements have markedly reduced operating costs.

f. Lifting of Crude Oil

After wells have been completed, conventional oil has to be brought up from the bottom of the holes to the surface. This can be accomplished in several ways, depending on the nature of the oil, the potential energy available in the reservoir, and the specific form that prior development has taken. The reservoir may have sufficient energy to cause the well to flow naturally for many years – as is the case in almost all Middle East fields – or it may continue for only a short period of time without further investment such as ‘gas lift’ or pumping. And, of course, these methods are also applied to wells that have never had sufficient energy to push oil to the surface.

g. Surface Treatment of Crude Oil and Gathering

When the crude has been brought to surface, the next step is to reduce it to the form in which it will be delivered to the refinery for processing. Oil as produced at the wellhead varies considerably from field to field not only because of its physical characteristics but also as to the amount of gas and water that it contains. These have to be separated from the oil.

The oil from each producing well is conveyed from the wellhead to a gathering plant, occasionally by truck but usually through a flow line. The gathering plant, which is located at some central point to handle the production from several wells, is equipped to separate any gas and water from the oil. The size and nature of the plant required for the separation of the gas from the crude will depend on the volume of gas dissolved in the oil as it exists in the reservoir and on the pressure at which it issues at the wellhead. Crude with very little gas in it, and possessing little or no pressure when it comes out of the wellhead, can be separated from the gas in a one-stage operation. High pressure crude with considerable gas content is subject to a multistage separation process.

The crude oil is then typically gathered up in pipelines and moved from the field to meet with petroleum from other fields (generating a ‘blended’ crude)

and is transported by pipeline to a main shipment and storage point in the region (e.g., in Alberta, for crude oil, the Edmonton terminals of the Enbridge and the Kinder Morgan pipelines. Enbridge began as the Interprovincial pipeline, moving oil eastward from Alberta; Kinder Morgan began as Trans Mountain, subsequently Terasen, moving oil westward).

As mentioned above, bitumen mined from the oil sands is separated from the sand, clay, and water; up to now it has then been substantially upgraded in Alberta to yield a synthetic crude oil (SCO), as has a portion (7% in 2012, ERCB, *Reserves Report*, ST-98, 2013, p. 3–14) of the bitumen from in situ projects. Indeed the physical characteristics of the bitumen extracted from the tar sands have made further processing mandatory. As one of the executives involved in Canada's first oil sands project wrote (McClements, Jr., 1968):

Below 50 degrees Fahrenheit it [bitumen] is almost solid and at ambient temperatures above that it is a sticky asphaltic material. It cannot be burned in any but special equipment and it cannot be pumped through a pipeline, even during summer months. Additionally, the market for it is very limited. Consequently, it must be upgraded to pumpable, saleable material competitive with conventionally-produced crude oils.

Recently, a number of refineries capable of handling bitumen have become accessible to Alberta producers. Before shipment, the bitumen is diluted with light hydrocarbons so it will flow readily through the pipeline.

Natural gas with high hydrogen sulphide content is called 'sour' gas. When the hydrogen sulphide is removed from the gas, it is converted to elemental sulphur. Natural gas that is produced from a gas reservoir not associated with oil may require little treatment (other than sulphur removal) before it is delivered to market. However, some non-associated natural gas, and natural gas produced in association with oil, is generally 'wet' and thus is processed at plants near the field to extract useful by-products – propane, butane, and pentanes plus – and remove unwanted ingredients like hydrogen sulphide and carbon dioxide before it is shipped by pipeline to consumers. Typically, the natural gas is then combined with other natural gas from the region and shipped on a main large-diameter ('trunk') pipeline through a natural gas plant ('straddle

plant'), where the natural gas liquids are removed or gas that has already been processed is reprocessed. Some 'deep cut' gas processing facilities have been located near to the field to remove NGLs prior to treatment at a straddle plant. This has generated dispute between local deep cut and straddle plant operators about who has primary claim to the NGLs.

B. What Constitutes 'Downstream' Activity?

As mentioned earlier, the term 'downstream' is used to refer to movements of petroleum beyond the main shipment point in the producing region. It includes transportation, refinery, and marketing activities for liquid oil and transportation and distribution for natural gas.

1. Transportation

For at least the past half century within North America, it has generally been most economic to move petroleum from the producing region to the consuming region by large-diameter high pressure pipeline (Lawrey and Watkins, 1982). (Ocean-going tankers may be cheaper for crude oil on one or two specific routes, e.g., from Alaska to California or along the U.S. Gulf Coast.) These pipelines are subject to 'economies of scale,' meaning that the average cost (unit cost) of shipment is smaller the larger the volume moved. Essentially this is because the total volume that flows through the pipeline rises more than proportionately to the diameter of the pipe. It is cheaper to ship large volumes of crude long distances than it is to ship the refined petroleum products (RPPs) derived from the crude, since the RPPs must be kept separate from one another in the line. For this reason, and because they also exhibit economies of scale, the main refineries are large and usually located close to consuming centres. The crude oil moved is normally a mix of the variety of crudes produced within a region (e.g., a blend of Alberta light and medium crudes). Some specific crudes, or types of crudes such as very light or heavy crudes, may be 'batched' and moved separately, usually with a relatively non-permeable petroleum product separating this crude from the blends at either end. Such batching involves higher shipment costs. Heavier crudes and bitumen, such as those from the Cold Lake and Lloydminster areas, are typically blended with lighter hydrocarbons ('diluent,' condensate, or pentanes plus) to increase their fluidity.

For any given diameter pipeline, the flow rate can be changed by varying the number, location, and size of pumping stations that regulate the pressure in the line. In addition, parts of the pipeline may be 'looped' by adding new, parallel pipe. During operation, pipelines must move a continuous flow of petroleum and will exhibit declining unit costs up to the level of capacity for existing equipment. Selecting the optimal capital configuration (e.g., pipeline diameter and associated pumping stations) is a difficult task, particularly when the product being shipped is a depletable natural resource, whose total availability in nature is necessarily uncertain. A system that is too small would leave new discoveries with no immediate access to market, while one that is too large will involve higher than necessary unit transmission costs.

The existence of significant scale economies in pipeline transport implies that the petroleum transmission sector tends to 'natural monopoly' status, that is, a single pipeline (a monopoly) is the most efficient shipment means. However, a monopoly on shipment implies that the pipeline may be able to charge high monopoly prices to users, thereby generating higher profits for itself. There are a number of ways in which such exercise of monopoly power may be limited. First, shippers (crude oil producers and/or refiners) may build the pipelines themselves, thereby precluding the possibility of paying high prices to a third party. Second, pipelines have frequently been subject to legal restrictions giving common carrier and/or rate regulated status. Common carrier status means that all potential users have access to facilities, so that a group of oil companies who build a line cannot deny access to other users. If access to the pipeline is entirely open, markets may develop in which buyers who contract 'space' on the pipeline can trade their space allotments; such active trading can help to keep pipeline tariffs more competitive. Rate regulation has normally insisted that pipeline tariffs be based directly upon shipment costs, and be non-discriminatory (i.e., the same rate for the same service). There are many disagreements about exactly how this is best accomplished.

Both crude oil and natural gas produced in Alberta are shipped to markets outside the province by pipeline. The much lower density of natural gas, and an associated rapid fall in pressure as it moves through the line, mean that the cost of moving natural gas, per unit of energy content, is significantly higher than the cost of moving oil. Therefore, the transportation component of the delivered energy price becomes

relatively more important for natural gas relative to crude oil the further the market is from the producing region. Expressed in other terms, the competitive advantage shifts toward oil the further the market is from the petroleum-producing region.

2. Refining

Crude oil is rarely consumed by final users. Instead, the crude is processed by a refinery into a myriad of refined petroleum products (RPPs) to generate an array of hydrocarbon products that best meet the needs of users.

The basic refining process is distillation in which the application of heat to the crude oil vaporizes different hydrocarbon constituents at different temperatures, so they can be separated. Subsequently, the resulting condensed components, ranging from the very light (refinery gases) to the very heavy (asphalt), are subject to a variety of other chemical manufacturing processes to generate a wide slate of separate RPPs. Any given grade of crude oil (e.g., Alberta light and medium blend) will have a particular set of distillation factors, but there are so many further 'cracking,' 'reforming' and other processing techniques available that the final RPP mix from any specific grade of crude oil is potentially quite flexible. More processing, however, involves higher refinery costs. It is technologically possible to build a refinery that could utilize almost any particular grade of crude oil to produce almost any mix of final RPPs. However, once a refinery is built, without any further capital expenditures it can normally accept only a somewhat restricted set of grades of crude oil and produce a restricted set of RPPs. It will be clear that the refinery investment decision is a very complex one, including analysis of the availability and cost now and through the future of differing grades of crude oil as well as the anticipated current and future demands for a large number of RPPs.

It is also noteworthy that refineries are subject to economies of scale; that is the average cost of refining a cubic metre of crude oil declines the larger the refinery (up to a capacity of about 25,000 m³/d for a typical North American refinery with a relatively high yield of motor gasoline). Thus small regional markets may have few refineries, thereby possibly conveying some market power to the refineries in their sales of RPPs and their purchases of crude oil. The extent of such market power is limited by the possibility of new competitive refineries being built, and the possibility

of buyers importing RPPs from other regions (or suppliers of crude oil selling their crude to refineries in other regions).

Within North America, demand and prices (even before retail taxes) have been particularly high for relatively lighter RPPs like motor gasoline and aviation fuel. This reflects our affluence, large distances between urban centres in North America, and the absence of good substitutes for these products. On the other hand, heavy RPPs are commonly used for their heat content in simple combustion processes where natural gas, coal, and even wood will substitute very easily. Since the lighter crude gives refineries a higher yield of the more valuable RPPs, and/or saves the costs of extra equipment needed to obtain a high yield of these RPPs, higher API degree crude oils (lighter crudes) command a premium over heavier oils. A further implication is that the relative values of different grades of crude oil (crude oil price differentials) will change over time in response to changes in the relative supplies of different crude oil grades, changes in demand conditions for different RPPs, and changes in refining operations and technology.

The price for any RPP depends on the price of crude oil in the producing region and the costs of crude transportation and refining, as well as the many factors affecting demand for the specific RPP. Prices vary greatly across RPPs. For example, since crude oil can be burned, it is a good substitute for a product such as heavy fuel oil (HFO). Thus, to sell HFO its price must be lower than that of crude oil. If you wonder how HFO (which has a refining cost) can have a lower price than the unrefined crude oil from which it comes, remember that a refinery is a 'joint product process' that necessarily produces more than just HFO. By analogy, think of the relative values of an ore containing gold and of the separated rock and the gold dust (Adelman, 1972). The economic requirement is that the value of all the refined products together must cover the cost of the crude oil and refining, not that each RPP must have a price higher than that of crude oil.

3. Marketing (Distribution)

RPPs are conveyed to final users in any number of ways. Large users like major manufacturing plants may be connected to the refinery by pipeline. In other instances, the product may be delivered to the final user by railcar or truck (e.g., home heating fuel deliveries), while in still others the consumer may collect the product at a local distribution centre (e.g.,

a service station). Natural gas is inevitably delivered to users by pipeline. Usually a local utility company performs this service, selling the natural gas to its customers, but some large users may purchase their gas directly from the trunk pipeline or even the producer, bypassing the local utility or paying a transit fee to the utility.

It is the marketing segment that finally brings the supply side of the petroleum industry into contact with society's demand for petroleum products. Businesses and individuals demand services such as warmth or transport or process heat, which must be produced by the combination of energy, capital equipment, labour time, and other materials. From this perspective, the demand for crude oil (or natural gas) is a 'derived demand' that depends upon three major types of factors:

- (i) demand for the basic services that utilize energy;
- (ii) production technologies and input supplies that produce those services within firms, governments, households, and other enterprises; and
- (iii) supply conditions in the transportation, refining, and marketing sectors of the upstream part of the industry, which are necessary to make crude oil usable by businesses and households.

C. How Is the Industry Organized?

As just discussed, the petroleum industry involves six linked stages that effect the transfer of oil from naturally occurring deposits to final users: exploration, development, lifting or extraction, transportation, refining, and distribution or marketing. Petroleum can be sold at any point along the continuous flow, even within any one of the six stages. For example, when Petro-Canada purchased the downstream assets of BP in Canada, it bought some oil that was partway through the refining process. Most petroleum companies exhibit some degree of vertical integration, extending over more than one of the six stages. This is so customary over exploration, development, and production activities that such firms are normally labelled crude petroleum producers and are often called 'independents.' The term 'integrated' refers to companies that do more than one of crude petroleum production, transportation, refining, and marketing. Within the Alberta petroleum industry, large vertically

integrated companies have been active participants from the very beginning, but so have companies that have operated at only one level of industry activity.

There are, as a result, a number of different organizational structures used by petroleum firms. Most large integrated oil companies, for example, have a 'production' section or department whose responsibility it is to search for and establish a supply of crude petroleum that is sufficient for other aspects of the company's operations. There may even be exploration subsidiary companies. Whatever the organizational set-up, the purpose is to keep the company's reserve situation under constant review, actively bringing forward new projects to add to existing reserves, or replace depleted reserves, as well as to ensure that these reserves are scientifically and economically exploited. Which activities are delegated to the production arm of a company depends to a large extent on the individual circumstances under which a company operates. For example, the production department of a large integrated company, in addition to being responsible for the more obvious activities relating to exploration, development, and extraction, may also be in charge of processing the petroleum lifted from the wellhead to meet pipeline specifications and for arranging transportation of this crude to the company's refinery. A smaller independent production company may confine its operations to finding and bringing petroleum to the surface. And, since most of these smaller firms do not have processing facilities of their own, the petroleum is delivered to gathering systems (oil) and gas-processing plants for treatment. But these processing costs come out of the producer's pocket, and so, even though the company has no direct involvement with the processing of the petroleum, this activity can properly be included as part of the production process.

Government-owned oil companies, some vertically integrated, have been popular in many parts of the world. In the industrialized western world, these have generally operated in competition with privately owned companies but have been established for a variety of reasons. For example, for strategic reasons, the government of the UK, in 1913, provided financing and took over ownership control of the Anglo Persian Oil Company (the forefather of BP). Statoil in Norway was founded in 1972, and Petro-Canada in Canada in 1975, to increase domestic ownership in the petroleum industry and to provide a 'window' on industry activities. (Both BP and Petro-Canada have since been privatized.) Some developing nations, for example Brazil, have also established state-owned oil

companies to operate in competition with privately owned companies (often with special advantages). Many developing countries (for example, most OPEC members) have established a government oil company (or nationalized private companies) to leave a single state oil company in operation.

In conclusion, the consensus would be that all activities beginning with initial geological and geophysical studies to determine whether there is petroleum underneath the surface up to the stage where the oil and gas is to be stored or transported to refiners or market should be classified as 'crude petroleum production' activity. We use this term in the broadest sense of the word, for, as we have seen, a more narrow interpretation of 'production' (also referred to as 'extraction' or 'lifting' or 'operation') represents only the final stage of the crude oil or raw natural gas production process, being preceded by exploration and development.

It is the crude petroleum production industry, so defined, which has been of such significance in Alberta. We will not emphasize the specific organizational structures and decision-making methods that various producing companies have utilized. Rather, we shall be concerned with the aggregate activities of the industry with particular emphasis on the production of crude petroleum and the operation of crude oil markets. That is, our main interest is the upstream industry. However, we do not consider in any detail natural gas liquids, natural gas processing, or gathering pipelines.

3. What Are the Economic Aspects of the Petroleum Industry?

A. What Is the Economic View?

Obviously analysis of the petroleum industry must be based on the physical realities of petroleum production and use. However, purely physical factors are an insufficient basis for private or social decision-making. Deposits of crude oil and natural gas in Canada are a natural resource available for human use. Whether humankind is broadly defined ('all people of all generations'), or more narrowly ('today's Albertans'), or more narrowly still ('shareholders in oil companies'), the fact remains that the value of the resource is not inherent in its physical characteristics but must be mediated through people. Economic analysis stresses that the production of a resource such as petroleum

normally contributes both positive and negative effects to the parties concerned. There are costs involved in devoting effort to the production of oil and in depleting nature's stock, but the consumption of oil generates beneficial work or products. It is a presumption of most economic analysis that decision-makers are interested in deriving the maximum 'efficiency' from energy resources, where economic efficiency, in its broadest sense, means maximizing the excess of the benefits of resource use over the costs.

In this book we shall consider petroleum investment, production, and consumption from two points of view, the 'private' and the 'social.' The 'private' view is that of specific oil companies or consumers who make decisions about the utilization of Alberta's petroleum resources and whose activities are mediated through the operation of economic markets. The basic simplifying assumption is that these decision-makers evaluate benefits and costs from a 'private' perspective, seeking to gain the maximum net benefits for themselves. Companies producing crude petroleum, for instance, are generally understood to be trying to maximize the profits received from their activities. Economists would not claim this as an accurate description of the behaviour of every decision of every private decision-maker, but it is a useful working assumption that usually leads to relatively accurate depictions of individual transactions and aggregate behaviour in economic markets.

From a 'social' perspective, we will be largely concerned with assessing the desirability of certain public policies. We will assume that government decision-makers assess social efficiency with a view of benefits and costs that reflects the overall interests of the society they represent, not just private interests. Many differing definitions of social or economic efficiency are possible since different value systems or criteria exist and each would define social benefit and social cost within its own framework. Despite this, many economists have found one particular definition of social efficiency to be useful in policy analysis, in part because it leads to a concept of benefit and cost that is often readily measurable, but also because it derives from a particular value system that appears to enjoy wide acceptance. This view of efficiency assumes that social benefits and costs are equal to the net sum of the dollar values all individuals in society associate with the benefits (positive) and costs (negative) that they perceive. The approach is, therefore, individualistic rather than paternalistic; the measuring rod for the intensity of feeling of the individual is his or her 'willingness to pay' (that is, a particular dollar value). If, on

balance, an energy policy measure generates a positive aggregate dollar sum of social benefits less social costs, it is judged by the social efficiency criterion to be a desirable policy.

It is important to realize that benefits and cost in the efficiency criterion are measured by reference to all members of society, irrespective of whether they are directly involved in the production and consumption of the product. One implication is that the social costs of petroleum may exceed the private cost to the individual oil company, for example, if there are environmental costs associated with production. Similarly private benefits of oil use to consumers may understate social benefits, for example, if there are national security benefits. This view of economic efficiency is controversial, and those who advocate its usefulness are generally careful to assert that it is only one of the objectives that social decision-makers may view as relevant. Often, for instance, the distribution of benefits and costs, as well as their net sum, matters. Moreover, there are conceptual ambiguities in measuring benefits and costs (Blackorby and Donaldson, 1990) as well as major practical difficulties in measurement and implementing policies based on economic efficiency.

There are also purely physical (thermodynamic) definitions of the efficiency of energy use. In the eyes of the economist, such measures of efficiency are an insufficient basis for social decision-making since they abstract from the values that people place on energy and its production (Berndt, 1977), whereas the economic concept of efficiency relies directly on such human-generated values.

B. How Does the Economic View Reflect Physical Reality?

If we adopt the private firms' perspective for the moment, the largely physical definition of economic activity in the earlier part of this chapter can be translated into the necessity of undertaking dollar expenditures (costs) in order to receive dollar revenues (benefits). The various stages of industry activity, then, are perceived not so much in terms of the physical activities performed as by the expenditures (on capital, labour, energy, materials, land, and taxes) and the sales receipts that result. The critical role of economics to industry behaviour cannot be denied. A strong expectation that petroleum deposits exist in nature in a region will not generate exploratory activity unless companies anticipate a positive net

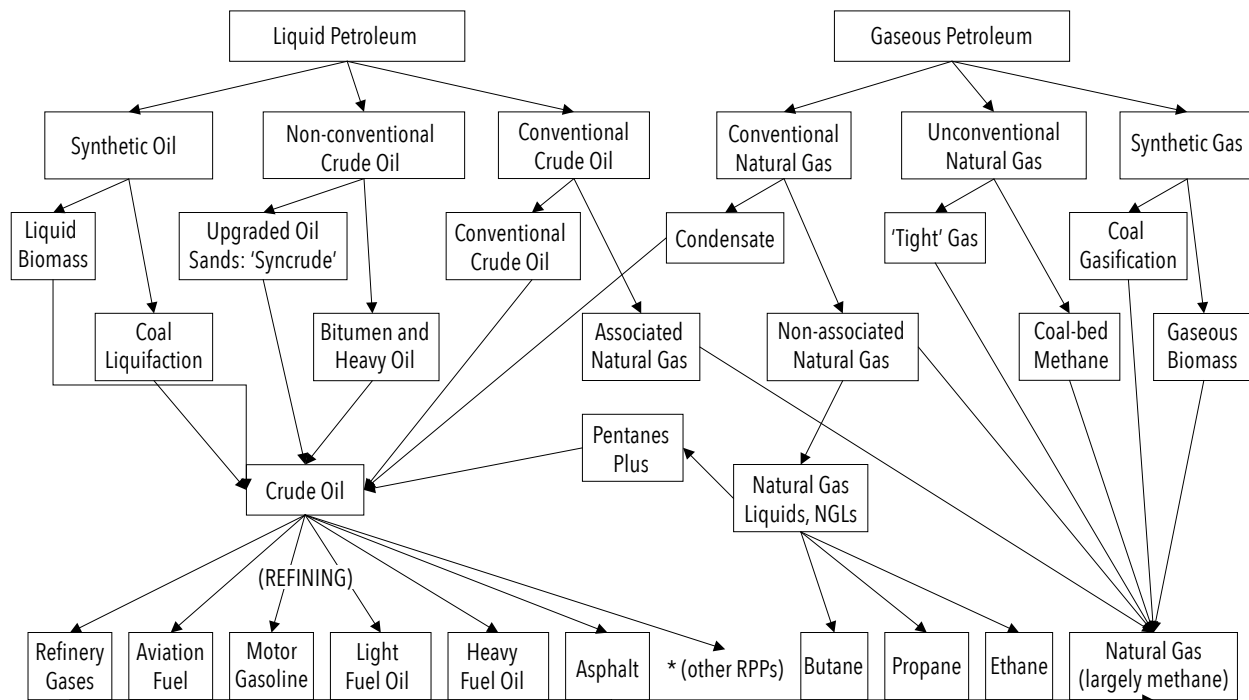


Figure 1.1 Types of Petroleum

return after tax from their actions. The clear presence of crude oil in an exploratory well core will not guarantee development unless anticipated revenues will exceed the expenses needed to develop and lift the oil. A positive petroleum flow rate from an established well will not normally be allowed by a company unless the revenues from the oil are high enough to cover the operating costs of the well (including royalties and taxes). In this manner, all the important physical attributes of the industry generate economic effects that decision-makers will consider.

While the physical realities of petroleum production will generate economic implications for those parties producing petroleum, it is difficult for the external economic analyst to examine the activity of individual decision-makers. In most cases, whether the purpose is descriptive or normative (i.e., policy generation), economic analysis provides a simplified view of petroleum industry activities, but one that captures the essence of what is occurring. Simplification is necessary in part because of data limitations, since accurate statistics on all specific transactions are not available. More fundamentally, however, there are so many complex individual actions that they could not possibly be considered in a single analysis. Instead, simplified 'models' of petroleum industry activity are necessary.

The joint product nature of the industry generates particular problems for the analyst. As mentioned above, a joint production process is one in which a particular activity necessarily generates more than a single output, so that the markets for the products are linked (at least on the supply side). For example, a petroleum refinery produces an entire slate of separate RPPs. An exploratory well generates some general geologic knowledge applicable to other drilling sites, specific knowledge about this site, some estimated petroleum reserves (if it is successful), and some equipment that is utilizable in lifting oil to the surface. The fluids lifted through a petroleum well include a mix of products (hydrocarbons such as crude oil and natural gas, and non-hydrocarbons such as sulphur).

Some analysts try to handle the joint product problem by combining the different outputs into a single product. For example, natural gas discoveries can be converted to 'volumes of oil equivalent' by assuming some equivalency factor. Relative energy content (about 6Mcf of gas per barrel of oil) or relative market values are often used, but there is no obviously correct conversion factor because oil and natural gas have separate and non-interchangeable markets, reflecting the fact that the two products are far from perfect substitutes in use. Another approach

Table 1.1: Petroleum Industry Activities: Physical and Economic Aspects

Stage	Physical Activities		Economic Activities (oil)	
	Description	Final Product	Costs (Inputs) ^(b)	Benefits (Output) ^(c)
1. Exploration ^(a)	Geological and Geophysical (G&G) surveys; Exploratory drilling	Knowledge of presence or absence of petroleum-bearing geologic formations	Costs of K, L, E, M; T	Price of Undeveloped reserves Price of G&G data
2. Development ^(a)	Installation of Production Facilities; Extension and Infill drilling; EOR; Pumps, Gathering lines and separation equipment; Gas plants	Established reserves; productive capacity	Linkage: undeveloped reserves Costs of K, L, E, M; T	Price of developed reserves
3. Production ^(a) (Extraction or Lifting or Operation)	Bringing petroleum to surface separation of products; gas plant processing; shipment to regional gathering location	Crude oil (and natural gas, NGLs, sulphur) at input terminal of main pipeline or transportation facility	Linkage: developed reserves Costs of K, L, E, M; T	Price of crude oil, f.o.b., in producing region
4. Transportation	Movement of petroleum from producing region to export point or city gate (gas) or refinery gate (oil)	Crude oil at border or at refinery gate; natural gas at border or delivered to distributor	Linkage: Crude oil, f.o.b. Costs of K, L, E, M; T	Price of crude oil, c.i.f., at refinery gate
5. Refining	Distillation, catalytic processing etc. of crude oil into refined petroleum products (RPPs)	RPPs (gasoline, kerosene, fuel oil, etc.) at refinery gate	Linkage: Crude oil at refinery gate Costs of K, L, E, M; T	Prices of RPPs at refinery gate
6. Marketing (Distribution)	Conveyance of RPPs and natural gas to final users	RPPs and natural gas at point of final sale	Linkage: RPPs at refinery gate Costs of K, L, E, M; T	Prices of delivered RPPs

Notes: (a) Exploration development and production together make up the crude petroleum industry, or petroleum upstream industry.
 (b) K, L, E, M, are the services of capital, labour, energy, and materials used in production processes. T represents royalties, taxes and land payments. f.o.b. means 'free on board', before shipment costs.
 (c) Unit benefits (prices) have been shown; total benefits or values are the price multiplied by the quantity of output; c.i.f. means 'cost, insurance, freight', that is, after shipment costs.

is to divide the exploratory effort between the different products; for example, the proportion of total discoveries that are oil, or the percentage of total successful well metres drilled that was in oil discoveries, might be used. The important point is that there is no correct way to combine outputs or separate inputs in a joint product process. Any attempt to do so leads to economic fictions. However, analysis is made immeasurably more complicated if one must build economic models that always include all inputs and all outputs of the joint product activity. As is invariably the case, the economist must balance the costs of a theoretically more complex but realistic model against the benefits of unrealistic simplification. Increasingly,

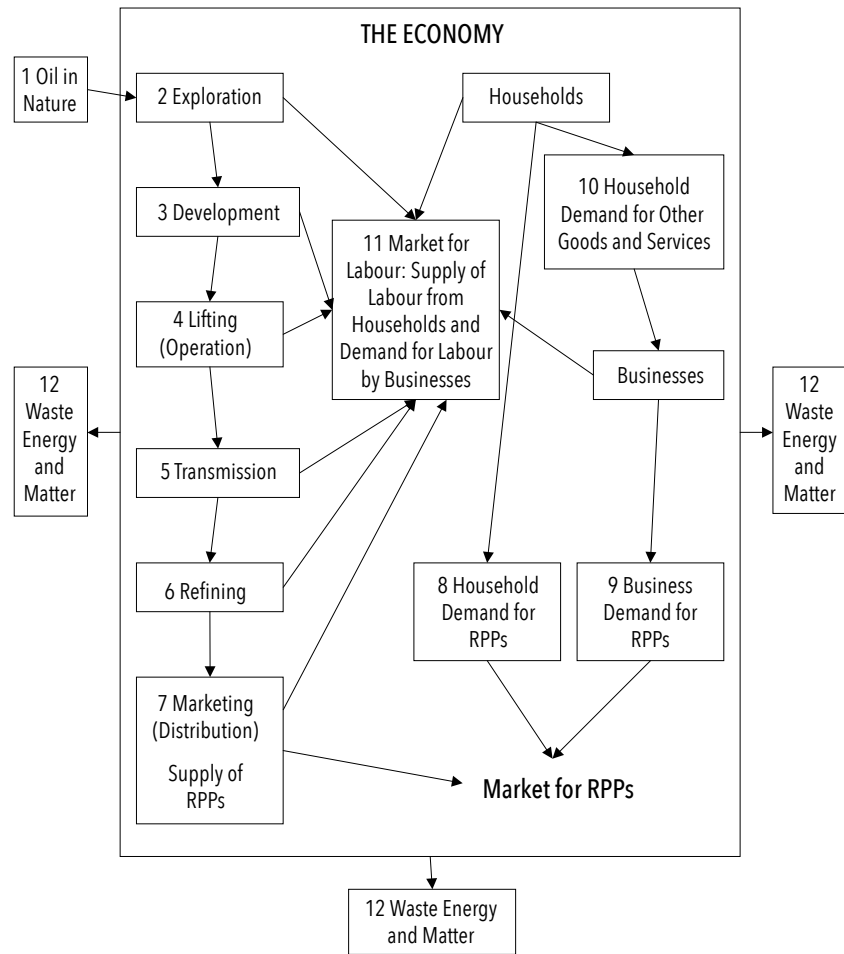
there is acceptance of the necessity of facing up to the joint product nature of petroleum industry activities and rejecting attempts to avoid it by combining two distinct products into one, or artificially separating a single activity into two.

4. Conclusion

Our introductory chapter concludes with three summary depictions of the petroleum industry.

Figure 1.1 sets out the main physical products the petroleum industry generates, divided into liquid and

Figure 1.2 Petroleum in the Economy



gaseous products including those drawn directly from nature and 'synthetic' petroleum and RPPs that are not immediate natural resources. Petroleum drawn directly from nature includes 'conventional' oil and natural gas, which are drawn from deposits where some of the petroleum flows to the surface through wells drilled into the deposit; this is the traditional ('conventional') way of producing petroleum. Non-conventional crude oil comes from oil sands and oil shale deposits holding such heavy, viscous oil that none will naturally flow to the surface through a well, so 'non-conventional' production techniques must be used. Synthetic oils are liquid hydrocarbons generated from some other natural resource such as coal or biomass. Historically, almost all of the world's petroleum has come from conventional crude oil, natural gas, and natural gas liquids. This book will focus on conventional crude and natural gas, which have been the mainstay of the Alberta petroleum industry. Alberta is one of the few areas in the world with significant

non-conventional oil production from its oil sands, so we also incorporate this resource.

Table 1.1 provides an overview of physical and economic views of the six stages of petroleum production, including physical descriptions of the activities and output of each stage and brief summaries of the economic costs and benefits to private decision-makers. Exactly how an oil company perceives the costs and benefits will differ depending on whether the company is vertically integrated or not. A vertically integrated company absorbs all the costs involved in the various physical stages of activity but generates benefits only at the downstream stage where sales occur. In the table, we have made some allowance for this by indicating at each stage a 'linkage cost' that ties this stage to the one just upstream. For a vertically integrated firm, the linkage cost is the *costs* of the previous upstream activities, while for a non-vertically integrated firm it is the *sales price* of the output of the adjacent upstream activity. Of course, vertically

integrated firms are never perfectly 'in balance' throughout all stages of petroleum industry activity; they will buy or sell some oil at most stages of activity.

Figure 1.2 is a flowchart that sets the activities of the petroleum industry within the larger economic system. The entire economic system is indicated by the large rectangular box, with the (unknown) natural endowment of petroleum deposits situated outside (1). The six stages of petroleum industry activity are shown (2 to 7), as is refined petroleum product (RPPs) demand by households (8) or business and other enterprises including government (9). The business demand for petroleum products derives from the production of goods and services, which is in turn derived from the household demand for goods and services other than petroleum products (10). Some indication of aggregate economic effects of the petroleum industry (the "macroeconomic" effects) can be seen in the box showing the labour market (11).

The six stages of petroleum production serve, along with other businesses, as a source of demand for the labour services of households. Similarly, although it is not shown in Figure 1.2, the petroleum industry demands the goods and services (capital, material, and other energy products) produced by businesses. The more active is the petroleum industry, the higher these demands. Finally, all those activities from exploration through to final consumption involve the ejection of waste heat and matter (12) back into the environment.

Chapter Two provides an overview of the Alberta petroleum industry, illustrating how the stages of industry activity developed there from 1950 to 2010, and introducing our theme of 'petropolitics' in the form of questions about the role of government in regulating the industry.

CHAPTER TWO

An Overview of the Alberta Petroleum Industry

Readers' Guide: Chapter Two provides a bridge from the discussion in Chapter One of what the petroleum industry does to the substantive description of the crude petroleum industry in Alberta, which occupies the remainder of this book. In this chapter we illustrate industry activity in Alberta for select years from 1950 through 2010. We also introduce the concept of 'petropolitics,' as we set out possible reasons for, and forms of, government regulation. Finally, we touch on some aspects of Alberta industry activities downstream from the crude petroleum phase, which will not be dealt with in this volume.

1. Introduction

Contrasts are often suggested between the neighbouring prairie provinces of Alberta and Saskatchewan; the Albertan may regard Saskatchewan with a certain old-fashioned nostalgia, and the Saskatchewan resident may be drawn to Alberta's dynamic multifaceted society. These images probably speak more of stereotypical simplification than reality, but they do draw attention to differences in the economic history of the two provinces.

In 1946 Alberta's population was 800,000, Saskatchewan's 830,000. By 2013 Saskatchewan's population had grown to just over 1,000,000, while Alberta's was approaching 3,900,000. Before 1946,

both provinces had been molded primarily by the wheat boom early in the century and their agricultural resources. Both economies have diversified since the end of World War II, but it is hard to avoid the conclusion that development of Alberta's oil and gas industry lies at the foundation of a coherent explanation of the very different provincial growth paths. Alberta's petroleum resources, especially crude oil, provided the base for a classic natural resource boom: strong export markets for oil and, later on, natural gas attracted new capital investment to the industry, and drew immigrants. The influx of people, plus backward and forward linkages from the crude petroleum industry into input supply and transmission and processing industries, generated further investment spending, especially in construction. The financial and service sectors expanded and government coffers swelled.

This chapter follows up on Chapter One's general review of the petroleum industry by providing a broad overview of the activities of the industry in Alberta. We illustrate how the industry's activities evolved from 1945 to the present and set out the major policy decisions faced by corporations and governments. We will begin by looking at the position of the Alberta petroleum industry in 1946, just prior to the start of the 'Oil Boom.' We then provide preliminary information on the operation of the six stages of the petroleum industry in Alberta. Subsequent chapters in this book will explore in greater detail a number of the issues introduced here with regard to the Alberta crude petroleum industry.

Table 2.1: Selected Statistics for the Alberta Crude Oil Industry

	1950	1960	1970	1980	1990	2000	2010
1 Petroleum and Natural Gas Leases outstanding (10 ³ acres)	4,410	30,004	46,348	60,807	65,550	81,706	87,898*
2 Western Canada Survey Crew Months	1495	632	936	n/a	n/a	n/a	n/a
3 Net G&G Expenditures 10 ⁶ current \$	24.5	33.0	80.3	452.3	452.0	824.1	716.1
4 Net G&G Expenditures 10 ⁶ 1990\$	160.1	164.2	292.0	739.1	452.0	695.4	488.8
5 Number of Exploratory Wells	224	403	963	2,623	2,286	3,114	799
6 Exploratory Drilling Expenditures 10 ⁶ current \$	11.0	44.0	83.8	1,621.6	950.2	2,364.8	2,145.2
7 Exploratory Drilling Expenditures 10 ⁶ 1990\$	71.9	218.9	304.7	2,469.7	950.2	1,995.6	1,464.3
8 Initial Oil Reserves Discovered 10 ³ m ³	81,809	11,910	9,439	29,357	12,990	11,842	735*
9 Initial Gas Reserves Discovered 10 ⁶ m ³	31,616	126,337	24,004	135,545	32,177	53,884	5,079*
10 Oil Discoveries per Exploratory Well 10 ³ m ³	366	30	4	11	6	4	1.8
11 Gas Discoveries per Exploratory Well 10 ⁶ m ³	141	313	25	52	14	17	11.4
12 Exploration Success Ratio	.25	.33	.25	.61	.53	.79	.84
13 Oil as % of Exploration Successes	62	31	23	23	32	19	42
14 Initial Established Conventional Oil Reserves 10 ⁶ m ³	174.8	711.6	1,734.3	1,913.2	2,256.1	2,534.4	2,829.7
15 Remaining Established Conventional Oil Reserves 10 ⁶ m ³	152.6	525.0	1,207.9	719.9	510.4	291.4	236.9
16 Initial Established Gas Reserves 10 ⁹ m ³	146.8	935.9	1,593.2	2,647.1	3,286.8	4,063.5	5,213.5
17 Remaining Established Gas Reserves 10 ⁹ m ³	129.0	926.8	1,352.0	1,812.1	1,694.1	1,210.7	991.4
18 Number of Development Wells	788	1,363	884	4,425	1,969	8,953	7,103
19 Development Success Ratio	.94	.83	.76	.88	.81	.94	.95
20 Oil as % of Development Successes	97	84	37	31	55	35	49
21 Development Expenditures 10 ⁶ current \$	67.5	165.0	327.7	2,340.7	2,566.7	8,105.6	15,600.3
22 Development Expenditures 10 ⁶ 1990\$	441.2	820.9	1,191.5	3,824.7	2,566.7	6,840.2	10,648.5
23 Conventional Oil Output 10 ⁶ m ³	4.3	20.8	52.4	63.2	53.0	43.5	26.6
24 Oil Sands and Bitumen Output 10 ⁶ m ³	0	0	1.9	8.0	19.9	35.3	84.7

/continued

2. Before the Boom: 1946

The embryo of an active petroleum industry was well-established in Alberta by 1946. Geological potential had long been recognized. Rocks of the Canadian Shield lie exposed in the North East corner of the province, and the Rockies run along the southwest border, but 90 per cent of Alberta's 662,000 square kilometres is overlain with sedimentary strata, part of the extensive central North American sedimentary basin that runs from the Mackenzie River delta south to the long-established petroleum producing fields of Texas and Louisiana. Tangible evidence of petroleum was familiar to members of the First Nations and immigrant settlers, exemplified by natural gas seepages near Waterton and surface crude showings along the shores of the Athabasca River near Fort McMurray. Commercial natural gas production had begun late in the 1800s, after a water-directed well hit a shallow natural gas deposit near Medicine Hat, and at least three commercial petroleum booms had been

stimulated by discoveries in the prolific Turner Valley field, southwest of Calgary. A small, shallow, Lower Cretaceous pool of wet gas, laced with light crude, was discovered just before World War I; in 1924, a deeper wet gas pool (in the Mississippian Rundle formation) came in; and a large, deeper oil pool in the Rundle formation was tapped in 1936. A provincial oil and gas conservation board was established in 1938 with regulatory powers over the industry. Oil output, mainly from Turner Valley, grew in the early years of the Second World War, peaking in 1942.

Other small exploratory successes occurred during the 1930s and 1940s, but Alberta's potential as a major oil producer was in doubt. Many communities, including Edmonton and Calgary, were connected to local natural gas supplies, but Alberta, by 1946, was a net importer of crude oil and refined petroleum products. Most of the major North American oil exploration companies were becoming disenchanted. Then, in February 1947, a crew drilling one of the last exploratory wells that Imperial Oil planned for Alberta struck

Table 2.1/continued

	1950	1960	1970	1980	1990	2000	2010
25 Marketed Gas Output 10 ⁹ m ³	1.4	9.1	42.9	62.1	84.6	142.2	112.8
26 Field Operating Expenditures 10 ⁶ \$	10.5	55.5	119.4	950.7	3,604.6	4,832.4	10,055.1
27 Field Operating Expenditures 10 ⁶ 1990\$	68.6	276.1	434.2	1,553.4	3,604.6	4,078.0	6,863.5
28 Total Operating Expenditures 10 ⁶ \$	16.5	92.0	219.5	1,679.2	4,445.4	5,751.2	12,097.6
29 Total Operating Expenditures 10 ⁶ 1990\$	107.8	457.7	798.2	2,743.8	4,445.4	4,853.2	8,257.7
30 Oil R/P Ratio	35.4	24.9	23.2	11.3	9.6	6.7	8.9
31 Gas R/P Ratio	88.0	96.2	31.9	29.2	20.0	8.5	8.8
32 Conventional Crude Revenue 10 ⁶ \$	80.6	318.4	844.1	6,185.1	8,209.9	10,756.8	12,302.5
33 Gas revenue 10 ⁶ \$	2.9	31.3	243.9	5,121.1	4,667.0	23,091.1	15,564.7
34 Oil Sands Revenue 10 ⁶ \$	0	0	32.8	1,676.7	2,799.4	8,044.4	36,690.0
35 Oil Average Sales Revenue \$/m ³	18.74	15.09	16.07	97.69	154.61	244.72	450.07
36 Oil Average Sales Revenue 1990\$/m ³	122.48	75.07	58.44	159.62	154.61	208.68	307.48
37 Gas Average Sales Revenue \$/m ³	2.04	3.46	5.69	82.51	55.18	162.34	137.98
38 Gas Average Sales Revenue 1990\$/m ³	13.33	17.21	20.69	134.82	55.18	137.00	97.50
39 Gas Price Relative to Oil (energy content basis)	0.11	0.23	0.36	0.85	0.36	0.66	0.29

Sources and Notes:

*2009 is the last year for which data is available.

Row 2: Values are for the end of the fiscal year (March 31) except for 2000 and 2009, which are as of December 31. From *Annual Reports* of the relevant Alberta government department (Mines and Minerals, Energy and Natural Resources and Energy); 2000 and 2009 from Dianne Johnston, Department of Energy.

Rows 3, 4, 7, 9, 10, 22, 24, 25, 26, 27, 29, 33, 34, 35, 36, 38: CAPP *Statistical Handbook*.

Rows 6, 13, 14, 15, 16, 17, 18, 19, 21: ERCB *Reserves Report ST-98*.

Rows not mentioned are calculated by the authors.

The Canadian GDP price deflator was used to calculate 1990 real dollar values.

oil in upper Devonian rock (the D-2 formation). A neighbouring 'stepout' well proved disappointing in the D-2 formation but was extended deeper in May, with good production flow from the D-3 formation. The Leduc success, following over 130 Imperial dry holes, marked the start of the Alberta oil boom.

3. Alberta's Upstream Petroleum Industry

A. Exploration

Exploratory activities, as discussed in Chapter One, include land (mineral rights) acquisition, geological and geophysical (G&G) prospecting, and exploratory drilling.

1. Land Acquisition

The legal right to explore for, develop, and produce petroleum must be acquired by petroleum companies

from the owner of the mineral rights. The mineral rights on more than four-fifths (81%) of Alberta's area are held by the provincial government ('Crown land'); the federal government holds another 9 per cent, on Indian reserves and, primarily, in National Parks; the remaining 10 per cent is held by private individuals and companies as 'freehold' rights on land issued to the Hudson's Bay Company, railroads, or homesteaders prior to 1887 (Alberta Department of Mines and Minerals, April 1972). Petroleum companies typically lease below-the-ground mineral rights from owners of mineral rights for a specified period of time, or as long as petroleum production might occur. In return, the original mineral rights owner is compensated, often with a lump sum bonus payment when the deal is signed, an annual rental, and a royalty out of any petroleum revenues. Companies must also obtain the right to the use of the surface of the land for purposes of exploration and production facilities.

Table 2.1 shows companies' holdings of Alberta Crown leases in selected years since 1946. (To illustrate the development of the industry in Alberta, this chapter includes data on the industry at ten-year

intervals, commencing in 1950). Oil companies must hold leases on the land before producing oil. In addition, a variety of reservations permits and licences have been issued to allow exploration and were partially or wholly convertible into production leases. By the 1980s most mineral rights were issued in the form of leases. The total amount of land held under some form of permit rose sharply after 1950 as unexplored parts of the province became of interest to companies and as leases above discoveries were retained to allow production. Companies allow rights to lapse on explored plots that do not appear to be economically productive, thereby saving rental payments. As the industry matures, the total area held in mineral rights can be expected to level out and eventually decline. This has not yet become apparent in Alberta, although land acquisition appears to have become more focused on natural gas and oil sands prospects than on conventional crude oil.

2. Geophysical and Geological (G&G) Surveys

As was discussed in Chapter One, G&G surveys precede costly exploratory drilling, in order to locate the most promising drill sites. Table 2.1 includes measures of such exploratory effort for select years.

Unfortunately, consistent data on crew months is available only to the 1960s. For 1950 and 1960 we report the number of months of effort during the year by petroleum survey teams in Western Canada (mostly in Alberta). There has been significant knowledge growth and technological change in G&G activities, especially from the mid-1980s, with the development of new computer techniques including 3-D and 4-D seismic surveys. As a result, a crew month in the year 2010 was more productive than in the year 1950. Surveys occur early in the life-cycle of industry activity, as low-cost information gathering. However, G&G work will continue, and even grow in later periods, as new areas or deeper formations become of interest, as new companies commence exploration and undertake their own surveys, and as growing scientific knowledge develops new G&G techniques or interpretations.

Table 2.1 also includes data on G&G expenditures in Alberta, both in current (nominal or 'as-spent') dollars and in dollars of 1990 general purchasing power ('real 1990 dollars'); the latter shows the size of expenditures after allowance is made for general inflation, therefore showing changes in expenditure by this sector in terms of general purchasing power in the economy. From an economic perspective, the real expenditures are of most interest, since an

increase in expenditures simply because price levels have been rising would be quite misleading. Nominal G&G spending tended to increase over the years. Real spending does not show a clear trend across time, presumably reflecting factors such as varying real oil and gas prices, changing views about exploratory prospects and different government policies.

Note that choice of the 'correct' adjustment for inflation is difficult. There is some ambiguity about the meaning of the concept of 'real' expenditures. We may intend it to refer to the activity undertaken by this sector of the economy, or what we might call the 'quantity of effort expended.' In this case one would wish to adjust current dollar expenditures by a price index specific to the activities of this sector. However, such detailed price indices are not readily available, so it is generally necessary to rely on a broader price index. It would also be desirable to modify expenditures to reflect technological (quality) improvements, but this is hard to do. Alternatively, real expenditures might refer to purchasing power in the economy at large, that is, what quantity of goods 'in general' could be bought by the expenditures of this sector. In this case, the adjustment index should be a general price index such as the Canadian GDP price deflator. However, there are different inflation rates across regions, and differently defined 'reference bundles' of goods, so that a number of general price indices are available. In a relatively open economy such as Canada's, the longer-term trends in broadly defined price indices are much the same, but this is not necessarily true for narrow indices, such as for one specific economic activity.

3. Exploratory Drilling

In Chapter One we said that exploratory wells generate two main products: geological knowledge (which is normally generalizable beyond the specific drill site) and petroleum discoveries. Most exploratory wells, particularly 'wildcat' wells located some distance from previously discovered pools, are 'dry,' not recording a commercial find.

Knowledge is particularly important for the initial wells drilled in a geographical area or through particular geological formations. The first exploratory well to discover a large pool in an entirely new formation is particularly productive for both knowledge and petroleum; significant examples in Alberta include Imperial Oil Leduc No. 1 in 1947; which, as noted above, signalled the beginnings of Alberta as a major crude oil producer, Socony Seaboard Pembina No. 1 in 1953; and Banff-Acquitaine Rainbow West in 1965.

Each of these defined a new geological ‘play,’ and set off a major surge in exploratory activity and oil discoveries in Alberta.

Table 2.1 shows petroleum industry exploratory drilling activity, including the total number of exploratory wells drilled, the oil and gas reserves discovered, the exploration drilling success rate, and current and real (constant) dollar exploration expenditures. Another measure of exploratory activity is the total exploratory drilling footage in a particular year; we have not included this variable. In models and descriptions of exploration, exploratory drilling effort is variously measured as the number of wells drilled, the total exploratory footage drilled, and the real expenditures on exploratory drilling. These measures are correlated with one another, but not perfectly. Thus, technological improvements might allow the same number of wells or footage to be drilled at a lower real expenditure; fewer wells might be drilled, but footage and expenditures increase if the average depth of wells rises. From a modeling perspective, different results might be attained in the same empirical model, depending upon which measure of exploration effort is used.

Reserves are volumes of petroleum known with a relatively high degree of certainty to be recoverable under current economic and technological conditions. The reserves reported in Table 2.1 are estimates made in the year 2009 of the size of reserves discovered in past years, that is, initial reserves (before any production) as reported in the discovery year and as ‘appreciated’ or revised since then. In this appreciation process, reserve additions reported in any year for an oil pool or gas reservoir are credited back in time to the year in which the pool was discovered. As was reported in Chapter One, most reserves are credited due to development activities (‘extension’ or ‘outpost wells’) in years after the pool is discovered. Pools discovered in 2000 and 2009 have had fewer years for such appreciation to occur, so reserves discovered may be understated relative to earlier years. The success rate is the proportion of exploratory wells that discovered oil or gas pools. As can be seen in Table 2.1, there are much higher success ratios for the years shown after 1980. This could reflect a number of factors, such as a fall in the proportion of wildcat wells, improved technology allowing increased efficiency in selecting drilling sites, and more emphasis on outpost drilling in natural gas pools. Table 2.1 shows that discoveries tended to shift towards natural gas over the fifty-year period, although relatively low gas prices near the end of the period led to renewed oil-directed exploration.

Year-to-year data show large fluctuations in the industry’s exploratory drilling activity in Alberta. The general trend was upwards, at least until the early 1980s, as Table 2.1 suggests. Exploratory drilling fell off in the 1980s, but then picked up again by the year 2000, although real expenditures were still smaller than in 1980. The cyclical variations reflect mainly the succession of new petroleum plays, the variability of oil and gas price expectations and changes in government tax and other regulations. The incentive to drill and obtain general geologic information tends to be strongest in the early years of industry activity, as is true of G&G work. However, the number of specific drilling sites in Alberta is very large, so, for many years, new knowledge and any increases in price, or cost-reducing technological improvements, will tend to make a significant number of new potential drilling locations attractive. As Table 2.1 makes clear, these new drilling sites have become less and less productive, as shown by the decline in the volume of reserves discovered per exploratory well drilled, although the decline would be smaller if more recent finds were adjusted to allow for future reserve appreciation. This falling finding rate typifies what many economists call a ‘stock’ or ‘degradation’ effect: as the stock of undiscovered resources in a given geological play becomes smaller, new discoveries require more effort (i.e., tend to become more costly). In short, diminishing returns emerge. Table 2.1 suggests that the degradation effect has not operated in Alberta through deposits becoming harder to find (the success rate has not shown a persistent tendency to fall); rather, discoveries have been becoming much smaller on average. Table 2.1 also suggests that discoveries have tended to shift towards natural gas, as oil productivity has declined, and as natural gas markets have grown.

The reserves per well drilled in Table 2.1 are only roughly indicative because petroleum exploration is a joint-product process. The industry’s exploratory drilling produces: (1) knowledge, (2) oil discoveries, and (3) gas discoveries. It is impossible to specify what proportion of the total wells drilled was necessary to produce, separately, any one of these three products. One of the three may have been dominant in the mind of the company drilling, but we rarely have access to this information.

B. Development

Recall, from Chapter One, that development activities by the petroleum industry are concerned with ‘proving up’ reserves (by demonstrating the existence

beneath the surface of commercially recoverable petroleum volumes) and providing productive capacity that can be used to lift oil, that is by installing such capital equipment as completed wells, enhanced oil recovery (EOR) injection facilities, water disposal wells, and gathering and separation equipment.

While exploration is necessary to locate oil pools, most oil reserves (except in very small deposits) are added through development activities, particularly extension drilling and EOR investments. Historical experience in Alberta suggests that the amount eventually recovered from a typical oil pool (excluding the smallest ones) will be on the order of nine times the reserves estimated to be present on the basis of the discovery well (four times for gas). More accurately, ultimate oil recovery will be nine times the first year's estimate of recovery.

Table 2.1 shows how total initial Alberta petroleum reserves have grown over time. Initial reserves are all those that have been discovered in the province up to the date shown and consist of the remaining reserves in that year plus past production. Since production continually depletes reserves, remaining established reserves are less than initial reserves. If total ('gross') reserves additions in a year exceed production in that year, remaining established reserves will rise, showing positive net reserves additions. Conversely, if production exceeds gross additions, net additions will be negative and remaining established reserves will fall. It can be seen that gross additions exceeded production for natural gas through 1980. Remaining established reserves for oil went into decline earlier.

Table 2.1 also provides an historical review of development drilling and development expenditures in Alberta since the Leduc discovery. As would be expected, the success rate is much higher for development than for exploration wells. The dominance of oil in the early decades of this industry's growth is evident, as is the increased importance of natural gas since 1960. As with exploratory expenditures, there was a peak in real expenditures in the early 1980s, followed by a decline. However, in the 1990s nominal development expenditures rose markedly, and, unlike for exploration, real expenditures were higher in the years 2000 and 2010 than in 1980.

C. Lifting (Operation or Extraction)

Table 2.1 indicates how Alberta oil and gas production and operating expenditures have changed since 1950. As was discussed in Chapter One, output in any year reflects underlying natural conditions (e.g., volumes

of oil in developed pools and reservoir characteristics), physical capital constraints (developed capacities of wells, gathering, separation and transmission equipment), market conditions (demand and prices) and government regulations (taxes, output controls, export restrictions).

Production has tended to follow levels of remaining established reserves, with natural gas output generally rising from 1950 to 2000, while conventional crude production increased to the mid-1970s, then levelled out and fell. Production changes have reflected both changes in the level of reserves and also the intensity with which reserves are used, as indicated by the R/P ratio, which shows end of year remaining reserves divided by annual production. As can be seen in Table 2.1, the R/P ratios for conventional oil and natural gas have both fallen. Oil sands production commenced in the late 1960s and has risen throughout the period, as plant expansion and new projects occurred. By 2010, oil sands and bitumen output significantly exceeded conventional oil production. Nominal and real operating expenditures have risen throughout the period, reflecting in part, output increases. In addition, unit costs have risen as oil discoveries have tended to become smaller, and output rates have fallen due to production decline in reservoirs. Also, in many pools the water to oil ratio rises over time, so water disposal costs increase.

The nominal sales value of Alberta petroleum output has risen dramatically over time, as illustrated in Table 2.1, partly due to output increases. In addition, beginning in the early 1970s petroleum prices increased very markedly. But, after the mid-1980s, prices declined again, especially for natural gas. During the 1990s, natural gas revenues surpassed conventional crude oil revenues for the first time, and by 2010 oil sands revenue exceeded that from natural gas. Alberta oil and gas prices (as shown by the average sales revenue figures in Table 2.1) have been affected most strongly by two factors: (1) international oil prices, which directly affect the value of oil everywhere in the world and influence the price of other energy products, such as natural gas, and (2) government regulations, particularly restrictions on international trade (which break the direct link with international prices) and direct price control regulations. Natural gas prices in Alberta have generally been well below oil prices on an energy-content basis, mainly reflecting the higher costs of shipping energy to markets in the form of natural gas. An exception to this was during the mid-1970s to mid-1980s, when oil and natural gas prices were fixed by Canadian governments; these regulations will be

discussed in Chapters Nine and Twelve. In the mid-1980s, crude oil and natural gas markets were deregulated and became subject to the interplay of market forces, exhibiting significant instability, so there has been considerable year-to-year variation in industry revenue. The late 1990s saw the relative value of natural gas increasing again as Alberta became increasingly integrated in the North American natural gas market and demand rises for gas in North America began to exceed supply increases, but by 2010 the gas price had fallen again relative to oil.

D. Government Activities in the Crude Petroleum Industry

1. Government Objectives

Governments are vitally concerned with the operations of the petroleum industry. As a result, the economics of the industry must be seen within the context of a regulatory environment: an economic history of petroleum is a story of petropolitics. Since 1930, the Alberta provincial government has been owner of most of the province's mineral rights, and so it has an obvious interest in ensuring that it receives a fair return on petroleum leases transferred to companies. Moreover, as the representative of citizens, the government has responsibility for establishing a legal/regulatory environment that is consistent with the interests of Albertans. Returns to owners, taxation (royalties, rentals, and bonus bids), conservation, and macroeconomic impact are major concerns.

The crude petroleum industry can be a major revenue source for governments. High quality natural resources generate surpluses above the required expenditures to find, develop, and produce the resource. (In economic terms, 'expenditures' include the return required on capital investment.) This surplus (a profit or 'economic rent') can, in theory at least, be taken from the industry without affecting industry activity, hence proving to be an ideally neutral and efficient source of funding for government activities. The practical problem is to approach such ideal rent collection as closely as possible in a world in which the precise size of the rent surplus is uncertain and changing. Some use the term 'taxes' to refer to the payments the petroleum industry makes to governments; other analysts call this 'government take.' It includes payments made to the government in its capacity as owner of Crown mineral rights (e.g., bonus bids, rentals, and royalties) plus those more conventional taxes (e.g., corporate income taxes) which apply

to the petroleum industry as to other industries. Some have argued that the two categories of payments to the government should be kept strictly separate. However, the government, unlike private mineral rights owners, can use its powers to unilaterally change the level of royalties it receives on previously issued mineral rights, just as it can change income and sales tax rates. Moreover, the levels of conventional taxes and payments of royalties and bonus bids are not independent of each other. Hence it is desirable to consider conventional taxes and petroleum-specific payments together. For industry, the 'bottom line,' after deduction of all payments to governments, is crucial. Chapter Eleven examines government rent collection in Alberta.

'Conservation' is, surely, an unexceptionable objective. Exactly what is meant, however, is often left vague. We will use the term quite generally as meaning 'good physical production practices' and note that it has implications both for current industry activities ('intragenerational') and for the future ('intergenerational'). Intragenerational concerns relate partly to the physical impacts of production, such as minimizing unnecessary surface damage during exploration and production; careful disposal of water and other waste material; handling abandoned wells; reducing the risks of pipeline leaks and well blowouts. Also important is the desire to minimize the loss to society of the petroleum resource itself (e.g., reducing the flaring of natural gas, and increasing the recovery factor, the percent of the resource volume physically available that is commercially producible). The intergenerational issue is that of balancing the legitimate needs and concerns of present and future citizens, given that the petroleum resource base is limited, at least in a geological sense. It is tempting to see only the costly side of this intergenerational problem – our production of petroleum must, by the very nature of physical depletion, reduce production possibilities in the future. Balanced against this, however, are any improvements in knowledge that reduce costs or increase recoverability in the future and the returns future citizens derive from investments undertaken today with petroleum revenues. An obvious question with respect to conservation is to ask why companies will not automatically incorporate good production practices, obviating the need for government regulations. In Chapter Ten we consider one such conservation issue in detail.

Macroeconomic impacts relate to the effects that petroleum activities have on population, investment, employment, and per capita income, since the industry is such a critical part of the province's economy. The Alberta petroleum industry can be seen as an

example of an 'export base' industry, one where external market conditions governing exports from the province play a key role in determining the value of the industry's output. Fluctuations in the level of petroleum industry activities will tend to generate similar fluctuations in the province's economy, with obvious possibilities for 'boom-bust' cycles. Sub-regions of the province may be especially prone to such cycles. At the macroeconomic level, it is usually judged desirable to have a relatively high and stable rate of economic growth, with low rates of inflation. Chapter Thirteen delves into these macroeconomic issues.

The three government objectives – revenue, conservation, and stable macroeconomic growth – are not independent of one another but need not always be in conflict. Consider, for example, an 'attenuated' resource development scenario, where the government imposes some limits on the speed of development of the resource base (Scott, 1976); annual tax revenues collected will tend to be smaller, at least in the earlier years of industry activity, but intergenerational conservation and macroeconomic stability may be enhanced, and total lifetime tax revenue from the industry may actually increase.

Government treatment of the petroleum industry is particularly complicated in a confederation like Canada since both provincial (Alberta) and federal ('Ottawa') governments may wish to regulate the industry in the interests of their constituencies. Sometimes the concerns of the two levels of government may coincide. For example, both may wish to minimize local pollution and obtain fair export prices. In other instances, the two may disagree; for example, Ottawa will have more concern than Alberta with the impact of higher petroleum prices on consumers, and the two governments can easily disagree on how tax payments by the industry should be shared. Later chapters, especially Chapters Nine and Eleven, will detail a number of vociferous intergovernmental disagreements about Canadian petroleum policies, especially after the revolutionary increases in world oil prices in the 1970s.

2. Government Policies

After the Leduc discovery of 1947, oil companies dramatically increased exploratory activity in Alberta. Initially corporate interest centred on the Devonian reef formations in the centre of the province, but the new-found optimism about Alberta's oil potential led to increased G&G surveys and drilling in all areas, and other productive plays soon followed. The government

is concerned with the nature of exploration activities, their pace, and the financial effects.

The industry's physical activities have been monitored and regulated by the Alberta government. The aim has been to prescribe safe and clean methods of exploration, to require that companies obtain a permit or licence before undertaking activity, and to watch over what companies do to ensure regulations are followed. Economists have frequently been critical of regulation by direct control of activities undertaken by firms; this approach may involve high costs of administration and lack sufficient flexibility to respond to the variety of conditions faced by the industry, and the rapidity with which our world changes. It has been necessary in Alberta, for instance, to recognize changes in the geographical interests of companies (e.g., from the central plains to the forested foothills and north to permafrost land) as well as changes in technique (e.g., new drilling fluids and larger all-terrain vehicles). The government of Alberta has transferred prime responsibility for regulatory administration of the petroleum industry to an independent body, funded by the province and a levy on petroleum company revenues.

The Petroleum and Natural Gas Conservation Board (PNGCB) was set up in 1938, initially to regulate the Turner Valley oil discovery (Breen, 1993). Some small producers were having difficulty finding markets for their oil, gas flaring was common, and output rates were so large that future productivity was in danger. The high production rates were a legacy of the provision of British Common Law known as the 'Rule of Capture,' which had long plagued the U.S. petroleum industry. Daintith (2010) provides a detailed review of the rule of capture in the U.S. and elsewhere (though not in Canada). He notes that it stems from provisions in Roman law and also operated under civil law in countries with no connection to British common law. Under the rule of capture, petroleum in a reservoir with divided interests is owned in common by all producers with access. It became the property of one company only when that company lifted it to the surface. In the circumstances, producers had strong incentives to drill many wells and produce at high output rates to capture the oil before their neighbours, even though this often damaged the recovery process in the reservoir. Turner Valley, prior to regulation, was a prime example.

In 1950, the PNGCB was given prime responsibility for administering the province's new *Oil and Gas Resources Conservation Act*. In 1957, with the *Oil and Gas Conservation Act*, it was renamed the Oil and Gas

Conservation Board (OGCB). In 1971 its responsibilities were extended over other energy products (coal and electricity), and it became the Energy Resources Conservation Board (ERCB). In 1994, the government announced that the activities of the ERCB would be combined with those of the Public Utilities Board in a new Energy and Utilities Board (EUB). Then, in 2008, the EUB was bifurcated and the ERCB resurrected.

The board has a large technical staff, which, among other things, monitors the industry to ensure that regulations are observed. It has been given quasi-judicial powers in certain areas to hold hearings and sanction or order changes in the actions of companies, and it frequently makes recommendations to the government about policy issues of concern, usually after hosting public hearings. Some economists and political scientists feel that one problem with agencies such as the ERCB is that they are 'captured' by the industry they are designed to regulate (Stigler, 1972). Many individuals have moved easily between the board and industry, but most observers regard the ERCB as an efficient and independent body in much of its regulation of the technical aspects of petroleum industry activities. In this book, we shall not investigate the administration by the board of regulations governing purely technical aspects of industry behaviour nor the more controversial issues related to public health and the environment. Later chapters will deal with several of the programs that have had a great impact on the economics of the industry, including market-demand prorationing schemes to regulate oil output rates from pools (Chapter Ten), and natural gas export sales restrictions (Chapter Thirteen).

In December 2012, the government of Alberta passed the *Responsible Energy Development Act*, which set up a new 'Alberta Energy Regulator'. As of final editing in April 2013, the regulator was still in the process of being established; it would be responsible for the regulatory functions previously handled by the ERCB including matters which require public hearings.

The pace of petroleum exploration is another matter of concern to governments. It can be influenced by licensing regulations for G&G surveys and exploratory drilling, and by government taxes and/or subsidies, depending on whether the government wishes to discourage or encourage activity. In Alberta, however, the most immediate influence on the level of exploration activity comes through the rate at which the province issues mineral rights on Crown land (Crommelin, 1975; Crommelin et al., 1976). There is little, if any, evidence of a specific government policy

on the rate of issuance of petroleum and natural gas exploration and production rights. The main influence on the number, and the surface area, of rights issued in any period appears to have been requests for rights by the industry. Alberta has, on occasion, issued regulations making it less attractive for companies to hold leased rights inactive and unexplored, thereby encouraging more exploratory activities. The requirement that exploration rights be partially relinquished back to the government, on a checkerboard basis, has ensured that the government retains an ongoing interest in sub-areas of the province that become particularly attractive for petroleum exploration. In addition, beginning in the 1970s, a series of royalty-rebate and/or subsidy programs – both at the federal and provincial level – were introduced to stimulate additional exploration. These programs came at a time of high oil prices but also of higher royalties/taxes and of reduced average discovery size, especially for oil, and continued as oil prices became lower in the 1980s.

Fiscal effects on exploration by the Alberta government are primarily tied to the financial terms of Crown mineral right issues. As was discussed earlier, the government would like to capture as much as possible of the economic rent (profit) from petroleum production. Three broad classes of financial payment have been common to virtually all mineral rights:

- (1) Bonus bids: the mineral rights are issued to the company that offers to pay most in a competitive, sealed-bid auction.
- (2) Rentals: an annual rental per hectare is assessed on mineral rights held.
- (3) Royalties: companies pay a portion of any petroleum sales revenue to the government.

Chapter Eleven will review these tax (rent collection) regulations in more detail. Provincial income tax also captures rent for the province, and the federal government has, of course, an interest in the petroleum industry as a tax base. From the government's perspective, it is very important to find the right mix and levels of payment. Table 2.2 gives some feel for the importance of the petroleum industry as a source of Alberta government revenue since 1950, excluding income tax. Considerable year-to-year variability in government revenues from the petroleum industry is apparent, particularly in bonus bids. Particularly high government revenue, in real terms, came in the early 1980s when world oil prices were at a peak, and total petroleum revenues amounted to over three quarters of total provincial government receipts. As

Table 2.2: Alberta Government Petroleum Revenues (10⁶ \$)*

	1950	1960	1970	1980	1990	2000	2010
Fees and Rentals	6.3	32.7	58.3	69.3	72.4	141	158
Royalties	3.6	27.3	143.7	3,456.1	2,118.8	3,970	6,533
Bonus Bids	23.2	81.3	26.5	1,057.7	389.1	743	1,165
Total	30.1	141.3	228.5	4,583.1	2,580.3	4,854	7,756
(% of Provincial Government Revenue)	(30.2)	(42.2)	(25.1)	(80.9)	(21.3)	(24.1)	(19.7)

* For the fiscal year ending March 31 of the year indicated.

Source: *Annual Reports* of the Department of Mines and Minerals, Department of Energy and Natural Resources, and Department of Energy, depending on the year.

will be discussed in Chapter Thirteen, the government questioned whether such high revenues from a depletable natural resource could be expected to continue indefinitely and whether some should be saved rather than spent immediately. Petroleum industry payments to the provincial government fell after 1980, and then rose again in the 1990s; however, after allowance is made for inflation, and the growing size of the provincial economy, the relative importance of petroleum revenues to the government is not as high as it was in the early 1980s.

As with exploration, the Alberta government has had responsibility for ensuring that development activities are carried out safely and in an environmentally sound manner. This book will not discuss details of these types of regulations, though we note that the possibility of well blowouts and other petroleum leakages has generated controversy, especially where population centres and sour (high sulphur) petroleum come together. There is also concern about clean-up costs of abandoned wells, particularly where wells were shut-in many years ago and where companies have gone out of business (Horner, 2011). There have been hearings before the EUB and its predecessor boards with respect to major EOR projects and natural gas processing plants. The EUB possesses some powers to force changes in development plans (e.g., compulsory EOR investment) if it is clearly in the interests of greater commercial oil recovery.

Government regulations with respect to well spacing (establishing minimum spacing requirements) have had a significant impact on the industry's development activity. The government has also had to examine how its policies affect the rate of development; high royalties, for instance, may discourage reserve development and lead to premature well abandonment unless they are mitigated. Output control

schemes such as market-demand prorating also affect industry development. These issues will be considered later in the book.

The board has also been given responsibility for assessing whether major oil sands ventures are 'in the public interest.' In Chapter Seven, we will look at how the board considered this with respect to the impact of oil sands production on the market for conventional Alberta crude oil. We will not, however, consider the board's treatment of the environmental (including health) impacts of oil sands investments. These issues have been quite different from the board's historic concern with oil and gas production techniques in the conventional industry; some critics have argued that the board has insufficient expertise in these broader environmental areas and is too sympathetic to the viewpoint of the industry.

As noted above, governments have an obvious interest in both the timing and value of petroleum output. Timing concerns relate to the depletable resource base, such that lifting today means foregoing future production. Governments may feel that output should be spread relatively evenly over time to help stabilize revenue and tax flows. Such timing concerns are clearly linked to prices. The provincial government may, for instance, prefer to restrain production if output rises would drive down market prices or to delay production if prices are expected to rise in the future. Once again, the question arises of why private producers would not themselves react in this manner, therefore making government action superfluous.

The two decades following Leduc were dominated by the desire to find markets for the province's rapidly expanding oil reserves; this search took place against a backdrop of falling real international oil prices. Two issues became the focal point of discussion, as discussed in detail in Chapter Nine. Should Alberta

oil be reserved primarily for use in Canadian markets, even if this meant bypassing closer markets in the Midwestern United States and shipping the oil to Montreal where it was less competitive with offshore international supplies? Should Alberta oil be offered protection from declining international crude oil values? As it happens, Canadian policy, implemented in Ottawa as the National Oil Policy, encouraged exports of oil to the United States and restricted Canadian access to offshore oil, thereby allowing Canadian prices above international levels. The United States was debating the same issues; the resultant oil import quota program maintained high prices in the United States and quickly incorporated special treatment for oil produced in Canada but did not leave the U.S. market completely open to Alberta oil.

The 1970s brought rising international oil prices and international supply disruptions in connection with political events centred in the Middle East. The government of Alberta, and oil producers, viewed higher prices and buoyant U.S. markets with pleasure. However, the Canadian federal government felt grave concern about the cost and security of oil supplies – both immediately, for users in Quebec and the Atlantic provinces, and through the longer term for consumers in Ontario. Ottawa also worried about the impacts on consumers, and its own fiscal position, of sharply increased oil and natural gas prices. The resultant tension between Ottawa and the petroleum-producing provinces brought a decade of intergovernmental rancour, with export limitations on oil, price controls to keep domestic oil prices below international levels, extension of oil transmission facilities to Montreal, and new federal taxes on the crude petroleum industry. The provinces and a new federal government in Ottawa finally agreed, in 1985, on a policy of ‘deregulation’ of the petroleum industry; this coincided with a collapse of international oil prices.

Natural gas policies over this period exhibited similar tensions between domestic security of supply and export potential as well as between higher prices for producers and lower prices for consumers. Ottawa introduced price controls on natural gas and a new federal natural gas tax. These policies are reviewed in Chapter Twelve.

These instances of government involvement in the crude petroleum industry highlight an underlying uncertainty by some about the wisdom of relying on relatively open markets to allocate oil and natural gas supplies, given the importance of factors external to Canada in setting prices and the depletable nature of the resource base.

The provincial government has also been concerned with variations in the level of petroleum industry activity and in the revenues received by the industry because such changes will impact on the level of economic activity in the province. In Chapter Thirteen, we look at the macroeconomic impact of the industry on Alberta.

4. Alberta’s Downstream Petroleum Industry

The focus of this book is on the Alberta crude petroleum industry. In this section of Chapter Two, we briefly review aspects of the downstream industry in Alberta and provide some comments on economic issues, which may be useful to an understanding of the upstream industry.

A. Transportation: Industry Activities

Chapter One argued that two different categories of crude petroleum transportation have been important in Alberta. First, a network of ‘gathering’ pipelines is needed to collect the lifted petroleum from various reservoirs in the province and move it to major collection points or local markets. Then large-diameter ‘trunk’ pipelines move volumes to major market destinations outside the province. The physical heterogeneity of crude oil raises some technical problems. As noted in Chapter One, most crude oils are mixed together (blended) as they are shipped, but it is sometimes desirable to separate a particular grade from others in the line (to ship by ‘batch’), or to build a separate line to handle a particular product (for example, heavy oil, or bitumen or natural gas liquids, NGLs). While there are chemical differences between volumes of gas from different pools (e.g., in the presence of sulphur and NGLs), natural gas is more homogeneous than oil, especially after treatment in gas plants. Transmission of crude oil and natural gas has proceeded quite differently.

Crude oil pipelines in Alberta were usually built by oil companies themselves, often companies that both produce crude oil and refine it. Estimating the appropriate size of a line is difficult. Economies of scale imply that a pipeline should be as large as possible (up to limits that are significant relative to the volumes of oil shipped from Alberta). Therefore, oil companies normally try to anticipate the likely

Table 2.3: Sales of Alberta Petroleum by Region

	1950	1960	1970	1980	1990	2000	2010
OIL SALES (10 ⁶ m ³)							
Alberta	4.3	4.1	6.4	16.1	19.3	23.9	26.6
B.C.	0	3.7	3.2	7.5	3.6	2.3	1.9
Sask/Manitoba	0	3.3	4.4	3.6	1.9	7.7	10.8
Ontario	0	6.4	13.4	25.8	20.5	1.3	7.7
Quebec	0	0	0	15.4	3.6	0	0
Total Canada	4.3	17.5	27.4	68.4	48.8	35.2	46.9
U.S.A.	0	4.1	32.5	8.7	29.8	55.6	79.3
GAS SALES (10 ⁹ m ³)							
Alberta	2.0	4.2	6.8	13.5	17.3	23.1	32.1
B.C.	0	0.2	0.3	0.3	0.9	2.9	2.6
Sask/Manitoba	0	0.1	2.4	3.5	2.9	6.5	8.5
Ontario	0	0	11.5	18.0	17.3	29.7	17.1
Quebec	0	0	1.4	2.9	4.8	5.9	1.1
Total Canada	2.0	4.5	22.4	38.2	43.2	68.1	61.5
U.S.A.	0	1.1	17.4	19.4	35.7	66.1	49.6

Note: Includes bitumen, synthetic crude oil, pentanes plus and condensate.

Sources: 2000 and 2010: ERCB, *Alberta Energy Resource Industries Monthly Statistics* (ST-3).

1950–1990: ERCB and OGCB, *Alberta Oil and Gas Annual Statistics* (ST-17) and *Cumulative Annual Statistics of the Alberta Oil and Gas Industry*.

volumes forthcoming from future discoveries in the area, as well as volumes immediately available. The various gathering lines have usually been constructed by the first company or companies to generate significant crude oil discoveries in a particular region. The major gathering lines converge on Edmonton, which is the starting point for two trunk lines, both of which were initially built in the 1950s. The Interprovincial Pipe Line (now known as Enbridge) heads to major markets in the east, looping below the Great Lakes into the United States, as far as Toronto (with a link to Montreal built in the 1970s). The Trans Mountain Pipe Line (briefly known as Terrason and now as Kinder-Morgan) traverses the Rockies to Vancouver and the Pacific Northwest states. The gathering lines are wholly owned subsidiaries of various oil companies, while the trunk lines are shareholder-owned, with shares traded on the public stock exchanges (generally, large blocks of shares have been held by oil companies).

The first natural gas pipelines were built by local Alberta distributors (utilities) to bring gas to their customers. In 1954, the government of Alberta introduced legislation that set up a shareholder-owned, publicly traded company called Alberta Gas Trunk Line (AGTL), which would have sole responsibility

for gathering natural gas in the province and moving it to the borders for ex-Alberta sales. (In 1980, AGTL became NOVA, an Alberta Corporation, then, in the late 1990s, it merged with TransCanada Pipe Line.) AGTL sold a transportation service to the owner of the gas. Until the 1980s, the gas was usually bought by and owned by the major trunk line transmission company, which took possession at the Alberta border. These gas-purchasing pipelines were not themselves natural gas producers but new investor-owned companies with publicly traded shares set up explicitly as gas transmission companies. The largest early buyers of gas were TransCanada Pipe Line (for sales to the East), Westcoast Transmission (for sales to the West), and Alberta and Southern (owned by Pacific Gas Transmission, for sales mainly to California). Beginning in the 1970s, a number of new marketers and shippers began to enter the Alberta market, generally purchasing gas for shipment to export markets in the United States. Deregulation in the late 1980s further increased the number of natural gas buyers, as will be discussed in Chapter Twelve.

Table 2.3 shows the destination of sales of Canadian crude oil and natural gas for various years since Leduc, clearly demonstrating the significance of markets external to the province.

B. Transportation: Government Activities

In addition to concerns about personal and environmental safety, governments have been interested in the price charged for transmission, access to facilities, and the route and destination of pipelines. As was discussed in Chapter One, pipeline tariffs are of concern largely because of the 'natural monopoly' nature of the service, since economies of scale usually mean that a single pipeline is the most efficient way to move the product. The government wishes to ensure that the transmission company does not take unfair advantage of its monopoly status by charging a tariff far above costs, or by buying petroleum itself at artificially low prices, or selling at artificially high ones. Access concerns relate to the possibility of the pipeline denying service to some potential users (e.g., refusing to move a competitor's oil or gas). A government may be concerned about pipeline routes because it does (or does not) wish to see a specific geographic market penetrated, or because security of supply or environmental risks dictate certain routes.

In Canada, there has been far less government attention to crude oil pipelines than natural gas, perhaps because the ownership of crude oil lines by the oil companies themselves was conducive to results that the industry found acceptable. In the early years of operation, the possibility of government regulations may also have helped persuade the owners of crude oil pipelines to keep access open to all potential users and to base tariffs on pipeline costs, following the approaches used by regulated pipelines in the United States (Lawrey and Watkins, 1982). In addition other government regulations on oil output, in the form of market-demand prorationing, ensured that all oil reserves holders were given the opportunity to produce; thus, the large oil producers could not use their ownership of pipelines to squeeze out other producers while increasing their own oil production. The *National Energy Board Act* of 1959 declared inter-provincial trunk lines (and intraprovincial lines used by more than the owner) to be common carriers, requiring that pipeline capacity be equally accessible to all potential shippers. In addition, the act gave the board the power to regulate oil pipeline tariffs, although the NEB did not begin to exercise this power until 1977 (Lawrey and Watkins, 1982).

Variations in Alberta oil output also raised questions related to government permits for pipeline construction. In the early days, the question was that of determining pipeline sizes and destination markets when the potential for oil production in Alberta was

unknown and just being established. As conventional oil reserves began to decline after 1970, there was concern about underutilization of facilities. Pipeline expansion became an issue again as the oil sands picked up in the new century, with discussion of whether pipelines would handle upgraded oil or bitumen and whether Alberta should continue to rely on traditional North American markets or look toward Asia.

Natural gas transmission has been more contentious from the start. For example, in the 1950s the federal government insisted that the TransCanada Pipeline be built entirely on Canadian territory, even though it would have been cheaper to follow the Interprovincial oil line through the northern tier of the United States, south of the Canadian Shield. The natural gas trunk lines' role as the main buyers of natural gas also raised potential problems. The pipelines – if they crossed provincial boundaries – were subject to cost of service rate regulation under the authority of Ottawa's National Energy Board, but petroleum companies frequently complained that the gas pipelines (especially TransCanada's) monopsony position as a buyer of natural gas led to artificially low prices. Exacerbating this problem was the prevalence of long-term natural gas purchase contracts, often of more than twenty year's duration, with relatively fixed prices. The issue came to a head in the 1970s when oil prices rose dramatically, increasing the value of competing fuels such as natural gas. The Alberta government began to use its export licensing requirements to force renegotiation upward of natural gas prices, and later began to cooperate with Ottawa in fixing natural gas prices in relation to oil prices.

Deregulation in the mid-1980s generated another series of public policy concerns. As a number of new pipeline proposals arose, drawing on Alberta natural gas, governments had to determine whether they were all compatible and in the public interest. Would there be costly duplication of facilities? Were markets strong enough to provide a fair return on Alberta gas (especially markets on the far east coast of the United States)? Could too many new facilities be constructed thereby providing so much additional Alberta gas to markets that prices would fall or increasing the risk of raising unit shipment costs? Readers will note that such questions all betray an anxiety about the operation of unregulated markets. The Alberta government was also under pressure to change its policies with respect to NOVA, and its method of handling gas movements within the province. NOVA was rate-regulated, but, for many years, applied a 'postage

Table 2.4: Alberta Oil Refining

	<i>Number of Refineries</i>	<i>Crude Oil Refining Capacity (m³ per calendar day)</i>	<i>Refinery Runs (m³ per day)</i>
1950	7	7,450	
1960	11	15,650	12,248
1970	8	27,810	17,909
1980	6	45,311	45,301
1990	6	63,200	55,612
2000	5	68,055	70,167
2010	5	72,135	69,498

Sources: CAPP *Statistical Handbook* (excludes oil sands upgraders).

stamp' tariff, in which all gas would be assessed the same charge regardless of pick-up or delivery point, even though some gas obviously had lower transportation costs. Only in the late 1990s did the government require that NOVA (now TransCanada) abandon the postage stamp tariff

C. Refining and Marketing: Industry Activities

It was mentioned in Chapter One that it is cheaper to transport crude oil than refined petroleum products (RPPs); thus, regional refining capacity tends to be geared to the size of the local market. Table 2.4 shows the number and capacity of Alberta refineries in select years from 1950 to 2010. Refineries exhibit economies of scale; the reduction in the number of refineries since 1960, and the significant rise in total capacity and throughput, reflect a move to larger more efficient refineries. The main Alberta refineries are owned by large vertically integrated oil companies; some of the smaller refineries are former assets of the major oil companies that were purchased by employees or smaller companies (perhaps other gasoline marketers) when the majors were rationalizing facilities and disposing of less profitable assets.

Table 2.5 shows the relative importance of utilization of different energy products in Alberta in 1966 and 1990. The importance of petroleum is evident. Natural gas plays a particularly high role in Alberta in comparison with other parts of Canada. Coal's role has increased as a source for thermally generated electrical energy, and as the demand for electricity has risen more rapidly than the demand for other major secondary energy products.

Table 2.5: Alberta's Primary Energy Consumption by Fuel (Primary Energy Shares, %)

	<i>Oil</i>	<i>Natural Gas</i>	<i>Coal</i>	<i>Hydro</i>	<i>Other</i>
1966	41	52	5	0	2
1990	48	36	15	1	0

Source: For 1990, ERCB, *Energy Alberta Reports* (oil includes 24% bitumen); 1966 figures calculated from energy use tables in Appendix C of NEB (1969).

D. Refining and Marketing: Government Activities

Government attention to petroleum refining and marketing has focused on competition policy, taxation, and conservation.

The importance of economies of scale in refining has meant that a relatively small market can support only a limited number of efficient refineries, raising the possibility of imperfectly competitive behaviour. In the oil industry, the oligopolistic nature of refining has combined with the vertically integrated nature of the industry to raise the possibility of restrictive competition from crude oil through to the marketing of oil products. For example, as will be discussed in Chapters Six and Ten, the process of refiners 'posting' prices that they would pay for crude oil, in conjunction with the government's 'market-demand rationing' regulations, led to rigid prices for crude oil from 1950 through 1972. In another possible example, in Alberta (but not to the same extent in Ontario) motor gasoline prices have often exhibited a certain amount of rigidity, rather than the short-term variability common to some other commodities. Concerns have also been expressed about restrictive tied marketing arrangements imposed by refineries on retail distributors (for example, forcing them to handle a particular brand of motor oil or tires). These concerns have attracted a number of government studies.

There has not been much regulatory response, however, since clear evidence of anti-competitive behaviour is not strong (Watkins, 1981). This may, in part, reflect effective competition among the limited number of firms active in refining, and the greater number in marketing. Competition is also enhanced

by the threat of new entry (Baumol et al., 1988), and the possibility of importing RPPs from more competitive external markets (e.g., the United States).

With respect to natural gas, distribution to consumers is efficiently done by a single company in any market area as a natural monopoly. Hence, gas utilities have been subject to cost of service rate regulation by the Alberta Public Utilities Board (PUB); after 1994, regulation was by the Energy and Utilities Board (EUB), and, after 2007, the Alberta Utilities Commission (AUC).

Some RPPs have been very attractive to governments as targets for taxation. For revenue purposes, a commodity is especially appealing for a sales (excise) tax if its consumption is relatively unresponsive to price changes. (Economists would say that the demand is 'inelastic'; this concept is set out in Chapter Four.) This is characteristic of a good that is viewed by many consumers as a necessity and for which few substitutes exist. Motor gasoline has been particularly appealing in this regard. In Alberta, the provincial tax on a litre of regular grade gasoline was 2.5 cents in 1962, 3 cents in 1970, zero cents in 1981, 5.0 cents in 1989, and 9 cents by 2011 (Canadian Tax Foundation, *Provincial and Municipal Finances*, various years). (The 1990 tax was equivalent to over eight dollars per barrel of oil.) In 2011 the federal gasoline tax was about 10 cents per litre (plus the 5% GST).

Conservation regulations include those designed explicitly to discourage current utilization of petroleum, as has been advocated by many as part of the response to man-made global warming. (Such environmental problems are beyond the scope of this book.) Higher taxes on RPPs, such as a carbon tax, can be useful here, since higher taxes discourage current use. Regulations may also prohibit the utilization of certain petroleum products for particular purposes. For example, from the mid-1970s until 1992, Alberta did not allow new thermal electricity plants burning natural gas. (The United States had similar regulations for much of the 1970s and 1980s.) The removal of these restrictions stemmed from apparent surpluses of natural gas even at falling prices and from recognition of the special environmental risks posed by coal and nuclear-powered generation facilities.

5. Conclusions

This chapter has provided a preliminary overview of major developments in the history of the Alberta petroleum industry and of issues that have attracted

the attention of governments. Underlying both historical events and government policies is the operation of petroleum markets and the extent to which such markets adequately reflect society's interests. The remainder of this book includes more formal analysis of petroleum markets and major government regulations and policies associated with the Alberta crude petroleum industry. Before concluding this chapter, however, brief comments are made on three important topics.

First, Alberta's economic performance after 1947 was tightly bound to developments in the conventional petroleum industry. In purely physical terms, however, the conventional petroleum resource base is dwarfed by the volume of non-conventional petroleum resources. For example, the year 2011 Canadian Association of Petroleum Producers (CAPP) *Statistical Handbook* estimates the total volume of conventional liquid in place in the province (including past production) to be about 10.6 billion m³, while non-conventional heavy oil and bitumen deposits are estimated to hold over 400 billion m³. Since at least the 1920s, private companies and government bodies such as the Alberta Research Council have experimented with ways to produce at low cost from these non-conventional deposits. In 2013 there were five operating oil sands mining companies, two having commenced more than thirty years previously – the Suncor plant (commenced in 1967) and Syncrude (commenced in 1978); in 2011, upgraded synthetic crude made up about 31 per cent of Alberta's liquid hydrocarbons. Several large-scale and a number of smaller *in situ* heavy oil projects were also in operation; in 2011, bitumen from such ventures amounted to about 45 per cent of liquid hydrocarbon production. While the physical potential for large volumes of oil from non-conventional sources is high, actual development hinges on perceptions of expected future economic conditions, the scope of technological innovations and the regulatory environment. Similarly, new techniques or improved economic conditions have been necessary to stimulate exploitation of Alberta's natural gas volumes held in very 'tight' (relatively non-permeable) formations or trapped as methane in the province's coal seams. The problems and potential of these non-conventional resources differ considerably from those of the conventional crude petroleum industry. Chapter Seven deals with Alberta's non-conventional oil, and we touch on non-conventional natural gas in Chapter Twelve.

Second, this chapter has not yet raised a controversial public policy issue – foreign investment in the

Canadian petroleum industry. Foreign ownership has been significant almost from the beginning, at least since Standard Oil acquired control of Imperial Oil back in 1898. By way of illustration, in 1989, the Federal Petroleum Monitoring Agency reported that 44 per cent of the revenues in the Canadian crude petroleum industry were foreign owned; if all aspects of petroleum industry activity were considered, the foreign ownership percentage rose to 46 per cent of revenues, 49 per cent of assets, and 52 per cent of expenditures. Pervasive and persistent foreign ownership in the petroleum industry touches the nerves of many Canadians. Opponents of foreign investment see foreign owners capturing jobs and profits that would otherwise go to Canadians. And large volumes of a scarce resource are seen as siphoned away from Canadian users to consumers south of the border. Foreign – read ‘American’ – values and mores are argued to be imported by the ex-Canada owners and imposed over traditional Canadian social values, transforming Alberta into a pseudo-Texas. Proponents of foreign investment see the financial

capital and technical expertise of the multinational oil companies generating employment opportunities and income gains for Canadians that would not otherwise occur. The higher per capita living standard that results makes it easier for Albertans and Canadians generally to provide those private and social goods that define our society. Such deep-seated and conflicting views cannot be reconciled by economic analysis alone, but, in Chapter Six, we briefly consider some of these views.

Third, there is no discussion in this book of significant issues in environmental economics, even though a number of controversial issues have attracted much public attention in Alberta, including the hazards of well blowouts (which generated an extensive public hearing after the Lodgepole blow-out in the 1980s); the health effects of petroleum production, especially sour natural gas; global warming; and the very significant environmental concerns associated with expanded oil sands production, especially from gigantic strip-mining ventures.

CHAPTER THREE

Alberta and World Petroleum Markets

Readers' Guide: Alberta is not an isolated economy. This chapter provides an overview of the world oil market, what it is, and how it has developed. Since the 1960s, this has been, to a considerable extent, the story of the Organization of Petroleum Exporting Countries (OPEC): the role of the OPEC governments gives obvious meaning to the term 'petropolitics.' We look at Canada's position in the world oil market and argue that it has been such a small player that changes in production and consumption here have minimal effects on world oil prices. In economic terms, Alberta has been a 'price-taker' in the world market, and the international price of oil sets the value of Alberta oil.

1. Why World Markets Matter

It is commonplace to remark that global interdependence has been growing. Rapid, low-cost transportation systems easily move people and goods across the globe, and falling costs of communication have led to almost instantaneous exchange of information. Glimpses of other lifestyles have fuelled consumer tastes everywhere, including the material expectations of the world's poor. Financial capital moves with ease, changing location and form at a moment's notice, its price in all parts of the world responding to the latest news or rumour. Branches of large multinational corporations reach into the world's most distant corners, part cause and part symptom of the shrinking global

village. For the world at large, international trade has been increasing faster than purely domestic trade, and governments throughout the world have been negotiating regional and global agreements that impact on trade and investment.

International trade in crude oil provided one of the earliest of truly global markets. There are a variety of reasons for this. First, energy is a necessary input to economic activity throughout the world, and oil provides a particularly convenient (and, in internal combustion engines, essential) form of energy. Second, oil is a relatively homogeneous commodity in the sense that crude oils from different deposits around the world can substitute for one another. Third, crude oil can be transported readily and at relatively low cost. Today, for instance, a charge of several dollars per barrel or less would normally be sufficient to cover the cost of moving oil up to 3,500 kilometres through a large-diameter pipeline, or the 7,000 kilometres between Saudi Arabia and Japan in an ocean-going tanker.

Crude oil is, and has been for decades, the most highly valued commodity moving in international trade, as measured by the total value of shipments. The ease of moving oil between markets means that, in the absence of any government regulation hindering the flows of oil between countries or imposing special import or export taxes, the price of crude oil within any one country is very closely tied to international oil prices. If the domestic price were significantly lower, those who own domestic oil (whether companies or consumers who have purchased it) have an economic incentive to move the oil into the higher-priced

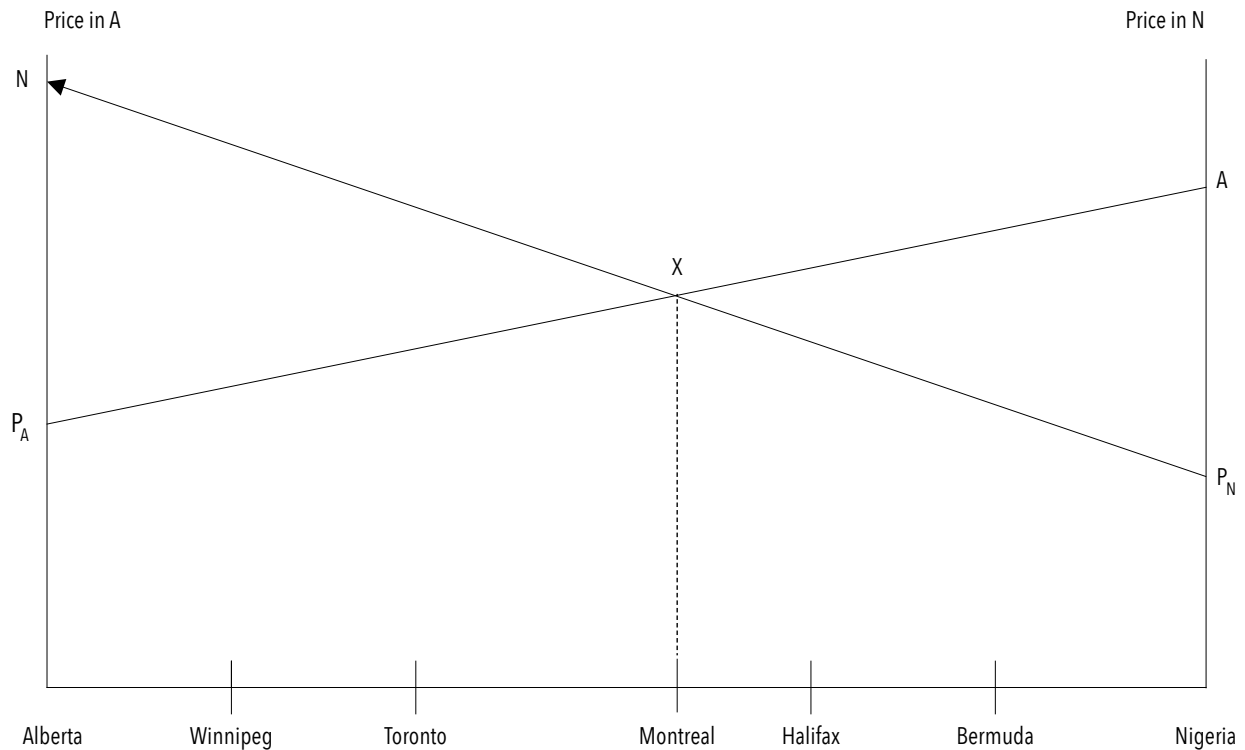


Figure 3.1 International Oil Flows and Prices

international market, and the reduced domestic supply would drive home prices up. Conversely, if domestic prices were above world prices, there would be strong incentives to purchase in the international market, and the reduced demand for domestic oil would drive the price down.

If oil could be instantaneously transported, and if the world oil market had immediate and perfect information flows to all actual and potential market participants, and if buyers and sellers were free to contract with one another and sellers could not discriminate amongst buyers, then oil prices in different parts of the world would differ, at most, by the marginal transportation cost between locations. Economists often refer to this as the 'Law of One Price,' and argue that the exploitation of profitable trading opportunities ('arbitrage') will ensure this result. More accurately, there would be a structure of crude oil prices. Prices would vary across different qualities of crude oil, and, for any particular grade of crude oil, prices between any two locations would differ at most by transportation costs between the two. Crude oil from any large producing region would satisfy demands in that immediate location, with the delivered price of oil rising by the incremental shipment cost as sales occur

in progressively more distant markets; at some location, oil from this region would be higher priced in the more distant market than oil from another producing centre, and no sales would occur.

Figure 3.1 is a simple illustration of this effect for two producing regions (Alberta and Nigeria). The vertical axis shows oil prices, initially P_A in Alberta and P_N in Nigeria, while the horizontal axis shows locations between the two producing centres (Winnipeg, Toronto, Montreal, Halifax, and Bermuda). The line $P_A A$ rising from left to right shows the delivered cost of Alberta oil in various markets, while $P_N N$ shows the delivered cost of Nigerian oil. The two lines meet at point X , in this case Montreal, with Alberta oil being chosen by consumers in Winnipeg and Toronto, and Nigerian oil chosen in Halifax and Bermuda. Prices in various markets are given by line $P_A X P_N$, and it can be seen that the price difference between any two regions may be equal to transportation costs between the markets (compare Montreal to either Alberta or Nigeria) or less than such transportation costs would be (if no oil moves between the markets; compare Alberta to Bermuda). The market where crudes from the two regions are priced equally (i.e., Montreal) is often called the 'watershed' market, or the 'competitive

interface.' It can readily be seen that if the price of crude oil fell in one of the producing regions (e.g., P_N declined) with nothing else changing (i.e., neither P_A nor shipment costs) the watershed would move further away from that market (e.g., to Toronto) and sales of the other region's oil would decline. Such a reduction in the demand for Alberta's oil might lead to a price fall in Alberta, with a new watershed somewhere between Toronto and Montreal and lower prices in all markets.

In an interconnected world market of this sort, the exact level of oil prices, and the specific geographic pattern of prices (and location of watershed markets), depends upon the entire global set of demand, supply, and transportation cost components. In general, any change in a major demand, supply, or shipment cost component will lead to changed prices, production, and consumption everywhere in the world. Consider, for example, the following stylized example of how a major oil conservation scheme in Tokyo might reduce the price of crude from the Alberta Pembina pool. Mandated improvements in transportation fuel economy in Japan reduce the Japanese demand for crude, which drives down the price of Indonesian crude oil sold in Japan; but a reduced Indonesian price cuts the price of Indonesian oil in India, and Indian consumers switch from Middle Eastern to Indonesian oil. The reduced Indian demand for Middle Eastern oil drives down its price in Western Europe so consumers there switch from Nigerian oil to Middle Eastern oil; in turn Nigerian oil prices fall, consumers in Ontario switch away from Alberta oil, and the reduced demand for Alberta crude oil drives down prices in Pembina.

Most economists have accepted this general depiction of interconnected world oil markets as accurate, or, as Adelman (1984b) noted, "the world oil market, like the world ocean, is one giant pool." Casual observation of the world oil market suggests that the Law of One Price is true, at least to a first order of approximation: any large price change for oil internationally has carried into oil markets in all regions. On the other hand, Weiner (1991) argues that the immediate and perfect interconnectedness implied by our simple model does not appear to be empirically valid. Price differentials between regions of the world tend to change over time, as market conditions vary, rather than moving strictly together as the "one pool" analogy would suggest. Weiner's results are somewhat difficult to interpret. They could reflect, as he suggests, varying degrees of market power in different regions, which allow sellers to exercise some degree of price discrimination as market conditions change. However,

short-term inflexibilities in transportation systems and unique local demand and supply conditions for specific grades of crude may also affect the results, as may varying lags in shipment time, differences in the effectiveness of arbitrage responses in different markets, and differences in contractual terms governing price adjustments. More recent research (Gulen, 1999; Kleit, 2001; Fattouh, 2010) has questioned Weiner's conclusion, finding that world oil markets exhibited a large degree of integration. Overall, we are willing to accept the simple model of an interconnected world oil market as a reasonable way to depict the general structure of world oil prices while accepting Weiner's caution that it may not properly capture very short-term market adjustments for specific crude oil grades or locations. By way of example, in 2010, the price of WTI oil at Cushing, Oklahoma (and also the price of Alberta crude oil which is linked to Cushing) fell significantly below that of North Sea Brent oil for the first extended period of time; this price differential still existed at the time of final editing of this volume (March 2013). The reason lies in a relative surplus of supply at Cushing and a shortage of pipeline capacity to connect Cushing with the rest of the oil market. The former reflects increasing oil production from the Alberta oil sands and the mid-west United States. The latter results from the lags in building new pipeline capacity to handle the increased output; this, in turn, may result from the difficulties in planning pipeline capital investments when oil production levels are uncertain, but it also comes from unexpectedly long lags in obtaining regulatory approval for pipeline construction.

Highly interconnected international gas markets have not developed, in large part because natural gas is so much more costly to ship, per unit of energy content, than oil. This is true for movement by pipeline but is particularly so for ocean-going tankers, which require facilities to liquefy and regasify the gas at either end of the shipment route. In addition, there are no essential energy needs that require natural gas specifically, and a high-cost pipeline distribution system is necessary to move natural gas to consumers, so that many regions of the world do not use much or any natural gas. The result has been that, up to now, natural gas markets have been regional rather than international. Therefore, it may make sense to speak of a North American natural gas market, and to expect the price of Alberta natural gas to be influenced by supply conditions in Texas and demand conditions in California, among other locations. However, the concept of a world natural gas market, with Alberta

natural gas prices directly tied to Algerian gas supplies according to the Law of One Price, is not particularly useful. Of course, Algerian natural gas developments could affect the Alberta natural gas market. However, in the absence of low-cost transportation for gas bound from Algeria to North America, any interconnections are likely to be more indirect. For example, a higher supply of Algerian natural gas to Europe by pipeline under the Mediterranean means lower European gas prices, thereby reducing the European demand for oil; this in turn might lead to lower world oil prices, which would lower oil prices in North America and lead to a reduced demand for natural gas and lower Alberta natural gas prices. But the mechanism here is the world oil market and regional energy markets for products such as natural gas, which are tied to local conditions in the oil market, not a world natural gas market. Of course, natural gas prices in North America could rise to a level high enough that large-scale imports of LNG from Africa and the Middle East become economic, so that the natural gas market also becomes a world market. Significant cost reductions in the movement of natural gas across oceans would further this globalization.

Recently there appear to be supply possibilities for large-scale 'non-conventional' natural gas production within North America (such as 'tight' gas, gas from shale formations, and coal bed methane) at prices lower than those required for large-scale LNG imports. It is not yet clear whether the additional supplies are sufficient to keep North American gas prices low enough to enable exports of LNG from North America; if such exports became feasible, the North American natural gas market would become globalized with prices tied to those in the export markets.

2. Alberta's Role in the World Oil Market

Alberta is a relatively small player in world oil market. Table 3.1 shows that Canada's oil output in 2011 was 4.3 per cent of the world total. Canada's share of proved reserves of oil was 10.6 per cent. (This percentage includes non-conventional bitumen and synthetic crude. This is the first year in which the BP source has included large oil sands volumes in Canada's oil reserves.) Similarly, Alberta's oil consumption, even all Canada's, is a small part of total world oil demand. In 2011 Canada consumed about 2.5 per cent of the world's oil (BP, 2012). For this reason, variations in Canada's supply and demand for oil tend to be relatively insignificant for the world oil market. It is

common, in fact, to assume that Canada is essentially a 'price taker' in international oil markets. Certainly, the actions of any single Canadian oil producer or consumer are so small that they will have no discernible effect on the world crude oil price; more generally, plausible variations in the Canadian oil supply (certainly Canadian conventional oil supply) or Canadian demand for refined petroleum products (RPPs) are small enough that they would generate barely noticeable effects upon *world* oil prices. The effect upon *Alberta* oil prices will tend to be small, but not necessarily negligible, depending upon the size of the regional markets in which Alberta oil sells, as well as the responsiveness of demand to price changes. Consider, for example, an increase in Alberta oil supply in the framework of the simple market depicted in Figure 3.1. If imports of oil into the watershed market (Montreal) are large enough, some incremental Alberta oil supply may be absorbed there with no price change by backing out Nigerian oil. However, if imports of Nigerian oil are not large enough, then the price of Alberta oil will have to fall slightly, thereby encouraging more consumption of Alberta oil in all markets up to Montreal, and shifting the watershed slightly to the east. The 'price taking' assumption simply says that reduced Nigerian oil sales to Canada are such a small part of total world oil supply that no noticeable change is needed in the world (Nigerian) oil price. Hence, price changes for Alberta oil due to changes in the location of the competitive interface will be small; ripple effects in the 'world oil pool' will be minimal.

As was noted at the end of the previous chapter, Alberta's non-conventional oil resources, in the form of tar sands and bitumen deposits, are very large in comparison to current world oil reserves, with estimates of potential reserves of over 350 billion barrels (Alberta Energy Resources Conservation Board [ERCB], *Reserves Report*, ST-98, 2010). This is over one third of current estimated world reserves, and 32 per cent higher than Saudi Arabia's 2010 reserves. One can appreciate that any technological change, or crude oil price rise, which would be significant enough to make Alberta's non-conventional oil resources economic, would be of tremendous importance, not only to Alberta, but to the world oil market generally. In fact, OPEC spokesmen have expressed awareness of the importance of pricing their oil below the cost of such large-volume alternatives as tar sands and oil shale hydrocarbons. An implicit assumption underlying these concerns is the belief that non-conventional oil output will prove to be very supply-elastic above some critical price; that is, large quantities could be

Table 3.1: World Oil Reserves and Production, 2011

	Share of World Reserves (%)	Share of World Production (%)	R/P Ratio (Reserves/ Annual Production)
Canada	10.6	4.3	136.5
United States	1.9	8.8	10.8
Mexico	0.7	3.6	10.6
North America	13.2	16.8	41.7
Ecuador*	0.4	0.7	33.2
Venezuela*	17.9	3.5	298.6
South and Central America	19.7	9.5	120.8
Norway	0.4	2.3	9.2
Russia	5.3	12.8	23.5
United Kingdom	0.2	1.3	7.0
Europe and Eurasia	8.5	21.0	22.3
Algeria*	0.7	1.9	19.3
Angola*	0.9	2.1	21.2
Libya*	2.9	0.6	269.4
Nigeria*	2.3	2.9	41.5
Africa	8.0	10.4	41.2
Iran*	9.1	5.2	95.8
Iraq*	8.7	3.4	140.1
Kuwait*	6.1	3.5	97.0
Qatar*	1.5	1.8	39.3
Saudi Arabia*	16.1	13.2	65.2
United Arab Emirates*	5.9	3.8	80.7
Middle East	48.1	32.6	78.7
China	0.9	5.1	9.9
Indonesia*	0.2	1.1	11.8
Asia Pacific	2.5	9.7	14.0
OPEC Total	72.4	42.4	91.5
World Total	100.0	100.0	54.2

Notes: Reserves estimates are for December 31, 2011, and are "proved reserves" defined as "those quantities which geologic and engineering information indicate with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions." Reserves estimates for non-conventional oil in Canada ("under active development") and Venezuela (the Orinoco Belt) are included. Libya's production is unusually low reflecting the 2011 political instability associated with the Arab Spring.

* Member of OPEC (except for Indonesia which has had a suspended membership since 2009).

Source: BP Statistical Review of World Energy, June 2012.

forthcoming with very little increase in cost. If this were true, then non-conventional oil might help play a role as a part of the eventual backstop technology for crude oil. A 'backstop technology,' strictly speaking, is an energy source available in essentially unlimited quantity, at constant cost, which is a perfect substitute for conventional crude oil (Nordhaus, 1973). Such a backstop would set a ceiling price for crude oil.

Table 3.1 makes clear the very uneven geographic distribution of conventional crude oil reserves, particularly their concentration in the phenomenally productive, low-cost oil fields of the Middle East and North Africa, which held over 50 per cent of world reserves at the end of 2011. The political instability of this region raises concerns about the security of supply of much of the oil moving in international trade, although it is easy to overstate security risks. Most of these Middle East reserves, plus those of a number of other countries, amounting in total to over 70 per cent of world reserves, are held by members of the Organization of Petroleum Exporting Countries (OPEC).

OPEC is an intergovernmental group of 'third world' nations that rely upon crude oil exports for the majority of their foreign exchange earnings. OPEC was formed in 1960 by Venezuela, Iran, Iraq, Kuwait, and Saudi Arabia, and, by the end of 2012, had grown to the thirteen members listed in Table 3.1. (OPEC membership has changed somewhat over the years. Ecuador suspended its membership in 1992 but indicated intent to rejoin when domestic economic conditions improved; it re-entered in October 2007. Gabon departed in the mid-1990s. In 2007 Angola joined. Indonesia suspended its membership in 2009.) OPEC's share of world oil output in 2011 was just over 42 per cent, much smaller than its 72 per cent share of oil reserves. Clearly OPEC nations in general are using their proved reserves much less intensively than other countries. The ratio of end-of-year reserves to annual output (R/P) shown in the last column of Table 3.1 confirms this. In 2011 the United States, for example, had an R/P ratio of 10.8 in comparison to OPEC's 72.4. Most economists would attribute OPEC's output restraint to a desire to maintain cartel-like high oil prices, rather than to a lack of 'need' for revenue or to a conservationist concern about the long-term availability of energy supplies for consumers. Some OPEC members exhibit much higher R/P ratios than others, but only Algeria and Indonesia had ratios smaller than 20 in 2011.

It is interesting to note that, despite growing production, remaining proved reserves of oil in the world have increased over the past four decades. Remaining

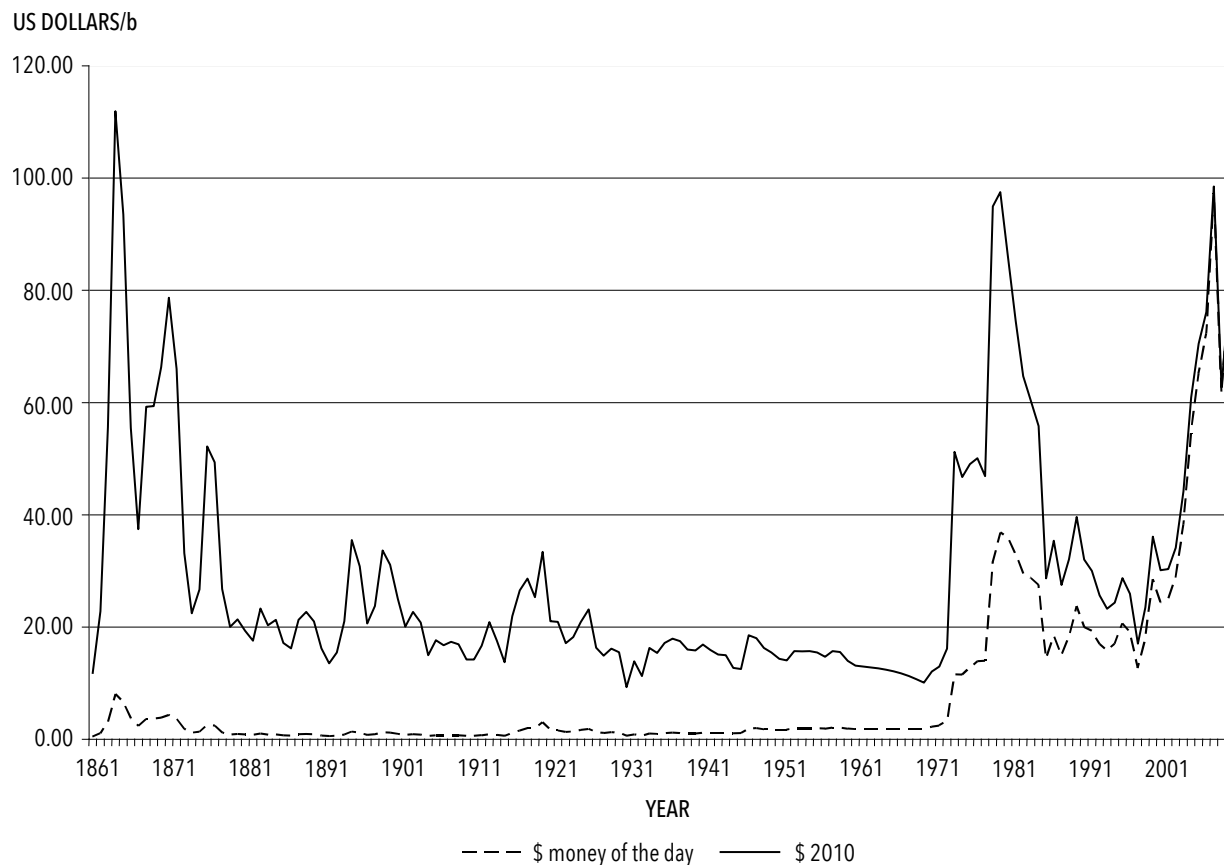


Figure 3.2 World Crude Oil Prices, 1861-2010

Source: BP Statistical Review of World Energy, June 2011

reserves of about 80 billion barrels in 1948 increased to about 350 billion barrels in 1965, doubled to just over 700 billion in 1985, and rose to over 1 trillion barrels by 1990, staying relatively constant at this level despite continuing production, then rising more recently to over 1600 billion barrels, partly as a result of the inclusion of non-conventional oil reserves in Canada and Venezuela (Dahl, 1991; BP, 2012). OPEC's share of remaining reserves has also been increasing, particularly in the late 1980s when Venezuela, Iran, Iraq, Saudi Arabia, and the United Arab Emirates (UAE) all added appreciably to their reserves.

3. Determination of World Oil Prices: History

We have argued that world oil prices are of critical importance to Alberta and Canada but that Alberta

is such a minor player in the world oil market that these prices are determined independently of any events in that province. What has been the pattern of international oil prices, and how have they been determined?

Figure 3.2 (from BP, 2011) provides an overview of the historical development of world crude oil prices, since the beginnings of the world oil industry in about 1860. The higher of the two lines on the figure shows the price that a reasonably well-informed buyer might expect to pay for crude oil at a major world production location, expressed in real U.S. dollars of 2010 purchasing power. The lower line gives the current dollar price of oil as actually paid in any year before 2010 (at the prices of that year); it is lower than the real 2010 dollar price due to inflation in the world economy over most of this period. The real price of oil provides a measure of the price of crude relative to commodities in general, and so is a more valid indicator of oil price changes than a nominal series

showing actual price quotations in each year. The figure shows an average field price for U.S. crude up to 1944, the posted price for Saudi Arabian 'light' at the Persian Gulf from 1945 to 1985, and the Brent spot price since then. (Brent refers to a blend of North Sea light crudes. The changes in pricing location imply slight inconsistencies in the series in 1945, with Saudi prices slightly lower than U.S. prices, and in 1986 with Brent prices slightly higher than Saudi Light.) The pattern of movements shown would hold for other grades of crude oil at other locations, though there would be small differences in values reflecting quality differentials and transportation tariffs. Price trends would look similar for purchasers outside the United States, although, again, changes in real crude oil prices would differ somewhat to the extent that other countries experienced different inflation rates than the United States and/or currency fluctuations vis-à-vis the U.S. dollar. These two effects tend to offset one another to some extent, since inflation rates markedly higher (lower) than in the United States tend to be accompanied by depreciation (appreciation) of the local currency relative to the U.S. dollar. Most refined petroleum product prices would also show the same broad trends as crude oil prices; for some products, however, changes in government consumption taxes have played a major role in changing final retail prices over time.

There is no simple long-term trend in crude oil prices. This casts doubt on the hypothesis that over time increasing physical scarcity of a depletable, non-renewable natural resource such as crude oil will necessarily bring increasing economic scarcity (in the form of real price increases). While each year-to-year price change will have its own unique set of underlying stimuli, it is useful to distinguish three broad periods of time: 1860–1930, 1930–70, and 1970–present. (Many authors have reviewed the history of international oil prices; see, for example, Adelman, 1972, 1995; Blair, 1976; Danielsen, 1982; Frank, 1966; Hamilton, 2011; Hartshorn, 1967, 1993; Jacoby, 1974; Odell, 1986; Penrose, 1968; Yergin, 1990.) Dvir and Rogoff (2009) provide a statistical analysis of world crude oil prices that finds three historical sub-periods similar to those noted here, though they date the end of the first period at 1878, while finding the years 1878–1934 to be more unstable than their first period.

Period 1, 1860–1930. International crude oil prices were dominated by events in the United States, which was far and away the world's largest oil producer. Apart from two years at the turn of the century when

Russia ranked first, the United States produced more oil than any other country every year until the early 1970s and was a net exporter until the late 1940s. By the turn of the century, a pricing pattern for oil had emerged, which was called 'Gulf Plus' pricing; the delivered price of oil anywhere in the world outside of North America was equal to the price of oil at the U.S. Gulf of Mexico (i.e., Texas) plus the cost of shipment from the Gulf of Mexico to that market. Gulf Plus pricing generally held up to World War II, apart from occasional local price wars and excepting markets that deliberately isolated themselves from the world market (e.g., Mexico after nationalization in 1938 and Russia after 1917).

Until the 1930s, U.S. crude prices showed instability occasioned mainly by the operation of the 'rule of capture' in conjunction with erratic reserve additions (McDonald, 1971; Daintith, 2010). As discussed in Chapter Two, the rule of capture is a legal provision that ownership of a mobile or fugacious natural resource (such as wildlife and water, or petroleum in an underground reservoir) belongs to the party that captures (lifts) the resource. Typically, in the United States, the mineral rights that landowners issued to oil companies covered small areas so that more than one potential producer would have access to any oil pool. The oil beneath the surface was essentially unowned; that is, it was 'common property' to the producers with access to the pool. It is as if keys to your store-room were owned by your competitors (Adelman, 1964). As a result, there was a powerful incentive for each producer to attempt to lift the oil early, rather than risking its capture by a neighbouring competitor, and despite the damage this might cause to the reservoir's natural drive and future producibility.

Combined with the unpredictability of discoveries, the rule of capture induced pronounced cycles of production, with resultant price instability. Discovery of a major new oil play attracted eager explorers and there was a rush of discoveries and rapid output increases under the stimulus of the rule of capture; market prices would plummet. However, before long, rapid production decline in reservoirs, occasioned by the high initial output rates, would reduce output and force prices up again until the next major oil discovery in a new geologic play. Refined product prices exhibited less price instability over this period, in part because unstable crude oil prices made up only a part of refined product prices. In addition, for much of this early period the refining sector of the oil industry was subject to strong anti-competitive corporate control, as exemplified by the Standard Oil Trust from the

1870s through to the 1911 U.S. Supreme Court decision that forced the break-up of Standard Oil.

Since the 1930s, the rule of capture has ceased to operate strongly as a factor influencing world oil prices, partly because the U.S. dominance of production began to disappear. Also of importance were government regulations in North America that offset wild production swings (McDonald, 1971; Daintith, 2010). Of particular significance were: (1) market-demand prorationing regulations adopted by several U.S. states (and Alberta), which restricted output to the amount the market could absorb at current prices, and (2) various incentives to companies to 'unitize' oil pools and run them as a single producing operation so that production took place cooperatively rather than competitively. In addition, the rule of capture did not operate in many parts of the world that were of increasing importance after 1930 because British common law did not apply and/or because single production companies (like the Arabian Oil Company in Saudi Arabia) held vast tracts of land so reservoirs were not shared among producers.

Period 2, 1930–70. The period from the early 1930s to the late 1960s is characterized by an unusual degree of price stability, relative to the earlier and later periods. Over these years, oil output in the United States grew, but at a slower rate than output elsewhere in the world, especially in less economically developed nations such as Venezuela, and some Middle Eastern and African countries. The majority of these new oil supplies were controlled by a small number of large, vertically integrated oil companies, the international 'majors,' often referred to as the 'Seven Sisters.' Three of the companies derived from Standard Oil – Standard Oil of New Jersey, now known as Exxon; Standard Oil of California or Chevron; and Standard Oil of New York, or Mobil. There were two other U.S. companies – Gulf and Texaco – plus one British/Dutch company long active in the United States – Shell – plus one company with significant British government ownership – the Anglo Persian Oil Company, now known as BP (privatized in the 1980s).

Despite occasional disagreements and price wars in some local markets, the majors maintained relatively tight oligopoly control in the world oil market outside of North America and the USSR. (As will be discussed in more detail in Chapter Four, an oligopoly is a market in which some producers are large enough that they are able to affect the market price significantly. Thus they have an incentive to restrict production below what a price-taking producer might

do, thereby increasing the market price and generating higher profits for themselves.) In earlier years, the companies entered into a number of formal agreements. After World War II interactions between the major producers involved their joint operating agreements in many countries along with more informal (tacit) understandings. Oligopoly markets, dominated by a few large sellers, exhibit an inherent tension between collusive (cooperative) and competitive tendencies. The large producers are motivated to cooperate, by restricting sales, to generate higher prices and profits. However, as a result of the high prices, any one of these collusive producers has potential additional production available with costs lower than price. It is tempting to produce this output, in violation of the formal or tacit group understanding, but such production will push the price down. These contradictory behavioural impulses clearly serve as a source of potential price instability in oligopolized markets. In such an uncertain situation, producers in a reasonably well-functioning oligopoly may tend to adopt a pricing and marketing strategy of relative inaction, to avoid sending frightening signals to competitors and to maintain the status quo. Such oligopolistic rigidity seems to fit the international oil market quite well for the period from about 1930 through to the mid-1950s, with the prices for Middle Eastern crude tending to follow prices in the U.S. domestic market; U.S. prices, in turn, were quite inflexible under the domination of market-demand prorationing regulations.

As was described above, prior to the mid-1940s, international oil prices generally followed a system known as 'Gulf Coast Plus,' in which the delivered price of oil anywhere in the world was the price in the Gulf of Mexico plus transportation charges between the Gulf of Mexico and the delivery point. This was true whether or not oil was actually shipped from the Gulf of Mexico to that market. As a pricing system, this made eminent sense when the United States was by far the world's largest producer of oil, the main source of incremental supply, and when most markets did in fact rely on shipments from the United States. However, Gulf Coast Plus pricing became increasingly inappropriate as regions outside of the United States became major oil suppliers. By the late 1940s, the United States had become a net crude oil importer and was beginning to draw supplies from the Middle East so that pricing oil throughout the world as if it came from the United States no longer made sense. The first major break in Gulf Coast Plus pricing had come in 1942 when, at the insistence of the UK Navy, the price of Middle Eastern crude was set equal to the

U.S. price (rather than the U.S. price plus the transportation charge from the U.S. to the Middle East). With the removal of price controls after World War II, U.S. oil prices rose more than Persian Gulf prices. Still, in the early 1950s, Persian Gulf Prices, while lower than those in Texas, followed any changes in U.S. crude prices.

The late 1950s saw the decoupling of North American and international oil prices. International prices fell under the pressure of increased competition, stimulated by the entry into the international oil market of new crude oil suppliers such as the USSR and a number of 'independents.' At the same time, the U.S. Oil Import Quota Program (1957) and the Canadian National Oil Policy (1961) allowed prices for North American-produced crude to remain significantly above the international level (U.S. Cabinet Task Force on Oil Import Control, 1970; Watkins, 1989). From 1959 to 1970 the selling price of international crude fell gradually from \$2.08/barrel (U.S. dollars for Saudi Arabia 34° crude f.o.b. Ras Tanura) to about \$1.20/barrel. (The 'posted' price, in fact, remained constant at \$1.80/barrel from 1960 through 1970 and served as a tax reference price, but this price was widely discounted in sales of oil.) The per barrel 'tax-paid cost' of oil to companies in Saudi Arabia included about \$0.10 of production costs and \$0.85 to \$0.95 in taxes throughout the 1960s, so that corporate profits per barrel fell drastically as the selling price of Middle East oil fell. Falling world oil prices meant that the consumption of oil rose very rapidly, with expanded Middle East and North African production providing much of the increased production.

Period 3, 1970–present. The third historical period, dating from 1970 to the present, is the OPEC-era (see Evans, 1986; Skeet, 1988; and Parra, 2004, amongst others). OPEC was founded in 1960 by Venezuela, Saudi Arabia, Iran, Iraq, and Kuwait, in response to the declines in oil prices in 1959 and 1960. (Lower sales prices meant lower tax revenues to the government.) After 1960, nine other members were admitted: Ecuador, Algeria, Gabon, Libya, Nigeria, Qatar, the United Arab Emirates (U.A.E.), Indonesia, and (in 2007) Angola; as noted above, Ecuador and Gabon left OPEC in the 1990s, with Ecuador rejoining in 2007.

OPEC had no dramatic effect on international oil markets during its first decade. It consolidated its existence and administrative structure, expanded to include new members, encouraged the standardization of the oil tax regimes of the members, and was, through its continued existence and periodic protests,

instrumental in persuading companies to accept royalty/tax assessments based upon the unchanging posted price of crude rather than the declining actual sales price. OPEC failed completely in its announced objective of forcing increases in international oil prices, in establishing an output control (prorating) scheme, and in substantially increasing its overall 'take' per barrel. But it did defend this take in the face of declining international oil prices.

However, since 1971, OPEC has been a dominant influence on world crude oil prices, although the degree of dominance has waxed and waned. The crumbling control of the large multinational oil companies was replaced by OPEC as an even more effective price-determining oligopoly. Initially OPEC exercised its power in the oil market by actions designed to increase the taxes paid by the major oil companies; as the tax-paid cost of oil to the companies increased, they were forced to raise the selling price of the crude oil. However, by the end of the 1970s, the OPEC governments had nationalized the oil reserves of the major oil companies, and the production and pricing of oil was the responsibility of the government-owned 'national' oil companies (NOCs). (Jaffe and Soligo, 2007, provide a recent survey of the relative significance of NOCs and shareholder-owned private oil companies in the world market.) Figure 3.2 demonstrates two ways in which this new (OPEC) oligopoly differed from the old (corporate) one: prices were increased to levels far above those of the 1930–70 period, and international crude oil price instability became pronounced once again. Competing explanations have been offered for the price changes over this period (Gately, 1984, 1986; Griffin and Teece, 1982; Mead, 1979). Our brief survey draws largely on the work of Morris Adelman, who has argued convincingly that the most critical factor is OPEC's role as an effective cartel (Adelman, 1980, 1984a, 1986, 1989, 1990, 1993a, 1995, 2002, amongst many others).

The major price rises after 1970 suggest that OPEC has been a much more effective cartel than were the major oil companies. A partial explanation must lie in OPEC's lack of inhibition in fully exploiting its powers in the market; OPEC is not, for instance, subject to corporate anti-combines (anti-monopoly) laws. However, in its search for higher profits, OPEC remains subject to the overall discipline of the market. Higher prices will induce conservation of energy and substitution away from oil to other energy products, as well as increased output by non-cartel suppliers. As a 'residual supplier' in the market, OPEC must beware lest declining sales more than offset rising prices.

Further, the quest for a price that maximizes OPEC's profits necessarily has certain similarities to a game of blind man's bluff. The OPEC cartel can see the current market situation but has only imperfect information about two key factors: what will happen to sales at prices significantly different from today's, especially over the longer run, and what changes in behaviour, technology, and government regulation may occur in the future (induced, perhaps, by current OPEC decisions). As a result, OPEC's search for the optimal price takes place in an environment of uncertainty in which the optimal price is best seen as a moving target.

OPEC's rise as a successful cartel was precipitated by actions taken independently by Libya and Algeria (both OPEC members) in 1970. Following the closure of the Suez Canal in 1967 and of the Trans Arabian pipeline from Saudi Arabia to the Mediterranean in Spring 1970, profits on North African oil increased. Shipment costs for oil from the Persian Gulf to Europe (now forced to travel around the Cape of Good Hope) increased, thereby raising the delivered price of oil in Western Europe and generating a higher value there for North African oil, which did not face a large rise in transport costs. Under the tax/royalty regime of the time, based on unchanging posted prices (that is, 'tax reference prices,' which were the price levels used in calculating royalty and income tax payments to the government), all the profit increase on North African oil went to the oil companies and none to the government. Libya responded by demanding higher posted (tax reference) prices and a rise in the income tax rate.

The bargaining position of the governments of the oil-producing countries was generally thought to be weak in circumstances like this. For instance, when Iran had nationalized the assets of the Anglo-Iranian Oil Company (AIOC, now BP) in 1951, the majors boycotted Iranian oil and increased oil output elsewhere in the Middle East, particularly from AIOC holdings in Kuwait. Iran found that it was unable to sell any appreciable amounts of its oil and was forced to negotiate a new agreement with AIOC and other international oil companies in order to get back into the world oil market. Libya's situation, however, differed in two important respects from that of the Persian Gulf OPEC members. First, rather than facing a single consortium producing virtually all the nation's oil, Libya had issued oil permits (concessions) to a number of companies. Second, some of these companies were 'independents,' like Occidental Petroleum, which had international oil output only in Libya, unlike the 'majors,' which had productive concessions elsewhere as well. Libya strengthened its bargaining

position by negotiating with the companies separately, by focusing initially on the independents, and by ordering production cutbacks for those companies. After the first independent agreed to Libyan terms, the other oil companies soon followed. Algeria, whose oil was produced by French companies, attained similar agreements.

Libya's success in generating more revenue per barrel for the government, through higher posted prices and tax rates, galvanized other OPEC members, whether or not they possessed Libya's temporary locational advantage. OPEC focused its attention initially on oil shipped from the Persian Gulf (which came from Iran, Iraq, Kuwait, Saudi Arabia, Abu Dhabi, and Qatar), demanding changes similar to those agreed to in Libya. The oil companies had always refused to recognize OPEC as a legitimate bargaining agent, insisting on separate single company-single government negotiations. However, this had not worked to their advantage in Libya and Algeria. In late 1970, meetings began between representatives of countries with oil moving from the Persian Gulf and representatives of all the companies producing that oil. On February 15, 1971, the Teheran Agreement was signed by the governments and companies, pretty well agreeing to the OPEC demands. Later in the spring, a similar agreement was signed at Tripoli covering oil that left OPEC from Mediterranean ports, and corresponding agreements quickly followed covering the rest of OPEC oil (i.e., Venezuela, Nigeria, and Indonesia). The Teheran-Tripoli agreements were to apply for five years, bringing 'stability' to the world oil market by providing for an increase in OPEC tax rates and a schedule of moderate posted price rises. We can see now that their real significance was in demonstrating to OPEC that it possessed the ability to increase the price of oil and that neither the oil companies nor the world's major oil importing countries would offer any effective resistance to this.

It is of some importance to note that the rises in posted price under the Teheran-Tripoli Agreements did not directly increase world crude oil prices because, as was noted earlier, oil was not in fact sold by the major oil companies at the posted price. However, the Agreements did raise oil prices in an indirect manner. Since the posted price served as a tax reference price, higher posted prices raised the 'tax-paid cost' of oil to the oil companies, who in turn were pushed to increase the actual selling price of crude to recover these higher costs. OPEC members began to nationalize the crude oil producers beginning in 1972, and the posted pricing system became less important.

Increasing volumes of oil were sold directly by the government oil companies at a price set by the government. Thus, in the early to mid-1970s, the major influence on international oil prices shifted from OPEC's determination of the posted price and tax rates (which affected the per barrel payments the companies made to the governments) to OPEC's direct establishment of a selling price for crude.

Opinions differ on why no effective opposition to OPEC appeared. It might be tied to the basic logistic and coordination difficulties involved in obtaining responses from the oil companies and consumer governments; that is, this side of the bargaining table was effectively competitive. However, others (Adelman, 1972) have argued that in 1971 a number of the other main players also desired higher oil prices. The major oil companies, for instance, had clearly lost much of their power over the oil market in the 1960s. If crude oil prices rose, they stood to benefit by higher profits, which would follow on non-OPEC oil, and even on OPEC oil, if they could increase the selling price of oil by more than increased taxes to OPEC. U.S. oil had become increasingly non-competitive throughout the 1960s, and higher oil prices would both make the relatively high U.S. oil prices more politically tolerable and bring oil costs in the rest of the world more in line with those faced by U.S. businesses. Moreover, most of the international oil companies were U.S.-based, so that higher international oil profits benefited U.S. citizens and the U.S. balance of payments. Other governments with important domestic energy production sectors (Canada's fossil fuels, coal in the UK, Belgium, and West Germany, etc.) may also have seen higher oil prices as desirable. In addition, the rapid growth in oil consumption in the 1960s, spurred by low and falling prices, had brought to an end most of the excess production capacity in North America and had increased the world's reliance on OPEC oil.

The promised stability of the Teheran-Tripoli agreements proved illusory, as some observers forecast (Adelman, 1972). Once OPEC began to receive the fruits of higher prices, why would its members settle back quietly for five years? Later in 1971 and again in early 1973, OPEC insisted that negotiations be reopened, and, in agreements with the oil companies signed in Geneva, posted prices and tax payments per barrel were increased again. Signs of growing disarray in the international oil market led to attempts by participants to stake out positions with a firm foundation. OPEC spoke of the priority of a "Principle of Changing Circumstances," to which responsible governments must respond in the interest of the citizens they

represent, while companies increasingly emphasized the "Principle of the Sanctity of the Contract." OPEC's Principle prevailed as the Organization moved to consolidate its power in world oil markets.

The result was an explosion in oil prices in the decade after 1972. This occurred with two separate price eruptions in 1973-74 and in 1979-81. Each followed a four-stage process (Adelman, 1995):

- (1) A disruption in international oil supplies (the 1973 Arab-Israeli War, or 1978 Revolution in Iran) put strong upward pressure on oil prices in spot sales. OPEC members not involved in the disruption faced contradictory incentives. On the one hand was a willingness to see oil prices rise, with a corresponding reluctance to immediately make up for all the supplies lost as a result of the supply disruptions. On the other hand, there was an incentive to increase production to generate more revenue at the high spot price.
- (2) Other participants in the crude oil market – oil producers outside OPEC, refiners, marketers, oil consumers – had no certain knowledge about how long the crisis might last or how high oil prices might rise. They reacted by stockpiling more oil for their own use or subsequent sale. But the resultant decreased supply and increased demand on the spot market drove the spot price even higher. Data on oil production during the crises suggests that the reduced output during the crisis was quickly replaced by higher output, mainly from other OPEC members, so that the main stimulus to higher prices during the crisis came from the inventory (stockpiling) effects.
- (3) Members of the cartel found that the high spot prices largely benefit companies that had purchased oil at the cartel's lower official selling prices. OPEC members individually or collectively acted to raise official prices, ensuring that they captured the incremental oil profits.
- (4) After the crisis passed, OPEC kept prices at the new higher level, adjusting its output so as to maintain the price.

Several dimensions of this four-stage process deserve further comment. First, from the mid-1970s to the early 1980s, OPEC operated as a 'price-fixing cartel.' At meetings of the OPEC conference, the group would decide upon a price for a 'marker' or reference crude oil (34° Saudi oil at the Persian Gulf). Individual

members were then responsible for fixing appropriate prices for their specific crude oils. Presumably, this was a price (relative to the reference grade) that would generate a demand for this country's oil such that its share of OPEC production was at a level recognized as appropriate by other cartel members. Prior to 1982, OPEC did not publicly announce any agreed-on output levels or quotas for individual members, but if one country set its price too low, so that its sales rose 'too high,' other cartel members would accuse it of 'cheating.' In other circumstances, during supply crises, for instance, with fixed OPEC prices, increases in spot market prices conveyed a message of 'foregone profits' to OPEC members.

Second, OPEC operates under a consensual method of decision-making, rather than through a majority voting procedure; on matters of any import to the group, a policy change can occur only if all members agree to it. More accurately, none must disagree, and it is possible that they may agree to allow different actions by different members. This method of decision-making brings rigidity to OPEC behaviour.

Third, uncertainties in the market meant that, while all OPEC members saw significant gains accruing from high oil prices in the early 1970s, no one knew how high the price should go in order to maximize group profits. Reference was made to the possible costs of alternative energy supplies such as non-conventional oil, but agreement on exactly how far to raise the price was hard to attain, especially if all members had to agree on the new price. Under these conditions, it is easy to see why spot prices may have been taken as an indication of how much consumers would be willing to pay for oil.

Fourth, in the short term, neither consumption of oil nor production by non-OPEC suppliers is very responsive to a price rise. Therefore, OPEC sales declined relatively little immediately after a price rise, even a large one, and higher prices initially raised group profits. The lack of near-term response by non-OPEC producers and consumers was accentuated by government policies in some non-OPEC countries, such as price controls, to limit oil price rises, and higher production taxes. Price controls keep oil consumption higher, and along with higher production taxes keep oil production lower, thereby reducing the fall in OPEC sales as OPEC raises the price of oil.

These factors help explain the peculiar course of the international crude oil price in the 1970s. Instead of a steady price rise as OPEC gained strength, a 'ratchet' process is apparent with periods of relative stability alternating with sharp increases. However, as

time passed, longer-run market adjustments began to occur, and OPEC was forced to reassess its strategy.

The fall in prices as the 1980s progressed illustrates the problems inherent in cartel management when responses to its actions are gradual and cumulative rather than abrupt. The Saudi Arabia reference crude had risen in price from about \$14.00/bbl in 1977 to as high as \$34.00/bbl in 1981 and was still at \$28.00/bbl in 1985. By 1985 OPEC was producing at only 50 per cent of the 1979 level. Thus, despite the doubling of nominal prices, members were in about the same earnings position as 1979 and worse off after allowance for inflation. Saudi Arabia was bearing a disproportionately large share of the burden of cutting output (falling from over 10 million barrels per day (b/d) in 1979 to under 3 million by early 1985). This reflected the Saudi adoption of a 'balance wheel' (or 'swing producer') role in 1982, where it agreed to vary production above or below its quota amount as necessary to maintain the OPEC price. Continuing declines in OPEC's share of the market were in prospect at these prices; OPEC had overshot the mark with its price increases of 1978 to 1981. Saudi Arabia precipitated the required market adjustment by increasing its output sharply, driving spot prices below \$10/barrel and forcing a new OPEC agreement. Revival of the OPEC cartel involved two components: agreement on the desirability of a significantly lower price, more compatible with the longer-term realities of the oil market; and a shift in group strategy from price-fixing to quantity-fixing, as OPEC instituted a system of production quotas.

The change in OPEC's method of operation can be seen as part of what some authors have called 'commoditization' of the world petroleum market (Verleger, 1982). The nationalization of the assets of the major oil companies by OPEC governments in the 1970s meant that the majors no longer controlled large volumes of petroleum within vertically integrated channels. The majors were transformed into large buyers of crude oil, broadening the crude market dramatically. Further, the spot market for oil, and in the 1980s futures and options 'derivative' markets, has grown rapidly. In the late 1960s, about 5 per cent of international crude oil sales were in the spot market, the rest being either intercorporate transfers or sales under longer-term contracts. By the early 1980s, over 50 per cent of sales were in the spot market. These new spot and derivatives markets have many active buyers and sellers, with flexible prices; entry is relatively easy, so that spot and future prices are very reactive to day-to-day perceptions about variations in demand and

supply whether occasioned by real events or rumour. Of course, the play of spot and derivatives markets is against the all-critical backdrop of OPEC's basic output decisions. By switching from a price-fixing to a quantity-fixing strategy, however, OPEC has moved to tie its exercise of oligopoly power directly to the volatile spot market, with the prices paid to the country reflecting current market values.

The importance of these changes can be seen in the similarities and differences between the 1990 Gulf War in the Middle East and the two earlier political crises. With the Iraqi invasion of Kuwait in August 1990, spot prices of oil rose markedly, as in previous crises, from under \$15/barrel in June 1990 for Saudi Light crude to near \$40/barrel in late September. The market reacted sharply to the decreased supplies from Iraq and Kuwait (even though these were largely replaced by increases in output elsewhere, especially in Saudi Arabia), and the levels of stockpiles desired rose sharply. However, unlike the earlier crises, the price of oil fell sharply back to lower levels, reaching around \$18/barrel by February 1991. The differences reflect five interrelated factors. First, OPEC had learned the longer-term dangers of pushing oil prices up too high. Second, even though Iraqi and Kuwaiti oil was completely lost to the market in 1991, other OPEC members – especially Saudi Arabia – were more than willing to make up the shortfall (as was necessary if continuing high prices were to be avoided). Third, as a quantity-fixing cartel, with sales prices for these quantities tied to spot prices, OPEC producers automatically benefited from the rise in spot prices during the crisis, unlike the earlier two crises where OPEC-fixed prices lagged behind the spot market and OPEC had to raise the official government selling price to profit from the crisis. Fourth, strategic petroleum reserves (SPRs) were higher in OECD countries, with the United States actually releasing small amounts from its SPR in September. The use of SPRs helped to dampen prices, and knowledge of their potential for a moderating effect may have reduced the incentive to build up inventories. Fifth, the development of oil derivatives markets meant that companies could reduce their exposure to possible price increases during the crises by engaging in futures markets transactions instead of building up inventories. This reduced the pressure on spot prices during the crises.

Since OPEC adopted a quantity-fixing approach to the oil market in 1987, almost all crude oil sales take place at fluctuating spot prices. The spot prices are highly variable, reflecting current market conditions and expectations. On an annual basis, from 1987 to

2002, the price of Saudi Arabia light oil was as low as \$12.16/bbl (1998) and as high as \$26.24/bbl (2000). On a daily basis, the price was as high as above \$40/bbl (during the Gulf War and the uncertainties of early 2003 leading up to the U.S. invasion of Iraq); it fell below \$10.00/bbl when world oil consumption declined during the economic crisis in the Asia Pacific in 1998. Participants in the world oil market have had to learn to live with price variability. There was no obvious trend in price over this time period, although prices from 1987 to 1999 were largely in the teens, followed by about four years with prices more frequently in the twenties. This was reflected in OPEC's 'target' price, which was \$18.00/bbl in the 1990s (and normally not attained!), but was increased to a range of \$22–\$28/bbl in 2000. (The target price is the average price for a 'basket' of seven specific crude oils.)

However, beginning in the year 2004, as shown in Figure 3.2, international crude oil prices rose dramatically, in a manner much welcomed by OPEC. (Smith, 2009, provides a good discussion of world oil prices with an emphasis on events from 2000 to 2009; see also Hamilton, 2009.) For example, Saudi Light oil was priced at \$27.08/b as of the start of 2004, \$31.86/b in 2005, \$50.86/b in 2006, and \$55.94/b in 2007. Midway through 2007, prices increased markedly again, so that Saudi Light was priced at over \$88/b by January of 2008, and still on an upward path, hitting a high of \$136.02/b for the first week of July 2008, well above the previous real price maximum in 1980. (It should be noted that the real price refers to international prices expressed in terms of real dollars of U.S. purchasing power. For the many countries, like Canada, the UK, Australia, and those in the Euro in Western Europe, the real oil price was still significantly below the heights of 1980 because their currencies had been appreciating relative to the U.S. dollar.) These high prices generated tremendous revenue increases for the OPEC nations. OPEC's March 2006 *Long-term Strategy* document re-stated OPEC's verbal commitment to helping maintain 'stability' in oil markets but included no mention of a long-term target price (OPEC, 2006).

However, the high prices of mid-2008 were short-lived, as prices fell steadily. Saudi Arabia Light averaged \$38.35/b in the last week of December 2008! International crude oil prices then resumed a generally upward trend, reaching \$71.58/b (for Saudi Light) in the first week of August 2009. From then until the time of final revision of this book (Spring 2013), prices have fluctuated but in a narrower range than that from 2004 to mid-2009, with a low weekly average price for

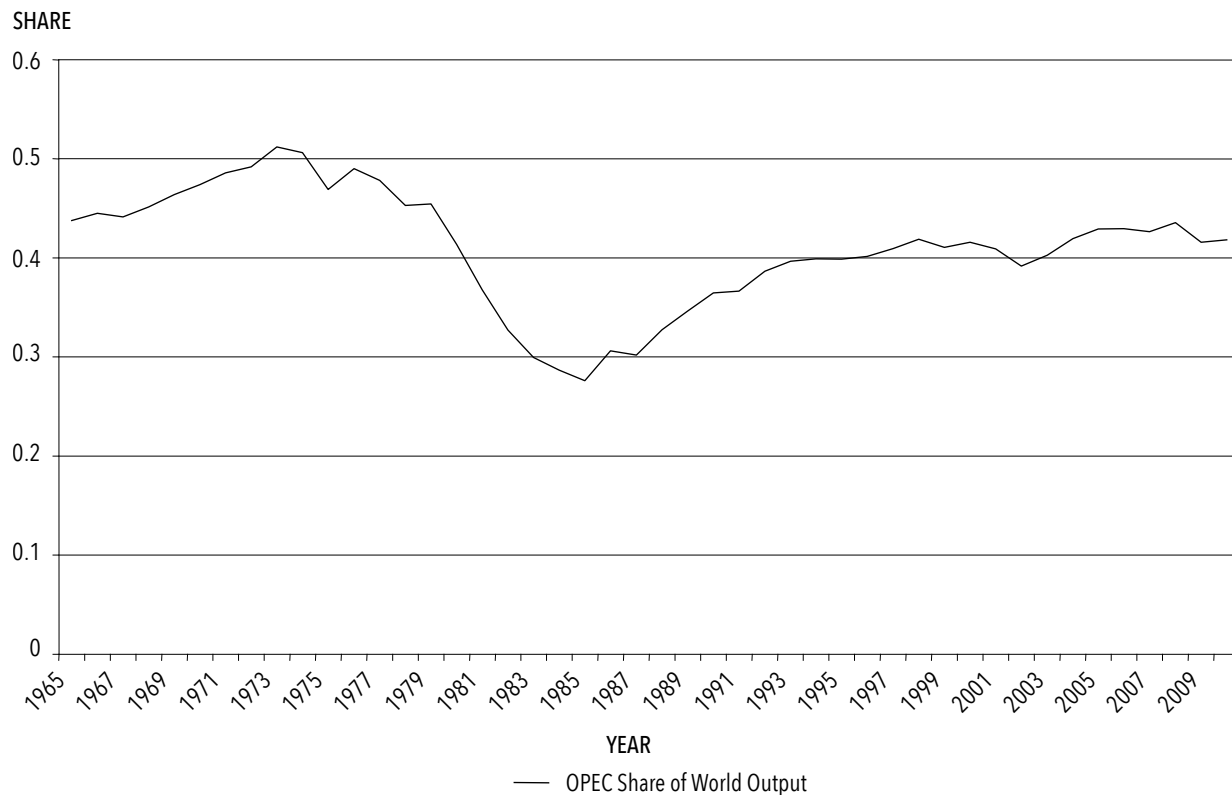


Figure 3.3 OPEC Share of World Crude Oil Output, 1965–2010

Saudi Light of \$66.33/b (mid-September 2009) and a high of over \$100.00/b (by the end of February 2011).

We now turn from this brief historical review of world crude oil prices to a more general discussion of the major factors that determine the level of oil prices in the world market.

4. Major Determinants of World Oil Prices

It is tempting to explain the evolution of oil prices by the physical ‘realities’ of petroleum as a scarce natural resource. For example, the inevitable depletion of the resource base may be called upon as justification for forecasts of higher prices. However, as mentioned above, over a century of history does not show a consistent tendency for higher real oil prices. Others have suggested that the geographic distribution of world oil necessitates increasing dependence on OPEC, especially Middle Eastern oil. Figure 3.3 shows that the world did become increasingly reliant on OPEC oil from 1965 to 1973, but that dependency fell after that.

A missing element in these physical explanations is the operation of the market, specifically the slowdown in total oil consumption (and, hence, production) and the increase in non-OPEC production (especially outside the United States and the USSR) after OPEC forced oil prices up in the 1970s. Physical realities must underlie what occurs, but petroleum prices reflect economic factors.

It is sometimes argued that OPEC producers maintain high R/P (reserves to production) ratios because oil left in the ground has a higher value to them than oil produced today; in terms that will be set out more fully in Chapter Four, oil has a relatively high ‘scarcity value’ or ‘user cost.’ In strict economic terms, based on oil prices, the argument makes little sense. A simple numerical example illustrates this. If we abstract from production costs (which are very low for most OPEC producers) and consider the use to which current oil revenue might be put, \$60/b, derived from the sale of one barrel of crude oil produced in the year 2010, would have a value of \$638 in eighty years if invested at a real rate of return of only 3 per cent per annum. Eighty years is used to approximate the length of time that would pass before a country with a high R/P

ratio would be required to draw on any oil left in the ground today. (If the long-term inflation rate were 2% per year, the nominal value of the investment, in dollars of year 2090 purchasing power, would be \$3112.) It would make sense to leave oil in the ground as an investment only if oil prices by 2090 were expected to be at these very high levels. This seems unlikely, given many analysts' estimates for such potential backstop technologies as non-conventional oil and various solar/electric/hydrogen alternatives. A more plausible explanation for the high OPEC R/P ratio is a cartel (oligopoly) reason: the group's desire to generate higher current prices and profits by restricting output. (However, Hamilton, 2009, argues that the higher oil prices after 2006 may incorporate a significant pure scarcity value, and, even if they do not now, rising world demand, especially in the developing world, is likely soon to generate such a scarcity value. While this would support competitive world oil prices higher than the production costs in the main OPEC nations, we do not believe it would justify prices of \$60/b or more.)

However, the high R/P ratios also point out a major source of potential instability in the oil market, since most OPEC members would have little technological difficulty in expanding oil output significantly. (At an R/P ratio of 25, still far above the 2010 non-OPEC ratio of 15.1, OPEC alone would have produced over 110 million barrels per day in 2010. Total world oil utilization in 2010 was about 82 million!)

Adelman (1990, 1993a) notes another sense in which the potential for rapid oil output increases is greater now, in the OPEC era, than it was when the multinational majors dominated the industry. When the Seven Sisters managed the market prior to 1970, their productive capacity was held quite close to planned output levels. The relative rigidity in pricing and market shares extended to restraint in the installation of new capacity, an accommodation that was, no doubt, fostered by the prevalence of joint production agreements amongst the companies. OPEC, however, has been operating in many years since early 1970s with significant excess producing capacity. In part, the excess capacity reflected the major fall in OPEC output after 1979, but, in addition, a number of members were active in increasing capacity. There has been little formal economic analysis of why countries might undertake expenditures for development that is not utilized. Among the reasons that suggest themselves are: forecasting errors, in the sense that they had expected to need the capacity but subsequently discovered it was not needed; preservation of the

ability to capitalize rapidly on increased sales if OPEC should collapse; holding spare capacity in reserve for use during any international supply disruption, like the 1990/91 crisis; using spare capacity as a potential threat to other OPEC members, thereby gaining greater influence over OPEC pricing policy and output quota allocations. Whatever the reasons, an overhang of spare capacity provides a clear threat of potential downward price instability to the market. The loss of Iraq's and Kuwait's 6.5 million b/d or so from the market in late 1990 dented the excess capacity considerably for several years. In addition, production decline as oil pools are depleted will gradually eat up spare capacity, though there is disagreement amongst experts on how rapidly production decline is occurring in the large oil reservoirs of the Middle East. The U.S. Energy Information Administration (EIA, 2013) reports relatively low OPEC spare capacity in the mid-2000s (from 1.0 to 2.0 million b/d in the 5 years from 2004 to 2008) but an increase to 5 million b/d by 2010, followed by reduced levels (2.8 million b/d by February 2013).

While the *potential* for a significant collapse of the world oil price is clear in a market with an overhang of spare capacity and high R/P values for key OPEC producers, the *likelihood* of the scenario is more difficult to estimate. The major inhibiting factor is the widespread recognition by OPEC members that they would all be worse off in this case, particularly if non-OPEC producing countries provide governmental support for their domestic oil production. On the other hand, prices of oil far above marginal production costs may tempt one or more OPEC members to exceed quotas; this behaviour could draw other members into similar action, trying to increase sales before prices plummet. Given the short-run unresponsiveness of world consumption and non-OPEC production to lower prices, even relatively small output increases could generate a significant price reduction and induce responses from other OPEC members. If the short-run elasticity of demand for OPEC oil were -0.2 , and total demand for OPEC oil were 22 million barrels/day, an output increase of only 400,000 barrels/day by any single cartel member would be sufficient to reduce price by almost 10 per cent. And no OPEC member would find a 10 per cent decline in revenue to be negligible. (An elasticity of demand of -0.2 means that if the oil price were to rise by 1%, the quantity of oil demanded would fall by 0.2%. Chapter Four provides discussion of the elasticity concept.)

While many OPEC members have often held significant spare production capacity, it is only fair to

note that there are disincentives to investing in unused capacity, most importantly the foregone opportunity costs of the required expenditures. This is particularly so given the highly politicized atmosphere in which most OPEC government oil companies operate, where governments would prefer to see oil revenues utilized on programs that generate political capital amongst the population at large. In the early years of the new millennium, OPEC spare productive capacity fell to historically low levels. In such a market, the short-run unresponsiveness (inelasticity) of production and consumption behaviour means that the predominant instabilities in oil prices are in the upward direction in the face of unexpectedly large demand increases or supply disruptions.

From an economic perspective, the crucial element in the determination of international crude oil prices is not the pressure of declining supplies of an exhaustible natural resource, but the oligopoly structure of the international oil market, and the opposing pressures on cartel members to collude for higher group profits or compete (cheat) for higher market shares. As a result, one can build plausible scenarios for international crude oil prices over the next several decades that range from under \$10/barrel to over \$100/barrel, as well as mixed scenarios that move from lower to higher prices as OPEC exercises more or less production restraint in the face of changing market circumstances, and as periodic political crises occur in the Middle East. Pindyck (1999) argues that no single empirical model of OPEC is likely to prove adequate. This is a realistic message but not a comforting one for producers, consumers, and governments who cannot avoid making policy and investment decisions that hinge on long-term oil prices.

Some oil market analysts find it useful to distinguish between day-to-day or month-to-month shorter-term market fluctuations and the underlying longer-term phenomena. Given the commoditization of the crude oil market discussed above, the short-term unresponsiveness of consumption and production to price changes, and the feasibility of short-term storage, prices in spot and futures markets may change rapidly and significantly. As a result, commodity trading activities, including the extensive trading in derivatives, have become critical for oil companies.

It is common to argue, however, that the price instability in the spot market is tied to, but relatively independent from, longer-term 'market fundamentals.' The hypothesis is that the *average* level of spot and futures prices is tied to longer-term factors, but that most changes in spot prices are largely independent

of the longer-term underlying determinants of price. The *trading* departments of oil companies are vitally concerned with spot market prices that respond to seasonal factors, crises in the Middle East, breakdowns in facilities, changes in patterns of inventory behaviour, and all-and-sundry news reports about possible changes in government oil policies, OPEC solidarity, new technologies, etc. But the *investment* divisions of companies are vitally concerned with the longer-term fundamentals. It is important to note that the hypothesized independence of short- and long-term influences on oil prices was not true during the supply crises of the 1970s, when OPEC used spot prices as a signal for their longer-term pricing strategies. As discussed earlier, the shift by OPEC to a quota-fixing strategy, and recognition of the unreliability of spot prices as an indicator of sustainable long-term prices, make a repetition of the crisis-driven price responses of the 1970s less likely. However, we should note that governments may become very quickly attached to the rapid rise in petroleum revenues from an oil price increase. (Revenue rises since, in the short term, sales fall very little as price increases.) However, such governments run the risk of very substantial sales declines in the longer run as consumers and other producers adjust their behaviour to the higher prices.

The longer-term course of world oil prices hinges critically on the cohesion of the OPEC cartel in light of the usual (though difficult to predict) evolution of economic growth, technological change, discoveries of new oil plays, developments in mature areas, changes in consumer tastes, and government policies.

As noted, a 'cartel' is an endeavour by producers to generate profits by withholding output from the market to induce higher prices. A cartel is subject to high tension between this collusive tactic and an opposing temptation to expand output and cheat on the group agreement. OPEC members are all sovereign states, not subject to any binding international law, so that the ultimate oil output and pricing decisions are those of the individual members. In effect, each OPEC member has the following three decisions it must make:

- (1) The individual member of OPEC has some proposal for the actions of the group in its entirety; i.e., some *target price and quantity (quota) for OPEC as a whole* which is consistent with current market conditions.
- (2) The individual member has some implicit or explicit proposal of how the group's total output will be allocated amongst the 13 members; e.g.,

proposed output levels (quotas) for the thirteen which add up to the target output.

- (3) The individual member must determine actual output or price levels for the various types of oil it produces; these may be consistent with the OPEC group decision or may involve 'cheating' by the individual member.

Numerous factors complicate these three decisions. While any one member will tend to prefer a group decision that favours it, the consensual group decision-making procedure means that none of the other members must find the proposed group decision unacceptable. Since conditions in the oil market are uncertain, the group decisions cannot fix both the price of OPEC oil and the quantity produced. One of the two must be flexible to allow oil markets to find their economic equilibrium. Since 1986 OPEC has functioned as a quantity-fixing cartel, so price is flexible, although the quotas have ostensibly been set with a target price in mind. (Starting around 2000, OPEC briefly flirted with a policy to automatically raise output if the price exceeds the target for a set period of time and to cut production if price falls below the target level. But this policy was not consistently applied.) While OPEC procedures require full agreement, it seems reasonable to suppose that some OPEC members have more ability to achieve their objectives than others. For example, small producers (like Algeria) may be able to attain particularly high output rates (relative to reserves) and, perhaps, successfully cheat because they have such a limited effect on the market. Conversely, the largest producers, especially Saudi Arabia, must be accorded great weight in group decision-making, simply by virtue of their huge reserves and ability to vary output significantly to help attain any proposal favoured and to frustrate any plan not liked. But these are generalizations, and need not be true at any particular time, especially since the high responsiveness of oil prices to short-term output fluctuations gives even middle-sized producers the ability to have a noticeable impact on the oil market.

It is difficult to know exactly when an OPEC member is cheating by overproducing. For one thing, output statistics are not available immediately, nor are they perfectly reliable, and OPEC's auditing procedures have been singularly unsuccessful. Also, one must assume that the quota represents an average to be met over the period of agreement (e.g., half year); but the quota may well be exceeded for some weeks or even months, without any implication of cheating. Another possible ambiguity lies in the definition of what

constitutes oil – does it include condensate, NGLs, or very heavy oil (bitumen)? Apparently OPEC interprets the quotas as applying to the production of crude oil in member countries, excluding liquid petroleum derived from natural gas production.

The inescapable conclusion is an awkward one: decision-makers in the oil industry must base their actions on expectations about the future course of international oil prices, but the outlook brackets a wide range of possibilities.

5. Conclusion

The impact of the OPEC governments on world oil prices illustrates 'petropolitics' writ large. To label OPEC a 'cartel,' as do most economists, conveys some economic information, but not a great deal. It implies that members of OPEC cooperate to restrict output and generate higher world oil prices. But cartels come in all shapes and sizes and change form over time. Adelman (1980, 1989) characterizes OPEC as a 'loosely cooperating oligopoly' which has tended to move back and forth between two different modes of operation: a 'full cartel' mode in which all members operate to vary output together to control the market, and a 'residual supplier' mode in which only certain producers (especially Saudi Arabia) take responsibility for controlling the market by playing a balance wheel role. (Hansen and Lindholt, 2008, provide a statistical analysis of the world oil market that seems consistent with Adelman's characterization.) It is easy to be misled by the size of Saudi Arabia's output and reserves and to assume that it is the only OPEC member that really matters. In fact, empirical investigations of OPEC's behaviour over the years since 1973 suggest that almost all OPEC members have been willing to cooperate to some extent to share fluctuations in the demand for the group's oil (Griffin, 1985; Jones, 1990; Smith, 2005). Nevertheless, a cartel always walks a knife edge between collusion and cheating. And the rest of the market must live with the resultant price uncertainty.

What is the relevance of this to the Alberta petroleum industry?

A country such as Canada can have little if any direct impact on world oil prices, at least until large non-conventional oil reserves come into play. Two concluding comments, therefore, are in order. First, if Alberta, or Canada, does wish to address concerns about OPEC's control of international oil prices, or security of supply risks for international oil, the most

effective action will involve cooperation with other similarly concerned industrialized nations. Second, apart from such cooperative action, Canadians must accept international oil prices as determining the commercial value of domestically produced oil. These international oil prices are necessarily subject to uncertainty. The short-term instability of oil markets and the political instability of the Middle East mean that very high prices may occur, and a cartel may maintain such prices for some period of time. There is also potential instability on the downside. Cartel members maintain prices by holding output lower than one might expect under more competitive conditions, as demonstrated by the high reserves to production ratios of most OPEC members. However, weakening of cartel resolve may lead to widespread cheating and large price declines. Adelman (1989) notes that this possibility may be made more likely if attempts to gain intra-cartel bargaining power lead members to install excess capacity, since production increases can then occur very quickly.

The difficulties in forecasting international oil prices became all too apparent after the year 2000. For the previous fifteen years, oil prices, except during political crises in the Middle East, were rarely over \$20/b. Then prices crept over \$20/b and OPEC, its members pleased by the increased revenue, raised its 'target price.' By 2003, the prevailing expectation seems to have been that OPEC would likely be successful in maintaining real crude oil prices at these levels (in the mid-20's per barrel) through the rest of the decade. Instead prices rose dramatically (to over \$130/b) by mid-2008. Oil analysts were left grasping for explanations. (For a discussion see Smith, 2009.)

Some saw the rise as largely temporary, reflecting a shortage of spare capacity in the market when faced by unusually large consumption increases and continuing political uncertainty in the Middle East (the war in Iraq, continued Palestinian-Israeli violence, and fears over Iran's nuclear intentions). From this point of view, the high prices include a significant, and presumably temporary, 'security premium.' At some time in the not-too-distant future, prices would come down again, although many expected that OPEC, happy with the revenue increase the higher prices brought, would

now try to defend a price in the range of \$40 to \$60/b. Presumably OPEC would monitor world consumption and non-OPEC production to ensure that its market share did not plummet, as had happened with the price increases of the 1970s.

Other analysts suggested that the large price rise from 2004 to mid-2008 reflected a permanent change in the oil market, with increasing demand, driven by high growth in countries such as China and India, pressing against resource limits for conventional oil. Often those making this argument suggested that OPEC members have overstated their reserves and understated the production decline problems in existing producing fields. Even were this not true, OPEC may simply prefer very high prices, nearer \$100/b, so long as there is no evidence of the rapid decline in sales which occurred in the 1980s.

Proponents of these opposing views have relevant criticisms of the other side. The lower-price advocates remind us that, back in the 1973–80 period, it took many years for significant supply and demand responses to occur and that behavioural adjustments are further inhibited if governments (like China) are slow to pass through price increases. Those anticipating continued high prices note that oil inventories did not increase as dramatically as would be expected if the price was as high as it was largely due to a 'security premium,' so the high prices must reflect 'real' factors.

As was shown above, oil prices fell drastically after mid-2008, as forecast by the first of these two lines of argument. However, they quickly rose again and stayed in the \$70/b to \$80/b range for most of the next two years, then rose up over \$100/b. As Figure 3.2, shows, this is higher than prices have been for any time in the industry's history, apart from brief periods in the 1860s and from 1980 to 1984. This might be taken to support the second line of argument but only if prices remain at this level over the longer term.

The history of international oil prices suggests that high, low, or medium prices are quite possible for either brief or more extended periods. Canadian decision-makers – producers, consumers, and governments – have no choice but to live with this uncertain situation.

CHAPTER FOUR

Economic Analysis and Petroleum Production

Readers' Guide: Chapter Four reviews the major microeconomic tools and concepts utilized by economists to analyze the operation of the market for a specific product and shows how they can be applied to the petroleum industry, focusing on the market for crude oil. The tools are applied to a number of specific policy issues in oil economics with specific reference to the objective of economic efficiency. Readers who are well acquainted with the vocabulary and tools of economics may wish to skim this chapter.

1. Introduction

Is petroleum too important to be left to the marketplace? Can it be rational to allow people to purchase scarce oil for use in a third snowmobile? If petroleum were an 'irreplaceable asset' how could we rely upon the decisions of profit-maximizing corporations? Questions such as these are frequently asked and betray a common concern: oil and natural gas – the main energy sources in our modern world – are finite in a physical sense. With these physical limits, how can we trust an allocation procedure based upon selfish economic valuations? To view petroleum as just another economic good is often seen as perverse.

It is not surprising to find that most economists disagree with this thesis!

Most people take for granted the ready availability of goods and services without thinking of

the complicated coordination problems involved. In Chapter One, we summarized the many specific tasks that make up the modern petroleum industry. Obviously countless individuals are involved in the production and consumption of petroleum products, and each of these individuals is driven by complicated personal goals. How is it possible to bring together these many interests in an efficient manner? For most economists, the essence of the answer is clear: through the mechanism of the 'market,' which is potentially open to all.

Much economic analysis is concerned with the analysis of the operation of markets as a way of handling society's complex production and consumption decisions. Amongst the goals of economic analysis are the following:

- (a) to help us understand the physical and social world in which we live;
- (b) to provide useful input into the decision-making processes of individuals, companies, and governments.

Economists have developed a number of tools of analysis to aid attainment of these goals. This chapter includes an introduction to the most important of them, and illustrates how they can be applied to several policy issues in the petroleum industry. Attention will focus upon the concepts of 'supply' and 'demand,' and the precise meaning economists attach to such words as 'competition' and 'monopoly.'

2. Supply and Demand

A. Introduction

Supply and demand are the most ubiquitous of the modern economist's analytical tools. Transferring goods or services from one party to another involves some explicit or implicit exchange ratio. The exchange ratio is approximated by the price of the product, and this price is a major variable in reconciling the interests of buyers and sellers. Attendant conditions of exchange, beyond the market price, may also be a part of the 'true' exchange ratio; for example, service guarantees, credit terms, delivery arrangements, pleasantness and promptness of service, etc. The following discussion abstracts from these considerations. Economic exchange in a market is a voluntary activity, so for exchanges to occur the price of the good or service must settle at a level that is acceptable to both buyers and sellers. Hence economists' tools of supply and demand focus upon market price as the key element in exchange.

The basic concepts of 'supply,' 'demand,' and 'market equilibrium' will be reviewed with specific reference to the wellhead price for crude oil. The term 'supply' (or 'demand') is most frequently utilized by economists to refer to a curve (or schedule) that shows a hypothetical relationship between (1) the quantities of a product that would be supplied (or demanded) in the market place over a particular period of time and (2) various possible market prices of the product. The relationship is hypothetical in that it is not a description of what actually does happen but of what would happen if a certain price were to prevail. For example, a supply schedule for oil might indicate that, at a price of \$70.00 per cubic metre (\$70/m³), Canadian producers would be willing to bring 300,000 cubic metres of oil a day (300,000 m³/d) to the market, whereas at \$30/m³ they would supply only 100,000 m³/d. It is not the intention of economists to argue that only the price of the product affects the quantity supplied (or demanded). Rather, a particular supply (or demand) curve is defined for a specific and fixed set of underlying variables other than price, and the curve shows the quantities supplied (or demanded) at various alternative prices, given the values of those other variables. A well-functioning market will tend to an equilibrium price at which it clears; that is, the quantity willingly demanded by buyers is exactly matched by the quantity willingly supplied by sellers, and neither buyers nor sellers wish to change their behaviour (at that price).

Prices and costs for these demand and supply functions should be thought of as real (constant dollar) values that show prices relative to other goods in the economy. General inflation in the economy will not ordinarily shift supply and demand curves, since real dollar values are unchanged. What is relevant is a greater or lesser change in input costs and other values for this industry than for the economy in general.

B. Supply

1. The Supply Curve

One could postulate a 'supply function' that shows the relationship between the quantities of oil (in m³/d) that producers would be willing and able to supply at the wellhead and all the major variables that determine that quantity. We have not said whether buyers are there to take the quantities concerned: this is the meaning of the independence of demand and supply. The reader can probably make a long list of factors that might influence the quantity of oil the producer would be willing to supply. Economists typically handle a complex problem such as this by building a simplified analytical model that is assumed to be a reasonable depiction of the behaviour under study. In the case of crude oil supply, for instance, it is commonly assumed that producers wish to maximize profits, so that the following factors would influence supply.

- (a) the **price of oil** (the higher the price, the greater the quantity supplied, everything else affecting supply held fixed);
- (b) the **technological conditions** of production, including the nature of the equipment used and the physical characteristics of the reservoir (the better the technology, or more amenable the reservoir, the greater the quantity supplied);
- (c) the **costs of inputs** such as labour, materials and supplies, land and capital, including the minimum profit the operator must receive in order to continue his activity, i.e., the 'normal profit' (the lower the costs of inputs the greater the quantity supplied);
- (d) the **price of natural gas**, natural gas liquids, and other products produced in conjunction with oil;
- (e) other financial charges incurred with production, e.g., royalties and income **taxes** (the lower the taxes the greater the quantity supplied); and

(f) **expectations about the future** values of all these variables (generally, the less favourable to profits the operator expects these to be, the greater the quantity supplied now out of available reserves, but the less attractive are additions to reserves). In addition, in light of uncertainty, production closes off the option of waiting until more information is available; an opportunity cost of foregone anticipated profits may be associated with this (Dixit and Pindyck, 1994). (Kellogg, 2010, finds evidence of such an effect on oil investments in Texas.)

If all factors except the first (the price of oil) were assumed to be fixed at some level, then we arrive at a hypothetical supply schedule of the type described earlier. The supply curve is the locus of points of maximum quantities that would be supplied to the market at various prices. At any given price, suppliers will be willing to supply less, but they can't be induced to supply more. That is, the curve tracks the minimum prices that will induce suppliers to place the various quantities on the market. Suppliers will be happy to accept a higher price for a given quantity but will not supply that quantity for a lower price. The minimum price necessary to entice the supply is called the 'supply price.' To be profitable, this minimum price must cover the cost of producing the unit of oil in question, so the general condition for supply is that price equals marginal cost ($P = MC$) for the last unit of oil the producer is willing to bring to market. ('Marginal' is the term economists use to refer to the individual unit.)

We expect the supply curve to slope upward to the right, showing a greater quantity of oil willingly supplied at a higher price (curve S in Figure 4.1), since a higher price will cover the higher-cost units of petroleum that were not profitable to producers at the lower price. Such a curve could be imagined for any unit of production in the industry (well, pool, field, or company). Horizontal summation of the quantities across all units of one type (e.g., oil pools) at each price would generate a market supply curve for the region. This supply curve would have a positive slope both because a higher price may induce more production from any one unit (e.g., pool of oil) and because a higher price makes higher cost units (e.g., low productivity pools) attractive to produce.

We have been speaking of the wellhead supply of oil. Oil is non-homogeneous in two important respects, in a regional producing market. Firstly, pools differ in location, with pools closer to the market in a

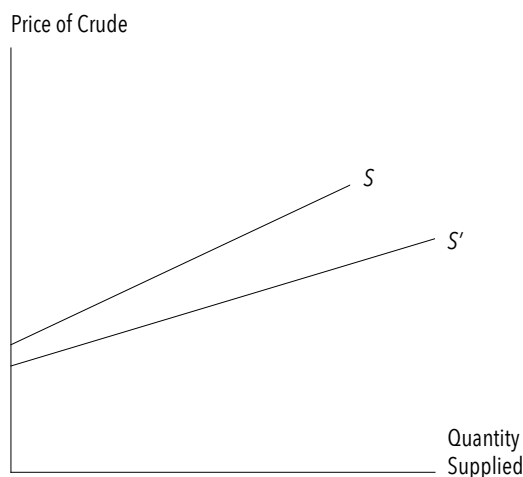


Figure 4.1 The Supply Curve for Crude Oil

preferred position. Secondly, crudes differ in quality, yielding differing arrays of product when refined and possessing undesirable impurities (e.g., sulphur) to varying degrees. Because refined products differ in price, this affects valuation of the crude; also different quality crudes incur different costs of transportation and processing. Hence it is best to think of the market supply of crude oil in a producing region as defined for one specific grade of crude oil at a central gathering point in the region. In Alberta, for instance, the reference oil might be light (42°), low sulphur crude oil at the Edmonton terminal of the Enbridge pipeline. The actual wellhead price for any specific barrel of crude oil will be higher (or lower) than this reference price as: (1) the transportation cost to the central gathering point is lower (or higher) than that for the reference crude, (2) the market value of the array of refined products obtained from the crude is higher (or lower) than for the reference crude, and (3) the cost of moving or refining the crude is lower (or higher) than for the reference crude.

There are, obviously, an infinite number of hypothetical market supply curves derived from the infinite number of possible assumptions about variables other than price that underlie the supply curve. However, at any particular time, one set of underlying variables will be extant and one of the hypothetical supply curves will exist. (This is subject to qualification about 'short-run' versus 'long-run' curves, as will be discussed below.) If the specific value of one of the underlying variables should change, then a new supply curve would be generated. For instance, in Figure 4.1,

the curve S' shows an increase in supply relative to curve S ; that is, at every hypothetical price the quantity supplied is greater on curve S' than on curve S . This increase in supply might result from successful new exploration, improved technology, or reduced royalties or input costs, among other possible causes. Similarly a shift to the left in the supply curve, for instance as a result of higher input costs, represents a decrease in supply. As time passes, decreases in the oil supply curve for a particular well are expected, at least in the later years of operation, reflecting the phenomenon of production decline in oil reservoirs: with the depletion of oil reserves, there is less oil available and the internal production drive of the reservoir falls.

2. Supply and Costs

The supply curve is usually taken to show the marginal cost (incremental cost) of the additional unit of output indicated on the horizontal (quantity) axis. This recognizes that the operator will be willing to produce an additional unit of output when, but only when, the price of the product is as high as the incremental cost involved in providing that unit. It is common (e.g., Davidson, 1963; McDonald, 1971; Watkins, 1970) to divide crude oil marginal costs into three components: (1) variable input costs including labour costs, equipment and material costs, rent, and normal profits; (2) production taxes (e.g., royalties); and (3) the present value (discounted value in today's dollars) of any future profit foregone by producing the cubic metre of oil now instead of leaving it in the ground for later production. A present value is an expected future dollar value multiplied by a discount factor that allows for the return foregone on those funds by having to wait for them rather than having them available now. If r is the relevant annual rate of interest, and the future value would occur in T years, the discount factor is $1/(1+r)^T$.

This third cost element is called the 'marginal user cost' of production, and derives from the consideration a profit-maximizing operator gives to possible conservation of a depletable natural resource like petroleum. The user cost of an oil pool reflects two ways in which current lifting of oil reduces future profit possibilities. The first is a pure 'timing' effect, which reflects the depletable nature of oil deposits so that one cubic metre produced today is simply not available for future lifting. The second is a 'stock' or 'degradation' effect, which captures the internal reservoir dynamics of an oil pool and measures the increase in future production costs caused by the

reduction in reservoir pressure as a result of producing the cubic metre today (Bohi and Toman, 1984). Obviously expectations of future prices, costs, and taxes influence the marginal user cost. The higher expected future prices, the higher will be the marginal user cost, and the lower current supply. Producers would be induced to wait for the better market in the future. Such conservation will operate only to the extent that producers are able to make reasonable predictions about the future and expect to control the oil pool then. It is also affected by government regulations that influence output rates, and by any contractual obligations the producer may have undertaken.

The user cost concept is particularly helpful in understanding the development of pools. Why, for example, would a company refrain from drilling a low-cost infill well that produces significant amounts of oil? Typically it is because the infill well has a high cost of foregone future profits because it reduces the later production from adjacent established wells; in essence, the infill well simply accelerates production, but the producer might find the future profits if he does not drill the well more attractive.

In analyzing oil supply it is necessary to distinguish between the supply of produced (lifted) crude oil and the supply of discovered oil in the ground (i.e., reserves) (Uhler, 1981). Exploration, and development activities, such as outpost (or extension) drilling and enhanced oil recovery (EOR), are concerned with the supply of oil reserves. Higher oil prices will cover higher cost reserve additions. Figure 4.2 shows, for a given set of underlying factors (input costs, geological and technical knowledge, future expectations, taxes, etc.) an upward sloping supply curve (S_{RA}) for reserves additions as the price of reserves additions rises. The 'price of reserves additions' is a sales value for oil reserves in the ground (an *in situ* price); it will be greater the higher the price of produced or lifted crude oil but will tend to be lower than the price of produced crude since the operator must still pay lifting costs for the oil and must wait into the future before he is able to recover all of the oil reserves.

Uhler (1976, 1977) argues that the supply curve of reserves additions in a given basin is subject to two contrary dynamic influences: technological improvements and new geological knowledge tend to increase the supply of reserves additions (shift it rightward to S'), while the depletion over time of the stock of undiscovered reserves tends to make new additions more costly and shifts the supply curve to the left, to S'' . Uhler has hypothesized that the first effect tends to dominate early in the history of reserves additions

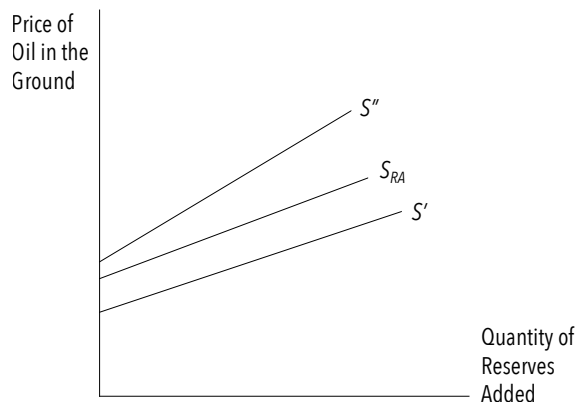


Figure 4.2 The Supply Curve for Reserves Additions

from a particular geological play (or formation), while the second effect dominates later on, thereby giving a tendency to first rising then falling reserves additions per unit of exploratory effort. Over the long run, it is reserves additions that support continued crude oil production.

In this book, we will emphasize the supply of oil production (lifted crude) rather than the supply of reserves in the ground.

3. The Analytical Time Dimension

Economists commonly distinguish between short-run and long-run supply curves. The short-run supply curve describes the relationship between the price of the product and the quantity that operators are willing to supply when some of the factors of production (e.g., major pieces of capital equipment, like the number of wells in a pool) are fixed and cannot be changed. The long-run supply curve describes the relationship between price and quantity when the operator has enough time to vary all inputs. Some writers further differentiate the short-run (when all capital facilities, including the number of wells, are fixed), the medium-run (when already discovered pools can be drilled more intensively and EOR schemes put in place, but no new pools can be brought on stream) and the long-run (when operating, development, and exploration activities are all variable) (McDonald, 1971). These analytical distinctions provide a convenient bridge from physical to economic descriptions of petroleum industry activity. Figure 4.3 shows short-run (S_{SR}), medium-run (S_{MR}) and long-run (S_{LR}) supply

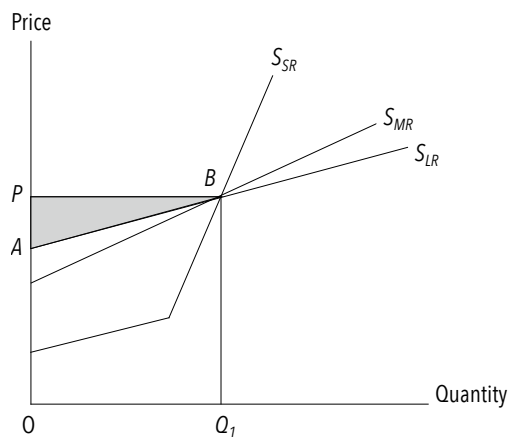


Figure 4.3 Short-, Medium-, and Long-run Supply Curves for Crude Oil

curves of lifted crude oil from a region for some particular year. Recall that these are 'hypothetical' curves illustrating what would happen under certain assumed conditions. Figure 4.3 illustrates the variations in supply if capital investment decisions possess a specified flexibility: complete inflexibility in the short-run so only existing equipment is used; flexible development capital but no new exploration in the medium-run; and both development and exploration possible in the long-run. Other factors influencing the supply of oil are assumed to remain at fixed levels.

Consider an initial price such as P , which is assumed to apply to identical short-, medium-, and long-run outputs (Q_1). The short-run supply curve is very steep (inelastic) since higher prices can draw forth very little additional output given that no new capital is installed; a higher price does serve to cover the marginal costs of some higher-cost (and, usually, low-output) wells, which would otherwise be abandoned or shut-in. The greater quantity responsiveness of the medium- and long-run supply curves is due to a higher price covering increased marginal costs of lifting and development in previously discovered pools (medium-run) and of lifting, development, and exploration in newly discovered pools (long-run). The shape of the short-run supply curve (S_{SR}) indicates that the price of oil would have to fall very low before it failed to cover the operating and user costs of those wells currently in operation (see for Canada, Edwards, 1972; for the United States, Griffin and Jones, 1986, and Adelman, 1992). The vertical distance between the S_{SR} and S_{MR} curves, for output levels below Q_1 , represents the (sunk) development expenditures undertaken in

the past to support output up to level Q_1 , while the vertical distance between S_{MR} and S_{LR} represents sunk exploration costs.

An increasing cost industry (i.e., one with rising supply curves), such as the crude petroleum industry, will earn unit revenues (prices) higher than marginal costs. For price P , and output Q_1 , this excess dollar profit (usually called ‘economic rent,’ or ‘producers’ surplus’), can be represented by shaded area APB in Figure 4.3; this rent is also known as a ‘differential rent’ or ‘Ricardian rent’ and measures the difference in cost between the highest cost unit produced (at Q_1) and lower cost units. Economic rent is usually defined to include the user cost component of the supply (marginal cost) curves since this represents an expected future profit, not an expenditure on production or required return on capital; this component of economic rent is sometimes labelled a ‘scarcity rent,’ deriving from the exhaustible nature of an individual oil deposit.

It is important to note that the differences between the three supply curves relate to an *analytical* time distinction (the time required to invest capital) rather than a *calendar* time distinction. A price rise for oil that was expected to be sustained would immediately induce short-, medium-, and long-run supply responses. Some of these might take place very rapidly (a new shallow exploratory or development well), while others might take many years (a large EOR scheme or frontier exploration program). Therefore, observed real world supply behaviour would include a mixture of (i) oil supply decisions as indicated by supply curves and (ii) the process of adjustment between different supply curves due to shifts in those curves and the process of capital investment.

Between any two calendar time periods the three supply curves of produced oil can be expected to change position. These dynamic adjustments can be credited to two somewhat different forces. First, a number of the factors that are assumed constant in an initial time period may change; examples would include changes in technology and knowledge, in input costs, in taxes, in expectations about the future. Second, the potential supply of lifted oil is affected by the supply of reserve additions. If at current prices (of both oil as produced and oil in the ground) additions to reserves just equal production, then the supply curves for output would tend to remain unchanged. However, if production exceeds reserves additions, then the process of production decline in existing pools would reduce supply (shift the supply curves to the left). On the other hand, if reserves additions

exceed current production, then the supply of lifted oil would tend to rise, with the supply curves shifting to the right.

The underlying physical dimensions of the crude oil production decision, and the related economic supply concepts, may be made somewhat clearer by the slightly more extended graphical treatment of Figure 4.4, which examines a single oil pool in more detail. Panel A illustrates the capacity output path over time from an oil pool with a fixed amount of capital equipment in place; this is a short-run situation and the output path, q_p , shows falling production due to the depletion of reservoir energy as cumulative output rises. The dashed line, q_a , shows, for each year, the minimum output level acceptable to the producer. It is the output level that would generate just enough revenue to cover operating costs, and it is equal to the operating costs (OC) of the wells divided by the price (P) of oil. (If $P_t \cdot q_a = OC_t$, then $q_a = OC_t/P_t$.) Production decline means that actual output is steadily pushed down towards the minimum acceptable output rate; typically this defines a time of abandonment, T_A , at which the oil pool will be shut down. The variable tax component of the short-run production decision is treated sometimes as a component of operating costs (OC) and sometimes as a deduction from price (P) to yield a net (after-tax) price.

Panel B translates this pool’s output path into economic short-run supply curves (abstracting from complications of the user cost component). Given that capital costs are sunk, the variable operating costs of a pool would typically yield a marginal cost curve like MC_o . The decision to operate (produce even one cubic metre of oil) requires an expenditure to maintain the equipment for the year. But once that is done, the incremental lifting cost is very low (e.g., pumping costs only) until capacity of the equipment is reached under the pool’s current reservoir conditions (capacity output q_o , where the marginal cost curve becomes extremely steep). Curve AVC_o shows the average variable cost of various possible output levels; the first cubic metre has the same average and marginal cost and, thereafter, the low cost incremental units reduce the average cost, up to output level q_o . Under these conditions the producer will decide either: (1) to produce at capacity, where price, $P_o = MC_o$, so long as average revenue covers average operating costs i.e., $P_o \geq AVC_o$) or (2) to shut down (if $P_o < AVC_o$). Therefore the short-run supply curve (S_o) for the oil pool is the marginal cost curve above the minimum point of the average variable cost curve. Production

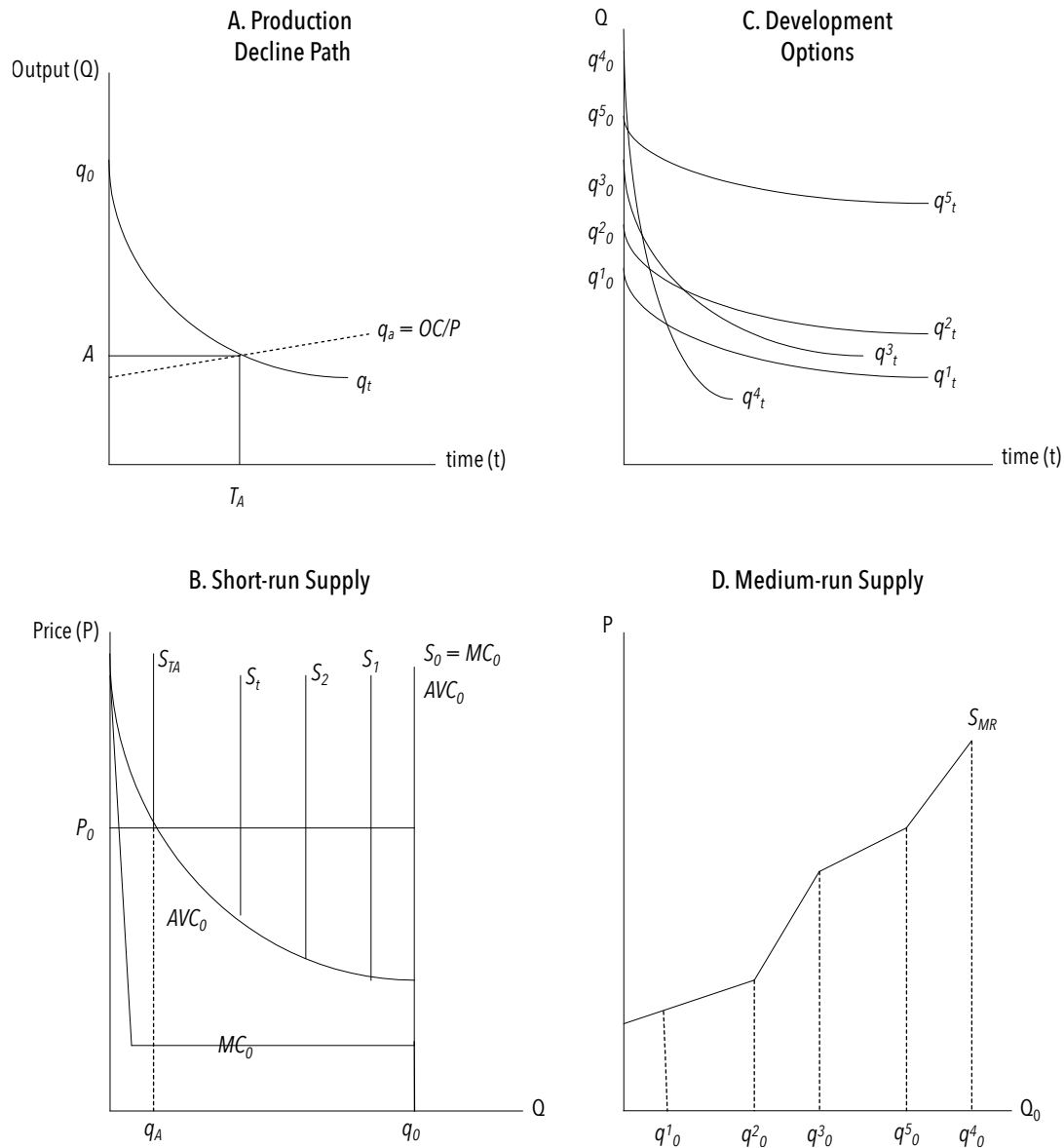


Figure 4.4 Crude Oil Supply: One Pool

decline means that the capacity output level from the fixed capital becomes smaller and smaller, so that the short-run supply curve shifts back to the left over time (to S_1, S_2, \dots, S_t) until the year of abandonment (S_{TA} , if the real price of oil is fixed at level P_0).

Panel C of Figure 4.4 shows changes in the time-path of output from the pool as more wells are drilled. Apart from occasional dry holes, additional wells will increase the initial output rate from the pool (q_0). Panel C shows five possible developmental options with progressively higher initial output rates from q^1_0 to q^5_0 , illustrating different types of medium-run pool

development. From an initial development plan (q^1_t), output path q^2_t shows extension (or outpost drilling) which brings more oil reserves into production and allows higher output levels in all years. Output path q^3_t is an example of infill drilling that produces the same reserves more quickly, so that $q^3 > q^2$ in early periods, but $q^3 < q^2$ later. Curves q^2_t and q^3_t illustrate 'pure' cases of extension and infill drilling; in most oil pools, incremental development will involve a gradual transition from extension to infill activities. Output path q^4_t shows a somewhat perverse case of infill drilling in which the high initial output rates significantly

damage reservoir flow rates so that the production decline becomes very high. Most petroleum reservoirs have a 'maximum efficient rate' (MER) for oil wells or for the reservoir as a whole, which, if exceeded, results in high output decline rate and a loss in total recoverable reserves. Profit-maximizing producers ordinarily have no incentive to exceed the MER since it means a large loss of future profits (i.e., user costs are very high above MER). A significant exception is when several companies jointly produce from an oil reservoir, have no agreement on sharing output and profits, and operate under the legal convention known as the 'rule of capture' in which ownership of the oil belongs to the party that brings it to the surface. Here companies may exceed the MER since they believe that any oil left unproduced today will be captured by the other companies in the pool. Government agencies like the Alberta Energy Resources Conservation Board (ERCB) often impose regulations that restrict output to levels less than the MER. (See Chapter Ten.)

Finally, output path q^5_o , in Figure 4.4, Panel C, shows the impact of a successful EOR project that raises the recovery factor, thereby bringing new reserves into production, allowing more output in all periods. Panel D of Figure 4.4 shows the medium-run supply curve for crude oil produced this year from the pool shown in Panel C. Pure extension drilling adds output at a cost very close to the initial wells (q^1_o to q^2_o); infill drilling generates higher per unit costs due to well interference and rising user costs as current production reduces future output and profits (q^2_o to q^3_o); EOR schemes are typically more costly than primary recovery schemes (q^3_o to q^5_o); output in excess of the MER has very higher user costs of forgone future profits so is very high in cost (q^5_o to q^4_o).

The way in which various development options might be sequenced is very reservoir-specific.

4. Elasticity of Supply

Economists frequently use the term 'elasticity of supply' to describe the shape and position of the supply curve. The concept of 'elasticity' is important: it is the relative (percentage) change in one variable divided by the associated percentage change in a related variable, and shows the responsiveness of one variable to change in another. 'Own-price elasticity of supply' (usually called, simply, 'elasticity of supply') is the percentage change in the quantity of a product supplied divided by the percentage change in the price of the product, all else being equal; that is, it describes

movement along the supply curve. Where the symbol ' Δ ' is used to represent a change:

$$E_s = (\Delta Q_s / Q_s) / (\Delta P / P) = (\Delta Q_s / \Delta P) (P / Q_s).$$

The own-price elasticity of supply (E_s) is equal to the reciprocal of the slope of the supply curve ($\Delta Q_s / \Delta P$) multiplied by the ratio of price to quantity. The slope of the supply curve by itself is not a satisfactory measure of supply responsiveness. Exactly the same supply information can be conveyed using a number of different quantity measures; i.e., b/d; b/year; tons/year, m³/month, etc. The same supply curve would yield quite different numerical values for its slope in each of the cases, even though the relative changes in price and quantity were the same. It is desirable to measure elasticity as a pure number, independent of the particular units of measurement chosen, and using percentage changes does this.

A higher price elasticity of supply means that any given percentage rise in price yields a higher percentage rise in quantity supplied. Thus, for instance, the long-run price elasticity of supply for crude oil will tend to be higher than the short-run elasticity as was seen in Figure 4.2.

It is customary to refer to a value of E_s greater than unity as showing 'elastic' supply and a value of E_s less than unity as showing 'inelastic' supply. Empirical work by economists has clearly demonstrated that the elasticity of a supply for crude oil is significantly greater than zero (e.g., Uhler, 1977; Bradley, 1989). This gives lie to one of the common beliefs in energy analysis – that fossil fuel availability is determined solely by nature, and that economics is essentially irrelevant to energy policy: price does affect availability.

C. Demand

Our treatment of demand is analogous to our discussion of supply. One can postulate a 'demand function' that shows the relationship between the quantities (in m³/d) that purchasers are willing and able to buy and the major factors that influence that desire. Amongst the important factors affecting demand for crude oil at the wellhead would be:

- (1) the **price of oil** (the lower the price, the greater the quantity demanded);
- (2) conditions in the markets for refined oil products, for example,

- (i) tastes of consumers (Do they prefer compacts or larger cars? Do they like really warm houses or cooler ones? Is it an austere, puritanical society, or a conspicuous-consumption-oriented one?);
- (ii) incomes of consumers;
- (iii) population in the market;
- (iv) prices of substitute products (e.g., natural gas, insulation) and of complementary products (e.g., automobiles);
- (v) technological and cost conditions in industries that use petroleum products in their production processes;

- (3) conditions in the supply industries between the oil field and the final consumer, e.g., pipe line and tanker systems and oil refineries (the higher the costs of moving or refining the oil, the lower the quantity demanded at the well-head); and
- (4) current expectations of the future values for these variables and the price of oil (higher expected prices in the very near-term tend to induce higher current demand to capitalize on today's lower prices, while higher expected prices in the far-term tend to induce lower current demand as consumers purchase non-oil-using capital equipment today).

A demand curve shows the hypothetical relationship between the quantity demanded and various prices of the product, with all the other factors that might affect demand assumed to be constant. The demand curve is the locus of points representing the maximum rate of purchase at the given price; equivalently, it is the maximum price that would be paid for the given quantities. It should exhibit a downward slope since a reduced price for crude oil will both free income for more consumption (including more crude oil) and induce the consumer to substitute crude oil products for products whose price has not fallen (e.g., other fuels). If any of the other factors underlying demand should change, then a new demand curve would appear. In Figure 4.5, for instance, an increase in demand from curve D_{SR} to curve D' can be seen (at every price the quantity demanded is higher on curve D'). This might result from a rise in the price of natural gas, an increase in consumers' income, a rise in population, a fall in refining costs, or the like. In addition, it is useful to distinguish between the short-run demand for crude oil, when the ability of purchasers

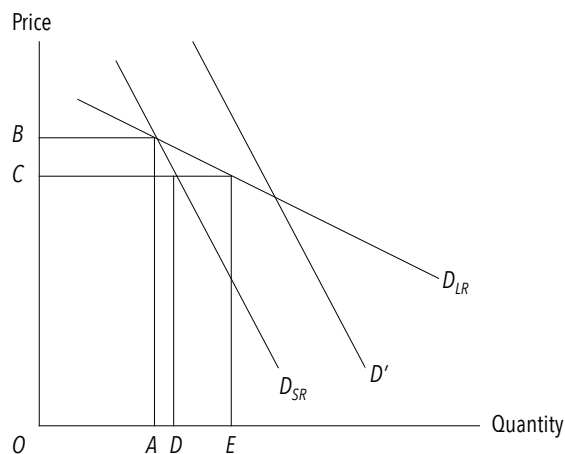


Figure 4.5 Crude Oil Demand

to adjust their capital equipment is assumed to be non-existent, and the long-run demand, shown by D_{LR} , when the stock of energy-using capital equipment can be adjusted in a way that is optimal for that oil price. For example, in Figure 4.5, a fall in price from OB to OC would lead to an increase in quantity demanded of only AD in the short-run, but of AE in the long-run.

The (own-) price elasticity of demand (E_d , usually called the elasticity of demand) measures the percentage change in the quantity demanded divided by the percentage change in price of the product, other things affecting demand held unchanged; i.e.

$$E_d = (\Delta Q_d / Q_d) / (\Delta P / P) = (\Delta Q_d / \Delta P) (P / Q_d).$$

The elasticity of demand will normally be negative since a price rise means a fall in the quantity demanded. (It is wise to be aware that some economists drop the negative sign, utilizing the absolute value of the elasticity.) A "large" elasticity of demand (e.g., an elastic demand, where $|E_d| > 1$) implies that a given percentage change in price gives a relatively large change in quantity demanded. The long-run elasticity will exceed the short-run elasticity. Empirical evidence clearly demonstrates that price changes do affect petroleum consumption (e.g., Berndt, 1977; Berndt and Greenberg, 1989; Berndt et al., 1981; Watkins, 1991c). Hughes et al. (2008), however, find that the short-run elasticity of demand for motor gasoline appears significantly lower after 2000 than it was in the 1970s and 1980s.

An interesting relationship exists between the price elasticity of demand and changes in consumer

expenditures as a result of price changes. With an elastic demand ($|ED| > 1$), a rise in price will generate a fall in the amount consumers spend for oil; conversely, a price fall will give increased expenditures. If the demand curve is inelastic ($|ED| < 1$), a price rise (fall) gives increased (decreased) expenditures. With unitary elasticity of demand ($|ED| = 1$), expenditures are constant as prices change. By way of example, consider a price rise along a downward sloping demand curve. If all else were equal, an $x\%$ rise in price would imply that expenditures on oil rise by $x\%$. However, the price rise generates a reduction in the quantity purchased; if quantity fell by $y\%$, all else being equal, then expenditures would fall by $y\%$. The change in total expenditures clearly depends on which of these two effects is larger. (That is, which is larger, x or y ?) Recall the definition of the price elasticity of demand: percentage changes in quantity along the demand curve (i.e., y) divided by percentage change in price (i.e., x). If the curve is elastic ($|ED| > 1$), then the numerator (y) must exceed the denominator (x), so that a price rise implies reduced expenditures after the consumer adjusts his purchases to the higher price.

This price elasticity/expenditure relationship helps explain some economic phenomena. Consider, for example, the effect on oil-importing regions of the OPEC-generated oil price rises of the 1970s. Recall that in the short-run the demand curve for oil is quite inelastic, as low as -0.1 or -0.2 according to some studies. Sharp increases in the price of oil, then, generate large increases in expenditures on oil, at least in the short term. This helps us understand OPEC's desire for higher crude oil prices. Or, to put the issue somewhat more generally, large price rises are not simply a result of the establishment of effective oligopoly power by sellers but also depend on conditions on the demand side of the market (i.e., the elasticity of demand).

We might also point out some macroeconomic implications of the elasticity/expenditure connection. For oil-importing regions, the oil price rises of the 1970s generated larger expenditures on imported oil because of the short-run demand inelasticity. Therefore consumers had less money to spend on other goods and services, generating a deflationary effect. In the absence of some countervailing change to increase the economy's aggregate demand (e.g., expansionary monetary or fiscal policy, or large increases in investment by domestic energy industries or substantially increased exports of goods and services to OPEC), the oil price rise was recessionary, giving lower growth and higher unemployment.

3. Market Equilibrium in Perfect Competition

Supply and demand provide a ready framework to explain market price when the selling and buying sides of the market are completely independent of one another. This condition is met under 'perfect competition,' in which a great many fully informed buyers and a great many fully informed sellers buy and sell exactly identical units of some product with no collusion whatsoever; it is assumed that new buyers and sellers can enter the market, and old buyers and sellers leave, with no impediment. Perfect competition is an idealized market form. In the real world the hypothetical perfectly competitive results may be approximated under conditions of 'effective' or 'workable' competition.

Under such competitive market conditions, the price will tend toward an equilibrium point at which demand is equal to supply, i.e., the market clears at price P_E and quantity Q_E in Figure 4.6, Panel A. A price higher than this (for instance, a price of OA) will mean that the quantity sellers are willing to supply (OC) exceeds the quantity purchasers are wishing to buy (OB); this excess supply (BC) can be expected to put downward pressure on market price until the equilibrium point is reached. For purposes of illustration, it is convenient to assume that the market always adjusts instantaneously to the equilibrium point. This avoids the difficulty of illustrating the nature of the adjustment process, including any lags and the accumulation and disposal of unwanted inventories. Of course, in the real world, this adjustment process might proceed in a variety of ways and is a matter of major concern to participants in the oil market. Trading departments in oil companies and assorted middlemen (including speculators) operate in large part in response to current disequilibria. And in a well-informed trading environment, their actions help to move the oil market to equilibrium.

The analytical advantages of the demand and supply tools become evident when attention is turned to the impact on market equilibrium of changing circumstances. The major factors underlying both demand and supply were noted earlier; changes in any of those factors will lead to changes in the equilibrium price and quantity. Figure 4.6, Panel B, for instance, shows the short- and long-run effects of an increase in the demand (from D to D') for oil at the wellhead (for example, as a result of increases in natural gas prices, rising population, etc.). In the short run, when supply responsiveness (elasticity) is low, there is a large rise

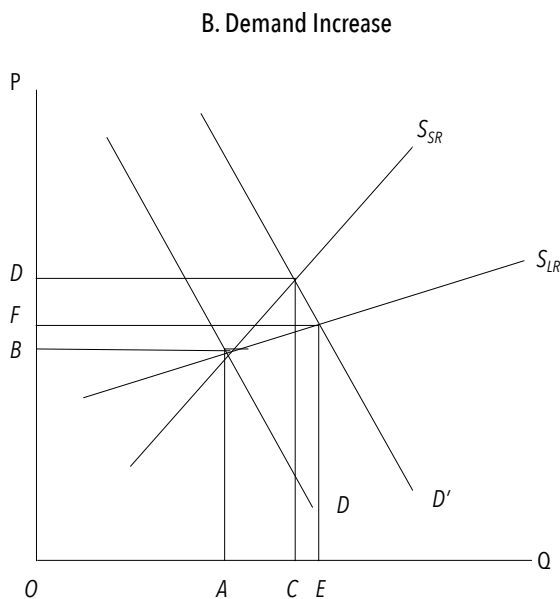
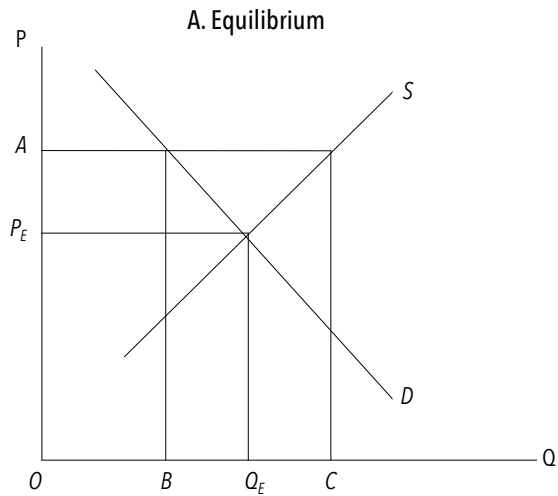


Figure 4.6 Market Equilibrium

in price from OB to OD and a relatively small rise in quantity from OA to OC . In the long run when producers are fully able to adjust to the price rise, the equilibrium will be established at a lower price (i.e., OF) and higher quantity (i.e., OE) than in the short-run.

It is easy to examine the impact of other shifts in demand and/or supply and the associated changes in equilibrium price and quantity: a number of cases will be considered later in this chapter. Remember that the more inelastic the demand curve (and/or the supply curve) is the greater the extent to which adjustments

occur in the price of the product rather than the quantity. It is generally conceded that the short-run supply and demand elasticities for petroleum are low; less certainty exists about the long-run elasticities, except that they exceed short-run elasticities. It is also true that the more narrowly a market is defined, the more elastic at least one of the curves tends to become. For example, the demand for 36° oil from the Redwater pool would be very elastic because a wide variety of other crudes substitute very easily for this grade of oil.

We make two final comments. First, at any particular time only one market price and quantity will be observed. Under the simplifying assumptions made here, this is the equilibrium result, a point on both the demand curve and the supply curve. All other points on the two curves are hypothetical (i.e., unobservable in the market): they tell what buyers (or sellers) would do if the price were at some level other than the equilibrium one. The fact that most points on the demand and supply curves are hypothetical makes empirical derivation of the curves extremely difficult. Economists speak of the 'identification problem,' meaning that the plotting of price/quantity combinations as observed over time will not generally trace out either a supply curve or a demand curve. If all observations come from various intersections of the two curves, this information alone cannot be used to derive the parameters of one of the curves. More sophisticated techniques are needed that take account of the many other changing factors that affect supply and demand, and different modellers will generally estimate somewhat different supply and demand functions. Second, the terms 'demand' and 'supply' are frequently used in a much looser way than as defined here. Sometimes 'demand' is used to mean consumption and 'supply' is used to mean production (or availability), but the words then refer to observed market results, not hypothetical price-quantity schedules. For the economist bound by the conventions of current economic terminology, the equivalence of 'consumption' and the 'demand schedule' (or 'production' and the 'supply schedule') only make sense if the quantities of oil demanded (or supplied) are completely unresponsive to (perfectly inelastic with respect to) price and other variables discussed above. To say that the 'demand' for oil is higher because consumption has increased need not mean that there has been a rise in the demand schedule: it may simply be that the price of oil has decreased, generating a movement along the demand curve. The distinction between movements along a curve and shifts in a curve is important.

4. Normative Aspects

Thus far, we have dealt with several analytical tools of value in describing why a particular result occurs in the market for oil. Society is interested not only in why changes occur but in whether they should occur. This involves a change in focus from 'positive' (or descriptive) analysis to 'normative' analysis and means that the analysis of the economics of the petroleum industry is an exercise in 'petropolitics' rather than pure economics. Is the price of natural gas too low? Should Canada allow the price of crude oil to rise? Is a gasoline rationing system desirable? Should we impose a depletion tax on non-renewable energy resources? These are issues of social policy. What can economics contribute to their solution? Some economists feel that the tools of demand and supply are useful not only because they help us describe the operation of the economy but because they tell us something about the desirability or 'efficiency' of alternative economic positions. As a general criterion for policy, economic efficiency is concerned with maximizing the benefits attainable from society's scarce resources.

That argument has been popular since an early version was propounded by Adam Smith in 1776. It relies strongly on the acceptance of what might be called 'individualistic liberalism' as a preferred social ethic: it assumes that the individual is the best judge of his or her own well-being, and that, if one individual is moved to a preferred position without harming anyone else, society is better off. Since most changes, however much they may benefit some people in society, involve moving others to a less-preferred position, it is necessary to further supplement the assumptions of individualistic liberalism. Specifically, it is often assumed that a common additive measuring stick can be applied equally to all people, that measuring stick being the monetary value individuals associate with changes, and that there is a social gain (rise in efficiency) if the sum of (dollar) benefits exceeds the sum of costs. This involves abstraction from all 'equity' considerations: how costs and benefits are distributed across different individuals. More accurately, it is usually suggested that equity considerations must be considered as well but can be considered independently of the efficiency criteria outlined so far. We shall return to this point shortly.

It might be noted that 'efficiency' can be treated as a purely descriptive concept: that is, efficiency rises if aggregate dollar benefits from a policy exceed aggregate dollar costs. However, to say that an increase in efficiency is desirable does necessitate the acceptance (explicitly or implicitly) of the value system outlined

above. This is an extreme version of what Sen calls 'welfarism.' (For a discussion of this and other ethical premises for social policy see MacRae, 1979, and Sen, 1987.) That this is an extreme version is suggested by the observation that even where acceptance of this general system of beliefs has been most common, it is not usually applied to all segments of society (e.g., to children, lunatics, and criminals). It has also been suggested that the emphasis upon the individual fails to give adequate weight to humans as social animals. And some critics have questioned whether the individual's choices can be taken as representing the individual's best interests.

There are other ethical premises for valuing social policy. Some alternate value systems are 'paternalistic' in the sense that individual preferences are overridden by some other criterion of the social good. Still other value systems may give equity considerations over-riding importance: for example, a change is never acceptable if it moves poorer people in society to a less-preferred position. Other value systems may be strictly libertarian, arguing that a person should never be forced by government policies to move to a less-preferred position. Despite these alternatives, many economists feel that the concept of economic efficiency provides a workable and plausible basis for evaluating policy alternatives and feel comfortable enough with its underlying individualistic premises.

If the efficiency criterion is accepted as socially desirable, one can quite easily see why a well-functioning perfectly competitive free market economy is frequently characterized as preferable to alternate forms of economic organization. It is, after all, based upon the expression of individual desires through demand and supply and does not involve individual producers or consumers exercising control over market prices to their advantage.

The argument may be advanced in slightly more formal terms. Effectively competitive markets are assumed. Moreover, it is necessary to assume that all the real gains and losses from economic transactions are felt only by individuals actually participating in the market transactions. In formal economic terms, this means that there are no 'externalities' of either a positive sort (e.g., one firm benefiting by adopting, without appropriate charge, another firm's innovation) or a negative sort (e.g., harmful pollution, which a firm does not take into account as a cost of its production). Under these circumstances, the supply curve can be interpreted as representing costs for the whole society (i.e., social costs) as well as showing marginal costs to the individual private operator. In other words, it measures the amount society must pay inputs in order

to achieve that particular unit of production. Both input costs and user costs would be accepted as valid marginal social costs. Royalties and taxes normally would not, since they are a transfer of profits from the private decision-maker to the landowner or government, rather than a cost to society. An exception is where the government devises a 'perfect' tax scheme to capture the marginal user costs and institutes a royalty equal to what these costs would be without the royalty. (With the royalty the user costs are zero, since the operator cannot capture any future profits, but the royalty is equivalent to the user costs. The games economists play!)

In the absence of externalities, the demand curve can be interpreted as a marginal social benefit curve, in that it approximates the amount that the individual is willing to pay to obtain that particular unit of output and is thus a measure of the value of that unit

Market equilibrium occurs where the marginal social benefit curve (D curve) intersects the marginal social cost curve (S curve). (See Figure 4.6A, again.) This quantity of output, with the associated market clearing price, is preferred to any other. Why? Any additional unit of output has a social cost greater than the social benefit (i.e., $S > D$, for that unit, as measured on the value or price axis), so it should not be produced. But all the previous units of output have a (marginal) social benefit greater than (marginal) social cost (i.e., $D > S$, for each unit), therefore each contributed a net benefit to society and should be produced. The conclusion? Competitive free markets yield the most desirable economic results for society: less production reduces net social benefit, as does more production. It is important to remember that this result depends on all benefits and costs being 'internalized' into the oil market.

It is useful to elaborate slightly on this idea of economic efficiency in effectively competitive markets, and on the concepts of 'producers' surplus' and 'consumers' surplus.' Recall that producers' surplus (economic rent) is the excess of market revenue above aggregate costs. In an efficiently competitive market (Figure 4.6A), it is the area between the price line and the supply curve. Consumers' surplus is the difference between the (maximum) amount a consumer would be willing to pay for a unit of output and the amount actually paid. In the market equilibrium in Figure 4.6A, it is the area between the demand curve and the price line. The producers' and consumers' surpluses represent net gains to market participants – profits (the excess of price above marginal cost) for producers, and net consumption gains (the excess of the value of consumption above price) for consumers. It is

easy to see in Figure 4.6A that the price and quantity where supply intersects demand maximizes the sum of producers' and consumers' surpluses.

We would suggest that there are several normative interpretations of the result. Suppose, for instance, one were to look at the possible output levels in the market for a product, as illustrated in Figure 4.6A, and to ask what is the most desirable output level for society. Even without a clearly expressed general normative criterion, a plausible choice is the output level that maximizes the sum of producers' and consumers' surpluses. The fact that this is exactly the response that economic efficiency suggests can be taken as offering support to efficiency as a useful normative objective. A second normative interpretation is that which initially generated this discussion. If efficiency is the normative goal, then free and effectively competitive markets are socially desirable precisely because they do tend to generate maximum efficiency.

There are, of course, complications, including the concepts of 'second-best' and externalities. The failure of the economy as a whole to function in a perfectly competitive manner poses special problems in determining the value of inputs drawn from other sectors and the value of output in this sector. Costs and prices may no longer measure marginal social values. This is what economists label as the 'Problem of the Second-Best.' This book abstracts from these problems, although it has been argued that they dominate economic activity (Blackorby, 1990; Blackorby and Donaldson, 1990).

Externalities in the petroleum industry can, in theory, be incorporated within the normative theory: quantities can be evaluated at hypothetical costs and prices ('shadow prices') that include the dollar value of the externality. For example, we could find the maximum payment an individual would be willing to make in order to avoid industry-generated pollution and include this as an additional cost to society of the industry's activities. In this case the private industry would not be expected to produce at the efficient level unless forced to recognize ('internalize') the pollution cost.

Most market adjustments for a single product have relatively minor effects upon the overall distribution of income in the society. If the effects are not minor, they can usually be overcome by some general tax or subsidy arrangement. Hence, for many policy changes, an acceptance of the ethic of individualistic liberalism suggests the desirability of improvements in efficiency, regardless of the equity effects. Critics note that several major problems arise from the decision to separate efficiency and equity. The efficiency rule

is based upon current prices of goods and services. To separate efficiency and equity suggests that these prices are independent of the distribution of income. If our equity judgment tells us that income differences between the average North American and the average resident of South East Asia or Ethiopia are morally indefensible, can we accept the price structure the current world income distribution gives us? The second problem relates to the weight given to future generations. They have no direct vote (can have no direct vote) in the efficiency rule: is the role given to them through our expectations about their demand for goods and services an adequate one? On this issue, see Page (1977).

Acceptance of the normative aspects of the efficiency criterion is obviously not universal. Some feel the concentration upon dollars as measured in the market is too restrictive, ignoring as it does historical processes, the non-market aspects of individual and social life, and pervasive second-best problems. Others simply do not accept an individualistic approach. Such criticisms argue that individual preferences do not equate with social welfare. However, a majority of North Americans seem inclined to an individualistic ethic; hence, in the remainder of this study, the normative model will be used on occasion. Readers who are sceptical of the appropriateness of the normative efficiency criterion might give careful consideration to the two following arguments:

- (1) One of the major advantages of the efficiency objective is its broad applicability, with the associated virtue of consistency in policy recommendations. There is a tendency – especially strong if the economic system is viewed from the perspective of a specific interest group – to reject the policy conclusions of the efficiency rule, but to replace it with a series of *ad hoc* judgments. The resulting policy recommendations often turn out to contain contradictions. Two examples might be cited:
 - a. The efficiency argument suggests that North American domestic oil prices should equal international (OPEC) levels, since we import OPEC oil. Therefore, OPEC is a marginal supply source for Canada and the United States, and one extra barrel of oil consumption costs the OPEC price. But, it is often argued, higher prices reduce the standard of living of oil consumers. Therefore, oil prices within the country should be kept low. However, as the economic

reasoning outlined earlier makes clear, lower oil prices both induce greater consumption and inhibit new supply additions, therefore increasing the dependence on high cost imported oil and generating even larger transfers of funds to oil producers in the OPEC world. Thus the viewpoint of current oil consumers is far too narrow a basis for consistent long-run policy analysis. The point is not that the effects upon oil consumers are unimportant. Rather, the point is that oil producers and taxpayers who subsidize imports from OPEC are also members of society and it is desirable to have a policy guide that incorporates the effects on them as well. The efficiency rule provides such a guide.

- b. A second example relates to exports of energy products. It is frequently suggested that, since oil is a depletable natural resource, we must save all we can for future generations of Canadians. Therefore, all current exports should cease. What is less frequently suggested, but should surely follow as strongly, is that current generations of Canadians are also consuming too much of this scarce resource, at the expense of future Canadians. Limiting exports, without additional regulation, will increase availability for the domestic market and lower prices thereby tending to generate more energy consumption by current consumers in Canada. How does this meet the obligation to future generations?

It is not our intent to argue that Canada must export oil or that the efficiency argument is the only correct basis for public policy. However, what happens far too frequently is that policy recommendations are made on the basis of very limited or expeditious judgments. What is required is some broad overview of public welfare: the normative efficiency rule is one such view and therefore ranks among useful criteria for economic policy evaluation.

- (2) Many critics of the efficiency criterion would suggest that the clearest proof of its failure lies in the area of energy policy, for reasons suggested in the first paragraph of this chapter: how can policy based upon the satisfaction of selfish desires of today's oil producers correctly allocate the fixed stock of petroleum that time and chance have bequeathed? Supporters of the

efficiency rule have two lines of argument in support of their position:

a. The first is to point to the historical record. For the past century or more, in the industrialized world, economic production and consumption have been based in large part on individual market decisions. This does not guarantee economic efficiency, but, as we noted above, the concept of economic efficiency does give strong support to the institution of free markets. Over this period we have witnessed sustained improvements in our physical well-being (measured both by consumption and health statistics). Moreover, most depletable natural resources seem, if anything, to have been more available (i.e., cheaper) in the post-World War II period than before. Thus, while admitting that there have been instances of monopoly power and agreeing that some externalities require correction, the historical record can be interpreted to suggest that free markets have not led to overly rapid exploitation of the resource base. Several simulations of the long-term future conditions in energy markets have reached the conclusion that energy needs can likely be met through the indefinite future, if the efficiency rule is followed. (For example, see Nordhaus, 1973, and Manne, 1976.) Of course, the argument that supplies of energy are likely sufficient for the indefinite future does not preclude the possibility that we are over consuming energy today because markets fail to recognize negative externalities such as environmental costs.

b. The second line of argument stresses the theoretical model of resource markets. In particular, it notes that efficient natural resource producers do take account of the expected future values of resources and will be quite willing to save resources for consumers in the future, if it appears profitable. The argument that the efficiency rule should be abandoned because it includes consideration only of immediate profitability is incorrect.

Once again, it has not been our intent to argue that the efficiency rule is the only feasible one for social decision-making. One can, for instance argue, that it gives insufficient weight to future generations because discount rates used by private decision-makers are too high

(Lind, 1982). However, the rule is not as limited as many critics suggest, and it is reasonable to suggest that efficiency is one criterion that is useful for evaluating economic policies.

5. Market Equilibrium in Imperfectly Competitive Markets

Many markets do not have independent buyers and sellers: individuals (or small coalitions) are able to affect the market price. Supply and demand cannot, then, operate independently to establish price since one side or other of the market (or both, in some cases) is able to determine, in part, what the other side will do – in short some participants possess ‘market power,’ and competition is ‘imperfect.’

It is important to note that market power is not conveyed to a firm simply because it is large. What is relevant is the size of the firm compared with the market and ease of entry. A large firm (measured by assets or sales) in a large industry may have no market power, whereas a small firm in a small market may have significant power. Moreover, it is not only current but potential participation that determines the extent to which markets may be effectively competitive. One approach emphasizes potential entry into (the ‘contestability’ of) markets (Baumol, 1986). This raises the contentious issue of the formal definition of a market. Obviously, it must be rather arbitrary, an extreme view suggesting that there are no markets, only buyers and sellers. Should we speak of the market for non-leaded premium motor gasoline in Don Mills, Ontario? Or the market for gasoline in Ontario? Or the market for oil in Western Canada? Or the market for energy in Canada? The most critical requirement of a ‘market’ would seem to be that it includes all individual buyers who show high willingness to move from one seller to another; similarly, all sellers must be very willing to move between buyers. A market typically covers a relatively homogeneous product and has good information flows among market participants.

Five cases of market power will be examined:

A. Monopoly

There is only one seller, so the monopolist faces the entire market demand for the product and can select where on that curve to operate. (The case of a

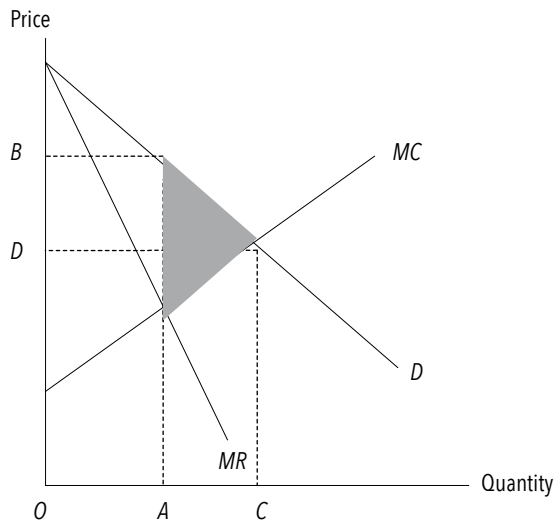


Figure 4.7 Monopoly in the Crude Oil Market

‘price-discriminating monopolist,’ which charges different prices for different units sold, will be discussed below.) In this case a company may profit by restricting sales in order to charge a higher price. Economists have formalized this in a simple but useful model. The firm will maximize profits if it produces output up to that unit which has a marginal cost (MC) equal to the marginal (incremental) revenue (MR) (Figure 4.7) and charges the price shown by the demand curve for that unit of output. The marginal cost of production for a monopoly is equivalent to what was called the ‘supply curve’ for a competitive firm. But the monopolist’s marginal revenue curve lies below the market demand curve. The monopolist can sell an additional unit of the product only by cutting price and accepting a lower price on all sales. Thus to calculate marginal revenue it is necessary to deduct, from the revenue on the new unit sold, the reduction in revenue on all units that were previously sold at the higher price. For example, if 150,000 m^3/d were sold at $\$35/m^3$, total revenue would be $\$5.25$ million/d. Demand conditions might be such that 160,000 M^3/d could be sold if the price were reduced to $\$34/m^3$; revenue would be $\$5.44$ million. Marginal revenue (per additional cubic metre) would be $\$190,000/10,000m^3 = \$19/m^3$, which is less than the market price of $\$34$. The $\$190,000$ consists of $\$340,000$ on the new sales ($10,000 m^3$ at $\$34$ each) less $\$150,000$ ($\$1$ less on each of the $150,000 m^3$, which used to be sold at $\$35$).

Contrast this with an effectively competitive market. Price is determined where market supply intersects market demand. Individual firms have no

ability to influence the price of the product. If a firm attempts to charge more than the market price, no one will buy its product. It has no need to charge less than the market price because its small size means it can sell as much as it wishes at the market price. As far as the individual firm is concerned, the demand curve is perfectly elastic (i.e., flat) at the market price and this price will be the marginal revenue from each extra unit sold. In order to maximize profits, each firm in a perfectly competitive market produces where $MR = MC$, but this means it produces where price equals marginal cost.

In Figure 4.7 the monopolist would charge OB and sell OA units. An effectively competitive market with the same costs, including user costs, would yield price OD and quantity OC . If the normative efficiency criterion is applied, it is evident that there is a welfare loss (efficiency loss) under monopolistic conditions. The monopolist values additional units of sale (as indicated by the MR curve) less highly than does society as a whole (as indicated by the demand curve, D). The welfare loss of the monopoly is given by the shaded area: it is a dollar sum equal to the amount consumers would be willing to pay for the units of output the monopolist does not produce, less the cost the firm would incur in producing them, up to the unit of output at which the marginal benefit (demand) equals the marginal cost. Expressed slightly differently, by restricting output in order to maximize its own profits, the monopolist generates a market result that no longer maximizes the sum of producers’ and consumers’ surpluses.

For most changes in underlying market conditions – that is, if the demand and/or marginal cost curves shift – a monopoly market will react in the same directional manner as an effectively competitive one. Thus, the tools of competitive demand and supply are often useful for analyzing the direction of changes in equilibrium price and quantity, even though the market may not be perfectly competitive.

The discussion thus far has assumed that a monopolist charges a single price to all purchasers. Another possibility is a price-discriminating monopoly that charges different prices to different customers, or even to the same customer on different units. In this manner, the monopolist can capture more of the consumers’ surplus. For such price discrimination to be possible, the purchasers in different price classes must be effectively segregated. For example, Buyer ‘A’ who is charged a lower price must not be able to increase purchases and resell them to Buyer ‘B’ to whom the monopolist is quoting a higher price. Geographical

distance may provide a segregating factor, as when Buyer 'A' has to pay a shipment cost to move the product to Buyer 'B'. The presence of price discrimination is sometimes difficult to determine (Phlips, 1983). It includes, for instance, the obvious case of different prices for identical units of output. However, it also includes price differences not justified by differences in the characteristics of the output. For instance, to charge the *same* price for delivered output to customers in *different regions* would involve price discrimination because the prices do not reflect differences in the cost of delivery to the regions. It is interesting to note that a perfectly effective price discriminating monopolist would produce at the efficient output and price (just as under perfect competition, where the demand curve cuts the marginal cost curve). Each unit of output would be sold at the price indicated on the demand curve; all potential consumers' surplus, as well as producers' surplus, would be captured by the monopolist. Monopolies, let alone price-discriminating monopolies, are relatively rare. Their existence in the long-run depends upon an ability to exclude new firms from the industry, even in the face of substantial monopoly profit.

Four significant types of barriers to entry, and their possible application to the petroleum industry, will be discussed:

1. **Economies of Scale (Natural Monopoly).**

Technical conditions of production may mean that the average cost of production for a firm decreases with increased output, up to the full extent of market demand. In this case, efficiency requires only one facility in the market so that production costs are at a minimum. On the other hand, efficiency requires a pricing policy other than the monopoly one. Small firms find entry difficult since costs are so high, and large firms will not wish to enter because the market is not large enough for them as well as the established monopoly. Significant economies of scale exist in the petroleum industry in pipeline transportation and natural gas distribution, though there is a size of pipeline above which no further economies can be realized. If the market were small enough, economies of scale in refining could also prove significant, although they would be circumscribed by diseconomies of distribution, depending on location in relation to markets – one giant refinery might serve all the market with the lowest unit cost of

refining but would incur less than optimal distribution costs. Economies of scale may also be significant in 'frontier' areas in exploration and development. It should be noted that economies of scale serve as a barrier to entry only if they hold up to a level of output that is large relative to the size of the market demand.

2. **Government Monopoly.** Legislation or government decree may bring about monopoly conditions. The favoured company may or may not be government-owned. Often it is coupled with an enforced pricing policy that is designed to avoid the welfare costs of the monopoly.

3. **Absolute Cost Advantage.** The monopolist may have such a significant cost advantage over competitors that, even at the monopoly price, and with monopoly profits, new firms are not attracted to enter. This refers to the case in which the monopolist has lower levels of cost at all possible output levels, in contrast to the natural monopoly case where all firms have a lower average cost at higher output levels. Such cost advantages may arise, for example, from special knowledge, natural resource scarcity (one firm controls the lowest cost resource), vertical integration with a monopoly in upstream activities (the monopolist can charge high prices for essential inputs that it produces itself), monopoly in essential processes (generally supported by patent rights), access to unusually low cost capital, etc. In the petroleum industry, the major companies have been vertically integrated, often with a high degree of concentration in one or more levels of industry activity (e.g., the Standard Oil Trust in refining in the late 1800s, Middle Eastern crude oil reserves, refining in countries with small markets, pipelines). This opens up the possibility of input or output pricing practices that discourage entry at other levels of industry activity.

4. **Brand Loyalty.** On the demand side of the market, a particular firm may command such loyalty from consumers that new entrants are unable to break into the market place, even though the monopolist earns great profits. Usually this requires some legal protection (e.g., a patent or copyright) so that a competitor cannot produce an identical product. It may involve an absolute cost advantage, if a new entrant must undertake a major 'educational' expenditure to make buyers aware of its product.

These cases illustrate that the advantages of effective competition are not as clear as was suggested above. If there were significant economies of scale, or absolute cost advantages not due to monopoly restrictions of input supply or process technology, then real cost advantages accrue to society as a result of the monopoly. However, the monopolist's profit-maximizing position is not optimal for society since he will underproduce and overcharge. Usually government regulation or ownership is advocated by economists, such as the rate regulation that has been pervasive in the pipeline industry. Further, on the basis of dynamic considerations, some economists, like Joseph Schumpeter, have emphasized the importance of monopolistic markets in a technologically innovative society: the inventor of a new technology that benefits society also generates market power for itself, at least temporarily, so some degree of monopolization may be a price we pay for progress.

In general, unless entry barriers are extremely low or government regulations very effective, monopolies charge higher prices than effectively competitive industries and can generate efficiency losses.

B. Monopsony

There is one firm buying the product. The buyer may be able to price discriminate by paying less for some units purchased than for others, in effect picking up different units along the supply curve. In the absence of price discrimination, the result is analogous to the monopoly case (with a similar welfare cost), except that the reduced quantity produced is purchased at a price lower than with effective competition. The monopsonist buyer benefits by buying at the low price, but, as an upward-sloping supply curve tells us, at the lower price producers will make less available. If the monopsonist consumes the product directly, it has benefited by obtaining units at a price lower than the competitive one. If the monopsonist uses the product to produce something else, it benefits through the extra profits it gains from purchasing inputs at a low price. For the non-price-discriminating monopsonist, additional units of the product cost more than the price. This is because an offer to increase price in order to cover the increased marginal cost of the next unit of output also involves a higher payment for all units it was willing to purchase at the lower price.

A more complicated case arises if the monopsony buyer is a rate-regulated natural monopoly. For example, a natural gas pipeline company may be

the sole gas buyer in a region, and the sole seller in a market area, but subject to rate regulation. In this instance, the monopsonist has a direct profit motive to restrict purchases (and sales) by paying less for the product only to the extent that he is able to disguise extra profits as allowable costs in the rate base or is allowed a rate of return in excess of the normal profit rate. A more indirect motive comes from the increase in the size of the monopsonist's system if costs are lower so demand for the monopsonist's product is higher, but this raises obvious problems in obtaining the input supplies necessary to service customers since the low price paid to the input suppliers inhibits their willingness to produce. Some analysts have suggested that a monopsony of this sort existed in the 1950s and 1960s in the export market for Alberta natural gas. Large volumes of gas had been found as a result of the search for crude oil. While the market for this gas was being built up, a monopsonistic natural gas purchaser (TransCanada Pipeline, TCPL) was able to purchase gas at exceptionally low prices and rapidly expand its market east of Alberta. However, one would expect that, eventually, a market imbalance would become apparent, where more gas was being demanded at these low prices than TCPL could contract from natural gas producers.

C. Oligopoly

As noted in Chapter Three on OPEC, an oligopoly is a market situation with more than one selling firm but few enough firms (or with one or more of the firms large enough) that companies are able to affect the market price and must consider competitors' reactions to their decisions. Oligopoly market structures are prevalent in our society: the Canadian refining industry is an example, as is OPEC. Economists have no single model of oligopoly, since what occurs depends upon how companies perceive one another, and exactly how they interact. Preservation of a profitable oligopoly with a small number of firms requires barriers to entry of the type noted above. 'Profitable' here means continuing profits above and beyond the minimum return needed to keep firms in the industry. Sometimes the word 'cartel' is used interchangeably with 'oligopoly,' but we prefer to apply the term 'cartel' to an oligopoly market structure in which the oligopolists are in direct communication with one another.

An oligopoly market might generate a result identical to the monopoly one. This would be true of a 'strict' cartel, in which the companies act as if they

were a single firm – that is they rank output from the lowest cost unit to the highest cost unit, regardless of which firm produces it, and restrict output to the point where marginal cost equals marginal revenue. Investment in new facilities must also occur in the lowest cost manner. One can easily appreciate the difficulty in forming a strict cartel, particularly with regard to such matters as scheduling output shares, setting ‘fair’ profit shares, and determining the role of potential new entrants. Furthermore, there is a temptation for each individual producer to attempt to increase its share of industry output, especially if it feels that its share of industry profits is unfair.

In most countries, it is illegal for firms to enter into formal agreements to limit competition. However, a result close to monopoly may occur in oligopoly markets as a result of tacit (informal) collusion among firms. This is more likely if there are relatively few firms, producing virtually the same product, in an industry with high barriers to entry, and under relatively stable market conditions (e.g., steady growth in market demand). When companies all have the same information, they may collude by acting in a parallel fashion without direct communication. Frequently a pattern of price leadership evolves, in which one firm (often the largest) takes the initiative in changing price and other firms follow.

At the other extreme, an oligopoly situation may generate strong price competition among firms, with a result approaching the perfectly competitive one. This is the effective or workable competition model. If the good or service produced can be transported easily at low cost, effective competition may be attained with only a few domestic producers, given foreign competition.

Between the two extremes lie an infinite number of possible cases, some closer to the strict cartel end, some to the competition end. In comparison with the perfectly competitive case, all partake to some extent of the welfare criticism made of monopoly: the market result involves restricted production and higher prices. One type of intermediate position is thought to be very common in our society. Firms may compete in a non-price manner by means such as advertising, packaging, and changes in product quality, in order to differentiate their product. This raises costs, leading to a monopoly-type result (a higher price and lower quantity than with effective competition), but with the monopoly profits largely competed away. The absence of excess profits serves as a barrier to entry.

Generally speaking, the greater the number of firms in an industry and the smaller the largest firm

relative to total industry activity, the more effectively competitive the industry is likely to be. With a very large number of firms, or a moderate number of firms of roughly equal size, it will be very difficult for one firm to lead the industry or for all firms to reach a collusive agreement.

D. Oligopsony

Oligopsony is when there are few enough, or large enough, buyers that they must take into account their interactions with one another. As with oligopoly, the market equilibrium may lie between two extremes, in this case the monopsony and perfectly competitive cases. Aspects of non-price competition occur in oligopsonies as in oligopolies; examples include prepayment agreements (where an initial payment is made prior to delivery), inclusion of take-or-pay provisions in the contract (where the buyer must pay whether or not it takes delivery), absorption by the buyer of certain gathering or distribution costs, etc.

E. Bilateral Monopoly

This is the case where a monopolist sells to a monopsonist. The actual market result depends on the relative bargaining strengths of the two parties. The equilibrium quantity may lie anywhere between the competitive quantity and the extreme, restricted, non-perfectly competitive quantity. The price may be anywhere between the low monopsony one and the high monopolist one. The efficiently competitive result may occur in a bilateral monopoly case (e.g., if the monopolist and monopsonist are ‘perfectly’ matched, and will not compromise), but it is unlikely.

In general, imperfect competition involves restricted market quantities relative to perfect competition and (if the normative model is accepted) some welfare loss.

Little has been made in the preceding discussion of the existence of vertical integration, which is corporate activity at successive stages of processing in an industry. Vertical integration has been prevalent in the petroleum industry. Economic policy views horizontal concentration, at a single stage of the petroleum industry, as the more critical problem. Vertical integration is compatible with degrees of market concentration all the way from monopoly to effective competition. However, as was suggested above, there may be interactions between vertical integration and

horizontal concentration (often called ‘economies of scope’). Vertical integration may generate significant economies (reduced costs). These are seen largely in economies in the information process, greater flexibility in scheduling operations, and absolute cost economies or economies of scale due to large size. However, the existence of vertical integration does not necessarily imply that such economies are important. For example, in the international petroleum industry, a major inducement to vertical integration historically was to avoid the market power exercised by existing firms at the refining or crude oil production level.

6. Applications to the Petroleum Industry

The purpose of this section is to apply the tools of economic analysis to several public policy issues in the petroleum industry. For ease of presentation, we shall assume that the petroleum market is effectively competitive. Empirical analysis of several of these issues is included in later chapters.

A. Interrelations among Markets

The petroleum industry is international; no part of the world oil market is immune from the impact of changes elsewhere. However, any relatively small producing region or consuming area may, by itself, have very little impact upon the basic price level of oil. As discussed in Chapter Three, to a great extent this has been true for Canada. Field prices of oil and natural gas have always been very heavily influenced by prices in the United States, which both produces and consumes much more oil than Alberta or Western Canada. And both Eastern Canada and the United States have been closely connected to overseas oil producers.

From the viewpoint of a small producing region, the price in the larger market (‘the international price’) might be seen as a price ceiling. Analytically, this can be handled in one of two ways: either (1) the demand curve may be viewed as perfectly elastic (flat) at the left since if producers in this region tried to charge a price higher than the international price, sales would fall to zero, or (2) the supply curve might be viewed as perfectly elastic (flat) to the right, since at the international price large quantities become available from other sources. There is no real reason to prefer one of

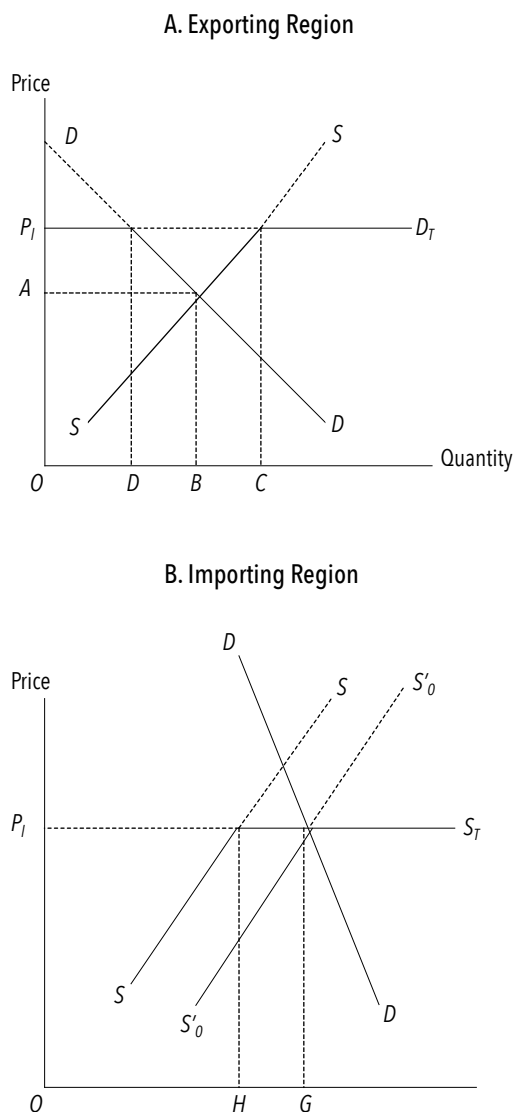


Figure 4.8 The Small Region in International Trade

these approaches to the other, so both are shown, but for somewhat different market positions, in Figure 4.8. In this figure, the price in the larger market is at level P_I , SS is the supply curve for the producing region, and DD is the demand curve in the domestic consuming market to which this region’s oil moves. The approach is simplified by the exclusion of transportation costs within the domestic market.

In Panel A, the effective domestic demand curve, as viewed by the producers, is the kinked curve $P_I D$: even though consumers would (hypothetically) be willing to pay more than OP_I for some oil, the producing region cannot charge more than the international price. This illustrates the situation in Central

and Western Canadian markets since about 1950. It is assumed that regional supply is large enough relative to demand that there is no need for purchases from the larger world market. If producers are restricted from selling in the larger market they would produce quantity OB and obtain a price of OA . However, if producers are free to move into the larger market, they will view the total demand curve for their oil as curve $P_I D_I$ and produce OC units for sale at the international market price P_I . Of this quantity, OD will be sold in the domestic market and DC will be exported. Given the international price, increases in supply, domestic demand unchanged, would mean increases in exports. Increases in domestic demand, supply unchanged, would mean reduced exports.

In Panel B of Figure 4.8, domestic demand is large enough that it cannot be satisfied by regional supply at a price below the international level, as has sometimes been true of Canada as a whole. In this case a total supply curve can be drawn as viewed by the consuming portion of the market; this would be identical to the domestic supply (SS) at prices lower than P_I but show unlimited quantities available (i.e., from the world market) at that price (curve SS_I). Given the local demand (DD), price would be P_I and the quantity demanded would be OG , of which OH comes from domestic producers and HG is imported. An increase in demand (regional supply unchanged) would mean more imports but unchanged domestic production. A rise in domestic supply (demand unchanged) would mean reduced imports, but no reduction in price until domestic supply is greater than that shown by curve $S'_o S''_o$. (A supply greater than $S'_o S''_o$ yields the situation in Panel A.)

The history of Canadian oil pricing and production is discussed in detail in Chapter Six. Chapter Nine looks at government regulations that interfered with the free movement of production, consumption, or price.

B. Royalties

The term 'royalty' is generally applied to a payment made by the producer of petroleum to the resource owner on the basis of the amount of petroleum lifted. In Canada, it happens that most petroleum rights are owned by governments, so the royalty has been viewed as a tax by some observers. Its purpose is to allow the landowner (government) to share in the profits (economic rent) from petroleum production. It may also represent compensation for any reduction in

the value of land transferred from an alternate use into oil production, though the resource owner may assess a rental payment for this purpose.

Royalties are viewed as a cost of production by the petroleum operator and therefore enter into the supply (private marginal cost) curve. It is evident that an increase in royalties will generate a reduced supply (leftward shift in the supply curve). Some aspects of royalties are shown in Figure 4.9. Panel A shows a 'specific' royalty, set at a fixed dollar value per cubic metre regardless of the market value of the oil (e.g., \$3/m³). SS is the supply curve without royalty and DD the demand curve, with price OA and quantity OC . With the royalty, the new supply curve is $S'S'$, the royalty being the fixed vertical distance SS' per cubic metre. The new equilibrium price is at price OD and quantity OG : price is higher (but not by the full amount of the royalty, since $AD < EF$), and quantity supplied is lower. The reduced quantity reflects reduced capital investment in exploration and development and earlier abandonment of existing equipment due to higher operating costs for the company. The government collects revenue equal to $SS' \times OG = \text{Area } SS'EF$. In the normative model, unless the royalty is set to internalize an external cost, there is a net welfare loss to society equal to area EFB (the shaded area), for the GC units now not produced. This equals the excess of their marginal value (shown by the demand curve) over their marginal costs (shown by the supply curve, SS). Formally, the royalty involves a loss of consumers' surplus and of producers' surplus (economic rent). The consumers' surplus loss is EHB for the unproduced units; it is the excess of the value of the marginal units to consumers (as given by the demand curve) over the price the consumer formerly paid (i.e., OA). The lost producers' surplus is FHB : it is the excess of the price formerly paid for the marginal units (i.e., OA) over the cost of production (as given by the supply curve). Taxes almost invariably involve some efficiency loss. One objective of taxation is to raise revenue with a minimum of such losses.

Owners of subsurface rights usually assess an '*ad valorem*' royalty instead of a specific royalty. An *ad valorem* royalty is some percentage of the market price of the product. Panel B of Figure 4.9 compares specific and *ad valorem* royalties. The initial demand is DD . If SS is the supply curve including a specific royalty, the market would clear with output OB at price OA . Consider now an *ad valorem* royalty that would generate exactly the same per unit revenue as the specific royalty when the price is OA . The supply curve with an *ad valorem* royalty would be $S'S'$, with greater

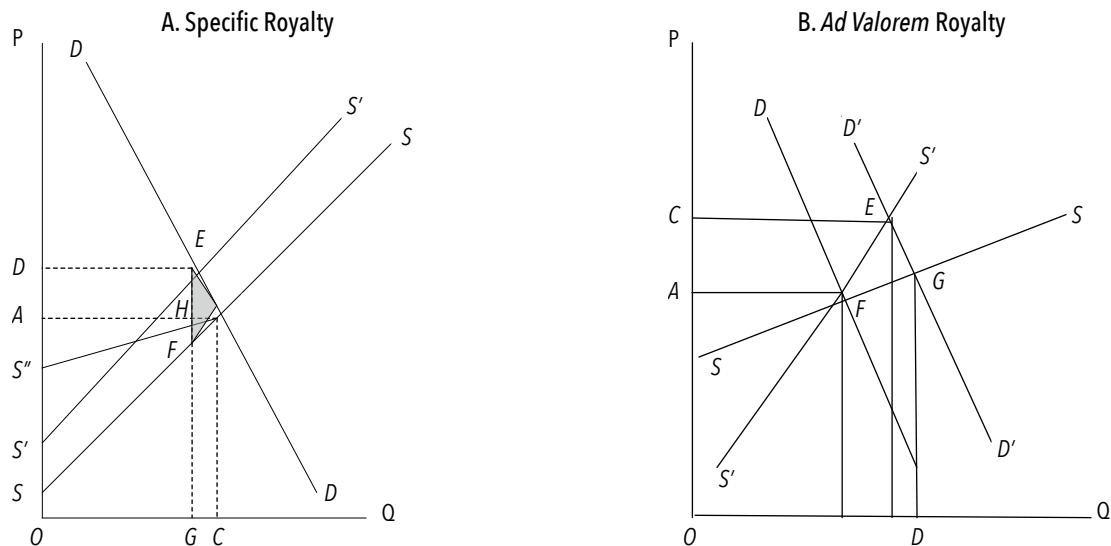


Figure 4.9 Crude Oil Royalties

supply than the specific royalty at lower prices and less supply at higher prices. If market demand were to increase, the new equilibrium would be at point E with an *ad valorem* royalty as compared to point G (a lower price) for a specific royalty. In the normative model, area EFH is the extra welfare cost of an *ad valorem* royalty as compared to a specific royalty, but the *ad valorem* royalty generates more revenue for the government or landowner than the specific royalty on the incremental units produced. (If the demand decreased, however, and price fell, there would be an increase in supply under an *ad valorem* royalty relative to a specific royalty, and a welfare gain.) Why are *ad valorem* royalties common? They have the advantage of allowing both the operator and the mineral rights owner to share in changing market conditions, since royalty payments vary directly with market prices.

Some attempts have been made to generate more revenue from the royalty, while lessening the welfare costs, by the use of 'sliding-scale' royalties that attempt to assess a higher rate on the least costly (i.e., most profitable) production. Look at curve $S''BS$ in Figure 4.9, Panel A. This involves a high royalty on the lowest cost units of output with royalties finally falling to zero on the OC th, and all more costly, units. So long as the price is OA , curve $S''BS$ is in effect a net royalty, as opposed to a gross royalty; that is, the royalty is based, not on the price alone, but the price less marginal cost. Unless the royalty is actually set up as a net profit tax, however, such an ideal scheme can only be approximated since (i) it would be too

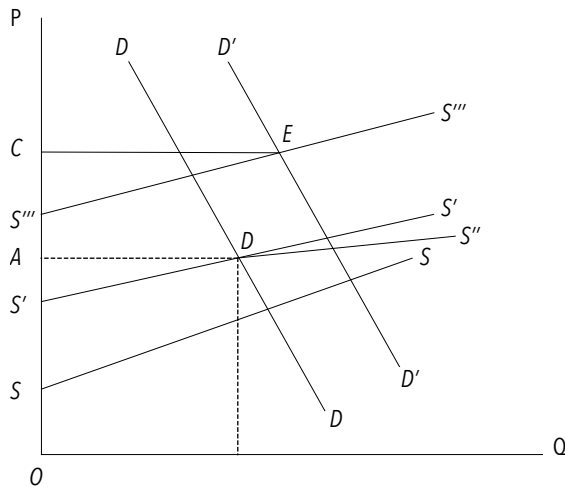
costly administratively to set a separate rate for each cubic metre of output, and (ii) the rates would have to change each time market price or costs changed, and it would be impossible to have an automatic formula that did so perfectly.

Frequently a sliding-scale royalty is based upon the well production rate, with lower royalties for wells with lower output rates, on the assumption that there is a significant negative correlation between costs per cubic metre and output per well. The assumption has some justification, since many costs are specific to the existence of a well, and invariant with respect to the production rate of the well, so that higher output means lower average costs. However, the correlation is not perfect, and some high output wells have high costs. This may hold for some, but not all, EOR schemes, and for very deep wells and those in hostile environments. As a result, a sliding-scale royalty will, like the royalties discussed above, generate reduced rates of oil production in a region, due to reduced investment and earlier abandonment dates for wells.

Sliding-scale royalties have also been tied to the price of petroleum, with higher rates the higher the price. Royalties have also been related to 'vintage,' generally the date of discovery of reserves, with higher royalties assessed on 'older' oil. This has been particularly popular if companies were willing to establish reserves in the past at lower prices, and subsequently prices rise substantially.

Panel C of Figure 4.9 illustrates some aspects of sliding-scale royalties. Curve SS is the industry supply

C. Sliding-scale Royalty



curve before royalties are assessed. An output-based sliding-scale royalty (assuming a negative correlation between cost and output levels) would shift the supply curve to $S'S'$, with price OA and quantity OB . A vintage dimension, which reduced royalties on 'new' oil, would give a supply curve such as $S'DS''$, since some of the incremental long-run production would now be assessed a lower royalty. (The precise definition of 'new oil' is of vital concern to companies: newly discovered reserves normally qualify and frequently so do reserves from new EOR schemes; reserves added through extension drilling are often more problematic, and higher output from existing reserves due to accelerated depletion [infill drilling] is usually labelled 'old oil'.)

The impact of a royalty scale that slides with price is harder to depict since the royalty payment (and hence the supply curve) will depend upon the equilibrium price. Thus, for instance, the supply curve might be $S'S'$ if the price were OA , but $S'''S'''$ if demand rose to $D'D'$ with the equilibrium price rising to OC . (The *ad valorem* supply curve of Panel B [curve $S'S'$] showed marginal costs including the royalty on the assumption that the last unit produced was the equilibrium unit at which supply equalled demand. In effect, it traced out equilibrium points, like D and E , along varying supply curves like $S'S'$ and $S'''S'''$ of Panel C.)

In general, royalties can be used to raise revenues for the mineral rights owner and/or government, but they also change the market equilibrium (price and/

or output) and generate welfare losses. More elaborate royalty schemes may minimize these changes and losses but cannot do so entirely and run the risk of becoming very complex to administer. For this reason, economists have not tended to favour royalties as the sole method of collecting economic rent from the petroleum industry.

Alberta's royalty and tax regime is discussed in Chapter Eleven of this book.

C. Production Controls

It has been common for government to impose limitations upon levels and methods of production from petroleum pools. Some of these regulations reflect safety and general conservation principles (like requiring that gas be reinjected rather than flared). In North America, the most important controls were largely dictated by the rule of capture. Consequently a number of governments (including Alberta) introduced prorationing (production control) restrictions, along with well-spacing regulations, with the avowed goals of (i) reducing the 'waste' in production associated with the rule of capture and (ii) protecting correlative property rights (i.e., the rights of access to the pool by adjacent property owners).

In Figure 4.10, Panel A, DD is the market demand curve in the region, and SS represents what the market supply curve would be if the rule of capture did not operate. This would be the case if the oil pools were 'unitized' – each pool produced by one operator only, although that operator might represent several companies. Equilibrium price would be OA and quantity OB . If the rule of capture (with shared oil pools) were suddenly to come into effect, the supply curve would shift to the right, to $S'S'$, with a corresponding fall in market price to OC and rise in quantity to OD . If supply and demand were inelastic, price could be much lower under the rule of capture. The increased supply (reduced marginal costs) reflects the tendency to ignore user costs under the rule of capture. Davidson (1963) argues that the rule of capture generates a negative user cost, which offsets the usual positive user costs. See also Watkins (1970) and McDonald (1971). Why would a company pay attention to the possible future profits that a cubic metre of reserves might generate if its competitor were likely to capture those reserves?

In theory, a well administered production control scheme could be imposed to limit production to quantity OB . In effect the supply curve would look

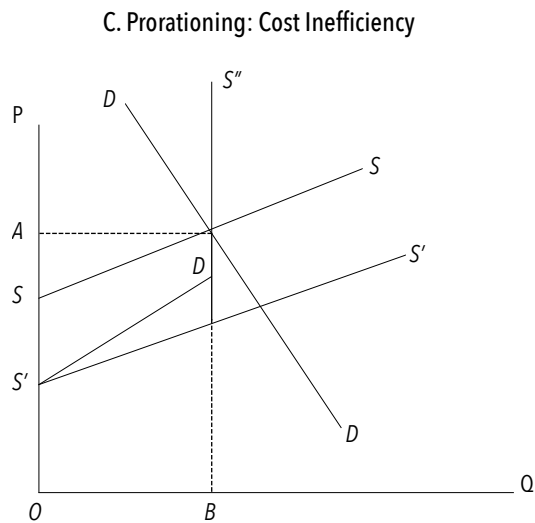
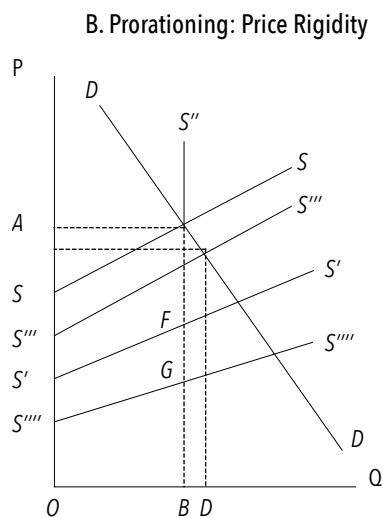
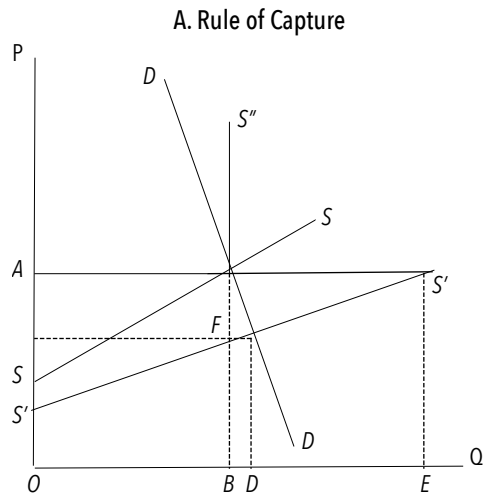


Figure 4.10 The Rule of Capture and Prorating

like curve $S'FS''$ (perfectly inelastic at quantity OB) and market equilibrium would correspond to that expected if the rule of capture did not operate. In practice, such a scheme is administratively infeasible since: (1) it would require restricting production to the lowest cost units of oil, even though at the price OA operators would be willing to supply substantially more (i.e., desired supply, without production control, is OE at price (OA)); and (2) with every change in demand (DD) or supply (SS), the regulations would have to change so that the only barrels produced would be those now corresponding to the hypothetical equilibrium without the rule of capture. It is unlikely that the administrators of the program would know exactly where the 'true' supply curve (SS) lies and which units of potential output have the lowest cost. Hence production controls are likely to give a market price higher or lower than the 'desired' price, OA .

Some critics of North American market-demand prorating schemes accused the government regulators of administering the schemes in such a way that their prime effect was to fix petroleum prices at artificially high levels, thereby generating high consumer costs and higher petroleum profits than would otherwise have existed.

Figure 4.10, Panel B, illustrates this contention. Initially, assume the existence of a well-functioning prorating scheme, such that production, OB , and price, OA , under the scheme (at the intersection of the demand, DD , and prorated supply, $S'FS''$) correspond to the competitive equilibrium levels without the rule of capture (where DD and SS intersect). Suppose several major new discoveries are made, so that the basic market supply (excluding rule of capture considerations) shifts to $S''S'''$ (and the supply curve with the impact of the rule of capture moves to $S''''S''''$). The equilibrium price without the rule of capture would fall to OC and the quantity rise to OD . But regulatory authorities may continue to hold production at level OB (and price at OA); the prorating equilibrium is where DD intersects $S''''GS''''$. The new supply addition is not allowed to affect the market, and there is a rise in 'excess capacity' (i.e., the amount producers would like to bring to the market at the existing price, but are not allowed to). In the normative model, there is a welfare loss equal to the excess of social benefit over social cost on the barrels that the regulatory authorities do not allow to be produced.

It is difficult to assess the extent to which prorating schemes in North America generated welfare losses of this sort. The price of oil was relatively stable under these schemes from 1950 through 1970,

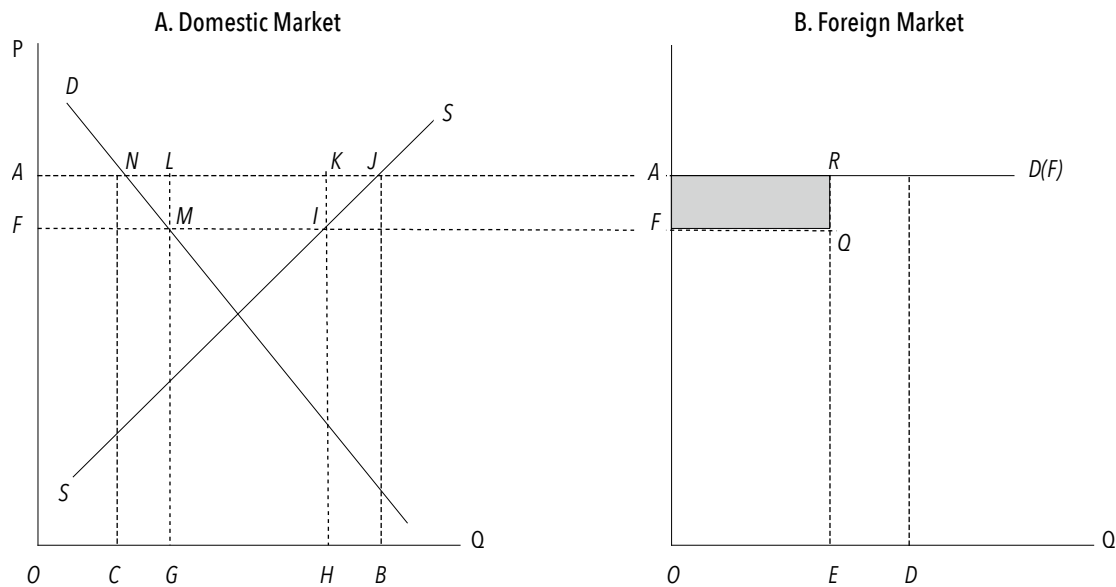


Figure 4.11 Oil Export Controls

even in the face of changing supply and demand conditions, while the amounts of excess capacity held off the market fluctuated more than price. It will be appreciated that under a prorating scheme an individual producer has little incentive to cut price since it will gain little of any increase in quantity demanded. The increased production to meet a rise in quantity demanded will be divided amongst among all producers.

Prorating schemes have also been criticized for inefficiencies due to their particular administrative structure. Typically (although not invariably) (i) some production from high-cost wells has displaced output from low-cost wells; and (ii) the schemes have induced the drilling of more development wells than is necessary to support allowable production. This situation can also be depicted by demand and supply curves, as in Figure 4.10, Panel C. In this figure, the curves DD , SS , and $S'S'$ are the same as in the earlier diagrams: i.e., they represent, respectively, market demand, market supply with no rule of capture effects, and market supply with the rule of capture but without regulations. We assume a prorating scheme is introduced that attains the 'desired' equilibrium price and quantity (i.e., OA and OB). The two administrative inefficiencies would lead to a supply curve under prorating like curve $S'DS'$, instead of the $S'CS'$ associated with perfect regulation. The area $S'CD$ is the welfare cost associated with this imperfect production

control scheme; it represents the dollar cost of oil production in excess of the lowest cost production pattern available. Empirical research has suggested that such extra costs have been substantial (Adelman, 1964; Watkins, 1971, 1977c).

Chapter Ten looks in detail at Alberta's conservation regulations.

D. Export Controls

The movement of oil between two separate jurisdictions increases possibilities for government intervention in the functioning of the market. For instance, at various times, both the Canadian and the U.S. governments have introduced measures to control the volume of crude oil, refined products, and natural gas flowing from Canada to the United States. Some useful conclusions about the economic impact of such measures can (of course!) be gained from the supply-demand apparatus.

Figure 4.11, Panel A shows a domestic producing region in which demand (DD) is entirely satisfied by domestic sources (domestic supply is SS). A much larger export market is available so that external demand is virtually unlimited as far as domestic producers are concerned, at a market price of OA . In the absence of trade controls, the equilibrium price would be OA and the equilibrium quantity of

production OB ; of this, OC is consumed domestically and exports are CB (equal to OD in Figure 4.11, Panel B, showing the export market). Suppose that the domestic government limits the volume of exports to OE ($< OD = CB$). (Or we could suppose that the foreign government limits the volume of imports.) The reduction in the demand for domestic oil will mean a fall in the domestic price to level OF , at which the quantity supplied (OH) is equal to the quantity demanded (OH , of which OG is domestic demand and $GH = OE$ is a foreign demand). Domestic consumers benefit by such a policy on the part of the government since the oil price is reduced, but domestic producers suffer. There is also a benefit to those in the foreign market who are fortunate enough to obtain oil from the domestic region: the market price in the foreign market is OA , but foreigners can purchase these barrels at price OF , thereby gaining to the extent of the shaded area. In the domestic market, efficiency (welfare) losses equal to $NMIJ$ occur: losses in revenue on exports ($LMIK = AFQR$), losses of producers' surplus on the reduced output (IJK) and the payments foreigners used to make in excess of the value of the extra domestic consumption (NLM). The program, therefore, involves income transfers from domestic producers to both domestic and foreign consumers.

If only select domestic producers are allowed access to export markets, those producers may be able to gain extra revenue by selling oil in the foreign market at price OA . This is an example of price discrimination, where foreign and domestic customers are charged different prices. The difference can exist only because the foreign customers are not allowed open access to competing Canadian suppliers.

Another possibility, an export tax, will be discussed below.

It must be noted that analysis is further complicated if the producing region operates a prorating scheme. In this case, the imposition of export controls may simply mean reduced production without corresponding price changes.

E. Price Ceilings

In some instances, the imposition of a price ceiling at a level lower than the market clearing price is identical in impact to export control, as analyzed above. One might interpret Figure 4.11, for instance, as showing the impact of a ceiling price in the domestic market at level OF . The ceiling price implies an excess demand in the market. Domestic consumers are assumed

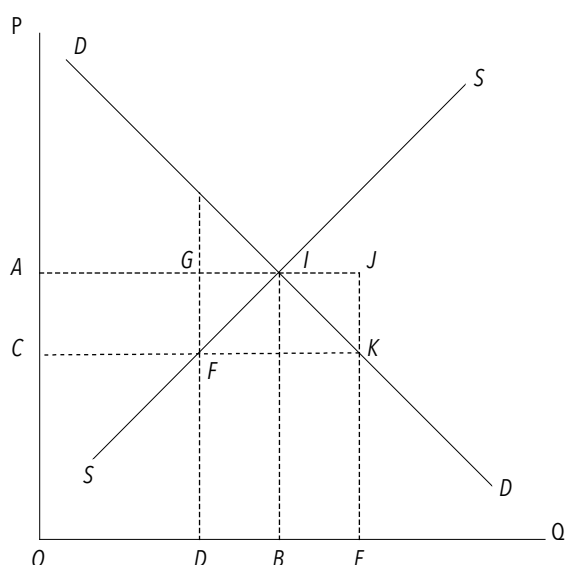


Figure 4.12 Oil Price Control

to buy all they wish, but foreign consumers cannot obtain all they would like. In Figure 4.11, the excess demand does not pose severe adjustment problems since foreigners can obtain what they want from other sources at a price of OA .

Once domestic demand is high enough to prevent exports, however, the price ceiling implies an excess of quantity demanded over quantity supplied within the domestic market. Some type of rationing scheme, deliberate or *ad hoc*, is necessary to allocate the shortage amongst users. Furthermore, a price ceiling, by definition, prevents the types of responses that are most natural in a market economy. For example, in response to impending shortages, there would be no price-induced restrictions in use and increases in investment and production.

Figure 4.12 illustrates the economic features of a price-control scheme that holds the quantity supplied domestically below the quantity demanded. In the absence of price controls, the equilibrium price would be OA and the equilibrium quantity would be OB . The imposition of a price ceiling at level OC ($< OA$) means a reduction in the quantity supplied (by BD) and an increase in the quantity demanded (by BE): a shortage (equal to DE) appears in the market. This shortage might be met by rationing the oil amongst buyers. If the scheme is perfectly efficient, in the sense that the petroleum goes to those areas that are willing to pay most for it, the net welfare loss to society is given by the area FHI . This is the excess of social benefit over

social cost for those units of output that are now not produced. In addition, the program involves a transfer of purchasing power, equal to area $CFG A$, from producers to consumers. Producers receive less revenue on each of the OD units sold than they would without the price ceiling, while consumers receive the same benefit as before from consuming even though the units cost them less. In other words, an amount equal to $CFG A$ is transferred from producers' surplus to consumers' surplus.

Alternatively, the domestic shortage might be met by imports at the international price (say OA in Figure 4.12), with the government subsidizing the imports to the amount of CA per unit consumed. In this case, in the normative model, there is a net social loss of $FGI + IJK$ relative to an absence of price controls. This loss consists of: (1) the excess (on the extra oil consumption) of the cost of imports over the value to consumers of that oil (i.e., area IJK) and (2) the excess of the cost of imports over the production cost of domestic oil on the extra units domestic producers would willingly bring to market at the higher price (i.e., area FGI).

F. Export Tax

The previous two sections showed that the imposition of export controls and the imposition of a price ceiling could lead to equivalent results, when crude oil is sold both at home and in a foreign market. A third alternative could also bring this result: the imposition of an export tax. In Figure 4.11, suppose that the government has imposed a tax per barrel on exports equal to AF . Given the foreign price (OA), the netback to domestic producers will be OF (i.e., $OA - AF$), at which price they see virtually unlimited demand in the foreign market. So long as the quantity supplied at this price exceeds the quantity demanded domestically, this will be the price for the product. In contrast to the other two programs, however, the shaded area in Figure 4.11 represents the export tax payment to the domestic government, not a subsidy to foreign users.

In a sense, then, for a country that exports oil, any one of the three programs outlined (export controls, a price ceiling, or an export tax) could be used to achieve the same effect upon domestic prices and quantities. In a dynamic sense, they differ, however: that is, changes in demand and supply lead to different results under the schemes. For instance, if the foreign price rises, so does the domestic price under any given export tax, whereas with a price ceiling or an export

quota there is no change in the domestic market. The dynamic differences, and the differing distributional effects, help explain why the Canadian federal government imposed all three types of schemes in 1973. At the same time, it must not be forgotten that Canada is a federal state, and that the government in Ottawa had to consider the ability of unhappy provincial governments to frustrate its policy goals. For instance, had the federal government imposed export controls alone and had Alberta prorationing authorities reduced the market allowable by an equivalent amount, there would have been no reduced price effect in Canada.

Chapter Nine will provide more detail on Canadian oil policies, and Chapter Twelve on natural gas, in the tempestuous 1970s and 1980s.

7. Conclusion

This chapter has been designed to demonstrate the usefulness of economists' analytical tools in describing the operation of petroleum markets. The tools are abstractions that aid in the understanding of real-world movements of market prices and quantities. They are also useful in describing the impact of changing market conditions or alternative regulatory policies upon different market participants: oil producers, domestic consumers, foreign consumers, and governments.

It has also been argued that the tools are useful in assessing the desirability of various alternative policies. Policy analysis should involve four stages:

- (1) a clear statement of policy objectives;
- (2) determination of alternative ways in which the policy objective might be achieved;
- (3) assessment of the likely effectiveness of these alternative policy tools, and selection of that thought best; and
- (4) assessment of the actual effectiveness of the policy chosen, after it has been applied.

This is a complicated process. For example, some of the policy objectives may conflict with others, and trade-offs must be considered.

The concepts set out in this chapter are of use in policy analysis in part for their descriptive value. However, beyond this, they have particular applicability to the assessment of one possible social policy goal – economic efficiency. This refers to the maximization of the difference between the dollar value of

benefits received by members of the society and the dollar value of the costs of obtaining those benefits. Under certain conditions, the attainment of this maximum net benefit can be equated with effectively competitive market-clearing prices and quantities. Unless there is a strong reason for supposing otherwise, many economists judge this outcome to be a desirable one for society. What reasons might be raised for not preferring such a position?

- (1) There are cases in which demand and supply forces do not accurately reflect benefits and costs to society. For example, there may be pollution costs not reflected in the supply curve. Or, profits on production may accrue to persons from outside the region. Or, monopoly power may exist. In this case, governmental action may be required in order that efficiency is achieved.

- (2) The maximum efficiency outcome may conflict with the attainment of some other social goal. For instance, it may involve extreme hardship on the poorest members of society, may be felt to transfer undue political influence to the capitalist sector, may be felt to treat vested property rights unfairly, etc. In this case, it may be judged desirable to accept some inefficiency in order that another goal be more nearly satisfied.

Normative policy analysis is a critical issue in any society. At the same time, the establishment of goals is a difficult task: no universal agreement on policy goals is to be expected, or, many would argue, desired. This book will concentrate upon the goal of economic efficiency but will note the implications of various policies for the attainment of other possible social goals.

Part Two: Overview

Ultimately the story of an exhaustible natural resource industry in a region is one of rise and fall. But within this skeletal history, many particular lifetimes are possible. Moreover, as Part Five of this book will argue, a regional economy need not mirror exactly the emergence and decline of a key natural resource: other natural resources may rise to take its place, and the benefits of natural resource production may be parlayed into a viable, ongoing, dynamic economy based on the wealth and skills of the local population.

Part Two of this book examines the Alberta crude oil industry from the beginning of its rapid growth in the late 1940s through to the early twenty-first century. Nature and humanity jointly determine this history. Nature conveys opportunities and imposes limits; humanity must determine which opportunities to exploit and how hard to push the limits. It is important to note that the activities of the oil industry reflect two quite different types of human influences: the directly productive decisions of individuals and companies in the petroleum industry and the government regulatory framework, which constantly changes the set of legal options open to these decision-makers. It is

the inescapable presence of government that has led to our use of the term ‘petropolitics’ in the title to this book. Our focus, articulated in the Overview to Part One, is on the interplay of nature, individuals, companies, and governments to generate the economic history of the crude petroleum industry.

This section of the book details the history of Alberta crude oil largely from the industry’s point of view, while Part Three is primarily concerned with the rationale for, and course of, government regulation. The distinction is one of convenience rather than reality, since industry decisions reflect the actual and anticipated regulatory environment, and the regulations introduced by government derive from actual and anticipated industry activities.

Part Two includes four chapters: Chapter Five examines the evolution of Alberta’s oil reserves; Chapter Six considers production and pricing; Chapter Seven looks at the province’s non-conventional oil resources; and Chapter Eight discusses various attempts to measure the ‘economic supply’ of Alberta oil.

CHAPTER FIVE

Alberta's Conventional Oil Resources

Readers' Guide: The crude oil industry in a region derives from nature's bounty. But no one can know for certain how much oil lies beneath the surface in an area such as Alberta and how much of that might eventually be produced. Chapter Five is concerned with attempts to understand how much conventional oil Alberta has and how these estimates have changed over time.

1. The Concept of Reserves

No one knows exactly how much conventional crude oil lies beneath Alberta or how much will eventually prove to be commercial. Exploratory activities of the petroleum industry are designed, in part, to reduce such uncertainties. Ongoing geophysical activities and exploratory drilling allow the interpretation and re-interpretation of accumulating records to generate theories and hypotheses about the pre-historic sources and migration of petroleum into trapped pools. However, our ability to see hundreds of metres beneath the surface will always be limited, so knowledge of the province's underlying resource base will remain imperfect. Moreover, knowledge and expectations in this regard are products of the human mind and are necessarily subjective. Skills, training, and experience differ among experts providing information to decision-makers in the oil industry. The resultant diversity of opinion is one of the engines driving industry activity, as different companies

seek out niches that reflect their particular expectations. Differences in behaviour among companies are observable to some degree, but the subjective evaluations that influenced that behaviour are rarely made public. Thus, while it is the expectations and decisions of individuals that determine what happens, most economic analysis of the oil industry is based on aggregate results, as reported in published statistics from government agencies, like Statistics Canada, the Energy and Resources Conservation Board (ERCB), the National Energy Board (NEB), the Geological Survey of Canada (GSC), and private industry groups, like the Canadian Petroleum Association (CPA), the Independent Petroleum Association of Canada (IPAC), or their 1992 amalgam, the Canadian Association of Petroleum Producers (CAPP). This chapter examines information about the amount of crude oil in the ground in Alberta, both the underlying physical resource base and the rate at which this oil has been discovered and rendered producible.

Some terminological and conceptual issues must be dealt with. (Tanner, 1986, and Thompson et al., 2009, provide useful reviews.) The term 'resources,' or 'resource base,' is commonly used to refer to the total physical volume of a resource as it exists in nature. However, as one early resource economist put it, resources "are not, they become" (Zimmermann, 1951, p. 15), and the becoming involves more than physical existence; usefulness and accessibility to humans are also required. In a similar vein, Firey (1960) noted that natural resources have characteristics of possibility (physical existence), adoptability (cultural acceptance), and gainfulness (economic feasibility). More

is at issue than the fact that a natural phenomenon must be recognized as of value before it is seen as a resource. Of what is available only some portion will ultimately prove to be utilizable by us. Some deposits may never be located, some that have been located may never be exploited, and some of the resource in a produced deposit will be left behind forever. In this light, it is wise to be skeptical of the simplistic view that we face a fixed stock of petroleum that must somehow be spread out over time until the resource is completely gone. Adelman (1990, pp. 1–2), in his discussion of the concept of a fixed stock, argues that:

... there is no such thing. The total mineral in the earth is an irrelevant non-binding constraint. If expected finding-development costs exceed net revenues, investment dries up and the industry disappears. Whatever is left in the ground is unknown, probably unknowable, but surely unimportant; a geological fact of no economic interest.... What actually exist are flows from unknown resources into a reserve inventory.... The fixed-stock assumption is both wrong and superfluous.

Profitable volumes of crude, as defined by physical, technological, economic, and political factors, are known as ‘reserves.’ Reserves consist of the entire resource in the ground multiplied by a recovery factor that equals the percentage of the resource that is actually produced. Only when an oil reservoir is abandoned, never to be reopened, is it known with certainty what the ‘ultimate reserves’ of the pool have been (abstracting from any errors in measuring production over the life of the deposit). Prior to that, any estimates of reserves are very much conditional, depending on assumptions made about a variety of key factors, and they always reflect the judgment of the individual or group making the estimate, including that party’s subjective evaluation of underlying uncertainties. Aguilera et al. (2009) provide a recent example of the argument that the world’s recoverable conventional petroleum resources will prove to be larger than has generally been expected, due both to exploration in new geological arenas and development extensions.

The basic meaning of the word ‘reserves’ is well accepted. The ERCB defines established reserves as “those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production; plus the portion of contiguous recoverable reserves

that are interpreted to exist from geological geophysical or similar information, with reasonable certainty” (ERCB, *Reserves Report 2010*, ST-98, p. A-2). As Tanner (1986, p. 23) notes, however, this basic definition leaves abundant room for disagreement. For example, the World Petroleum Congress has suggested a concept of ‘proven reserves’ that is based on current economic and technical conditions, while the ‘established reserves’ concept commonly used in Canada assumes current technology but anticipated, not just current, economic conditions. Beyond this, the necessity of ‘reasonable’ assurance for recovery, leaves room for differences of opinion. The conclusion is that reserves data must be treated with a certain amount of caution: estimates for a region, or a pool, may not be completely compatible if they come from different sources. Aggregate reserve estimates (e.g., all of Alberta) inevitably involve estimates from a number of different sources, though bodies like the ERCB and the CAPP (formerly CPA) have tried to ensure that all those making estimates use the same criteria; as a result, the aggregate reserves each of these bodies reports is widely regarded as reliable and consistent over time. Tanner notes (1986, p. 28) that the actual estimation practices did not change much for either the CPA or ERCB when they switched to ‘established’ reserves in the 1960s from ‘proved’ (ERCB) or ‘proven and probable’ (CPA) reserves.

Given the basic definition of reserves, there are three commonly used bases for measurement: ‘remaining,’ ‘initial,’ and ‘ultimate’ reserves. ‘Remaining reserves’ are those currently in the ground and recoverable, whereas ‘initial reserves’ are those that were initially in pools (at the time of discovery) and therefore consist of remaining reserves plus any past production. ‘Ultimate reserves’ are the total oil that will ever be produced in the region, and they are often not true ‘reserves’; in effect, they drop the requirement for ‘reasonable certainty’ in estimation in order to allow for the effects of more speculative future activities such as the discovery of new oil pools, extension drilling, and EOR schemes. Everyone knows with absolute certainty that many of these ventures will occur in Alberta, but no one can say with sufficient (‘reasonable’) certainty exactly where or when they will occur, so future activities of this sort are excluded from initial and remaining established reserves estimates.

Estimates of remaining established reserves will change over time. Production clearly reduces remaining reserves (while leaving initial reserves unchanged). There are three additional reasons for changes:

- (1) The industry undertakes activity to add reserves: exploration for new discoveries, and development to extend pool boundaries or add EOR schemes.
- (2) Apart from adding reserves, industry activity adds new information that may lead to a re-evaluation of the previous period's estimates: production, for example, provides additional information on reservoir characteristics including production decline, lifting costs, water to oil ratios, etc., which may or may not correspond exactly with what was anticipated last year.
- (3) Economic, political, and technological changes occur: e.g., oil prices fall unexpectedly, taxes are increased, a new and cheaper miscible flood agent is developed.

Whereas the first of these always leads to an addition to estimated reserves, the second and third may involve either increases or reductions. In practice, published estimates of reserves are not fine-tuned with the regularity that the discussion so far implies. Reserves additions for reason (1) are typically estimated each year, and any relatively significant re-evaluations for reason (2) are allowed for; but more minor adjustments of type (2) in any one pool often go unmarked, and only significant changes in economic or political conditions (reason (3)) will usually generate an adjustment in published reserves data.

The ERCB (and, for some years, the CAPP) have reported reserve additions due to new discoveries; this is the estimate, as of December 31, of the reserves in pools discovered that year. Recall that this typically underestimates the eventual reserves that will be booked in these pools since it makes no allowance for revisions and extensions or EOR investment (i.e., appreciations). The economic analyst faces severe data problems here. Suppose, for example, we are trying to model the exploration process. What volume of oil does this year's exploration actually discover? A company drilling on a large structure certainly expects that a success will hold much more oil than will be reported in that year as the size of the new discovery; this argues for some attempt to increase, or 'appreciate,' the new discovery reserves estimates. This can be done relatively easily for pools discovered many years ago. As we noted in Chapter Two, the ERCB estimated that a representative Alberta oil pool, unless very small, appreciated about nine times over the first year's estimate of initial reserves. But for recent finds future reserves additions due to extension drilling or EOR are unknown. Moreover, reserves additions

that do occur for these reasons may not have been anticipated but reflect new technologies or changes in economic conditions years after the initial discovery. As a further complication, this year's exploration may generate knowledge that makes future discoveries easier. The conclusion, in more formal economic terminology, must be that it is almost impossible to set out an 'oil reserves production function' that is completely satisfactory from an analytical point of view. An oil reserves production function is a quantitative (mathematical) relationship that relates the inputs in the oil exploration process (G&G, exploratory wells) to the resultant outputs – reserves additions of various types. In describing exploration, one must be satisfied with workable empirical models that seem 'reasonable enough.'

This chapter continues with two main sections: a review of the history of Alberta crude oil reserves additions and a survey of some studies of Alberta's ultimate reserves potential. Chapter Eight will review attempts to build supply models that 'explain' the process of oil discovery and reserves additions in Alberta.

By way of introduction, we present information from the ERCB's 2013 assessments of the size of Alberta's oil reserves (from chap. 4 in the 2013 *Reserves Report and Supply/Demand Outlook*, ST-98). By the end of 2012, the ERCB reported that 13,374 separate oil pools had been discovered in the province, 10,570 with light and medium oil and 2,804 with heavy crude. A majority of these pools (about 60%) were being drained by a single well. However, the smallest 75 per cent of pools held only 6 per cent of the estimated recoverable oil, while the largest 3 per cent contained 82 per cent of estimated initial recoverable reserves (and 70% of remaining reserves). The ERCB reported initial discovered oil-in-place at the end of 2012 as 12,026 million m³ (about 76 billion barrels), of which 17 per cent was expected to be lifted by primary means and a further 7 per cent by EOR, for a total recovery factor of 24 per cent. The average recovery factor was higher for light and medium crude (18.6% primary and 26.5% in total) than for heavy crude (11.7% primary and 15.8% in total). These recovery factors have changed little over the years.

2. Historical Reserves Additions

The CAPP (formerly CPA) and ERCB (the EUB from 1993 to 2008, and Oil and Gas Conservation Board in the 1950s and early 1960s) are the two main sources

Table 5.1A: CAPP Canadian Conventional Established Oil Reserves, 1951-2009 (10³ m³)

Year	Remaining at Beginning of Year	Gross Additions	Net Production	Remaining at End of Year	Net Changes
1951	191,106	35,169	7,519	218,756	27,650
1952	218,756	57,749	9,614	266,891	48,135
1953	266,891	39,222	12,857	293,256	26,365
1954	293,256	72,750	15,194	350,812	57,556
1955	350,812	68,240	20,262	398,790	47,978
1956	398,790	80,910	26,907	452,793	54,003
1957	452,793	32,868	28,882	456,779	3,986
1958	456,779	72,701	26,386	503,094	46,315
1959	503,094	81,832	29,198	555,728	52,634
1960	555,728	59,197	30,368	584,557	28,829
1961	584,557	113,788	35,123	663,222	78,665
1962	663,222	87,720	38,914	712,028	48,806
1963	1,062,733	13,944	40,758	1,035,919	-26,814
1964	1,035,919	255,384	43,033	1,248,270	212,351
1965	1,248,270	196,556	46,337	1,398,489	150,219
1966	1,398,489	208,887	50,224	1,557,152	158,663
1967	1,557,152	124,587	54,690	1,627,049	69,897
1968	1,627,049	93,668	59,030	1,661,687	34,638
1969	1,661,687	66,636	62,516	1,665,807	4,120
1970	1,665,807	26,894	69,606	1,623,095	-42,712
1971	1,623,095	37,636	76,297	1,584,434	-38,661
1972	1,584,434	22,229	82,319	1,524,344	-60,090
1973	1,524,344	6,537	99,423	1,431,458	-92,886
1974	1,431,458	-5,065	95,530	1,330,863	-100,595
1975	1,330,863	-6,280	79,897	1,244,686	-86,177
1976	1,244,686	5,921	69,683	1,180,924	-63,762
1977	1,180,924	10,227	70,872	1,120,279	-60,645
1978	1,120,279	37,426	67,647	1,090,058	-30,221
1979	1,090,058	71,415	79,469	1,082,004	-8,054
1980	1,082,004	-56,247	74,529	951,228	-130,776
1981	951,228	178,220	65,873	1,063,575	112,347
1982	1,063,575	19,314	61,756	1,021,133	-42,442
1983	1,021,133	66,074	64,488	1,022,719	1,586

/continued

of aggregate reserves data for Alberta. Tanner (1986) provides a review of the methodologies of these two bodies as well as detailed summaries of their estimates.

The CAPP Reserves Committee consisted of experts from member companies who were responsible for assembling reserves estimates for individual oil pools, concentrating on the largest ones in a region, and drawing on the practical expertise of the large companies in operating most of these pools. It has been more problematic to estimate reserves for the many small oil pools of the province, so after 1984 the CPA relied upon ERCB estimates for them

(Tanner, 1986, p. 43). Commencing in the year 2010, CAPP began to derive its conventional crude oil reserves from provincial sources and the NEB. Table 5.1 shows the type of reserves information available from the CAPP *Statistical Handbook*, as of 2011. Table 5.1A shows estimated (remaining) reserves at year end for all Canada for years from 1951 to 2009 and the major sources of changes in reserves each year. The change from a proven to an established reserves basis in 1963 increased estimated reserves by 64 per cent, largely as a result of the inclusion of 50 per cent of 'possible' reserves as established reserves after 1963. In some years, the CAPP reported only total gross

Table 5.1A/continued

Year	Remaining at Beginning of Year	Gross Additions	Net Production	Remaining at End of Year	Net Changes
1984	1,022,719	-588	73,108	949,023	-73,696
1985	949,023	39,837	73,030	915,830	-33,193
1986	915,830	98,719	70,138	944,411	28,581
1987	944,411	67,943	72,192	940,162	-4,249
1988	940,162	108,468	73,482	975,148	34,986
1989	975,148	31,677	68,832	937,993	-37,155
1990	937,993	18,350	68,386	887,957	-50,036
1991	887,957	22,359	69,014	841,302	-46,655
1992	841,302	39,697	71,265	809,734	-31,568
1993	809,734	65,439	74,587	800,586	-9,148
1994	800,586	56,607	78,400	778,793	-21,793
1995	778,793	78,078	78,844	778,027	-766
1996	778,027	71,518	80,176	769,369	-8,658
1997	769,369	97,177	82,607	783,939	14,570
1998	783,939	72,883	81,473	775,349	-8,590
1999	775,349	48,966	76,468	747,847	-27,502
2000	747,847	103,550	79,368	772,029	24,182
2001	772,029	48,559	80,492	740,096	-31,933
2002	740,096	58,867	84,986	713,977	-26,119
2003	713,977	47,049	84,739	676,287	-37,690
2004	676,287	97,629	81,975	691,941	15,654
2005	691,941	215,224	79,227	827,938	135,997
2006	827,938	36,292	78,540	785,690	-42,248
2007	785,690	92,816	81,169	797,337	11,647
2008	797,337	46,565	78,767	765,135	-32,202
2009	765,135	-7,786	69,693	687,656	-77,479

Note: Proved reserves, 1951-62.

Source: CAPP, *Statistical Handbook*, Tables 2.6a and 2.6b.

Table 5.1B: Canadian Liquid Established Conventional Oil Reserves, December 31, 2009 (10³ m³)

	Initial Volume in Place	Initial Established Reserves	Remaining Established Reserves
British Columbia	461,062	130,153	18,005
Alberta	10,644,160	2,803,966	237,716
Saskatchewan	6,752,312	951,610	152,398
Manitoba	222,442	51,610	8,400
Ontario	92,973	15,656	1,634
Other Eastern Canada	2,860	128	0
Mainland Territories (S.68°N)	92,911	43,003	1,906
East Coast Offshore	1,272,240	394,013	213,647
Total Conventional Areas	19,540,910	4,389,700	633,706
Mackenzie Delta/Beaufort Sea	173,000	54,000	53,950
Arctic Islands	1,440	463	0
Total Frontier Areas	174,440	54,463	53,950
TOTAL CRUDE OIL	19,715,350	4,444,163	687,656

Source: CAPP, *Statistical Handbook*, 2011, Table 2.15a.

reserve additions (1963–77, 1984–present) as shown in this table, while other years provided more detail including estimated new discoveries and (with varying degrees of breakdown) revisions and extensions. Gross reserves additions may be negative, reflecting large downward revisions of earlier discoveries, as occurred in 1980. Remaining reserves will decline (net reserves additions will be negative) when production exceeds gross additions, as has been the case in most years since 1969. Table 5.1B shows the December 2009 reserves reported for various regions in Canada, including Alberta. The *CAPP Statistical Handbook* includes a number of other tables of oil reserves, by region, detailing them, for example, by year of discovery and major geological formations.

The ERCB oversees most provincial regulation of the petroleum industry. It has a large technical staff that analyzes company data, including reserves and well reports, which it uses to estimate pool by pool oil reserves. The reserves estimates were important in determining allowable output rates under Alberta's prorationing regulations, as will be discussed in Chapter Ten. If an oil producer disagrees with the ERCB estimates for its pool, the producer may request reassessment. The ERCB provides reserves data for most individual pools in the province, including estimates of major pool characteristics, oil-in-place and initial and remaining reserves. Table 5.2 is a summary table of Alberta conventional crude oil reserves and reserves additions from 1951 to 2012. Additions have, over varying time periods, been divided into new discoveries, 'development and re-evaluation,' and (since 1958) EOR additions; gross additions are generally, but not always, positive. As with CAPP data, remaining crude oil reserves peaked in 1969. It is noteworthy that the ERCB's estimate of remaining conventional oil reserves rose significantly after 2009, attributable at least in part to newer horizontal drilling techniques and hydraulic fracturing which expanded oil recovery (ERCB 2013 *Reserves Report*, ST-98, p. 4-9).

The CAPP and ERCB each provide relatively consistent historical time series of reserves and reserves additions, but the two series are not directly comparable. The CAPP, for instance, estimated remaining Alberta conventional oil reserves at December 31, 2009, as 237.7 million m³, while the EUB reported 236.9 million m³. Tanner (1986, pp. 47–53) contrasts the two series, noting that the CPA's estimates of established reserves (from 1962 to the early 1980s) consistently exceeded the ERCB's, particularly prior to the 1980s, in part because of CPA's earlier willingness to credit reserves to EOR proposals. In earlier years, the

CPA may also have tended to overestimate reserves in the small pools for which detailed reservoir analyses were not undertaken. The general trends in remaining reserves estimates over time have been similar for both data series. Year-to-year correlations between reserves additions estimates are somewhat lower; for example, in the decade from 1964 through 1973, the ERCB estimate of new discoveries (gross reserve additions) varied from 34 per cent less (70% less) to 500 per cent more (300% more) than CPA estimates (Foat and MacFadyen, 1983).

Such differences highlight the dangers inherent in mixing data sources but raise more fundamental questions for economic analysis; if two such reputable data sources offer different time-patterns for what is, presumably, the same process – discoveries of conventional oil – then the same economic model is likely to generate different empirical results depending upon which series is used. Differences may relate in part to different criteria by the ERCB and CAPP on what determines the size of reserves, but it seems more likely that a significant part of the problem relates to differences in the timing of receipt of information and some differences in opinion on what constitutes 'reasonable certainty' about the existence of reserves. If three-year moving averages of reserve additions (or new discoveries) are used, the CPA and ERCB series are more similar, suggesting that time factors in estimation are critical.

Tables 5.1A and 5.2 showed CAPP and ERCB estimates of gross crude oil reserves additions from the early 1950s to the early 2000s. Immediately apparent are the great year-to-year variability of reserves additions and a tendency to long-term decline. The latter reflects a complex mix of factors, including: (1) depletion of the stock of undiscovered resources as exploration continues, (2) changing levels of exploration activity (where more drilling will add more reserves), and (3) growing knowledge and technological changes. Figure 5.1 shows reserves additions per well drilled, thereby reducing the influence of the second of the three factors; the values plotted are three-year moving averages, reducing the impact of wide year-to-year variability in drilling results. These simple adjustments make no allowance for the joint product nature of the exploratory process. The measure considers neither the full range of inputs like G&G, land and development investment, nor the complex mix of hydrocarbon and by-product outputs. Also, the economic principle known as the law of diminishing marginal returns suggests that incremental discoveries in any year due to drilling more wells will tend to be

Table 5.2: ERCB Conventional Crude Oil Reserves and Changes, 1947-2012 (10⁶ m³)

<i>Year</i>	<i>New Discoveries</i>	<i>EOR Additions</i>	<i>Development</i>	<i>Net Revisions</i>	<i>Net Total Additions</i>	<i>Cumulative Production</i>	<i>Remaining Established</i>	<i>Annual Production</i>
1948	0.5	0.0	7.9		8.4	14.8	14.0	
1949	4.8	0.0	41.2		45.9	18.0	56.7	3.2
1950	3.2	0.0	96.9		100.1	22.2	152.6	4.3
1951	15.3	0.0	29.2		44.5	29.4	189.9	7.2
1952	14.0	0.0	48.5		62.5	38.8	243.0	9.4
1953	24.2	0.0	42.4		66.6	51.0	297.3	12.2
1954	1.9	0.0	53.7		55.6	65.0	338.9	14.0
1955	9.4	0.0	58.8		68.2	82.8	389.3	17.8
1956	3.5	0.0	78.5		82.0	105.7	448.4	22.9
1957	10.8	0.0	29.1		39.9	127.4	466.6	21.8
1958	1.3	4.9	-4.8		1.4	145.2	450.2	17.8
1959	14.3	16.0	37.2		67.5	165.7	497.2	20.5
1960	0.5	18.1	29.9		48.5	186.6	525.0	20.8
1961	1.7	24.5	31.5		57.7	211.5	557.6	24.9
1962	2.9	19.9	21.8		44.5	237.9	575.6	26.4
1963	14.6	29.2	12.6		56.4	264.6	605.4	26.7
1964	9.5	250.8	88.2		348.5	292.4	926.1	27.8
1965	28.6	-2.4	42.6		68.8	321.6	965.7	29.2
1966	89.1	38.3	13.5		141.0	353.9	1074.2	32.3
1967	57.2	22.2	15.7		95.2	390.4	1132.8	36.5
1968	62	42.9	14.8		119.8	430.3	1212.8	39.9
1969	40.5	58.5	-44.5		54.5	474.7	1222.8	44.4
1970	8.4	36.1	-7.6		36.7	526.5	1207.9	51.8
1971	14	-0.8	8.7		22.1	582.9	1173.6	56.4
1972	10.8	14.8	-5.6		20	650.5	1126	67.6
1973	5.1	10.2	-6.0		9.2	733.7	1052	83.2
1974	4.3	30.8	3.3		38.5	812.7	1011.5	79.0
1975	1.6	3.3	2.1		7	880.2	950.9	67.5
1976	2.5	-27.0	5.9		-18.6	941.2	871.3	61.0
1977	4.8	9.2	5.1		19.1	1001.6	830	60.4
1978	24.9	1.4	-1.9		24.4	1061.6	794.5	60.0
1979	19.2	4.8	10.3		34.3	1130.1	760.2	68.5
1980	9	8.6	5.1		22.8	1193.3	719.9	63.2
1981	15	7.2	10.4		32.6	1249.8	696	56.5
1982	16.8	6.6	-16.5		6.9	1303.4	649.4	53.6
1983	21.4	17.9	24.8		64.1	1359	657.8	55.6
1984	29.1	24.1	-11.2		42	1418.2	640.7	59.2
1985	32.7	21.6	9.7		64	1474.5	648.5	56.3
1986	28.6	24.6	16.6	-30.7	39.1	1527.7	634.7	53.2
1987	20.9	10.5	12.8	-11.2	33	1581.6	613.8	53.9
1988	18	16.5	18	-15.8	36.7	1638.8	592.9	57.2
1989	17	7.8	12.9	-16.2	21.4	1692.6	560.5	53.8
1990	13	8.4	7.2	-25.6	3	1745.7	510.4	53.1
1991	10.2	9.1	10.6	-20.5	9.4	1797.1	468.5	51.4
1992	9	2.8	12.3	3	27.1	1850.7	442	53.6
1993	7.3	7.9	14.2	9.8	39.2	1905.1	426.8	54.4
1994	10.5	5.7	11.1	-22.6	4.7	1961.7	374.8	56.6
1995	10.2	9.2	20.8	14.8	55	2017.5	374.1	55.8

/continued

Table 5.2/continued

Year	New Discoveries	EOR Additions	Development	Net Revisions	Net Total Additions	Cumulative Production	Remaining Established	Annual Production
1996	9.7	6.1	16.3	-9.5	22.6	2072.3	341.8	54.8
1997	8.5	4.2	16.1	8.7	37.5	2124.8	326.8	52.5
1998	8.9	2.9	17.5	9.2	38.5	2174.9	315.2	50.1
1999	5.6	2.1	7.2	16.6	31.5	2219.9	301.6	45.0
2000	7.8	1.5	13.4	10	32.8	2262.9	291.4	43.0
2001	9.1	0.8	13.6	5.2	28.6	2304.7	278.3	41.8
2002	7	0.6	8.1	4.6	20.2	2343	260.3	38.3
2003	6.9	1	5.9	17.1	30.8	2380.1	253.9	37.1
2004	6.1	3.2	8	13.6	30.9	2415.7	249.2	35.6
2005	5.5	1.2	13.2	18.9	38.8	2448.9	254.8	33.2
2006	8.2	1.9	14.8	2.2	27.1	2480.7	250.1	31.8
2007	6.8	2.2	11.8	-0.2	20.6	2510.9	240.7	30.2
2008	6.9	6.2	9.3	-0.7	21.7	2540.1	233.0	29.2
2009	4.0	4.8	7.4	5.8	21.8	2566.5	228.4	26.4
2010	3.8	5.8	23.5	1.7	34.8	2592.8	236.9	26.6
2011	4.0	6.4	14.0	9.0	33.5	2617.3	245.9	24.5
2012	5.8	2.2	52.9	-2.4	58.5	2652.5	269.2	35.2

Sources:

ERCB ST98-2013 (*Alberta's Energy Reserves 2012 and Supply Demand Outlook*), p. B8, Table B.3 for New Discoveries, Net Total Additions, Cumulative Production and Remaining Established 1968–2012, for EOR 1981–2012 and for Development and Net Revisions 1986–2011.

ERCB 77-18 and 86-18 (*Alberta's Reserves of Crude Natural Gas, Natural Gas Liquids and Sulphur*) Tables 9a and A-4 for years 1948–67, plus 1968 to 1986 for EOR and Development. Values in the 'Development' column are for 'Development and Re-evaluation' plus 'Enhanced Recovery' 1948–57; enhanced recovery additions were first reported for 1958; for 1948–1985, 'Development' includes 'Development and Revisions'.

smaller the greater the number of exploratory wells drilled, regardless of whether or not there is a tendency to declining discoveries over time.

Three series are shown in Figure 5.1: (1) ERCB 'new discoveries' per exploratory well drilled, for Alberta; (2) ERCB 'gross reserves additions' per well drilled (development and exploratory), for Alberta; and (3) CAPP 'initial established reserves by year of discovery' (that is, 'appreciated' reserves as assessed at the end of 2008) per exploratory well, for western Canada. Each series has problematic features, as discussed in Section 1 of this chapter. 'New discoveries' measure only the first year's estimate of the volume of recoverable reserves, not the ultimate size of the find as proved up through subsequent development activities. 'Gross reserves additions' do include all estimated reserves established in that year, but most of these are from fields actually discovered much earlier. 'Appreciated reserves' include additions from development activities, including EOR, which may have become viable only years after the initial discovery.

The yearly fluctuations in Figure 5.1 reflect, in part, the vagaries of the reserves reporting procedures. More fundamentally, however, the inherently stochastic nature of reserves additions is responsible. Reserves additions inevitably include significant random variability as companies are unable to predict results, especially of exploration, with certainty. From the perspective of risk analysis, reserves additions instability is significant. It would hardly be surprising that different companies experience markedly different 'efficiencies' in reserves additions in any single year (even apart from variations in technical and management skills). For small firms in particular, there is a real risk of bankruptcy in the crude oil industry, even for well-run companies. The risk is smaller for larger firms, which are more able to spread exploratory risk around and to withstand runs of bad luck. Of course, even large firms may overextend themselves through a combination of unfortunate happenstance, such as large mega-projects that fail and poor management, for example insufficient spreading of risk. In any

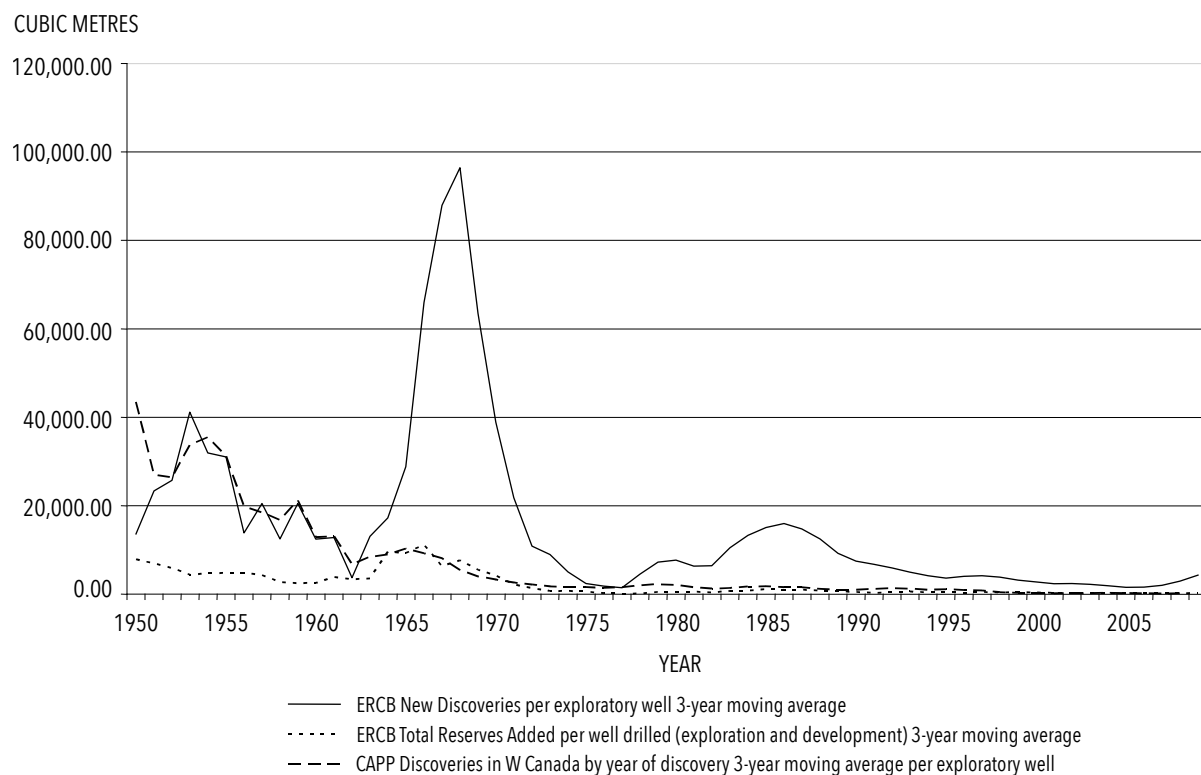


Figure 5.1 Alberta Conventional Oil Reserve Additions per Well Drilled, 1950-2009

particular year, even averaging across the many firms in the industry, the good and bad, lucky and unlucky, volatility in reserves additions per well still remains.

The three-year moving averages of Figure 5.1 smooth out some of this underlying variability and make clearer the long-term tendency to declining crude oil reserves additions in Alberta. This suggests that the first of the three factors noted above (a depleting resource base) outweighs the third (growing knowledge). An anticipated corollary might be that real crude oil costs will rise over time. This need not be true, however, as declining costs of exploration could offset the reduced physical productivity, as might productivity gains or falling real costs of development and/or lifting. As can be seen, the data is affected by the nature of the Keg River play in the mid-1960s in northwest Alberta; many small oil pools were discovered with a large proportion of the pool reserves credited in the year of discovery rather than waiting for subsequent development as is the case with larger pools. This factor has a particular effect on the annual ‘new discovery’ reserve additions; its impact is muted when all reserves additions are considered, or when our current knowledge of reserves is used to

credit reserves back to the year in which the pool was discovered.

Aggregate reserves addition data fail to provide much evidence on one of the more remarkable characteristics of the Alberta crude oil industry: major oil discoveries have occurred through a sequence of geologically distinct oil plays. As discussed in Chapter One, before nature can bequeath us a commercial crude oil reservoir, a complex set of underlying physical conditions regarding the generation, migration, and entrapment of hydrocarbons must occur in just the right way. This does not happen very often, but when it does significant numbers of deposits are typically created, all exhibiting much the same history; such a group of pools is known as an oil ‘play,’ defined by the specific geological formation in which these pools are found. Some geological judgment is required to define plays, so different authorities may use somewhat different groupings of pools. Table 5.3 shows a recent ERCB tabulation of discovered Alberta oil reserves, illustrating that a large portion of reserves lie in a small number of formations. (See also the *CAPP Statistical Handbook*. Hardy, 1967, chap. 2, provides a summary of Alberta geology.) Geologists have

Table 5.3: Alberta Conventional Oil Reserves by Geological Formation, End of 2007 (106 m³)

Formation	Initial Volume in Place	Initial Established Reserves	Remaining Established Reserves	Formation	Initial Volume in Place	Initial Established Reserves	Remaining Established Reserves
UPPER CRETACEOUS				UPPER DEVONIAN			
Belly River	302	47	9	Wabamun	70	8	2
Chinook*	6	1	0	Nisku	474	213	12
Cardium	1,704	294	31	Leduc	824	511	9
Second White Specks	42	5	1	Beaverhill Lake	1,142	408	23
Doe Creek	79	7	2	Slave Point	181	36	8
Dunvegan	24	2	0	MIDDLE DEVONIAN			
LOWER CRETACEOUS				Gilwood	309	134	5
Viking	355	68	5	Sulphur Point	9	2	0
Upper Manville	2,054	318	56	Muskeg	61	10	1
Lower Manville	997	226	30	Keg River	494	179	10
JURASSIC				Keg River SS	43	18	1
TRIASSIC				Granite Wash	56	14	2
PERMIAN-BELLOY*				* from 2007 ERCB Reserves Report ST-98-2007.			
MISSISSIPPIAN				Source: ERCB, Alberta's Energy Reserves 2007 and Supply/Demand Outlook, 2008 (ST98-2008), Table B.5. Later Reserves Reports did not include this information.			
Rundle	350	62	7				
Pekisko	97	16	2				
Banff	106	14	2				

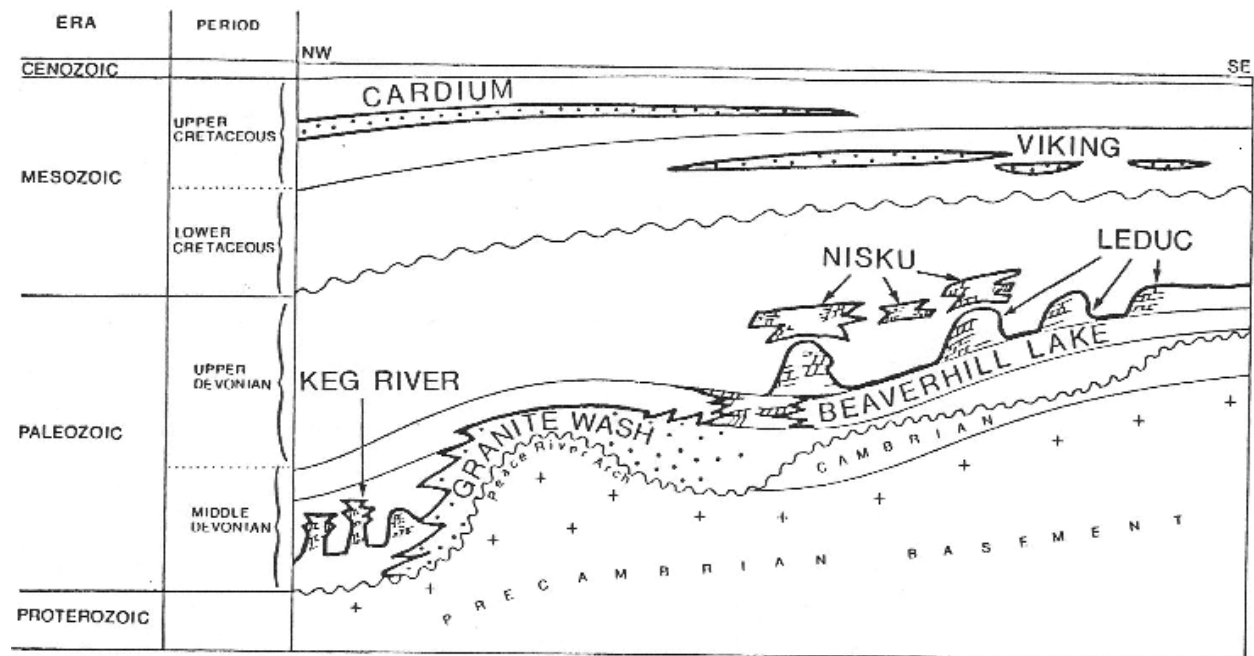
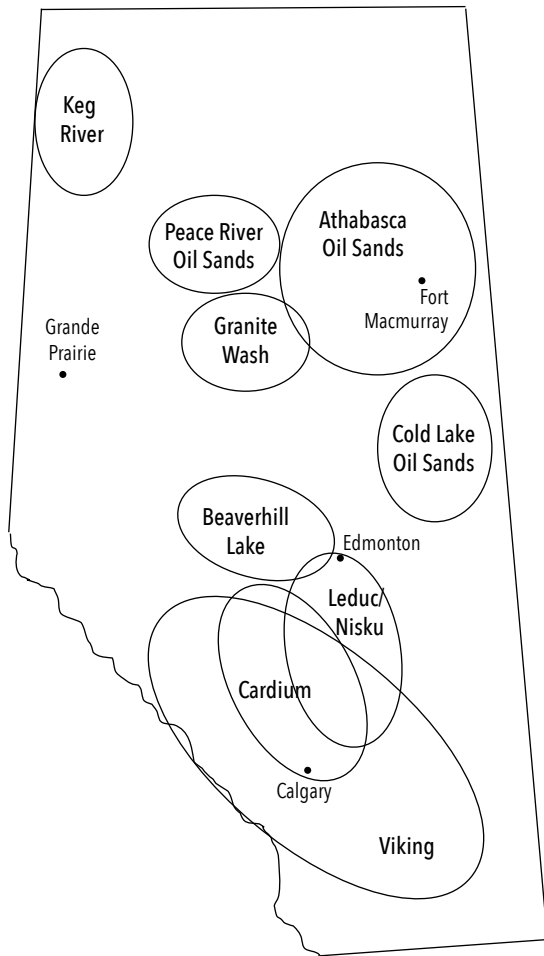


Figure 5.2 Main Alberta Oil Plays

Source: Foat and MacFadyen, 1981, p.25.



Map 5.1 Six Major Alberta Conventional Crude Oil Plays and Three Oil Sands Areas

Sources: The areas for geological plays are from Foat and MacFadyen (1981), Figures C.3 to C. 9. Areas for oil sands deposits from ERCB, *Reserves Report 2010*, ST-98, p. 2-1.

long been aware of the importance of oil plays, but the emphasis on separate plays in models utilized by economists is more recent; in the Alberta context, see, for example, Ryan (1973a,b), Uhler (1976, 1977), and Foat and MacFadyen (1983).

Figure 5.2 is a stylized geological cross-section showing seven of the most important Alberta crude oil plays; Map 5.1 shows the approximate geographic location of each (Foat and MacFadyen, 1983). There are many other small plays, and more are likely to be found.

The Geological Survey of Canada (1987) undertook play-specific modelling of the Canadian crude oil industry. It reported 78 'established plays' (with

reported discoveries) and 49 'conceptual plays' (with no discoveries yet, but oil potential) in Western Canada, for light and medium crude oil. Table 5.4 looks at 50 (mainly established) plays that lie largely in Alberta. Column (1) tells the first year a pool was discovered in that play; column (2) shows the number of pools discovered up to 1987; and column (4) gives initial established reserves as estimated in 1987. (The 'potential' columns will be discussed later in this chapter.) It can be seen that these 50 oil plays are a heterogeneous mix. In total over 3,000 pools have been discovered, ranging from 439 in the Keg River play to 2 in the Turner Valley (the only 'conceptual play' included in Table 5.4). Column 4 shows that reserves thus far established also vary considerably. The ranking of plays in terms of reserves is also shown. The five largest plays hold 43 per cent of the reserves from all fifty plays; the largest ten hold 52 per cent of reserves. The preponderance of Devonian formations for Alberta oil is evident. These are the oldest of the geological horizons indicated, and their importance reflects both the timing of major prehistoric oceans over Alberta, and the relative tectonic stability of the region (without frequent disturbances that would allow oil to migrate to newer formations).

Each oil play tends to mimic the pattern of aggregate oil reserves additions shown in Figure 5.1. There is considerable year-to-year variation in the size of the pools discovered, but the average discovery size tends to fall over time. Figure 5.3, for example, from data in Foat and MacFadyen (1983), plots annual discoveries by year from 1947 to 1976 in the Leduc 'D-3' play (using early 1980s estimates of reserves).

One artefact of discovery data arranged by year of discovery, as noted earlier, is the tendency to understate the size of more recent discoveries, since these pools may not be fully developed. Since average pool size has been falling for new discoveries, and smaller pools will tend to exhibit less appreciation, this underestimation may not be too severe. A large, or otherwise promising, initial discovery generates a rush of exploratory drilling directed at that play. However, a small initial find may be viewed as an isolated incident; in effect, the play is not widely recognized and concerted exploratory activity may not occur until after one or more additional discoveries many years later. The same result may occur if the initial discovery was largely accidental (e.g., by a well targeted at some other formation) and locating prospects in this play requires an undeveloped technology (e.g., there is no obvious structural feature locatable by seismic). A similar result may occur if the play seems to hold only

Table 5.4: Alberta Light and Medium Oil Reserves and Potential by Play: GSC 1987

Formation/Play	Year of Discovery	Number of Pools		Initial Recoverable Reserves, 1986, 10 ⁶ m ³		Median Recoverable Potential, 110 ⁶ m ³		Ultimate Potential 10 ⁶ m ³		
		Discovered	Expected		(Rank)		(Rank)	Oil in Place	Recoverable	(Rank)
DEVONIAN										
Beaverhill Lake	1956	21	60	406.1	(1)	25.1	(6)	1027	431.2	(1)
Leduc-Rimbey	1947	23	40	351.4	(2)	29.7	(4)	625	381.1	(2)
Keg River	1965	439	846	137.4	(4)	61.9	(1)	491	199.3	(4)
Nisku-Shelf	1947	65	150	119.4	(5)	37.3	(2)	278	156.7	(5)
Gilwood-Mitsue	1956	3	3	97.6	(6)	-	(50)	238	97.6	(6)
Leduc-Bashaw	1950	51	80	54.3	(7)	14.5	(8)	121	68.8	(8)
Leduc-Deep	1953	10	40	54.2	(8)	25.8	(5)	132	80.0	(7)
Nisku-W. Pembina	1977	45	50	32.8	(10)	3.6	(26)	91	36.4	(12)
M.Devon. Clastics	1954	106	280	32.8	(10)	33.3	(3)	161	66.0	(9)
Slave Point-Sawn	1958	37	80	6.7	(25)	4.6	(23)	72	11.3	(27)
Leduc-Nisku-S.	1951	11	60	6.2	(26)	7.7	(13)	45	13.9	(25)
Slave Point-Golden	1970	12	40	5.8	(28)	2.7	(30)	22	8.5	(32)
Nisku-Meekwap	1965	7	30	5.1	(29)	9.9	(12)	37	15.0	(22)
Zama	1965	71	160	3.6	(31)	5.7	(21)	56	9.3	(29)
Wabamun-Peace R.	1956	29	80	3.1	(33)	2.5	(32)	31	5.6	(34)
Keg River-Senex	1969	14	50	2.9	(34)	6.6	(17)	43	9.5	(28)
Bistcho	1965	15	70	0.8	(40)	1.6	(35)	17	2.4	(40)
Wabamun-Eroded	1952	9	40	0.8	(40)	0.9	(42)	11	1.7	(43)
Muskeg	1965	4	42	0.6	(44)	6.4	(18)	37	7.0	(33)
Leduc-Peace R.	1949	4	10	0.3	(48)	0.4	(47)	4	0.7	(48)
CARBONIFEROUS										
Elkton Edge	1955	36	60	30.8	(12)	4.1	(25)	125	34.9	(14)
Pekisko Edge	1946	78	110	27.3	(15)	1.3	(37)	220	28.6	(17)
Turner Valley	1936	2	n/a	22.3	(16)	4.2	(24)	189	26.6	(18)
Banff Edge-Central	1954	32	80	6.1	(27)	2.6	(31)	50	8.7	(31)
Desan	1983	17	80	0.8	(40)	2.8	(29)	44	3.6	(37)
Carbon. Sweetgrass	1936	11	40	0.5	(45)	1.2	(38)	17	1.7	(43)
Banff Edge-S.	1970	6	25	0.1	(50)	0.1	(48)	2	0.2	(50)
PERMIAN										
Belloy-Peace R.	1951	14	40	11.1	(22)	3.1	(28)	51	14.2	(24)
TRIASSIC										
Boundary Lake	1955	25	70	28.3	(14)	6.8	(16)	133	35.1	(13)
Peejay-Milligan	1957	35	50	14.1	(19)	1.6	(35)	49	15.7	(21)
Montney	1952	5	20	7.5	(23)	5.8	(20)	78	14.3	(23)
Halfway Strat.	1978	23	90	6.8	(24)	6.2	(19)	46	13.0	(26)
Inga Structure	1962	12	35	3.2	(32)	1.2	(38)	29	4.4	(35)
Halfway Drape	1960	12	35	1.3	(37)	0.8	(44)	11	2.1	(42)
Charlie L. Sond.	1952	32	100	1.2	(38)	1.0	(41)	13	2.2	(41)
Charlie L. Algal	1976	9	45	0.4	(46)	0.5	(46)	7	0.9	(47)
Doug Structure	1976	11	30	0.2	(49)	0.1	(48)	4	0.3	(49)
JURASSIC										
Gilby-Medicine R.	1956	23	45	12.3	(20)	7.5	(14)	79	19.8	(19)
Sawtooth	1944	12	40	1.1	(39)	1.7	(34)	13	2.8	(39)
Rock Creek	1956	14	35	0.4	(46)	0.7	(45)	7	1.1	(46)

/continued

Table 5.4/continued

Formation/Play	Year of Discovery	Number of Pools		Initial Recoverable Reserves, 1986, 10 ⁶ m ³	Median Recoverable Potential, 110 ⁶ m ³	Ultimate Potential 10 ⁶ m ³			
		Discovered	Expected	(Rank)	(Rank)	Oil in Place	Recoverable	(Rank)	
CRETACEOUS									
Cardium Sheet	1953	128	200	288.5 (3)	3.6 (26)	1506	292.1	(3)	
Viking-Alta	1949	137	270	43.5 (9)	16.5 (7)	312	60.0	(10)	
Lower Mannville	1920	329	600	29.1 (13)	11.3 (9)	268	40.4	(11)	
Belly R. Shoreline	1954	37	90	19.9 (17)	11.3 (9)	151	31.2	(15)	
Upper Mannville	1957	177	450	18.4 (18)	11.3 (9)	197	29.7	(16)	
Cardium Scour	1962	48	90	12.0 (21)	7.0 (15)	99	19.0	(20)	
Belly R. Fluvial	1956	34	100	4.5 (30)	5.5 (22)	48	9.0	(30)	
Dunvegan-Doe Cr.	1957	13	50	2.3 (35)	1.9 (33)	47	4.2	(36)	
Ostracod	1959	32	80	1.8 (36)	1.2 (38)	20	3.0	(38)	
1 and 2 White Specks	1961	16	50	0.7 (43)	0.9 (42)	16	1.6	(45)	
TOTAL		3036	5141	1918.4	404.0	7370	2322.4		

Source: Canada, Geological Survey of Canada, 1987.

MILLIONS OF BARRELS

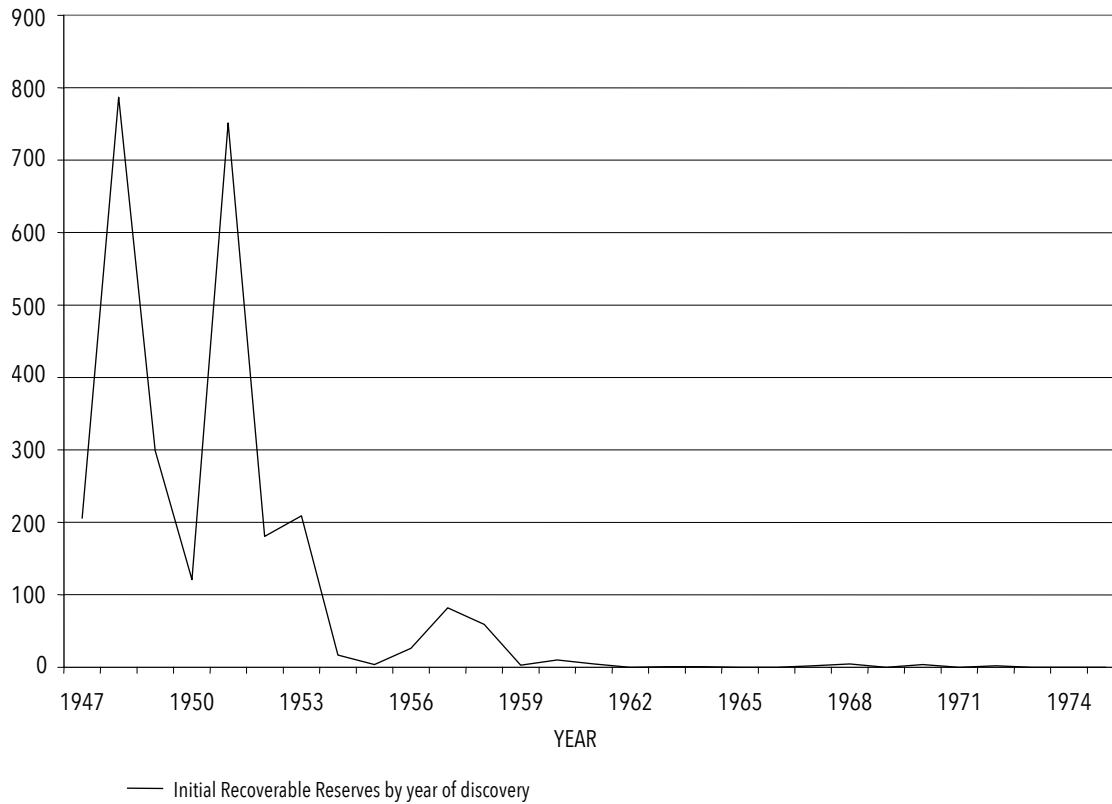


Figure 5.3 Leduc Play: Reserves by Year of Discovery

relatively small pools of questionable commercial feasibility, whence continued exploration may be delayed until the economics improves (e.g., oil prices rise).

The importance of the oil play as a significant factor in the underlying natural resource base provides a convenient opportunity to return to consideration of the inevitable and ubiquitous uncertainty of crude oil industry activities. There are at least four different 'levels' of uncertainty:

- U1: Existence of Oil Plays.** Of the large number of different geologic formations in Alberta, which ones will prove to be significant oil plays? In each case the resolution of the uncertainty tends to come abruptly, coincident with the first significant discovery in the play. As the industry matures, with a larger cumulative number of wells drilled throughout the region and a greater number of the plays discovered, the likelihood of finding a major new play becomes smaller; in this sense, uncertainty of type U1 will tend to become less significant over time.
- U2: Extent of the Oil Play.** The geographical and geological extent of the potential oil-bearing rock in the play will be subject to uncertainty. After the initial discovery, reinterpretation of records from already drilled wells will allow preliminary estimation of the extent of the play. Further refinement, and, presumably reduced uncertainty, will occur as more new wells are drilled looking explicitly for new discoveries in the play.
- U3: Existence of an Oil Pool.** Knowledge of the extent of the oil play begins to allow the selection of 'prospects' or specific drilling sites, but, prior to drilling, it is not possible to know for certain whether or not the prospect will contain oil. As with U1, uncertainty of this type is usually resolved in a sudden discontinuous manner as the exploratory well is either dry or successful. There may be more ambiguous cases in which very low porosity or permeability in the reservoir, or this part of the reservoir, make it difficult to tell whether a commercial deposit has been found.
- U4: Size of an Oil Pool.** Finally, it is the commercial volumes of oil (the reserves) which are of ultimate interest to the oil company. Reserves estimates are subject to geologic uncertainties (how large is the pool?), reservoir engineering

uncertainties (what is the permeability in the pool, and is it homogeneous across the entire pool?), technological uncertainties (will horizontal well-drilling techniques be effective here?), economic uncertainties (what will the price of oil be?), and political uncertainties (will the government change tax and royalty rates?). The geological and engineering uncertainties tend to be reduced by development activities and some production history, but the economic and political uncertainties are always present.

All oil companies are aware of these uncertainties and will take them into account in their decision-making. Part of the dynamism of the crude oil industry comes from companies' varying assessments. Moreover, risk preferences of decision-makers differ, reflecting different underlying psychological propensities and varying financial situations. Most of the aggregated economic analysis of the petroleum industry assumes that these individual differences between companies average out, in some sense, and so do not have to be considered explicitly. We would note that this assumption may be very useful in assessing total Alberta oil supply but is not at all helpful in deciding which company's stock you should buy. Nor would picking a Hawaiian holiday resort with very low average annual rainfall keep you from scanning the sky each day as you leave your room.

3. Ultimate Reserves Potential

Planners and decision-makers, both public and private, have an obvious interest in the potential for future oil discoveries in a region. The ERCB defines ultimate potential as "an estimate of the initial established reserves that will have been developed in an area by the time all exploration and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions" (ERCB, 2010, *Reserves Report*, ST 98, p. A-8). Reflection will demonstrate that ultimate reserves consist of the current remaining established reserves plus past production plus any future reserves additions. Estimates of ultimate potential, particularly its future reserves addition component, involve the exercise of subjective judgment to resolve the manifold uncertainties – geological, reservoir

engineering, technological, economic, and political – attendant on forecasting possible future petroleum production.

Many methods have been used to estimate ultimate natural resource potential in a region. (Harris, 1984; Kaufman, 1987; Power and Fuller, 1992; Walls, 1992; and Sorrell and Speirs, 2009, provide useful reviews.) Virtually all approaches are extrapolative, trying to extrapolate some historical evidence through the future. Many differences exist amongst studies, and some utilize a combination of approaches, but four main types of analysis emerge:

- (1) **Volumetric.** The (cubic) volume of potential oil-holding sediment in the region or play is estimated, and an anticipated quantity of oil (m³ or barrels) per unit volume is multiplied by the total volume. The quantity number may come from ‘similar’ geological formations somewhere else, especially if this region is relatively unexplored; or it may simply reflect considered expert judgment on potential for the region.
- (2) **Subjective Probability.** This method simulates ultimate oil volumes as the outcome of a multiplicative relationship among key underlying variables that define oil reserves, as in equation 5.1:

$$UR = (NP)(SR)(A)(D)(P)(WOR)(GOR)(RF)(7,758) \quad (5.1)$$

where:

- UR is ultimate recovery in barrels of oil;
- NP is the number of prospective drilling sites (prospects);
- SR is the success ratio, or chance that a prospect holds crude oil;
- A is the surface acreage of a prospect;
- D is the depth in feet of the oil-bearing sediment in the prospect;
- P is the porosity of the project (percentage pore space in the rock);
- WOR is one minus the water saturation (percentage of pore space with fluid other than water);
- GOR is one minus the gas to oil ratio (percentage of non-water fluid that is crude oil rather than gas);
- RF is the recovery factor (percentage of oil that will be recovered); and
- 7,758 is the number of barrels of fluid in an acre foot of pore space.

Equation 5.1 is an identity, showing ultimate reserves as the product of a number of variables. Each of the underlying variables is defined by a subjective probability distribution across possible values, as assessed by experts in the field. Sampling techniques like Monte Carlo analysis can be used to generate a probability distribution of possible values for UR, ultimate reserves. Generally the median value of the distribution is reported; this is the value for which higher values are just as likely as lower. Briefly, a Monte Carlo simulation work as follows: Assume that the variables in equation 5.1 are all independent of one another. Values are then selected ‘at random’ from the underlying probability distributions assumed for the variables in equation 5.1, so that the likelihood of selecting any value is equal to the specified probability of its occurrence. It may be useful to describe the process in detail. First select a value for NP, the number of prospects (e.g., 122), from the probability distribution for the number of drilling prospects in this region. Then this number (122) of drawings are made from the other probability distributions; each of the 122 drawings involves one value for each of the variables in equation 5.1, which, when multiplied together, give an estimate of likely reserves for that prospect. Then these 122 values are added together to give an estimate of the ultimate potential of oil reserves from the region. If this entire process is repeated a great many times (e.g., 10,000) then a frequency distribution of ultimate reserves can be constructed. Enough information on a region is necessary to allow construction of the subjective probability distributions.

- (3) **Econometric Estimation.** Statistical (econometric) techniques may be used to estimate the ‘most likely’ quantitative relationship in the past between variables that are assumed to be associated with one another. If one of the variables were, for example, reserve additions, then it would be possible, by assuming that the same relationship holds through the future, to estimate future reserves additions, and therefore ultimate reserves. The simplest case, for instance, would look at the impact of the passage of time on reserves added. If the relationship was a declining one, and therefore relatively bounded, ‘forecast’ future reserve additions

could be generated by extrapolating the declining reserves through the future until the new additions became small enough to ignore. Ultimate reserves would be total reserves added over the life of the industry including past history and the extrapolated future. Sufficient historical data is needed to allow econometric estimation of the hypothetical relationships between variables.

- (4) **Discovery Process.** Oil discoveries are viewed as occurring in separate oil plays, each of which exhibits its own discovery history. Discoveries in each of these plays are seen as involving a process of sampling without replacement from the finite number of pools that lie in that play in nature. Moreover, the larger pools are assumed to be easier to find than the smaller, so are generally discovered earlier in the life of the play. If very specific assumptions are made about the distribution of pools in nature (e.g., ‘the size distribution is log normal’), and the likelihood of discovery for each pool (e.g., ‘the likelihood of discovery is proportionate to the size of the pool’) then sophisticated statistical analysis may be applied to the discovery history of pools in the play to develop estimates of the total number of pools in the play and the size of each. Finally, a sum of all pools in the play (often subject to a minimum economic size constraint) provides an estimate of ultimate recovery. This method is obviously complex and requires a significant discovery history before it can be used.

Numerous attempts have been made over the years to estimate Alberta’s ultimate crude oil reserves. Many of the estimates were made by individuals for planning purposes for their companies; such estimates are not usually publicly reported. We will summarize the results of the main analyses undertaken by governmental bodies, federal and provincial, with two early estimates by private groups, the CPA (in 1969) and the Canadian Society of Petroleum Geologists (CSPG) in 1973. (See Canada. Energy Mines and Resources, 1973.) Unfortunately, not all studies separate Alberta from other parts of the Western Canadian Sedimentary basin (N.W.T., Northeast B.C., Alberta, Saskatchewan, and Southern Manitoba). As of December 31, 2008, according to the CPA, 70 per cent of initial established reserves of crude oil in this area was in Alberta (CAPP, *Statistical Handbook*).

CPA. In 1969, the CPA released results of a volumetric analysis of Canadian conventional crude oil

potential that set ultimate reserves for the Western Canadian Sedimentary Basin at 7.5 billion m³ (47.4 billion barrels) (Energy, Mines and Resources, 1973, vol. II).

CSPG. In 1973 members of the CSPG gave a petroleum potential of about 3.5 billion m³ (22.3 billion barrels) for the Western Canadian Sedimentary Basin (McCrossan and Porter, 1973, p. 74). The estimates were derived from “a very thorough analysis by volumetric techniques using geological analogy and by setting upper and lower limits of the yields through comparisons with a number of known areas to achieve what is probably a very reasonable figure for Alberta.” It was explicitly noted that no formal economic criteria were applied, so the numbers should not be interpreted as ultimate established reserves (McCrossan and Porter, 1973, pp. 595–97). The CSPG was substantially less optimistic than the CPA.

Federal Government. The Department of Energy, Mines and Resources (EMR – which in 1993 became part of the Department of Natural Resources) and the National Energy Board (NEB) have been actively involved in modelling Canadian oil supply. As far as ultimate potential is concerned, federal government bodies have generally relied in part on the work of the Geological Survey of Canada (GSC), a research body housed within EMR.

Geological Survey of Canada (GSC) models have progressed from volumetric through subjective probability to discovery process techniques. Table 5.5 summarizes the estimates of the GSC for the Western Canadian Sedimentary Basin. As can be seen, the GSC estimates were initially (1972) over 25 per cent more optimistic than the CSPG but have fallen considerably since 1973, with the 1987 estimate of ultimate potential for the Western Canadian Sedimentary Basin at 2.8 billion cubic metres (17.6 billion barrels), though this is only for light and medium, not heavy, oil pools. Of the 2.8 billion, about 500 million m³ (3.2 billion barrels) were yet to be established as reserves.

Table 5.4 provides more detail for 49 established oil plays, and one conceptual oil play (Turner Valley), largely in Alberta. The GSC uses a subjective probability approach for the conceptual plays. The established oil plays are subject to a discovery process model that provides an estimate of the total number of pools expected to be discovered in the play (column (3)) and the potential recoverable oil volumes still to be discovered (column (6), for the median, 50% probability estimates). Columns (7) and (8) show ultimate potential oil in place and recoverable volumes (i.e., initial established reserves, column (4) plus the potential, column

Table 5.5: GSC Estimates of Ultimate Crude Oil Potential

	<i>Estimated Ultimate Potential 10⁹ m³ (10⁹ bbl) (Western Canadian Sedimentary Basin)</i>		<i>Method</i>	<i>Source</i>
1972	4.5	(28.6)	Volumetric	EMR, 1973, Vol. II, p. 32-3
Feb. 1973	3.6	(22.4)	Volumetric	EMR, 1973, Vol. II, p.32-3
March 1973	3.4	(21.6)	Subjective Probability	EMR, 1973, Vol. II, p. 32-3
1977	3.3	(20.7)	Subjective Probability	EMR, 1977
1983	2.9*	(18.2)	Subjective Probability	Procter, Taylor and Wade, 1984
1987	2.8+	(17.6)	Discovery process and Subjective Probability	Canada, GSC, 1987

* The Alberta Basin and disturbed belt which cover Alberta and northeast British Columbia have ultimate potential of 2.4 billion m³ (15.2 billion barrels). These are the 50% probability estimates.

+ The 1987 study is for light and medium oil pools only.

(6)). Potential of 404 million cubic metres amounts to 21 per cent of already discovered reserves, though the percentage varies greatly across plays, from 0 per cent for the Gilwood-Mitsue play (in a very restricted geological formation) to over 1,000 per cent for the Muskeg play. The rankings of potential in column (6) are quite different from those for established reserves in column (4), though the largest volumes of anticipated additions do tend to occur in relatively large plays. Anticipated additions, like past discoveries, are concentrated mainly in a limited number of formations – 46.5 per cent in the most promising five and 66 per cent in the top ten. Of course, such potential numbers are subject to a wide range of uncertainty, and some of the ‘conceptual’ plays not included in Table 5.4 may turn out to be large. The 3,000 plus pools discovered in these 50 plays so far generated almost two billion cubic metres of oil reserves; the pools vary greatly in size but averaged about 630 thousand cubic metres (almost 4 million barrels). The remaining 2,105 pools anticipated (in the median case) would hold 404 million m³ of potential reserves, averaging about 190 thousand m³ in size. This declining average discovery size, at levels of both the play and the aggregate province, are a strong force pushing towards higher oil production costs.

In 1998 the GSC updated the 1987 study of light and medium oil in Western Canada, using similar methods and data up to the end of 1994. (This report, *Oil Resources of Western Canada*, by P. J. Lee, is summarized in NEB, 2001.) The number of established oil plays was reduced from 78 to 69, and the conceptual (“immature”) from 49 to 25; the GSC applied a modified discovery process modelling to the conceptual

plays. This report considered only oil in place, with no consideration of economic factors or estimated ultimate recovery of oil. Perhaps the most striking feature of the 1998 estimate was an increase in the estimated number of undiscovered pools, from 4,000 to 18,000, with newly discovered pools expected to be much smaller than the historical average. Discovered oil in place had been estimated at 7,377 10⁶ m³ in the 1988 Report, and undiscovered at 1,874 10⁶ m³; in the 1998 Report the equivalent numbers were much higher at 12,547 and 6,958. These estimates suggest that considerable amounts of conventional light and medium oil still lie undiscovered in the WCSB. However, for major additions to reserves to materialize, oil prices must be sufficiently high to offset the smaller pool sizes, and/or significant technological advances in discovery and recovery of oil must occur.

In 2001, the NEB published a study of conventional heavy oil in the WCSB (NEB, 2001), using the GSC methodology. This report drew on the oil plays from the 1998 GSC report; discovery process modelling was used, and prospective oil pools were subject to an economic analysis as well. The heavy oil plays lie in all four western Canadian provinces, not just Alberta. The NEB estimated that total heavy oil in place amounts to 7,926.6 10⁶ m³, of which 2,894.8 10⁶ m³ is as yet undiscovered. The recovery factor for previously discovered heavy oil is estimated at almost 25 per cent, with 372.8 10⁶ m³ of additional reserves additions expected from already discovered pools. Undiscovered pools are expected to be much smaller on average than already discovered pools; the NEB reports an estimated recovery factor of less than 12 per cent, yielding 337.8 10⁶ m³. It is interesting to note that the possible

Table 5.6: NEB Estimates of Ultimate Conventional Crude Oil Potential in Western Canada (10⁶ m³)

	1982	1984	1986	1989*	
LIGHT AND MEDIUM CRUDE					
Initial Established Reserves	2,055	2,165	2,264	2,370	(1,982)
EOR in Discovered Pools	404	367	295	295	(260)
New Discoveries	280	308	563	521	(454)
Ultimate Potential	2,739	2,840	3,122	3,086	(2,696)
HEAVY OIL					
Initial Established Reserves	366	404	434	488	(172)
EOR in Discovered Pools	381	378	370	320	(115)
New Discoveries	140	125	250	270	(107)
Ultimate Potential	887	907	1,054	1,078	(395)
ALL CONVENTIONAL CRUDE					
Initial Established Reserves	2,421	2,569	2,699	2,757	(2,154)
EOR in Discovered Pools	785	745	665	615	(375)
New Discoveries	420	432	813	791	(561)
Ultimate Potential	3,626	3,746	4,177	4,163	(3,091)

* Values for Alberta in 1989 are in parenthesis.

Sources:

1982: NEB, *Canadian Energy Supply and Demand, 1983-2005* (September 1984).

1984: NEB, *Canadian Energy Supply and Demand, 1985-2005* (October 1986).

1986: NEB, *Canadian Energy Supply and Demand, 1987-2005* (September 1989).

1989: NEB, *Canadian Energy Supply and Demand, 1990-2010* (June 1991).

future reserves additions for heavy oil amount to 710.6 10⁶ m³, which is about 3.75 times larger than remaining conventional heavy oil established reserves at the end of 2000. Supply costs (including royalties and taxes, and based on a 10% discount rate) varied significantly, from \$35/m³ to \$270/m³. As with conventional light and medium oil, this suggests that considerable potential for reserves additions of heavy oil exists, but at much higher costs than were seen in the earlier days of the industry.

NEB. In 1974 the NEB began to issue a series of reports dealing initially with Canadian oil supply and demand, then, starting in 1981, with all energy forms. The September 1984, October 1986, September 1988, and June 1991 studies all reported NEB estimates of ultimate conventional crude oil potential in Western Canada. The NEB relied heavily on GSC research, especially for light and medium crude. Potential, in addition to initial established reserves, included both enhanced oil recovery and new discoveries for light and medium oil and for heavy oil. Table 5.6 summarizes the estimates in the four NEB reports. It can be seen that the NEB estimates rose from 1984 to 1986, particularly insofar as possible new discoveries were

concerned. The 1984 Report alludes to rising prices, though no formal model illustrating the effect of rising prices is included. The 1989 estimate for light and medium crude from established reserves plus new discoveries is close to the GSC 1987 estimate (2.8 billion m³), but the NEB adds a further 295 million m³ of possible reserve additions through increased recovery in established pools. (The 1987 GSC model focused on oil in place, then applied recovery factors based upon averages in various oil plays.)

The 1991 NEB study provided a breakdown by geographical area, indicating that 87 per cent of the potential for light and medium oil lies in Alberta, as opposed to 36 per cent for heavy oil (where Saskatchewan is more important). It is also noteworthy that, for Alberta, possible additions to reserves were estimated at 36 per cent of already established reserves for light and medium oil, but 71 per cent for heavy oil. This suggests that the future mix of Alberta conventional oil output may tend to shift towards heavy oil.

ERCB. The ERCB has provided reserve estimates for Alberta, generally in conjunction with its Reserves Report (as noted above, since the late 1960s, this has

Table 5.7: ERCB Estimates of Alberta Ultimate Conventional Crude Oil Potential

<i>Date</i>	<i>Ultimate Potential 10⁶ m³ (10⁹ bbl)</i>		<i>Source (ERCB Report)</i>
1963	1.9	(1.2)	Report 64-8
1968	2.9	(18)	Report 69-18
1973	3.2	(20)	Report 74-18
1975	2.9	(18)	Report 76-18
1976	2.5	(15.9)	Report 77-18
1978	2.4-2.7	(15.1-17.0)	Report 79-18
1980	2.6	(16.4)	Report 81-B
1982	2.67	(16.8)	Report 83-E
1984	2.65	(16.7)	Report 85-A
1987	2.91	(18.3)	Report 88-E
1990	2.84	(17.9)	Report 91-18
1993	3.13	(19.7)	Report 93-18

Notes: The ERCB did not increase its estimate of ultimate potential through to the 2013 *Reserves and Supply/Demand* report (Report 2013-98), although it suggested in 2012 that “this estimate does not include potential oil from very low permeability reservoirs, referred to by industry as “tight oil,” which is now starting to be exploited using horizontal multistage fracturing technology” (p. 4-9).

Sources:

Report 64-8 and Reports xx-18 are *Reserves Reports*.
 Report 81-B is *Estimates of Ultimate Potential and Forecasts of Allowable Production Capacity of Alberta Crude Oil and Equivalent*.
 Report 83-E is *Alberta Oil Supply, 1983-2007*.
 Report 85-A is *Alberta Oil Supply, 1985-2010*.
 Report 88-E is *Alberta Oil Supply, 1988-2003*.

been issued annually as Report number ST-18 or ST-98). The ERCB has not provided much detail on its estimation procedures. Prior to 1977, “volume of sediments and exploration well statistics methods” were used. Since then, however, estimates have been based on “geological judgment with respect to trends reflected in exploration success, extent of exploration and development and likelihood of hydrocarbon accumulations in unexplored geologic horizons” (ERCB *Reserves Report* ST-18, 1977, p. 9-2). Table 5.7 reviews the ERCB estimates since the mid-1960s, with values reported for years in which the estimate of ultimate potential was changed. As can be seen, the estimate of 1.9 billion m³ in the early 1960s was increased to 3.2 billion m³ by 1973, perhaps due to the Keg River and assorted plays that developed in Northwestern Alberta in the late 1960s. In 1975 estimates were reduced and have been in the 2.4 to 3.1 billion m³ range since then. The ERCB has indicated that

the 1993 estimate is still felt to be reasonable, although the board states that “[g]iven recent reserve growth in low permeability oil plays, the ERCB believes that this estimate may be low” (2012 *Reserves Report*, ST-98, p. 6). Comparison with the NEB estimates for 1989 of Table 5.6 suggest that the ERCB is slightly less optimistic than the NEB. Comparison with the GSC is difficult, since the GSC estimates include only light and medium crude.

4. Summary and Conclusions

As of December 31, 2012, the ERCB estimated that Alberta held the ultimate potential to produce 3.13 billion cubic metres of conventional crude oil; of this, 2.65 billion (85%) has already been produced, 269.2 million (8.6%) lay in remaining established reserves, and 209 million (6.6%) had yet to be established as reserves through new discoveries or other means (e.g., EOR schemes). The degree of certainty attached to these numbers varies greatly, the past production data being very accurate, and the remaining reserves estimates reasonably good, though subject to revision in light of future production levels and other information. Considerable caution must, however, attend the 209 million m³ of possible future reserves additions, since they will hinge upon the major uncertainties associated with exploration at untested sites, the course of future technological changes, and the vagaries of oil prices and government regulations. If the ERCB is right, we have, as of 2013, less than ten percent of Alberta’s recoverable conventional oil reserve base left to find and develop. Moreover, these reserves are likely to lie in deposits that are relatively small in comparison to those that generated the large reserve additions of the first two decades after 1947. The GSC estimated in 1987 that discovered Western Canadian Sedimentary Basin conventional oil pools numbered about 3,300, while more than 4,000 pools remained undiscovered; the latter would hold only 25 per cent of the oil that might be recovered from the Basin (GSC, 1987, p. 124). On the basis of such expectations, prevailing wisdom has the Alberta conventional crude oil industry turning to increasingly more costly reserves additions, while undergoing a tendency to declining output as established reserves are run down. On a more optimistic note, the GSC 1987 estimate of about 7,300 light and medium crude oil pools in the entire Western Canadian Sedimentary Basin, had, by the year 2002, been surpassed in Alberta alone. And

exploratory drilling in Alberta is not yet as intensive as in the lower-48 United States.

Physical resource estimates are not infallible guides to economic outcomes and so must be treated with care. Adelman (1990, p. 1) said “The total mineral in the earth is an irrelevant non-binding constraint” and also that whatever is left after abandonment is “a geological fact of no economic interest.” Most useful analysis looks to only some portion of the total petroleum available in the ground. Consider, for example, the least controversial, and most widely accepted, of the various resource measures – the established reserves of crude oil. One might think that those reserves are a prime determinant of output rates, now and in the future. Often established reserves are compared to annual production in the form of the R/P (reserves-to-production) ratio, sometimes called the ‘life index.’ For example, in 1991, Alberta produced 51.4 million m³ of crude oil (per year), out of reserves as of December 31, 1990, of 510.4 million m³, yielding a R/P ratio of (510.4 million m³ / 51.4 million m³/year) or 9.9 years. The R/P ratio is not, however, an estimate of the future lifetime of the industry in Alberta; consider, for example, that in 2010 Alberta was still producing significant volumes of conventional crude oil, and the conventional oil R/P ratio was still close to ten years! As industry observers quite properly emphasize, remaining reserves are a dynamic concept, diminished by production but augmented by new reserves additions. Adelman (1990) is helpful in suggesting that established reserves are best seen as the industry’s on-the-shelf working inventory. As in any ongoing business, one of the industry’s tasks is to develop optimal withdrawals from and additions to this inventory. The R/P ratio itself is a measure of the intensity with which the current inventory is worked. While oil

pools vary significantly in their physical characteristics, the dynamics of oil reservoirs probably mean that sustained operation of oil pools at R/P ratios much less than 10 is difficult, without significantly damaging pool recovery mechanisms. In this case, established reserves serve as a severe constraint on the ability to increase production. On the other hand, high reserves to production ratios, like values in excess of 100 for some Middle Eastern countries, imply that output could be increased relatively easily from existing reserves. The Alberta conventional oil R/P ratio has, since 1947, been at both higher and lower levels. The point is that any given volume of reserves allows many different possible output rates.

As the Adelman quotes of the previous paragraph makes clear, the concept of ultimate potential must also be used cautiously. (See also Adelman and Watkins, 1992 and 2008, and Watkins, 1992.) In the first place, its precise value is subject to a wide range of uncertainty, since ultimate oil recovery depends on so many future technological, economic, and political factors, which simply cannot be forecast with accuracy. This is on top of inevitable uncertainties in basic geological knowledge. Moreover, what is critical from the economic point of view is the course of annual reserves additions and how they are brought into production, rather than the ultimate stock of such additions. Of course, the ability to add reserves in any period is limited by the amount potentially available, but this is only one of the factors affecting actual reserves additions.

From this discussion of Alberta’s conventional oil reserves, we turn to the question of the levels of Alberta oil production, and the prices received for that output.

Crude Oil Output and Pricing

Readers' Guide: Chapter Six looks at the history of the prices for Alberta crude oil and the levels of conventional crude oil production. In economic terms, price and output are determined in the market for crude oil, in which Alberta oil meets other crude oils in competition. However, the prices and output have a petropolitical dimension, since the operation of crude oil markets is affected by a variety of government regulations. As this chapter illustrates, Canadian government regulation of the crude oil market since the end of World War II has covered the spectrum from a relatively hands-off policy to an approach that directly fixes oil prices by government fiat. This chapter looks at the prices and output of Alberta conventional crude oil, while Chapter Nine presents detailed analysis of the government policies.

1. Introduction

As was discussed in Chapter Four, Alberta crude oil output and prices have been determined in crude oil markets whose operations reflect four factors: (1) supply-side decisions; (2) demand-side decisions (including refining and transportation components); (3) governmental regulations; and (4) adjustment processes as the market reacts to changing circumstances. The common assertion that demand and supply determine market outcomes is widely accepted, but, unfortunately, ambiguous. We must distinguish at least three senses in which supply equals demand in the market for lifted crude oil:

Sense (1): As an accounting identity and reflecting material balance requirements in the physical world, every unit produced ('supplied') in a period must end up somewhere (i.e., 'demanded').

Sense (2): As a condition for economic equilibrium, the total quantity willingly produced ('supplied') will equal the total amount willingly consumed ('demanded'); in other words, there are no undesired build-ups or downturns in inventories of crude oil held by producers or users. It should be remembered that the inventories of crude oil held by producers are generally in the form of reserves in the ground.

Sense (3): As a condition for a perfectly ('effectively') competitive equilibrium, price and quantity will be where the willingly undertaken supplies of 'price-taking' producers just equal the willingly undertaken demands of 'price-taking' purchasers. (Price-takers are producers or consumers who form such a small part of the market that their variations in output or purchases have no effect on the market price.)

Supply and demand are always equal in sense (1). In the real world, participants in a market are often in the process of adjusting their behaviour in response to changing conditions with some undesired change in inventories, so that the market is not in equilibrium in senses (2) and (3). However, it is common for

economists to assume that markets adjust to equilibrium quite quickly, as would be anticipated if buyers and sellers are well-informed and communication flows accurate and rapid. Thus, observed values in the market are taken to be equilibrium values subject only to some small random error reflecting adjustment difficulties (disequilibrium). At any point in time, the crude oil market can be in short-run equilibrium, when, for example, at current prices, producers are lifting and selling just as much as they wish from installed productive capacity, but in medium-run disequilibrium, if producers wish to install more capacity in existing reservoirs to add more reserves. In long-run equilibrium, producers would have the desired levels of lifted crude oil, productive capability and reserves, including anticipated reserves from newly discovered reservoirs.

It is the effectiveness of competition in the market that determines whether prices and output are determined by demand and supply in sense (2) or sense (3). Sense (2) encompasses sense (3), effective competition, but also includes those instances in which market participants exercise their ability to manipulate quantities in order to influence price. As was discussed in Chapter Four, this may include producers restricting output to generate higher prices (oligopoly), buyers restricting sales to generate lower prices (oligopsony), or some combination of the two (bilateral oligopoly). Such exercise of market power will generate prices that differ from the effectively competitive level. It may also involve price discrimination, typified by the case in which different consumers pay different prices for identical products, and more accurately “defined as implying that two varieties of a commodity are sold (by the same seller) to two buyers at different net prices, the net price being the price (paid by the buyer) corrected for the cost associated with the product differentiation” (Phlips, 1983, p. 6). Economists are generally concerned with persistent price discrimination, rather than isolated cases that may occur as markets feel their way towards equilibrium.

Vertical integration in the petroleum industry complicates the issue. Many ‘crude oil’ companies are both producers of crude oil and purchasers (as oil refiners) and most of the large oil refineries have crude oil production facilities of their own. In such circumstances, the major buyers of crude oil (even if an oligopsony) might prefer higher prices for crude oil, particularly if high crude oil prices help to serve as a barrier to entry to ‘independent’ refiners (those without their own crude oil). Lower effective income tax rates on profits from crude oil than on profits from refining, as has generally been true in North America,

might reinforce this preference by major vertically integrated refiners for higher crude oil prices. The main point is that a highly concentrated market on either the seller or the buyer side tends to translate into pressure for higher or lower prices for crude oil than under effective competition.

This chapter is concerned with how the four factors underlying the oil market have operated to determine the price of Alberta crude oil. Section 2 sets out the underlying data with minimal discussion – the annual course of crude oil prices, conventional crude oil output, and domestic and export sales from 1947 through 2012. Section 3 then discusses the major influences on Alberta oil prices and output, with five time periods considered:

- (i) **Prior to 1947**, when Alberta was an oil-importing region;
- (ii) **1947 to 1960**, when new market areas were being established;
- (iii) **1961 to 1972**, when the Canadian National Oil Policy and U.S. Import Oil Quota Programs were dominating influences;
- (iv) **1973 to 1984**, when stringent federal (Ottawa) controls operated, including the National Energy Program; and
- (v) **1985 to the present**, when deregulation exposed Alberta to direct contact with an increasingly volatile international market.

Section 4 looks briefly at the corporate structure of the industry, including the degree of concentration of production and the extent of foreign ownership.

2. Alberta Oil Production and Prices: The Data

Table 6.1 details Alberta annual oil production, including conventional crude oil and, since 1967, synthetic crude oil. The synthetic crude oil industry is discussed in more detail in Chapter Seven of this book. Synthetic crude oil rose from 3 per cent of Alberta’s liquid hydrocarbons production in 1970 to over 35 per cent by 2012. Petroleum from the oil sands (synthetic crude oil plus bitumen) accounted for over 72 per cent of Alberta production by 2012. Since crude oil is not a perfectly homogeneous product, output in any year includes a mix of hydrocarbons, ranging from lighter crude oils and condensate from natural gas pools through to heavy crudes and bitumen. Table 6.1 divides the oil into that sold in domestic markets and

Table 6.1: Alberta Oil Production and Sales, 1914-2012 (10³ m³/d)

	<i>Crude Oil Production</i>	<i>Sales</i>				<i>Synthetic Crude Production</i>
		<i>Domestic</i>	<i>Export U.S.A. (East)</i>	<i>Export U.S.A. (West)</i>	<i>Export (Offshore)</i>	
1914-21	0.003	.003				
1925	0.07	.07				
1930	0.6	0.6				
1937	1.2	1.2				
1942	4.4	4.4				
1946	4.0	4.0				
1947	3.8	3.8				
1948	4.8	4.8				
1949	8.8	8.8				
1950	12.0	12.0				
1951	20.2	20.2				
1952	26.0	25.5	0.5			
1953	33.7	32.7	1.0			
1954	38.5	37.4	0.7	0.4		
1955	49.6	43.2	1.5	4.9		
1956	63.1	47.1	4.9	11.1		
1957	60.3	42.7	2.7	14.9		
1958	49.8	43.9	2.0	3.9		
1959	57.3	49.4	2.1	5.8		
1960	58.7	47.5	3.3	7.9		
1961	72.0	49.1	8.5	14.4		
1962	79.1	48.1	11.2	19.8		
1963	82.3	50.2	12.6	19.5		
1964	87.0	51.6	13.3	22.1		
1965	91.7	56.2	13.6	21.6		
1966	100.4	58.4	17.9	24.1		
1967	113.4	61.1	23.9	28.4		0.2
1968	125.6	66.9	34.1	24.6		2.5
1969	142.1	68.9	42.4	30.8		4.4
1970	165.6	76.4	56.2	33.0		5.3
1971	181.2	80.3	68.4	32.5		6.8
1972	213.5	81.3	90.7	41.5		8.2
1973	261.8	102.6	120.1	39.1		8.0
1974	249.2	123.2	95.4	30.6		7.3
1975	215.7	115.6	73.3	26.8		6.8
1976	196.3	132.5	49.2	14.6		7.6
1977	194.7	156.7	34.5	3.5		7.2
1978	192.9	161.8	28.9	2.2		8.9
1979	222.0	184.9	33.1	4.0		14.6
1980	211.4	187.6	20.6	3.2		20.3
1981	191.8	172.0	16.7	3.1		17.7
1982	186.4	162.0	21.4	3.0		19.1
1983	195.3	164.1	28.1	1.5	1.6	25.4
1984	205.6	162.1	40.5	2.8	0.2	21.2
1985	207.2	150.1	53.6	2.9	0.6	26.7
1986	205.5	135.9	64.7	3.4	1.5	29.4
1987	214.9	140.3	71.1	1.4	2.1	28.7
1988	227.8	140.3	83.5	1.1	2.9	31.9

/continued

Table 6.1/continued)

	Crude Oil Production	Sales				Synthetic Crude Production
		Domestic	Export U.S.A. (East)	Export U.S.A. (West)	Export (Offshore)	
1989	221.6	139.9	78.3	1.6	1.8	32.6
1990	217.1	133.4	81.2	0.6	1.9	33.1
1991	216.7	121.6	90.9	0.8	3.4	35.9
1992	224.0	122.1	98.9	–	3.0	37.7
1993	228.8	124.4	102.6	–	1.8	38.7
1994	235.8	127.8	102.3	7.1	0.6	41.6
1995	242.4	122.1	117.4	6.3	0.8	44.7
1996	245.2	117.8	120.8	10.3	2.0	44.7
1997	253.0	103.8	136.7	10.8	1.9	43.7
1998	254.6	101.3	139.3	11.3	3.2	49.0
1999	239.4	101.2	136.4	7.1	0.5	51.4
2000	257.3	96.6	139.1	7.5	–	51.0
2001	259.0	88.2	156.8	7.5	–	55.4
2002	243.7	94.2	155.6	6.2	–	70.1
2003	257.9	128.2	161.7	8.5	3.3	80.9
2004	274.7	132.4	176.2	14.3	1.4	96.3
2005	268.9	123.6	175.2	11.3	4.4	86.9
2006	287.2	127.4	199.6	14.3	4.0	104.4
2007	295.0	131.4	197.0	16.2	6.1	109.2
2008	293.7	127.3	200.5	17.7	6.7	104.1
2009	305.8	134.3	203.8	15.9	22.0	121.7
2010	326.4	128.6	198.7	18.9	21.7	125.8
2011	355.1	135.5	192.1	22.0	7.0	137.1
2012	389.8	143.2	201.8	21.1	9.7	140.0

Notes: All production prior to 1952 is assumed to be for domestic use. Production includes condensate and pentanes plus and synthetic (tar sands) oil. Domestic sales include inventory changes and miscellaneous losses and adjustments plus resale of minor volumes of crude imported into Alberta in some years. Western U.S.A. is PAD (Petroleum Administration District) V (Washington, Oregon, California, Nevada and Arizona). There are data problems for the year 2001 which the ERCB has indicated it is addressing.

Sources:

1914–51: *Annual Report of the Department of Mines and Minerals* for the Fiscal Year Ended March 31, 1952;
 1952–2012: Energy Resources Conservation Board (or Energy Utilities Board or Oil and Gas Conservation Board) as follows:
 1952–61: *Oil and Gas Industry Annual Report*, 1961;
 1962–63: *Oil and Gas Industry Annual Report*, 1963;
 1964–71: *Cumulative Annual Statistics of Western Oil and Gas Industry*, 1973 (ST74-17);
 1972–80: *Cumulative Annual Statistics of Western Oil and Gas Industry*, 1981 (ST82-17);
 1981–97: *Alberta Oil and Gas Industry Annual Statistics*, assorted years (ST-17);
 1998–2012: *Alberta Energy Resource Industries Monthly Statistics*, various issues (ST-3).

that exported to the United States, where the ‘west’ of the United States is PAD V (Petroleum Administration District V, which includes states on the west coast plus Nevada and Arizona). Occasional barrels of Alberta crude oil made their way to other markets; markets other than those in Canada and the adjacent northern part of the United States have had ready access

to easily transported international crude oil supplies at prices with which Alberta has been unable to compete.

Table 6.2 shows the course of Alberta light crude oil prices from 1948 through to 2012, for 35° crude oil at the field gate of the Redwater pool just northeast of Edmonton to 1985 and for Alberta ‘Par’ at Edmonton

Table 6.2: Alberta Crude Oil Prices, 1948–2013

<i>i) Market Penetration</i>		$\$/m^3$	$\$/b$	<i>iii) Covert Controls/continued</i>		$\$/m^3$	$\$/b$
1948	(January 1)	20.14	3.20	1982*	(January)	146.31	23.25
1949	(January 1)	16.87	2.68		(July)	185.64	29.5
	(September 1)	18.12	2.88	<hr/>			
1950	(October 16)	17.18	2.73	<i>iv) Deregulation</i>		$\$/m^3$	$\$/b$
1951	(April 24)	15.35	2.44	1985	(June 1)	231.27	36.75
	(June 1)	15.48	2.46		(4th quarter)	232.83	37.00
1952	(April 23)	14.57	2.315	1986	(March)	111.2	17.67
	(June 1)	15.48	2.46		(October)	124.2	19.11
1953	(March 19)	15.01	2.385	1987	(March)	142.4	19.74
	(July 21)	16.64	2.645		(October)	155.52	22.62
1954	(October 15)	16.08	2.555	1988	(March)	119.65	19.01
1955	(January 7)	15.64	2.485		(October)	100.13	15.91
	(February 1)	15.67	2.49	1989	(March)	135.61	21.55
1957	(January 16)	16.80	2.67		(October)	143.41	22.79
	(August 30)	16.55	2.63	1990	(March)	149.9	23.82
1958	(April 12)	16.11	2.56		(October)	255.83	40.65
1959	(March 24)	15.23	2.42	1991	(March)	137.07	21.78
<hr/>					(October)	156.67	24.90
<i>ii) National Oil Policy (Covert Controls)</i>		$\$/m^3$	$\$/b$	1992	(March)	132.33	21.03
1961	(September 11)	15.86	2.52		(October)	163.31	25.95
	(May 10)	16.49	2.62	1993	(March)	146.31	23.25
1970	(December 15)	18.38	2.92		(October)	139.69	22.20
1973	(May 1)	21.9	3.48	1994	(March)	114.54	18.20
	(August 1)	24.42	3.88		(October)	141.29	22.45
<hr/>				1995	(March)	155.95	24.78
<i>iii) Covert Controls</i>		$\$/m^3$	$\$/b$		(October)	140.73	22.36
1974	(April)	41.41	6.58	1996	(March)	176.17	27.99
1975	(July)	50.82	8.075		(October)	207.57	32.98
1976	(April)	51.00	8.105	1997	(March)	176.53	28.05
	(June)	51.13	8.125		(October)	179.48	28.52
	(July)	57.74	9.175	1998	(March)	127.45	20.25
	(November)	57.99	9.215		(October)	131.97	20.97
1977	(January)	62.40	9.915	1999	(March)	131.43	20.88
	(June)	62.58	9.945		(October)	204.77	32.54
	(July)	68.88	10.945	2000	(March)	273.30	43.42
1978	(January)	75.17	11.945		(October)	311.77	49.54
	(February)	74.98	11.915	2001	(March)	258.21	41.03
	(July)	81.24	12.91		(October)	213.15	33.87
1979	(July)	87.54	13.91	2002	(March)	239.30	38.01
	(October)	87.67	13.93		(October)	276.52	43.94
1980	(January)	93.95	14.93	2003	(March)	309.86	49.24
	(August)	106.35	16.9		(October)	242.29	38.50
1981*	(January)	112.71	17.91	2004	(March)	305.84	48.60
	(June)	113.21	17.99		(October)	405.87	64.50
	(July)	119.57	19.00	2005	(March)	425.38	67.60
	(October)	132.97	21.13		(October)	472.13	75.02
				2006	(March)	429.13	68.19
					(October)	397.52	63.17

/continued

Table 6.2/continued

iv) Deregulation/continued		\$/m ³	\$/b
2007	(March)	435.86	69.26
	(October)	511.31	81.25
2008	(March)	664.51	105.60
	(October)	538.68	85.59
2009	(March)	379.83	60.39
	(October)	483.18	76.78
2010	(March)	511.89	81.34
	(October)	470.38	74.75
2011	(March)	614.41	97.63
	(October)	589.14	93.62
2012	(March)	541.36	86.03
	(October)	581.37	92.39
2013	(March)	560.54	89.07

Note: Quarterly figures are end-quarter prices. * Price refers to "old" oil. 1948–85, price is for Redwater 35° oil. After 1985, price is 'Canadian Par Price.'

Sources: 1948 to 1974, Alberta, Energy Resources Conservation Board, unpublished data, and Esso Canada, *Esso Price Bulletins* (various years); 1975 to 1985, Alberta Petroleum Marketing Commission, *Selling Price Bulletin for Crown Petroleum* (various years); 1985, Esso and Shell, *Crude Oil Pricing Bulletin* (various months); 1986 to 2013, Natural Resources Canada, Petroleum Resources Branch, *Crude Oil Data, Selected Oil Prices – Monthly Data*.

after that. Oil of different quality or at a different location would exhibit a price differential from this oil but would otherwise tend to follow the same historical price path. Only when a crude oil differs quite significantly from the Redwater "reference" crude oil, for example very heavy oils from some eastern Alberta pools, might changes in the size of the price differential itself be a significant factor in the general trend.

Little concerted economic analysis of crude oil price differentials is available. Conceptually, in a well-functioning relatively competitive market, one would expect that there is, in any time period, an equilibrium set of price differentials that reflects:

- (i) **transportation cost differences**, with crude oil further from market than the reference oil having a lower price (a higher negative differential relative to the reference crude oil), as would heavier crude oils which are more costly to ship;
- (ii) **refining cost differences**, with heavier crude oil having higher refining costs (especially if subject to special processes such as cracking designed to increase the yield of lighter

products), and therefore less value to the refiner, generating a larger negative differential; and

- (iii) **refined petroleum product refinery gate values**, with heavier crude oil having a lower yield of the more highly valued light products, therefore commanding a larger negative differential.

Changes in transmission costs, in the configuration of purchasing refineries, in refinery technology and in the values of refined petroleum products would all change price differentials across different grades of crude oil. In practice, the industry and governments have generally handled the hydrocarbon quality part of the price differential by means of relatively fixed conventions, accepted by all and holding for lengthy periods of time. The locational differences have reflected the costs of transmission.

Historically, Alberta oil price differentials from 1947 on (as set out by Imperial Oil) were 3 cents per barrel for every degree API difference, and 2 cents per barrel for every 0.1 per cent sulphur difference (above .49% sulphur). (See Bertrand, 1981, vol. iv, pp. 4–8.) Bradley and Watkins (1982, pp. 66–68) argue that the inability of individual refineries to select output from particular oil pools as a result of the Alberta government market-demand prorating scheme meant that market flexible differentials were not viable and some more arbitrary way of determining relative crude oil values was required. Acceptable fixed differentials provide a low-cost solution to this problem. Much of the analysis of the crude oil industry in the Bertrand Report on the *State of Competition in the Canadian Petroleum Industry* (Bertrand, 1981, vol. iv) was concerned with whether these set differentials up to 1980 were, in fact, appropriate.

Figure 6.1 shows two price differentials for the years from 1986 to March 2013. One largely represents a locational differential: it shows amount by which the Alberta light oil price at Edmonton is less than the price of North Sea Brent oil delivered to Montreal. If Alberta oil were to be competitive in Montreal, the Alberta price had to be lower than the Brent price by at least the shipment cost from Edmonton to Montreal. Up until 2005, the price differential was relatively small, usually less than \$10/m³. However, after 2005 it increased, rising sharply in 2011 until reaching over \$160/m³ by the time of final editing in March 2013.

The second differential shown is for Alberta heavy oil as compared to Alberta light oil. Except for a brief

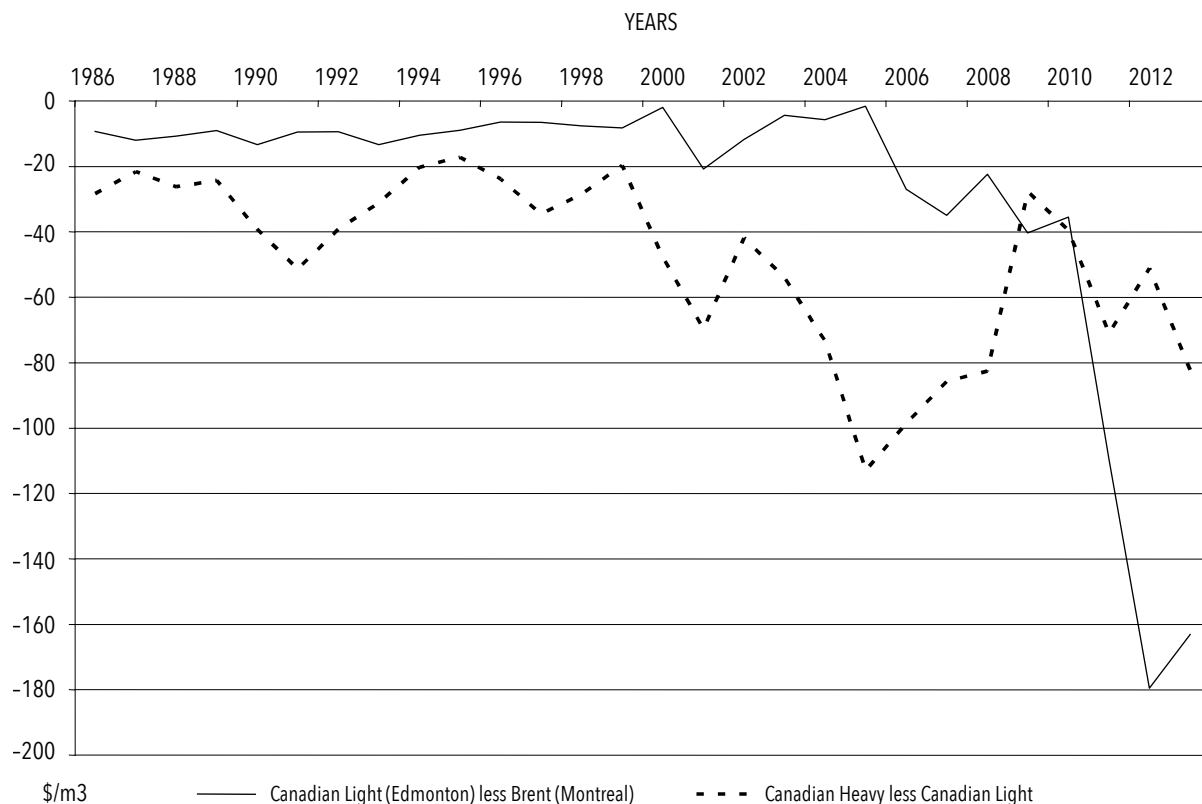


Figure 6.1 Oil Price Differentials

Note: Annual averages, except for 2013, which is the month of March.

Source: Natural Resources Canada, *Selected Crude Oil Prices Monthly*, 1986–2013.

period in 1990, the price difference was less than \$40/m³ until the year 2000. After that it tended to rise, to as much as \$60/m³ (in December 2007), until falling back below \$10/b through much of the next two years. The differential has fluctuated since then but was up to \$94/m³ at the time of writing in April 2013. A larger price differential indicates a relative surplus of heavy crude oils relative to lighter grades and offers an incentive to refiners to buy and upgrade the heavier oil. Some observers of the international oil market have been on record for many years arguing that larger differentials are to be expected as world crude oil production shifts to heavier grades and transportation demands (for light refined petroleum products) become more dominant; however, this forecast has not yet been realized.

The discussion of price and output that follows draws heavily upon Watkins (1977a), Watkins (1981), Bradley and Watkins (1982), Watkins and Bradley (1982), Watkins (1989), and Helliwell et al. (1989).

3. Determination of Alberta Crude Oil Output and Prices

A. Tentative Beginnings: Pre-1947

Native Indians and early explorers and settlers found scattered evidence of Alberta's petroleum potential in oil and natural gas seepages, frequently in ravines or springs by rivers or creeks. (For more detailed discussion of the earliest industry activities in Alberta, see Beach and Irvin, 1940, Toombs and Simpson, 1957, Hanson, 1958, Simpson et al., 1963, de Mille, 1969, Gray, 1970, Gould, 1976, Dow, 2005, and Finch, 2007. Also useful are the *Annual Reports* of the Alberta Department of Lands and Mines after the transfer of resources from Ottawa to the province on October 1, 1930.) Henry Kelsey, of the Hudson's Bay Company, was brought a rock sample from the Athabasca tar sands in 1719 by a Native named Wa-pa-su, and Peter Pond (1778) and Alexander Mackenzie (1781) both

saw the Athabasca deposits during their expeditions. Other early reports of oil seepages were by John G. (Kootenay) Brown at Cameron Creek near Waterton (in 1874), John Ware on the Sheep River (in 1888), and G. M. Dawson and R. G. McConnell of the Canadian Geological Service at Tar Island near Peace River (1893). (Dormaar and Watt, 2008, provide a history of the Waterton finds.) However, the earliest commercial petroleum activities in Alberta centred on natural gas for local use, though this was more a result of accidents of discovery than intent.

The first commercial petroleum well came in at Langevin near Medicine Hat when a CPR water-directed well hit gas. Despite oil traces in several wells at Cameron Creek at the turn of the century, the significant early discoveries were of natural gas, particularly in two major finds at Turner Valley in 1914 and 1922. The Turner Valley natural gas reservoirs signal the start of the Alberta crude oil industry, since both held 'wet' gas (with high liquid – i.e., condensate – content). In fact, the production of gas from Turner Valley was largely driven by the demand for liquid oil, with much flaring of gas and public concern about waste of the gas resource.

As Table 6.1 shows, Alberta oil production was negligible until the late 1930s and did not increase significantly until the late 1940s. Most date the Alberta oil industry from the Leduc finds of February and May 1947. The only significant oil discovery prior to that was the Turner Valley discovery of 1936, on a deeper southwest incline below the gas cap that had been discovered in 1922. Seventeen other smaller oil pools were discovered before Leduc, including Del Bonita (1931), Princess (1939), and heavy oil deposits at Wainwright (1925), Taber (1937), Lloydminster (1939), and Vermilion (1939) (Hanson, 1958, pp. 52–57). None of these early oil finds were part of a major oil play, so the initial discovery was not followed by a flurry of drilling activity and new discoveries in the same geological formations. Turner Valley is anomalous, apparently a large oil pool that is not part of a larger play; this may reflect some chance element in its generation, or the peculiarities of the complex highly fractured geology of the Foothills. Small discoveries, and those involving less attractive heavy oil, are not likely to stimulate an active oil play.

Turner Valley proved to be both a large oil pool and a learning experience. Production there raised several problems that would continue through the years after Leduc. Problems related to the rule of capture, to protection of correlative property rights of oil producers on adjacent properties, and to the orderly marketing of crude oil. The problems were

interrelated. The rule of capture pushed companies to attempt rapid recovery of the fugacious (flowing) oil before their neighbours could capture it, but this pressure occurred in a market that was underdeveloped both in terms of infrastructure for shipment and institutional forms for market exchange.

Companies that built their own pipeline facilities and/or had well-established connections with refiners would have a competitive advantage and might be able to produce significant volumes of oil from beneath neighbouring companies' property. The large, so-called 'major,' oil companies were especially favoured, with good access to financial capital and their own refineries. Smaller producers, concerned about the situation for obvious reasons, cried out for some control over development of the Turner Valley field, and the government responded by establishing the Petroleum and Natural Gas Conservation Board (PNGCB) in 1938. A Turner Valley Gas Conservation Board had been set up in the early 1930s. The PNGCB was the precursor of the Alberta Oil and Gas Conservation Board (OGCB, 1948), its successor in 1968, the Alberta Energy Resources Conservation Board (ERCB), the 1994 Alberta Energy and Utilities Board (EUB), and, once again in 2008, the Energy Resources Conservation Board. Regulatory duties are due to be taken over by the new Alberta Energy Regulator in June 2013. For a detailed history of these bodies prior to 1990 see Breen (1993).

The low recovery rates under the rule of capture were accentuated for the Turner Valley field by production from the natural gas cap discovered in 1922; total primary recovery for the main oil pool is currently estimated at only 13 per cent. Imperial Oil in 1931 limited its purchases of oil from Turner Valley to one half of well potentials in what seems to be the first recorded example of 'proration' in Alberta, albeit at the instigation of private industry rather than government. Later in the 1930s the PNGCB initiated a prorationing scheme in the Turner Valley field to help control depletion of reservoir energy. (See Chapter Ten for a discussion of prorationing.) The McGillivray Royal Commission on Petroleum and Petroleum Products (McGillivray, 1940) agreed that prorationing was necessary for Turner Valley oil, but argued that, for other oil pools, it would be preferable to apply unit operations, where each pool would be operated as a single entity. However, Alberta continued to utilize prorationing in preference to unitization right through to the end of the 1980s.

Turner Valley pushed Alberta's liquid hydrocarbon production up from about 3,600 b/d (570 m³/d) in 1936 to a war-time peak of 27,800 b/d in 1942,

transforming Alberta from a net oil importer to a net oil exporter, with ex-Alberta sales going primarily to Regina. However, by 1947 Alberta's oil output had fallen to 24,000 b/d, as Turner Valley moved into a phase of production decline.

The price of Alberta crude oil in this period was tied to the price of oil from adjacent areas of the United States, particularly the Cutbank pool in Montana. The McGillivray Commission of 1940 summarized the explanation of Alberta oil pricing that has gained most credence (McGillivray, 1940, pp. 56–57). North America was viewed as an integrated crude oil market, with prices everywhere, including Montana, tied to prices at the U.S. Gulf (of Mexico). This reflects the Gulf Coast pricing system for oil throughout the world ('Gulf Plus') as discussed in Chapter Three. Montana oil served as the competition to Alberta oil in Regina and hence was the prime determinant of the price of Turner Valley oil. For example, in 1939, a field price of US\$1.10/b for Cutbank 37° oil in Montana generated a delivered price (in Regina) that could then be netted back to Turner Valley by deducting the Turner Valley to Regina shipment cost, with further allowance for quality differences and the exchange rate. This implied a price in Turner Valley for 43° oil of CDN\$1.28/b, which was just about the prevailing price. The Commission noted that if Turner Valley oil were shipped further east to Portage la Prairie, its price would have to fall to compete with oil and products supplied from Sarnia and that the revenue earned would fall since the extra volume shipped would not make up for the price decline. The report did not, however, discuss what forces prevented sales from occurring in the Portage market, though it noted that production decline would soon necessitate a falling off of sales in Saskatchewan.

Thus, Alberta crude oil prices, from the beginnings of production in 1914, followed U.S. crude oil prices. In the period from 1925 through 1946, average per barrel receipts on Alberta crude oil fluctuated with North American prices with a low of CDN\$1.22/b in 1939 and a high of \$4.60 in 1927. The average value of Alberta oil sales in 1947 was \$2.66/b.

The McGillivray Commission noted that the vast sedimentary basin covering most of Alberta offered high crude oil potential but that new discoveries were essential even to maintain the output levels of the early 1940s. The full extent of Alberta's oil potential was uncertain.

In the early 1900s, the chief geologist of Standard Oil had been negative about Alberta's potential. However, the company's subsidiary in Canada (Imperial Oil) had persuaded Standard that an exploration

program in the Western Canadian sedimentary basin was warranted (de Mille, 1969, p. 154). Imperial had a share in the Turner Valley pool, but of 134 Imperial exploratory wells drilled up to 1946, only one had found a significant oil pool (and that was too far north, at Norman Wells, in the Northwest Territories, to be of commercial value) (Gray, 1970, p. 98). Despite contrary pressures, Imperial decided not to abandon exploration in Alberta. A group of senior geological experts recommended drilling on land Imperial held near what was then understood to be the Alberta 'hinge belt' where the shallower sedimentary rock layers to the northeast suddenly deepened very sharply to the southwest. The well was targeted primarily to rocks of Mesozoic age. The ironies of the Leduc well have often been noted. Oil was discovered, unleashing the first of the major oil plays that transformed the Alberta economy. The irony lies, not in the discovery of oil itself, but in the location, which was not in the geologic target but in a deeper Devonian formation; moreover, an Alberta hinge belt, as envisioned in 1947, does not exist. Decision-making in an uncertain world guarantees surprises, some of them pleasant!

B. Market Penetration: 1947–60

After Leduc, Alberta's reserves swelled with new discoveries. New markets for western Canadian crude oil needed to be found. This would entail displacement of other oil supplies in areas increasingly far from Alberta. Expansion in an eastward direction would require acceptance of lower netbacks to compete with the delivered price of oil from the alternative source of supply – the United States. Markets progressively further east from Alberta were closer to U.S. mid-continent pipeline terminals, so had lower shipment costs for U.S. crude oil. Figure 6.2 (a modification of Figure 3.1) illustrates the general relationships. Distance is shown along the bottom of the figure, while the vertical distance shows the price of oil. P_T represents the delivered price of U.S. crude oil, up the Niagara peninsula, to Toronto. The line $P_T X$ shows the delivered price of such crude oil moved westward from Toronto to various Canadian markets. In 1947 Alberta crude oil was competitive as far east as Regina; this is indicated by an Alberta price at level P_A and a delivered price for Alberta oil in markets to the east as indicated by line $P_A Y$. As can be seen, the watershed market (where U.S. and Alberta crude oils are equally attractive) is just east of Regina. In Winnipeg, Manitoba, in 1947, U.S. oil was cheaper than Alberta

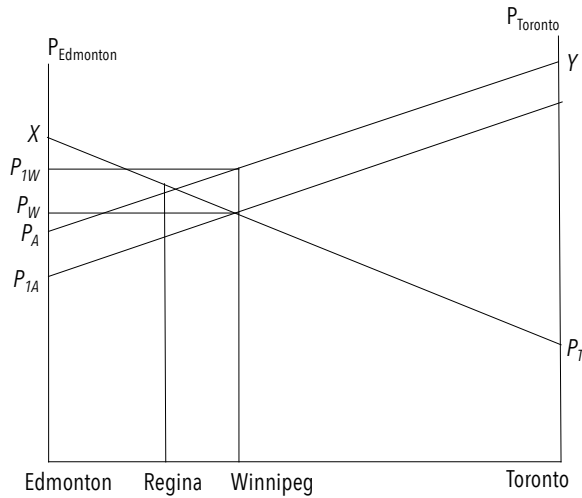


Figure 6.2 Alberta Crude Oil Market Penetration

oil ($P_W < P_{1W}$). Only if the Alberta oil price fell to level P_{1A} would customers in Winnipeg be induced to purchase Alberta crude oil.

The precise way in which the market would respond to increased Alberta oil reserves would depend upon the degree of competition in the market. We begin by considering two possible geographic pricing patterns.

1. Competitive Pricing Patterns

What sort of pricing structure would arise if output grew under competitive market conditions? As just discussed, acquisition of new eastern markets would involve absorption of shipping charges. To meet the United States delivered price in, say, eastern Saskatchewan, Alberta producers would have to lower their wellhead price.

As still more reserves were discovered, Alberta output would continue to expand, absorbing all Saskatchewan demand, then moving into Manitoba. A lower Alberta price would be necessitated with each eastward extension of the market area in order to keep the oil competitive with imported oil into the new market. Under competition, this would become the price at which all Alberta crude oil would be sold, regardless of destination. At each step, sellers would, of course, like to maintain the previous higher price level. However, if individual companies tried to hold the price up, producers without contracts would bid down the price of all oil to the new, lower level. Under competition, this process would continue until the

Alberta wellhead price fell to the long-run incremental cost of supply.

2. Monopolistic Pricing Patterns

What price structure would have evolved had Alberta producers been able to exert monopolistic power? Such power would likely involve price discrimination. Producers would have continued supplying Alberta at the original Alberta wellhead price, while supplying Saskatchewan at a lower wellhead price, and Manitoba at a still lower price, reflecting higher transportation costs. The incremental benefit of each market expansion step would be greater for producers than in the competitive case: even though the netback on new, more distant sales would be lower, prices would be maintained at previous levels in nearer markets.

Price on at least some of the sales would be in excess of the long-run incremental supply cost of the crude oil. Although producers would clearly prefer to keep price higher in markets adjacent to the supply region and only cut it for the new markets, a monopolistic result might occur without price discrimination, but with price in excess of incremental costs. That is, a uniform wellhead price could emerge but be held above long-run marginal cost by restricting output.

3. What Pattern Evolved?

What happened to Alberta oil prices as output expanded in the late 1940s and 1950s? Table 6.2 shows that, by and large, crude oil prices were reduced in a series of steps corresponding to the penetration of successively more distant markets.

In 1947, Alberta oil supplied Alberta requirements and a portion of Saskatchewan's. By 1948, Alberta oil had begun to penetrate the Manitoba market, and in 1951 deliveries to the Ontario market commenced, as did exports to the United States.

In 1947, the price of Alberta oil was \$3.20 per barrel. By December 1948, this price had been reduced to \$2.68 to make Alberta oil competitive with the delivered price in Manitoba of United States supplies from Illinois, Oklahoma, and Texas. Alberta oil prices fluctuated in 1949 and 1950, according to changes in the exchange rate of the Canadian dollar. The reduction in price in 1951 was intended to make Alberta crude oil competitive with Illinois crude oil at Sarnia. The price rise in 1953 reflected an increase in equivalent delivered prices of U.S. and world oil at Sarnia. The price fell in 1955 with a change in the price of Illinois crude oil and exchange

rate adjustments but rose in 1957 as world oil prices increased. Subsequently, the 1958 decline in world oil prices induced a fall in Alberta oil prices. In 1962, the devaluation of the Canadian dollar to a pegged rate (CDN\$1 = US\$0.925) resulted in an Alberta (Redwater) wellhead price of \$2.62. This price held until 1970.

Up to 1960, the behaviour of Canadian oil prices is compatible with the competitive model outlined above. The build-up in supplies induced market expansion. Prices for all markets were reduced as the competitive interface for Alberta oil shifted eastwards to displace United States supplies. Also, up until 1960, changes in world crude oil prices were directly reflected in Alberta prices.

However, further consideration suggests that neither the price adjustments nor the level of prices were fully consistent with the competitive market outcome. Rather, a mix of oligopoly (with some large powerful sellers) and oligopsony (with some large powerful buyers) was operating (Bradley and Watkins, 1982).

4. The Oligopoly-Oligopsony Case

In a situation of few sellers (and that of few buyers can be treated similarly), it would be irrational in the view of an economist, and folly in the view of a business manager, for a given seller to adjust the terms of sale – in particular, the price – without taking account of how rival sellers would respond. As the most familiar example, consider the possibility of a unilateral price cut. Word of bargains usually travels fast, so, long before the path to the price-cutter's door could become well worn, rivals might be expected to match the price cut in order to preserve their sales. If this were the case, why make the initial cut, creating only the prospect of lower prices for everyone? This recognition of mutual dependence must form part of the explanation of price formation in oligopolistic industries, as was seen in the discussion of OPEC in Chapter Three.

The degree of group organization in oligopoly can vary greatly, yielding results that bear resemblance to monopoly at one extreme or to competition at the other. Resemblance to monopoly is most likely to occur where the group is small in size, its members share similar situations and interests, and entry to the industry by outsiders is impeded. Such a group can enjoy greater aggregate profits by exerting some degree of control over price without the aid of any formal organization because individual producers condition pricing decisions upon recognition of the circumstances facing the group as a whole.

Discretionary behaviour by the group is curtailed if these conditions are altered – for example, if there is a larger group, members with diverse situations and conflicting interests, or if entry to the industry is unimpeded. In this case, the industry is subject to the discipline that would be imposed by an impersonal, competitive market. Because market behaviour in an oligopolistic industry can vary so widely, industry analysis must identify and take account of factors that enhance or diminish group action.

Drawing on commonly observed patterns, it is possible to formulate a model of price formation in an oligopoly. The key presumption of recognition of mutual dependence has already been noted. The success with which individual pricing decision can be aligned will depend on what may be classed as internal considerations (Osborne, 1978), the two main ones being: (1) the degree to which a given price level suits all sellers; and (2) the degree of confidence possessed by each seller that others are adhering to the given price. The first, or 'compatibility' factor, is determined by such circumstances as the similarity of cost structures and growth objectives among the sellers. The second, or 'discipline' factor, rests upon the availability of information about transactions and the means for deterring individual departures from the industry price. The effectiveness of a pricing strategy for increasing group profits (hence, those of individual sellers) will depend on external considerations, of which the key factor is the ease with which new sellers can join the industry.

Much of our discussion will focus on how external and internal circumstances condition price formation in crude petroleum markets, but any explanation is incomplete without an indication of the mechanism by which price itself is established. If there is no outside auctioneer or broker, some member of the group must name a price. The development of active international spot markets and the growth of futures trade for crude oil on various Mercantile Exchanges in the 1980s has provided an outside source of oil prices in recent years; but earlier this was not the case. There must be some means for efficiently adjusting price because a group of sellers is not well served by a rigid price when demand and cost conditions in an industry are continually changing. This means is most frequently provided through the convention of price leadership.

The price-leader is likely to be the largest or the longest-established member of the group, although this is not necessarily the case. It is more important that the prices set by the price-leader be regarded by

the members of the group as appropriate, or at least tolerable, in light of market conditions. Where such a leader exists and is followed, not only can price wars be avoided, but prices can be adjusted appropriately to 'soft' or 'firm' market conditions. Where leadership is not well-established, a price announcement by a prospective leader might be followed by some jockeying – other members testing slightly higher or lower prices – before the group price is established. This interval of uncertainty can be avoided when the leader has been identified through practice and the firm's prices continue to seem reasonable to other sellers.

Whether or not oligopoly pricing can be sustained depends on elements we characterize as internal factors. For instance, a company desperate to increase its market share in order to spread overhead or meet cash needs might provoke a price war if it incorrectly believed it could successfully conceal price concessions. At the same time, external factors determine the degree of market power that can be achieved through successful oligopoly pricing. We have noted that if new firms can join the industry readily when price-cost margins rise, then this threat will limit price increases. (Such markets are sometimes said to be 'contestable,' as argued by Baumol, 1986, and Baumol et al., 1988). There can be other constraints, for example, loss of markets to imports or fear that government will remove industry privileges or actually intervene to set prices.

The oligopoly-oligopsony model of price formation proves useful in understanding the evolution of Canadian crude oil prices as the market area was expanded in the 1950s. Deliveries through two pipelines, the major Interprovincial Pipe Line (IPL) to the east (now known as Enbridge), and the smaller Trans Mountain, to the west (now known as Kinder-Morgan), disposed of the bulk of the increased output. As noted above, during this period, prices paid by a small number of refiners in the most easterly markets – refiners who had access to alternative crude oil sources – were decisive in establishing the price of all Western output. Alberta crude oil prices evolved to meet competition in the most distant market as a competitive model would imply.

What were the actual circumstances of crude oil markets in the 1950s? There was a moderate degree of concentration in the production sector. (See Table 6.6 and Section 4 of this chapter.) In 1957, the largest four producers accounted for about three-eighths of total output; the largest eight, for just over half. There were many smaller producers, some affiliated with refiners

and marketing organizations, but most independent. The extent of concentration in the industry was less than is generally assumed to be necessary in order to achieve significant market power through coordinated oligopoly pricing. However, the possibility of price competition in the sale of crude oil within Canada was constrained by government regulation. Market-demand prorationing in Alberta, the principal supplying province, suppressed competitive selling strategies. (See Chapter Ten.) A seller had little reason to propose a lower price when there was no possibility of increasing the quantity of oil sold, since any increased sales at lower prices would be spread across all the producers in the province.

Not only had discoveries materialized, but throughout the 1950s development drilling, over-stimulated by the land tenure system and by incentives in the Alberta prorationing system, had proceeded at a rate that maintained and even widened the gap between productive capacity and actual output. In fact, there was more to the predicament than is revealed by the low overall utilization of capacity since the method of quota allocation under prorationing was such that low-cost fields bore the brunt of unused capacity. As an example, Imperial Oil noted that its Golden Spike field in 1958 had a "maximum permissible rate" (MPR) of 45,000 barrels per day but was only assigned production of 3,400 barrels per day.

How then was the price of crude oil established? The task could have been assigned to the Alberta Oil and Gas Conservation Board, which was then supervising the prorationing system. In fact, while it was authorized under the *Oil and Gas Conservation Act* to regulate quantities produced, the board had no authority to establish prices directly. It remains to look to the buyers' side of the market, where the price of oil was given by matching posted prices of major refiners.

There are only a few refiners in any region of Canada. Even on a national basis, the number of different companies represented in refining is not large since each of the four major oil companies has refineries in most regions. This level of concentration suggests potential market power on the buyers' side. Because the refiners were in varying degrees integrated back into crude oil production, different objectives might have been served by the exercise of market power. However, it will be shown that the range within which prices could be set was severely limited. The price that could be charged in the market most distant from Alberta was limited by the price of that region's alternative crude oil supply, while the way in which prorationing suppressed pressures from

excess capacity tended to preclude market-clearing price reductions. Furthermore, price discrimination by destination was never instituted.

Organizing a market so that pricing may serve group interest proceeds in our model through the mechanism of price leadership. Individual refiners are likely to see it to be in their long-term interest to match the crude oil price postings of a leader. There is evidence that Imperial Oil consistently led in posting crude oil prices from the 1950s onward (Bertrand, 1981, vol. iv, pp. 6–7). Imperial Oil was a pioneer in exploring the Western Canadian sedimentary basin, and by the 1950s it had succeeded in establishing itself as the largest producer. In 1957, Imperial's share of Western Canadian production exceeded that of the next three largest producers combined (see Table 6.6). In fact, output shares understate Imperial's position. Much of its crude oil came from the more productive and hence lower cost reservoirs, and Alberta prorationing imposed the most severe output restrictions on such reservoirs. Consequently, Imperial's share of marketable reserves would have been higher than its share of production. Thus, it had strong motivation to promote market expansion.

Before Interprovincial Pipe Line was organized, Imperial had already taken the initiative toward market expansion to the east by making arrangements for construction of a pipeline from Edmonton to Regina. In July 1948, after a survey of possible routes, negotiations were begun for 16-inch diameter pipe. When mounting discoveries provided justification for a pipeline that would reach the east via the Great Lakes, Interprovincial Pipe Line Company (IPL) was incorporated by a special act of Parliament in April 1949 to carry forward construction of a line. In August 1949, Imperial subscribed to the first 10,000 shares of IPL. For several months, until October 1949, IPL was a wholly owned subsidiary of Imperial, but at that time a further 10,000 shares of stock were sold, of which 3,000 were subscribed by oil companies – 2,000 by Canadian Gulf Oil and 1,000 by Canadian Oil Companies Limited. Imperial assumed significant parental responsibilities with respect to IPL. It undertook to provide guarantees that a minimum amount of crude oil would be shipped (the Throughput Agreement) and that if throughput fell below a stipulated figure it would make up the tariff shortfall to IPL in cash. Inability of IPL to meet its financial obligations would be remedied by Imperial under a Three Party Agreement among Imperial, IPL, and the Royal Trust Company, stipulating that if IPL failed to meet interest or principal payments to Royal Trust, the

deficiencies would be made up by Imperial. (These agreements are reproduced as Appendices C and D in Interprovincial Pipe Line Company, Submission to The Royal Commission on Energy, February 1958.)

To foster the development of IPL, Imperial not only utilized the line for transport of crude oil to its Regina, Winnipeg, and Sarnia refineries, but it also signed contracts with British American Oil Company (BA) and Canadian Oil Companies Limited to supply crude oil to their refineries in Ontario. Contracts were also made to supply U.S. refiners who could be served by IPL. Shipments of crude oil under all these contracts reduced the risk that IPL would fail to meet projected shipment volumes, thereby necessitating payments by Imperial under its throughput and financial deficiency agreements.

In describing the model of oligopoly-oligopsony price formation, reference was made to internal factors related to compatibility and discipline. Willingness to match a price posted by the leader is enhanced if that price is seen to serve well-understood industry objectives. In the 1950s, there was consensus among producers on the desirability and even need to supply the Ontario market and parts of the U.S. market that could be reached by the Interprovincial pipeline. This established a clear limit for price: it had to match the price of alternative suppliers at the competitive interface, which came to be Sarnia, Ontario.

The explanation thus far for Canadian crude oil price changes in the 1950s may be summarized briefly: sellers had little influence on prices that were set by buyers acting as a group in pursuit of the industry objective of orderly market expansion. Accordingly, crude oil prices were reduced in a series of steps, corresponding to the penetration of successively more distant markets.

The policy of expanding the marketing area placed a ceiling on crude oil prices. We must now consider how the price floor was supported. The guiding spirit of the system set up under the *Oil and Gas Conservation Act* was equality of treatment for all producers. The act is strongly worded in its insistence that no discrimination be practised, although there does not appear to have been any subsequent litigation that developed the law on this point. Had the price-setters not been operating in this atmosphere, they might have been more aggressive in lowering the price of crude oil in order to increase the level of utilization of low-cost fields (where their ownership interest was strongest) at the expense of high-cost fields.

It will be recalled that the evolution of Alberta crude oil prices began from a starting point at which

price matched the delivered cost of U.S. imports. Thus, it was economically feasible to develop a particular pool of oil so long as costs were no higher than this price. Pools developed under this price umbrella were entitled to produce according to the formulae of the prorationing system. Aggressive price-cutting by refiner-buyers, as might have occurred in other circumstances, would have rendered the high-cost pools unprofitable. Re-allocation of output in favour of low-cost pools would not have constituted discrimination as the economist defines it, but it seems certain that it would have been at variance with the non-discriminatory thrust of the statute, which allowed for a “reasonable opportunity to produce.” The regulatory regime not only eliminated competition among sellers but precluded buyers from selectively securing lower-cost crude oil by posting lower prices.

Crude oil price formation in the 1950s does appear to have evolved in a manner consistent with our oligopoly model, but the degree of buyer power was circumscribed within narrow bounds. The structure of prices at the end of the decade was similar to what would have been observed under a competitive pricing model: one price was quoted at Edmonton for a particular grade of crude oil regardless of its destination or place of origin. Had complete monopoly power been available and exploited, buyers in each market (not just the most distant one) would have been charged a price for Alberta crude oil that approached or matched the price from alternative sources. Had monopsony (or buyer) power been exploited, different prices would have been offered for different crude oils, depending on their cost of production. Both forms of discrimination were precluded by several factors – the fairness principle inherent in the prorationing system and associated regulation, the administrative complexity that would have been entailed, and probably also a sense of what was customary elsewhere in the petroleum industry.

While the structure of prices that evolved was consistent with what would have occurred under competitive markets, the level was not necessarily so. A downward trend in prices had taken place as a prerequisite to continued extension of the market area. However, the downward pressure on prices was never severe enough to force demand to be met from lowest-cost sources. Instead, excess productive capacity was always present. Price changes supported the objective of increasing industry output through orderly market expansion and were sustained by the way proration automatically adjusted supply. But the dynamics of price formation were both

conditioned and restrained by the Alberta Oil and Gas Conservation Board.

Alberta’s oil production and sales, as shown in Table 6.1, reflect the expansion of the market westward to Puget Sound and eastward to Sarnia in 1953 and Port Credit (near Toronto) in 1957. The capacity of the initial Interprovincial Pipe Line facilities was increased by the installation of various extra loops, pumping stations, and compressors. By the early 1970s, there were three large-diameter lines between Edmonton and Superior, Wisconsin, and two from there to Sarnia. The temporary surge in sales in 1956 and 1957 reflected, in part, increases in North American oil output to offset the international oil supply decrease associated with the Suez Crisis of 1956. Alberta oil output was largely supply driven from the start of construction of the major trunk pipelines in 1950 through to 1957, and demand driven subsequently, as sales were tied to demand growth in the markets adjacent to the pipeline.

As was discussed above, the tie to refinery demand was supported by the Alberta market-demand prorationing regulations. The significance of demand constraints can be illustrated in several ways. For example, the ratio of remaining oil reserves to annual production rose from about 18 in 1956 to 22 in 1960, suggesting relatively low, and declining, utilization of available reserves. Furthermore, after 1953, the growth of output was exceeded by the growth of production capability. After being restored to over 70 percent from its 1950 low of under 45 percent, capacity utilization fell steadily so that by 1957 only about half of Alberta’s potential was being utilized (Bradley and Watkins, 1982, p. 70).

The situation for the Canadian industry by the late 1950s was graver than the low and sagging capacity utilization indicated. The U.S. oil industry was lobbying vigorously for more effective protection from imports. With voluntary limitation proving inadequate, the United States was moving toward mandatory controls. Canadian producers were concerned that they might be prevented from expanding exports into the mid-continent of the United States. Exports to the West Coast appeared to be restricted to the Puget Sound area already connected by pipeline. If the oil had to be transhipped by tanker to the California market, it could no longer compete with overseas crude oil.

The decline in international oil prices that began in 1957 served to heighten the oil industry’s concerns. The Canadian industry was in trouble, and it turned to the federal government for help.

C. The National Oil Policy and Covert Controls: 1961-73

1. The Borden Commission

In October 1957 a Royal Commission, chaired by Henry Borden, was appointed by the federal government to look into such questions as energy export controls, the regulation of pipelines, and the functions that might be assigned to an administrative agency to be known as the National Energy Board. The Commission did indeed investigate these various issues, but the specific question that dominated its deliberations was how best to nurse the ailing crude oil industry back to health. Chapter Nine elaborates on these issues, but an outline will be given here.

Submissions to the Royal Commission addressing the problems of the crude oil industry all endorsed the need to find markets for more Canadian crude oil. The most widely discussed means was to supply Canadian crude oil by pipeline to Montreal refineries. The Montreal pipeline proposal was championed by the independent oil producers, but it was strongly opposed by the Montreal refiners, who were at that time being supplied by cheaper offshore crude oil, principally from Venezuela. The refineries included major oil companies that were important producers in Alberta (Imperial, Shell, McColl-Frontenac [Texaco], and British American [Gulf], as well as Petrofina [which had a little western Canadian output] and British Petroleum [BP, which shortly afterward acquired Triad Oil with Alberta crude production]). The majors and BP were also affiliated with the international majors which held Middle Eastern and Venezuelan oil concessions.

Companies which refined in Montreal made submissions to the Borden Commission setting out the difficulties with an oil pipeline extension to Montreal. For Canadian crude oil coming east as far as Toronto, to remain competitive with United States crude oil involved meeting price in a market where the price level was relatively high. But bringing Canadian crude oil into Montreal meant meeting world competition, implying western producers faced an immediate price cut, with the risk of more to follow. Furthermore, past pipeline expansion had involved guarantees by users to maintain agreed-upon levels of throughput. As long as they had access to alternative supplies from overseas, the Montreal refiners were certainly not prepared to offer guarantees of this sort. Based on market conditions in April 1958, W.J. Levy estimated Canadian crude oil would have been delivered in Montreal at a

price disadvantage of about 12 cents per barrel compared with oil from Venezuela. Canadian producers would have had to reduce the price on all the crude oil they sold by 12 cents in order to meet the overseas price (Levy, 1958, pp. II-18, 18A). This would have greatly diminished the marginal value of the extra sales to them. The continuing decline in international oil prices in the late 1950s only exacerbated this difficulty.

It was evident to Levy and to others that, before Montreal refiners would accept Canadian crude oil, either a method would have to be devised to offer special prices in that market or the government would have to erect some kind of barrier to offshore imports. Levy recognized “the possible commercial preference of refiners in the area (Montreal) for foreign crude oil, even should Canadian crude oil be available at competitive prices.” He explained:

Access to the foreign production of international companies with which Montreal refineries are affiliated offers opportunities of profit that Canadian crude cannot match. So long as this is the case for the area as a whole, no individual company could reasonably afford to switch to Canadian crudes no matter what other considerations it may wish to defer to. (Levy, 1958, p. III-19)

To meet this problem, proposals were advanced to establish pricing procedures that cross-subsidized Canadian crude oil going to Montreal at the expense of crude oil delivered elsewhere. One approach was to have refiners post delivered prices (including costs, insurance, and freight) at all refinery centres, prices that would reflect the delivered cost of competitive crude oil. This discrimination by destination would have been at variance with the Alberta regulatory system and would have created a complex administrative problem of dividing the proceeds from different markets of varying profitability. Another suggested form of cross-subsidization was through the pipeline tariff structure, which would have been amended in order to load charges onto short-haul crude oil so as to reduce the Edmonton-Montreal tariff.

When these types of special treatment found little support, attention turned to protection – in particular the imposition of tariffs or import quotas. Imperial Oil suggested an alternative to penetration of the Montreal market, as an intermediate strategy. It contained two lines of action, the first of which was to secure the entire Ontario market for Canadian crude oil. Although the volume of foreign crude oil refined

in Ontario at this time was small, a substantial volume of oil products was imported, either from abroad or from Montreal refineries. It was suggested that these imports should be supplanted with oil products refined from Canadian crude oil. The second part of Imperial's proposal was to expand crude oil exports to the United States. In the longer term, Imperial expected that the United States would rely much more heavily on imports and that Canada would be a natural supplier to northern and western regional markets. It was important, therefore, to negotiate favourable treatment of Canadian exports by the United States. To alleviate the immediate problems of the Canadian producing industry, an effort to saturate the United States Puget Sound market was suggested – an effort parallel to that proposed for Ontario.

In July 1959, the Borden Commission published its *Second Report*, which dealt entirely with the problems of the Canadian oil industry. In essence, the Commission followed the suggestions of the major oil companies, at least as a near-term strategy. It recommended the oil industry take “vigorous and imaginative action ... to enlarge its markets in the United States” and “displace, with products refined from Canadian crude, ... products now moving into the Ontario market from the Montreal refinery area.” A Montreal pipeline was to be held in abeyance, pending the opportunity given “to the oil industry to demonstrate it can find markets elsewhere in Canada and the United States.” But the Commission recommended that import licensing be imposed if markets for Canadian oil did not expand (Borden, 1959, pp. 6–32, 33). In effect, then, the Commission told the integrated majors with refineries in Montreal to expand markets for Canadian oil in Ontario and to increase exports of Canadian oil to the United States or face displacement of foreign oil in the Montreal market by Canadian crude oil.

2. The National Oil Policy (NOP)

In 1961 the government adopted the recommendations of the *Second Report* of the Borden Commission with little alteration. The measures selected to secure designated markets for Canadian oil became known collectively as the National Oil Policy (NOP). Target levels of production were set at 640,000 barrels per day in 1961 rising to 800,000 barrels per day by 1963. The latter figure was expected to approximate levels that would have been achieved with a Montreal pipeline. A production goal of 850,000 barrels per day was set for 1964, but no targets were specified thereafter. The

targets were to be reached by substituting Canadian crude oil for both foreign crude oil refined in Ontario and imports of oil products from Quebec or offshore to Ontario, and by additional exports to markets served by established pipelines. The National Energy Board (NEB) was to exercise surveillance over progress of the program. Subsequently, the United States indicated the acceptability of the general levels of exports contemplated under the NOP. In this way the policy was ‘continental’ rather than nationalistic. It relied on a voluntary (covert) mechanism, but regulation loomed if the voluntary program was not effective.

U.S. acceptance of the export provisions of the NOP were important because that country was also adopting measures to protect output of the domestic oil industry in the face of increasing international competition (falling world oil prices). In March 1959, the United States had adopted an oil import quota program that limited the volumes of foreign oil allowed into the country. (See, for example, U.S. Cabinet Task Force on Oil Import Control, 1970; Adelman, 1964; Shaffer, 1968; Watkins, 1987a; Bradley and Watkins, 1982.) Initially, Canadian oil was treated like any other oil import, but on April 30, 1959, Canadian and Mexican oil, shipped overland to the United States, were exempt from mandatory quotas, though their utilization did involve a slight penalty on the U.S. refinery purchasing Canadian crude oil. From 1959 through 1972, increased volumes of Canadian exports to the United States were accepted by the U.S. government, but the U.S. market was never completely and unrestrictedly open to Canadian oil; a number of formal and informal controls were imposed.

The NOP essentially divided the Canadian market into two parts, along the Ottawa River Valley (ORV). Markets to the west were to utilize Canadian oil only. Markets east of the ORV (the Maritimes, Quebec, and several eastern Ontario counties) would continue to utilize imported oil, attainable at prices below those prevailing in the United States and in Canada west of the ORV.

3. Alberta Crude Oil Prices under the NOP

As Table 6.2 shows, Alberta oil prices rose by 10 cents per barrel in 1961, and again in 1962 and were then fixed (at \$2.62/b for Redwater crude oil) until late 1970. Why were crude oil prices so rigid?

Given the United States Oil Import Quota Program and the way in which it dealt with Canadian oil, the price of Alberta oil would, of necessity, be located between an upper limit set by the United

States domestic price and a lower limit set by the landed price of Middle East or African crude oil in the United States. During this period, crude oil import prices were falling, while United States prices rose markedly in the latter half of the decade. It is somewhat difficult to determine U.S. oil import prices precisely, since international sales generally took place at a discount to posted prices and transport rates are variable over time and between different buyers. However, by way of illustration, Newton (1969) estimated the price of Saudi Arabia 34° API crude oil, delivered to the north east coast of the United States, at US\$3.07/b in 1956, \$2.48 in 1959, \$2.08 in 1963, and \$1.78 in 1968. (At the fixed exchange rate of the 1960s of US\$0.925 per Canadian dollar, the latter two prices would be CDN\$2.25 in 1963 and CDN\$1.92 in 1968.)

The posted price of U.S. mid-continent 36° API crude oil was US\$2.97/b from 1959 through 1963, fell slightly (US\$2.92/b in 1965), then rose up to US\$3.23/b by 1969 (Bradley and Watkins, 1982, p. 117). It will be noted that the gap between U.S. and import crude oil prices widened considerably over the decade, so that the effective protection to the U.S. domestic crude oil industry due to the oil import quota program was around \$1.50/b (Adelman, 1964, 1972) by the end of the 1960s. (At an exchange rate of US\$0.925 per Canadian dollar, the per barrel mid-continent crude oil price would be CDN\$3.21 in 1963 and CDN\$3.49 in 1969.)

It can be seen that a Canadian price of \$2.62/barrel lies between the upper limit of U.S. domestic prices and the lower limit of U.S. offshore oil import costs. Precise comparisons would involve the inclusion of actual or hypothetical transportation costs to a watershed market such as Chicago for all three types of crude oil, as well as the requisite quality adjustments. In any event, in the 1960s there was, it would appear, scope for either upward or downward movements in Canadian crude oil prices. Neither occurred. Why?

Consider first possible upward movements. One consideration was the exchange rate. As previously noted, the Canadian dollar was pegged at 92.5 cents United States during the 1960s, so adjustments to Canadian prices were not required for this reason. With United States prices creeping up, and with Canadian pipeline tariffs falling, there would seem to have been room for a modest upward movement in Canadian crude oil prices in the United States without a marked impact on market penetration. (The Interprovincial Pipe Line tariff from Edmonton to Superior, Wisconsin, fell from \$0.465 per barrel in 1954 to \$0.363 in 1964 (Lawrey and Watkins, 1982,

p. C-6).) A comprehensive time series on delivered costs of oil in U.S. markets is not available, but data for the Detroit area, for example, show a trend of widening differentials in delivered prices of Alberta and United States crude oils in U.S. markets in the 1960s, from 20 cents per barrel in 1961 to 62 cents per barrel in 1969 (Bradley and Watkins, 1982, p. 128). At the same time, the attraction of Canadian oil to U.S. refineries under the Oil Import Quota Program decreased somewhat, implying a rising penalty to the use of Canadian oil instead of domestic U.S. oil. (For reasons discussed in Chapter Nine, the use of oil imported from Canada reduced U.S. refiners' claims on cheap foreign oil; the lower the foreign oil price, the greater the penalty for buying Canadian instead of domestic U.S. oil.)

The rising penalty may help explain the reluctance of the price-leader (Imperial Oil) to offer higher posted prices for Canadian oil. But a more compelling explanation may lie in the increased political tensions that higher prices would probably have created. In particular, higher Alberta oil prices would have made even larger the growing disparity in prices in Canada east and west of the Ottawa River Valley, as eastern consumers used ever cheaper international oil. By holding the Alberta crude oil price fixed, instead of increasing it, Canadian consumers west of the ORV would be more accepting of the market division imposed by the NOP.

What about lower prices for Canadian crude oil? Certainly this would have reduced pricing tension between the unprotected and protected parts of the Canadian market. But it would have increased the attractiveness of Canadian oil in the U.S. market. The excess demand for Canadian oil which already existed was only held in check by intergovernmental agreements. Increasing the attraction of Canadian oil would have been provocative, leading in all likelihood to controls of a more formal nature, which in turn would have made the special treatment given to Canadian oil under the U.S. Oil Import Quota Program more obvious. In other words, a lower price for Canadian oil would have entailed the risk of further U.S. regulation of export volumes.

These conflicting factors within the framework of government policy appear sufficient to explain why inertia in Canadian oil prices made sense during the 1960s: Imperial Oil's adherence, as price-leader, to \$2.62 per barrel at Edmonton may have seemed unrealistic, but it was also astute. Keeping Canadian crude oil prices where they were caused fewer problems than varying them up or down.

However, when international oil prices began to increase in 1971 under the stimulus of the Tehran-Tripoli agreements between OPEC members and the international oil companies, these restraints on Canadian oil prices were loosened. The Alberta price began to rise. But, by this time, the revolution in the world oil market was ringing the death knell for both the NOP and the U.S. Oil Import Quota Program.

4. Alberta Oil Output under the NOP

In the 1960s, Alberta's output was conditioned in large measure by government regulatory programs – the NOP, the U.S. Import Quota Program, various agreements between the U.S. and Canadian governments and Alberta market-demand prorationing. The NOP reserved markets west of the ORV exclusively for Canadian produced crude oil. So long as the price of oil remained fixed, demand would respond primarily to economic growth in this region. Canadian oil was priced attractively for U.S. refiners, but expanded sales into the United States were limited by U.S. unwillingness to increase imports from Canada too far (thereby offending domestic U.S. producers and other oil exporters such as Venezuela). A 1967 secret agreement between the two countries limited imports into the Chicago area when the Interprovincial Pipe Line facilities reached that market, and in March 1970 the United States imposed a ceiling on imports from Canada. Thus there were sharply increased exports of Canadian oil to the United States in the 1960s, stimulated by the output targets of the NOP, and the attractive pricing of Canadian oil, but the exports never became as large as they might have.

In small part, the demand for Canadian-produced oil was met from provinces other than Alberta (mainly Saskatchewan, especially for heavier crude oil). However, the large residual came from Alberta, as determined by the market-demand prorationing regulations. Prorationing kept over 50 per cent of Alberta's crude oil productive capacity inactive in every year from 1960 through 1969 and prevented the downward pressure on prices that the excess capacity might have been expected to generate. Of course, a large price fall would have been necessary to stimulate much of an increase in sales since: (i) the elasticity of demand for crude oil in established Canadian markets west of the ORV, especially in the short term, is relatively low; (ii) the Quebec market could only have been attracted with a major price decline, both to cover the incremental transportation cost beyond Toronto, and to meet the lower delivered price of Venezuelan and Middle Eastern crude oil; and (iii) the U.S.

government, under pressure from U.S. producers, and competitive oil-producing areas such as Venezuela, simply would not have tolerated large incremental sales of Alberta oil.

In summary: after the 1950s, the pricing and production of Alberta oil came under increasing regulatory control, though largely of an indirect or voluntary nature (hence the use of the term "covert controls"). The 1950s had been influenced by the extension of Alberta's market into central Canadian markets, with prices adjusted so as to make the oil competitive. The period of the NOP from 1960 through the early 1970s saw regulations by Ottawa to define a protected Canadian market, and a restricted market extension into the United States under the watchful eye of the Washington regulators of the U.S. oil import quota program. The levels of prices possible were limited by these regulatory programs, and even more so by the political realities of the situation. Alberta's market-demand prorationing regulations were the mechanism that ensured that expanded output from Alberta did not upset the equilibrium that resulted.

D. Overt Controls: 1973-85

North American oil policy in the 1960s was protectionist: both Canada and the United States created a sheltered market for domestic crude oil producers, at prices higher than international levels. In the early 1970s, changing internal and external circumstances overtook these regulations.

In the United States, it became increasingly clear that reserve additions were insufficient to support the output levels that the U.S. Oil Import Quota Program was designed to allow. Initially *ad hoc* modifications were made to the program, and then, in April 1973, the United States abandoned it entirely. External changes had improved the political acceptability of this to domestic oil-producing interests, since the price of international oil had increased markedly in the wake of the Tehran-Tripoli Agreements of early 1971. In fact, as reviewed in Chapter Three, by mid-1973, international oil prices were beginning to lead U.S. prices upwards. Then, in the fourth quarter of 1973, international oil prices quadrupled, and U.S. authorities began to ponder the effects of domestic oil prices following international prices.

Canada's National Oil Policy cracked under these pressures. Initially, the changes were favourable to the domestic crude oil industry. Increasing demand for imported oil in the United States meant rising Canadian shipments. Table 6.1 shows sales of Alberta

oil in Canada rising from about 47,000 m³/d in 1960 to 81,300 in 1972 (a gain of 73%), while exports to the United States rose from 11,200 to 132,200 m³/d (up 1,078%); by 1972 exports accounted for 62 per cent of Alberta's crude oil output. From 1967 to 1973, sales in U.S. markets east of Alberta climbed by over 400 per cent. As the United States opened to more Canadian oil, and as international prices began to rise, the U.S. market began to look like the 'watershed' that would determine Canadian prices. The link would be those marginal oil supplies to the United States with which Canadian oil was competing. The Canadian price-leader (Imperial Oil) increased the posted price for Redwater oil by 30 cents per barrel, to \$2.92, in December 1970. Several other increases followed, up to \$3.48/b by May 1973, when Canadian oil was priced competitively with U.S. domestic oil supplies delivered to Chicago.

The sharp rise in Alberta oil production in the late 1960s and early 1970s came just as the Alberta crude oil finding rate fell off as the last major oil play (the Keg River play in northwestern Alberta) began to die down. The ratio of conventional crude oil reserves to annual production (R/P ratio) fell from about 30 in 1966 to about 14 by 1973. Meanwhile the capacity utilization rate rose from about 50 per cent in the late 1960s to 85 per cent by 1973.

Changes this rapid are often perceived as revolutionary, and it is often felt that revolutionary change calls for revolutionary action. Ottawa may not have verbalized the situation in exactly this way, but in 1973 the NOP was completely overturned: the month of May saw export limits placed on crude oil shipments; September saw the imposition of a price freeze on crude oil, an export tax on oil, and announcement that Montreal would be connected to the Interprovincial Pipe Line; and in December Prime Minister Trudeau formally acknowledged the death of the NOP and the advent of an oil policy based on direct control of pricing and exports.

1. Price Controls

Table 6.2 outlines the changes in regulated oil prices over the period from the initial price freeze of September 1973 (\$3.88/b) through to deregulation in 1985 (\$29.50/b in July 1983 as the last regulated price, in this case for what is called "old oil"). These prices are for Alberta-produced crude oil. It is noteworthy that oil imports were also price regulated, in the sense that consumers of imported oil in eastern Canada paid a price equivalent to the price for Canadian-produced oil (delivered to Central Canadian markets), with the

Canadian government paying the differential up to the import price on foreign-oil deliveries. Price controls on Canadian-produced crude oil led the government into an export tax so that U.S. consumers would not be subsidized by the Canadian program. The export tax would raise the price of Canadian oil to the level of the U.S. marginal supply source, i.e., imports from OPEC.

Chapter Nine provides detailed discussion of these oil control programs. At this point, it might simply be said that the policies tread a fine political line (for an energy abundant, developed nation) between the interests of energy consumers in lower prices and the interests of energy producers (and the provincial governments which owned oil and gas Crown land) in higher prices. International crude oil prices (for Saudi Arabia 34° crude oil in the Persian Gulf) rose from under \$3.00/b in 1972 to \$10.50 in 1974 to \$36.00 by 1981; the market value of crude oil throughout the world followed right along. Federal government authorities in Ottawa argued that such rapid rises in oil prices might significantly disrupt Canadian macroeconomic performance, that they had startling implications for the federal-provincial Equalization Program, and that they were not based directly on either international or Canadian costs of supplying crude oil. Furthermore, there was no guarantee that OPEC control would be successful in maintaining price increases. Thus, for a variety of reasons, it was argued that it was reasonable for Canada to allow only moderate increases in the price of oil, so that consumers and the economy could adjust gradually. Needless to say, most oil-producing interests and many others (including a large number of economists) were not fully persuaded.

The precise regulatory mechanism controlling oil prices varied over the 1973–85 period. The initial price freeze was a unilateral act by Ottawa, tied both to the price explosion in oil markets and to the government's fall 1973 anti-inflation package. By 1975 Ottawa had passed legislation giving it the legal authority to set the price of any oil (or natural gas) moving interprovincially or leaving the country. However, in practice, beginning in 1974, oil prices were set by joint agreement among the federal and provincial governments, sometimes at ministerial conferences involving all the provinces and, on occasion, by negotiation between Ottawa and Alberta (sometimes with other oil-producing provinces represented).

The federal government's 1976 energy study, called *An Energy Strategy for Canada*, announced that Canadian oil prices would gradually be increased to international levels, but the doubling of world oil

prices that began in 1978 left the regulated Canadian oil price further and further behind. In this environment, Ottawa and Alberta had great difficulty in reaching a new agreement on prices. This difficulty was complicated by the defeat of the Progressive Conservative minority government in the House of Commons in December 1979 and election of a majority Liberal government (which was bound by a campaign promise to maintain a “made-in-Canada” oil price). In August 1980, Alberta unilaterally raised the crude oil price by \$2.00/b. The newly elected federal government responded with a budget in October 1980 that consisted in large part of a National Energy Program (NEP). Among its many provisions were schedules of anticipated crude oil prices, including proposed regulated prices for Canadian oil over the coming years. Alberta vigorously objected to such unilateral federal price controls and introduced output cutbacks in protest. Accommodation ensued, with a September 1, 1981 *Memorandum of Agreement* between Ottawa and Alberta (and similar agreements between Ottawa and each of B.C. and Saskatchewan). From this date, until deregulation in 1985, Canadian oil prices were once again set by joint intergovernmental agreement. The NEP itself is defined by a total of eight sets of documents over the five years from the initial October 1980 announcement.

The complexity of the institutional mechanisms for establishing controlled Canadian oil prices pales beside the intricacies of the prices themselves. For Alberta crude oil, the key regulations applied to wellhead prices, but not all oil was treated in the same way. Once oil was produced, export prices were subject to further regulation via the export tax, and various government levies entered into Canadian consumer prices. Moreover, since the price controls applied to reference crude oil (“Alberta light” – of average grade delivered to the Edmonton terminals of the main trunk pipelines), the issue of the quality differentials for different grades of crude oil was also relevant. Table 6.2 provides details of the changes in wellhead prices for Alberta crude oil. (We discuss the major price changes; the minor changes in the table represent adjustments due to changes in location/quality differentials or the exchange rate.)

a. *Alberta Producer (Wellhead) Prices*

Throughout the controlled-price period, there was continual tension between the wish to hold prices below world levels in order to benefit oil-consuming interests and the obvious disincentive effects on production of lower prices. At first glance, it may seem

reasonable to suggest that domestic prices for an abundant (and critically important) natural resource should reflect domestic production costs. In practice, for a heterogeneous natural resource such as crude oil, where different natural deposits have quite different costs, the notion of the domestic production cost is hopelessly ambiguous. It can be noted that certain reserves were voluntarily brought into production at historic (e.g., pre-1973) prices, but production decline means that the volumes of oil forthcoming from these reserves will eventually begin to fall. Output therefore becomes increasingly dependent upon new reserve additions, and the incentive to undertake such additions is positively tied to the level of the oil price. Initial recognition of this came with respect to tar sands oil, which was obviously high cost, and was, in the late 1970s, allowed international prices.

Incentive pricing for conventional crude oil was introduced in October 1980 with the NEP and became increasingly complex. The October 1980 regulations defined a new category of conventional oil output labelled “tertiary” oil, which consisted of oil from new (and officially recognized) reserves additions and enhanced recovery techniques other than waterflooding. Tertiary oil would command a price of \$30/b (as compared to the \$16.75 price for other conventional oil, and the world price of about \$38.00/b, netted back to Edmonton). At Alberta’s insistence, the principle of higher prices for incremental supplies was broadened in the September 1981 *Memorandum*, to create a price category called NORP (“new oil reference price”) which would apply to “new” oil from pools discovered after 1980, as well as oil from all new enhanced recovery projects other than waterfloods, and from the Cold Lake heavy oil deposits. (It went also to oil from the frontier “Canada Lands” and synthetic crude oil, including that from “experimental” projects.) Effective July 1, 1982, after the June 1982 NEP *Update*, the NORP was applied to all tertiary and experimental oil, and to output from wells that had been shut down for at least three years (so long as the provincial government also levied lower “new” oil royalties on these wells). In addition, a SOOP (supplemental old oil price) category was created, above the “old” oil price but below NORP for oil discovered between April 1974 and December 1980. Subsequently, a June 1983 amendment to the NEP moved SOOP up to NORP and added oil from infill wells in all pools. Watkins (1989) notes that by the last year of the NEP there were 10 classes of Alberta oil. Overall, about 60 per cent of Alberta’s oil production was “old” oil and 40 per cent NORP oil of one class or another.

Table 6.3: Crude Oil Prices under Overt Controls, 1973-85 (Canadian \$/b, at year end)

	World Oil (W_p)			Old Oil			New Oil (NORP)		
	Actual	Oct. 1980 Forecast	Sept. 1981 Forecast	Conventional Oil 1973-80	Oct. 1980 NEP	Sept. 1981 Schedule	Oct. 1980 75% W_p	Sept. 1981 Tertiary	June 1982 Schedule
1973	5.28	n/a	n/a	3.00*	n/a	n/a	n/a	n/a	n/a
1974	12.40	n/a	n/a	6.58*	n/a	n/a	n/a	n/a	n/a
1975	13.78	n/a	n/a	8.08*	n/a	n/a	n/a	n/a	n/a
1976	13.68	n/a	n/a	9.18*	n/a	n/a	n/a	n/a	n/a
1977	16.14	n/a	n/a	10.95*	n/a	n/a	n/a	n/a	n/a
1978	18.25	n/a	n/a	12.91*	n/a	n/a	n/a	n/a	n/a
1979	30.42	n/a	n/a	13.93*	n/a	n/a	n/a	n/a	n/a
1980	40.68	38.00	n/a	n/a	16.75*	n/a	n/a	n/a	n/a
1981	40.38	41.85	41.67	n/a	(18.75)	21.25*	30.29	30.00*	n/a
1982	40.63	45.80	47.69	n/a	(20.75)	25.75*	30.47	(33.05)	(49.22)
1983	37.39	49.85	56.25	n/a	(22.75)	(33.75)	28.04	(36.15)	(57.06)
1984	39.71	54.10	62.31	n/a	(27.25)	(41.75)	29.78	(39.35)	(63.48)
1985	n/a	58.55	69.10	n/a	(31.75)	(49.75)		(42.70)	(70.23)

Notes: n/a = not applicable.

Old oil shows 35° Redwater oil from 1973-79, and the 38° reference crude in the various agreements after 1979.

The October 1980 world oil price forecast is the projected synthetic crude price in the NEP, which was to be the lesser of the international price or the 1980 value of \$38.00, increased by the Canadian Consumer Price Index. It therefore is a lower limit on the international oil price projections of the October 1980 NEP. (By 1989, the value had risen to \$79.65/bbl.)

Tertiary oil entered the NORP category in the September 1981 *Memorandum of Agreement*. SOOP oil is not shown; it originated in the June 1982 Update and was to be priced at 75% of the world level, but in June 1983 was incorporated in oil subject to NORP.

Values with * are the actual prices received on Alberta oil, except that old oil exceeded the limit of 75% of the world price by July 1983 so received \$29.75/bbl from that date up to June 1985. Values in parenthesis were prices specified in an agreement but which were superseded by another provision or agreement.

Only end-of-year values are shown, although scheduled prices under the various NEP agreements generally rose each six months.

The actual world oil price is based largely on the Official Government Selling Price for 34° Saudi Arabian Crude, f.o.b. Ras Tanura, shown in Chapter 3, and as reported in the *Petroleum Economist*. The SA price in U.S. dollars has been increased by \$2.05/bbl to derive a Canadian oil price (for par crude) in U.S. dollars in Alberta; this takes the average excess of the WTI price over the SA price from 1987 to 1991 (\$3.13/bbl as reported in the OPEC, 1991 *Annual Statistical Bulletin*), less the average excess of the WTI price over the Alberta par price in 1991 and 1992 (\$1.08/bbl as reported in the Energy, Mines and Resources, *The Canadian Oil Market*). The resultant price for Alberta oil in U.S. dollars per barrel was then translated into Canadian dollars using the end-of-year exchange rate reported in IMF, *International Financial Statistics*.

The categorization process was obviously fluid and increasingly complex. The associated controlled prices were also complicated. This arose in part from the inherent contradictions of a “made-in-Canada” oil price. The phrase suggests a price reflective of Canadian demand and supply conditions, but, from the very beginning of the control period, the level of price was always established with reference to prevailing world prices. Thus, as noted above, the 1976 federal government plan, *An Energy Strategy for Canada*, envisioned a gradual adjustment of Canadian prices to world prices. The NEP exhibited an even more marked interdependence. The October 1980 budget included a projection of world oil prices through the future and set out a schedule of regulated Canadian prices

that were lower than, but reflective of, the anticipated trend in international prices. Moreover, the authors of the NEP were well aware that no one could accurately forecast future world oil prices; in fact, the October 1980 projections were soon revealed as far too high. As a result, throughout the NEP period, controlled prices were often set as the lower of: (i) some specified price (presumably tied to forecast world oil prices) or (ii) some percentage of the actual world oil price.

Table 6.3 provides further detail on the various regulated prices. (It shows the price provisions at year end, so not all price changes are noted.) The prices are for the reference crude oil of the various agreements, which was 38° crude oil (instead of the 36° Redwater oil used in Table 6.2). The symbol n/a (not applicable)

indicates that the particular category did not apply at that date (e.g., NEP price forecasts before 1981; NORP oil before 1981). A price in parenthesis is a controlled price under one regulation, which was superseded by another regulation. Where several prices might apply in different years, the actual regulated price is indicated by an asterisk (*). As can be seen, the failure of world oil prices to match the increases in the early NEP forecasts meant that by 1983 wellhead prices were established by world oil prices, rather than specified levels of controlled prices. For example, a decline in world prices in 1983 meant that the price level fixed under NORP now exceeded the world price, so the new oil price was the world price. Rather than reducing the old oil price in line with the fall in world prices, old oil was simply held at \$29.75/b from July 1982 on.

The shift to actual world oil prices as the basis for calculating Canadian oil prices raised a practical problem of administration – what was the relevant world oil price? Under the NEP, world prices were calculated on the basis of the average price of imported oil landed in Montreal in the latest three months for which data were available. This meant that Canadian prices lagged about one quarter (three months) behind world prices (Helliwell et al., 1989, p. 46). From the start of 1984, world price estimates were based on current official government selling price (OGSP) for international crude oil, therefore eliminating the problem of the lag, but failing to allow for the increasing prevalence of spot sales at discounts from OGSP. As a result, the NORP was sometimes in excess of international values.

b. Alberta Producer Prices: Price Differentials

The issue of quality differentials became increasingly problematic as North America became more fully integrated with the international oil market. Until 1981 differentials for light and medium crude oil continued to be established on the same basis as had been introduced by Imperial Oil in 1947. The September 1981 *Memorandum* set up wider differentials for NORP oil and allowed the established differentials on old oil to increase as the old oil price rose (Helliwell et al., 1989, pp. 46–47). Schedule A of the *Memorandum of Agreement* established the NORP differentials at \$0.22/b per API degree and \$0.165/b per 0.1 per cent sulphur; old oil differentials were eventually to reach \$0.15 per API degree and \$0.101 per 0.1 per cent sulphur. The differentials were also supposed to be in line with those in the international market. This would prove to be a difficult task in tracking. OPEC

members would be acutely aware of the appropriate differential so as to ensure they met output quotas (after 1982), and might, further, utilize price differentials to test out possible gains from cheating on the group agreement.

Effective at the start of 1984, each quality of crude oil in the NORP category was to be priced on the basis of the cost of equivalent quality crude oil delivered to Montreal (with the field to Montreal transportation costs then netted out). However, so long as OGSP rather than spot prices were used, and for grades of crude oil that were not actually shipped to Montreal, it was very difficult to ensure that the NORP was accurate. Thus the differential problem also contributed to NORP values in excess of international price levels as were observed in 1983 and 1984. As Watkins (1989, p. 117) notes, these pricing problems, plus difference in import compensation for crude oil and product imports, led some Montreal refiners to begin importing oil instead of purchasing Western Canadian oil.

c. Purchase Price for Alberta Oil: Domestic Sales

One might assume that refiners would buy oil from Alberta producers at the regulated prices. However, field price regulation covered only a part of the federal government's policy, and other aspects of the policy impacted on the refiners' purchase price. In essence, the government argued that refiners should pay an average or "blended" price for oil that covered the costs of all the various types of oil utilized in Canada, though the interpretation given to this requirement varied somewhat over the 1973–85 period. The initial move in this direction came in 1976, when a charge was imposed on all oil refined in Canada to provide the extra payment to Syncrude's synthetic tar sands oil, which received the world price. After 1980, there was an additional charge assessed on the refiners' cost of oil, the Canadian Ownership Special Charge designed to help cover the government's costs of establishing and expanding Petro-Canada. Prior to the NEP, the cost of subsidizing imported crude oil had been viewed as being offset to a significant extent by the export tax on oil sold to the United States. As crude oil exports fell sharply in the later 1970s, even with reduced imports due to the Montreal pipeline extension, the net cost to Ottawa grew, and pressures to include imports in a blended price became very strong.

The blended concept idea was embedded in the October 1980 NEP, which had refiners paying an amount equal to the average cost of oil to Canadian

Table 6.4: Canadian Crude Oil Exports and Export Taxes, 1973-85

	<i>(Net) Exports (10³ m³/d)</i>				<i>Year-end Export Tax (\$/m³)</i>	
	<i>Light and Medium^a</i>	<i>Heavy</i>	<i>Total</i>	<i>Crude Oil Exchanges</i>	<i>Light and Medium Blend</i>	<i>Heavy^b</i>
1973 ^c	n/a	n/a	149.4	n/a	2.52	2.52
1974	n/a	n/a	144.8	n/a	32.72	25.80
1975	n/a	n/a	112.4	n/a	28.32	23.28
1976	n/a	n/a	73.9	2.7	23.60	18.25
1977	34.6	8.6	43.2	8.7	32.41	21.71
1978	16.1	10.6	27.7	14.8	33.98	23.60
1979	6.9	18.1	25.0	19.7	119.65	107.00
1980	0	14.8	14.8	14.2	180.80	102.90
1981	0.8	15.0	15.8	10.8	165.05	108.70
1982	0.3	24.5	24.8	10.0	97.20	44.40
1983	11.0	31.8	42.8	4.9	43.75	16.25
1984	14.3	36.0	50.3	7.7	32.55	34.50
1985	33.4	41.9	75.3	4.0	36.30 ^d	31.35 ^d

Notes:

n/a: figures not available.

a Includes condensate and synthetic crude.

b Lloydminster blend; other grades of heavy oil faced other export taxes.

c 1973 exports are for March to December.

d May and June 1985.

Source: National Energy Board, *Annual Reports; National Energy Program; NEP Update.*

refineries, essentially the costs of old oil, imported oil at world prices, synthetic crude oil, tertiary crude oil, and after 1981 NORP oil, and after 1982 SOOP oil.

d. Purchase Price for Alberta Oil: Export Sales

After September 1973, foreign refiners purchasing Alberta oil were assessed an export tax designed to raise the cost of Canadian oil to that of other foreign suppliers to the U.S. market. Initially, the Chicago market was used as a basis for comparison, and all Canadian exports were assessed the same tax, one presumably based on the values of blended light oil in the Chicago market. The export tax in the 1970s rose or fell in line with changes in world oil prices and the regulated Canadian price, based largely on the analysis and recommendations of the National Energy Board (NEB). The tax began at \$0.40/b in September 1973, and rose to \$6.40/b by February 1974. By late 1980, as the NEP was introduced, the export tax hit \$26.00/b, for light crude oil. The initial export tax, in 1973, had applied at the same level to all crude oil, but producers of heavy oil were soon complaining that the tax discriminated against their less-valued product and

was harming sales to U.S. refiners. In November 1974, the NEB allowed a special, lower tax on heavy oil and continued as time progressed to set differential taxes for different grades of crude oil (Helliwell et al., 1989, p. 37). Here, as elsewhere in the regulated oil environment, it was apparent that more and more detailed fine-tuning of regulations was necessary if undesirable distortions of production and consumption were to be avoided. Table 6.4 includes more detail on the NEP crude oil export taxes.

Table 6.4 shows the level of the crude oil export tax at year's end over this period. (The 1985 value is for June, the last month in which an export tax was assessed.) Taxes are shown for two grades of oil: (i) light and medium blend (and condensate); and (ii) Lloydminster blend heavy crude oil. By June 1985, the NEB distinguished 13 different grades of oil, each with a different level of export tax subject to review each month. It can be seen that while the general trends in the tax for heavy and light oil are similar, there is no consistent relationship between the two. The taxes reflect the NEB's efforts to follow changing world crude oil quality differentials, as well as demand

conditions for Canadian heavy oil in the specialized mid-continent U.S. refineries that bought such crude oil.

2. Production Under Overt Controls

The 1973 changes to Canadian oil policy essentially reversed the National Oil Policy of 1961. Instead of reserving the Montreal market for oil imports, the Interprovincial Pipe Line would be extended from Toronto to Montreal; rather than encouraging increased exports, the volume of exports would be limited through a licensing scheme to ensure they were not 'excessive.'

Table 6.1 shows the impact of these changes as exports fell off drastically (from about 160,000 m³/d in 1973 to 31,000 m³/d by 1978, down to the 1962 level). As the Montreal extension came on stream in 1976, Canadian use of Alberta oil rose, from 115,600 m³/d in 1975 to 187,600 m³/d by 1980. Other factors influenced oil sales as well. For example, exports to the U.S. west coast fell sharply in the mid-1970s, reflecting the contribution of North Slope Alaskan oil to the U.S. market – in the early 1980s U.S. authorities specified that Alaskan oil could not be sold outside the United States. Sales in domestic markets, and oil output, declined in response to declining oil consumption as a result of the sharply increased price of oil. (See Helliwell et al., 1989; Berndt and Greenberg, 1989.) In 1980 Ottawa imposed formal procedures for light and medium crude oil to ensure that available supplies were allocated 'fairly' to refiners in Montreal and Ontario; allocations were based largely on historic refinery runs (Ontario) and available capacity (Montreal).

Export controls, as introduced in March 1973, consisted of a licensing system administered by the NEB. Such licensing had been permissible under law ever since the act creating the NEB and had been applied to natural gas since the early 1960s (as Chapter Twelve details). Concern about oil exports was initially stimulated by complaints about crude oil availability by some Canadian refiners and deepened with the Arab oil embargo and output cutbacks of late 1973, during the Arab-Israeli war (Helliwell et al., 1989, pp. 39–40). The NEB was willing to issue export licences for 'surplus' crude oil; it argued that, especially with the Montreal pipeline extension, no obvious surplus existed so that exports should be eliminated. For light and medium oil, this is basically what happened in the later 1970s. However, heavy crude oil was not acceptable to most refineries unless it is passed through a

special upgrader to be transformed into lighter oil. The mid-1970s saw significant excess production capacity for heavy crude oil, so the NEB was quite willing to allow its export.

Table 6.4 shows Canadian exports of crude oil from 1973 through 1985, with separate details for heavy and light crude oils after 1977. Net light oil exports virtually disappeared by 1980, while heavy oil exports were allowed to increase from 1977. Saskatchewan was a particularly important source for heavy oil. Light crude oil exports were allowed again in 1983. The table also includes a column for crude oil 'exchanges'; those included agreements in which crude oil (usually of light or medium gravity) was exported to the United States (generally the mid-continent region), and in turn equivalent volumes of U.S. oil were provided to eastern or central Canadian areas. Net exports exclude such exchanges.

3. Conclusion

Whatever the advantages of a "made-in-Canada" price for oil, the administrative complexities in such regulation were huge and failed to capture fully all the heterogeneities of crude oil markets. Moreover, as is discussed in Chapter Nine, the whole idea of fixing Canadian prices below world levels was coming under concentrated attack as the 1980s progressed. Certainly, even for proponents of such regulation, the process began to look increasingly trivial as world oil prices, instead of rising, become progressively weaker. A change in the federal government consolidated the forces for change.

E. Deregulated Markets: 1985–

On March 29, 1985, the recently elected federal Conservative government negotiated the Western Accord with the provincial governments of Alberta, B.C., and Saskatchewan. The Accord deregulated crude oil prices and eliminated a variety of federal taxes and grants, thereby eliminating the NEP. Starting June 1, 1985, Canadian oil prices would be free from both overt and covert controls for the first time since the 1961 NOP. Procedures to allocate light and medium oil supplies to central Canadian refiners were also dropped, as were quantity and price restrictions on exports of light and medium crude oil with shorter than a one-year contract (less than two years for heavy oil). The 1989 Free Trade Agreement (FTA) essentially codified much deregulation through formal

Canada-U.S. commitments to allow free movement of oil between the two countries, without discriminatory trade practices. (Chapter Nine discusses the FTA, and its successor, the North American Free Trade Agreement (NAFTA), in more detail.)

After the long period of government-administered pricing, oil companies found the need to market their oil a novel and, for some, chastening experience. The basic price-setting procedure that was established was familiar from the post-Leduc days, with the major refiners 'posting' the price they would pay at Edmonton for any oil offered to them. As the 1990s progressed, new market initiatives began to develop, such as specialized electronic clearing houses that enabled prospective buyers and sellers to establish quick contact.

If deregulation were effective and a 'workably' competitive market established, what kind of pricing behaviour might be observed?

First, the price of Alberta crude oil posted at Edmonton by refiners would be set within a narrow band at any one point in time. A significant spread in posted prices for oils of the same quality would suggest price discrimination, behaviour not sustainable in a competitive market.

Second, the level of posted prices would be closely related to 'netbacks' from the main market interfaces where Alberta crude oil competes with other supplies, namely (in 1985) Montreal and Chicago. Or to put it another way, the delivered price (laid-down cost) of Alberta oils in market regions where Alberta faces competition would correspond closely to the delivered prices from other sources. Since international prices are denominated in U.S. dollars, the price in Canada would also reflect changes in the exchange rate, rising as the Canadian dollar depreciates relative to the U.S. dollar and falling as the Canadian dollar appreciates.

Third, refiner postings would be sensitive to changes in world prices. If world prices were quite volatile, correspondingly frequent changes would be seen in posted prices.

To what extent do refinery postings in Alberta satisfy these tests? We look at the market in the late 1980s to assess this issue.

August 1989 postings at Edmonton by three major refineries – Esso, Shell, and Petro-Canada – were \$21.61/b, \$21.29/b, and \$21.29/b, respectively, for 40° API gravity crude oil (0.5% sulphur). The spread in prices is minimal.

Estimated netbacks in July 1989, for international crude oil at Montreal and Chicago are shown in Table 6.5 (Watkins, 1989, p. 25). The upper panel develops

Table 6.5: Alberta Netbacks from Foreign Crudes

<i>Netback for Brent Crude from Montreal, July 20, 1989</i>	<i>\$/b</i>	
Representative Price (spot) Brent 38.0° API	18.25	(US\$)
Plus Tanker Charge	0.81	(US\$)
Plus Portland-Montreal Pipeline Tariff (includes terminaling charge)	0.96	(US\$)
Laid Down Cost at Montreal	20.02	(US\$)
Laid Down Cost at Montreal	23.80	(CDN\$)
Less IPL Tariff to Edmonton	1.53	(CDN\$)
Netback at Edmonton	22.27	(CDN\$)
Quality Adjustment for 40° API	0.30	(CDN\$)
Netback for 40° API, equivalent type crude	22.57	(CDN\$)

<i>Netback for WTI Crude from Chicago, July 20, 1989</i>	<i>\$/b</i>	
Representative Price (spot) West Texas Intermediate at Cushing, 40° API)	20.35	(US\$)
Plus Pipeline Tariff, Cushing to Chicago	0.39	(US\$)
Laid Down Cost at Chicago	20.74	(US\$)
Less IPL U.S. Tariff	0.46	(US\$)
Border Price	20.28	(US\$)
Border Price	24.11	(CDN\$)
Less IPL Tariff to Edmonton	0.51	(CDN\$)
Netback at Edmonton	23.60	(CDN\$)
Quality Adjustment for 40° API	0.00	
Netback for 40° API, equivalent type crude	23.60	(CDN\$)

(Based on Exchange Rate of \$0.84 US/\$1 Cdn.)

Source: Watkins (1989), p. 25.

the Edmonton netback for North Sea Brent oil delivered to Montreal; the lower panel develops Edmonton netbacks for West Texas Intermediate (WTI) oil delivered to Chicago (WTI is the most popular 'benchmark' crude oil in the United States). The spread in netbacks is about \$1 per barrel, suggesting that Chicago (the nearer market) is a more attractive one for Alberta crude oil. More importantly, the actual light crude oil price prevailing was CDN\$22.98/b, straddling the two netbacks. This confirms that Alberta oil was competitively priced with international crude oil.

Finally, over the period July 1988 to June 1989, one refiner – Shell – registered eleven changes in postings, precisely the kind of volatility expected in light of the frequent changes in world oil market conditions. Parallel changes were registered by other refiners.

Thus, all three competitive pricing criteria have been met: deregulation has been effective. A competitive market exists for the sale and purchase of Canadian crude oil, interfacing with the world oil market.

Formerly, the supply of Alberta crude oil was governed by prorationing. Prorationing reduces incentives for direct price competition. It remains on Alberta's legislative books. But, in large measure, deregulation induced changes in administration of the prorationing scheme that allowed producers to sell any shut-in oil on the spot market, although control for technical reasons is retained on maximum production rates. Before, strict quota control kept the prices of oil from a reservoir uniform. And by 1989, market-demand prorationing was consigned to history.

Of course, pipeline transportation remains federally regulated, but common carrier legislation provides for open access. However, the pricing mechanism has yet fully to intrude on the 'menu' of pipeline services offered.

Deregulation has also affected the disposition of Canadian production. With the removal of federal transportation subsidies, Atlantic refineries no longer used Canadian oil, and the share of refinery runs held by imports in Quebec began to rise, until the Sarnia–Montreal link of the Interprovincial Pipe Line was closed in 1991, and then reversed in October 1999 to allow imports into Ontario. At the same time, the share of Canadian output absorbed by more proximate (U.S. Midwest) export markets has tended to increase. This more efficient distribution of Canadian production is what would be expected if deregulation were effective.

The 1986 price collapse, when the spot price of Persian Gulf oil fell into single-digit figures, provoked proposals for re-regulation of prices (not the least from some in private industry), with calls for import tariffs, floor prices, income stabilization plans, and the like. Admittedly, most proposals stressed that assistance would be temporary. However, the federal government resisted the temptation to introduce price supports and confined itself to some tax relief and incentives.

In sum: deregulation has resulted in a more competitive market structure for the oil industry than at any time since the Leduc discovery of 1947.

Table 6.1 shows that Alberta conventional oil production rose from 1984 to 1988, but then fell, largely reflecting production decline in established reservoirs along with relatively small reserve additions. However, oil sands production continued to rise, offsetting declining conventional production

and generating modest total production increases for Alberta oil production through the 1990s. Sales in Canadian markets east of Ontario fell off through to the early 2000s with deregulation and closure of the pipeline link to Montreal but have since risen again. Exports to the U.S. mid-continent region have risen sharply. The increased exports are based largely on expanding non-conventional oil production (synthetic crude oil and bitumen from the oil sands), as will be discussed in Chapter Seven. Closure of the Montreal pipeline link makes it clear that the competitive price watersheds for Alberta oil now lie in the Chicago and Toronto markets. Sales prices internationally, and for Canadian crude oil, have become increasingly volatile in the short term as a preponderance of sales have become tied directly or indirectly to spot markets for crude oil. Oil brokerage services have grown in importance, providing intermediaries between crude oil producers and refiners, and more oil companies are developing their own trading division to monitor and participate in spot markets and the futures and options markets for oil, which expanded rapidly in the 1990s.

Expectations of further increases in Alberta crude oil production have raised the issue of major market expansion for the first time since the 1960s. Expansion of existing facilities, into existing markets, had begun in the 1990s as crude oil output in Alberta rose somewhat. However, with larger output increases, driven by the oil sands, the most obvious routes would be to press further into the U.S. market, effectively driving out more offshore imports. As of March 2013, TransCanada was still awaiting approval of its Keystone XL line which would carry additional Alberta bitumen through Cushing, Oklahoma to the Texas Gulf. The northern portion of this line was denied U.S. regulatory approval in 2012; a modified route is now under consideration. TransCanada has announced plans to proceed independently with the Oklahoma to Texas portion. The possibility of increased sales of Alberta oil in central Canada has attracted attention, as Enbridge is applying to reverse the Sarnia–Montreal pipeline so Alberta oil can once again access the Quebec market. Attention has also turned to the possibility of significant sales in east Asian markets, especially China and Japan. At the time of writing in the Spring of 2013, Enbridge is pushing forward with plans for a new oil pipeline (called the Northern Gateway) from near Edmonton to Kitimat on the B.C. coast; a parallel line would carry condensate eastward from Kitimat, which could be blended with bitumen to allow its movement back to Kitimat. In addition, Kinder Morgan has expressed

interest in expanding its pipeline from Edmonton to Vancouver, which would enable additional exports to the U.S. west coast and to Asia. Given the longer distance to Asian markets, it is not clear Canadian oil could be as competitive with Middle Eastern oil there as it is in North America. However, the project sponsors seem to feel either that buyers in Asia (most likely Chinese) will be willing to pay a premium for Alberta oil (especially if it is produced from the oil sands by the Chinese companies establishing a presence there) or that the international price differentials between light and heavy oils will be such as to establish a demand for Canadian bitumen in Asia. (The markets for Canadian oil and the transmission alternatives are discussed in NEB, 2006, chaps. 4 and 5.) Another possibility is that North American crude oil production will increase sufficiently to allow exports of oil from the Texas Gulf Coast, but that the U.S. government will prohibit such exports, restraining prices in the United States. In this case, Alberta oil producers would find the Asian export market more attractive than the United States.

Table 6.2 shows that Canadian oil prices increased dramatically after 1999, following international oil prices; the rise was somewhat less pronounced than in the United States, since the Canadian dollar appreciated significantly beginning in 2003. Canadian prices followed world oil prices, up to a peak in mid-2008 (the maximum monthly price was \$138/b in July 2008 for the Canadian par price at Edmonton), then collapsing (to \$32/b in December 2008). The Alberta crude oil price rose after that, and has fluctuated in line with world crude oil prices.

However, as Figure 6.1 showed, the usual small price differential between Alberta and North Sea light crudes oil rose dramatically, particularly after 2010, and persisted through final editing of this book, in spring 2013. This reflected a combination of increased oil production in central North America (including in Alberta, but also in regions such as Texas and North Dakota) and pipeline constraints in moving this oil to the most profitable markets. As a result, the crude oil market centred on Cushing, Oklahoma exhibited a supply excess with downward pressure on the price of WTI (West Texas Intermediate) and such linked oils as that from Alberta. (Chapter 1 of the ERCB 2012 *Reserves Report*, ST-98, offers a discussion of this issue.) Presumably this unusual price discount for Alberta oil reflects a temporary (short-run) disequilibrium in the crude oil market while modifications in the transmission system are made to allow the increased crude oil supplies access to the broader world market. The modifications are of two types,

both under consideration in 2013. The first is new pipeline capacity, such as the Keystone XL, Northern Gateway, and Kinder Morgan projects mentioned above. The second is the reversal of pipelines which allow imports of oil into central North America, turning them into export lines; we mentioned the proposed reversal of Enbridge's Sarnia–Montreal line, and several companies are planning reversals of pipelines currently carrying oil from the U.S. Gulf Coast to Cushing, Oklahoma.

It is interesting to note that no significant price differentials between Alberta and world oil were apparent in the first period of rapid expansion of Alberta oil production following the Leduc find of 1947, when producibility of Alberta oil exceeded the pipeline capacity to carry it to market. At that time, prorationing regulations restricted production to levels the available market would absorb, so the potential excess supply could not push prices lower. Since the late 1980s this government output control mechanism has no longer been in operation, so, after 2010, WTI and Alberta prices were free to fall (relative to the world price) as local supplies increased.

Alberta oil prices will continue to be determined primarily by international crude oil prices, which reflect the output decisions of OPEC, but with significant day-to-day variability as stockpiles, weather conditions, political events, and changing expectations impact on the spot market.

4. Crude Oil Market Structure

For much of the historical period, as we have seen, the price and output of Alberta crude oil have been strongly influenced by government regulations, both provincial (e.g., market-demand prorationing) and federal (e.g., the NOP and the NEP). However, industry behaviour also reflects the structure of the petroleum industry, in particular the degree to which the industry is or is not free of large, concentrated, monopoly-like firms, an issue that has been touched on already. Government regulations have had the most pronounced impact, so much so that we have argued that understanding the economics of the industry is an exercise in 'petropolitics.' During those periods that allowed market price flexibility, oil did not exhibit such clearly oligopolistic behaviour as geographic price discrimination. This concluding section of Chapter Six will discuss, briefly, two structural issues that have attracted much critical attention. The first is whether the private market structure is

so concentrated as to make monopolistic behaviour likely. The second is whether the presence of foreign capital in the industry has significantly affected behaviour.

A. Competition in the Alberta Oil Industry

It is widely recognized that real-world markets rarely meet all the conditions of the economists' model of perfect competition (i.e., many small buyers and sellers trading units of a perfectly homogeneous commodity in a market with free entry and exit and with instantaneous, perfect, and costless information flows). The question, rather, is how 'effective' or 'workable' the competition is. Does the real-world market come close to approximating the perfectly competitive outcome? This is not easily determined, if only because a number of key determinants of perfectly competitive prices are typically not observable (for example, individual buyer's utility or preference functions, and individual seller's expectations about the future). The Canadian petroleum industry has frequently been accused of harmful 'monopolistic' (more properly, oligopolistic) actions. For examples, see Laxer (1970, 1974, 1983). Our discussion earlier in this chapter relied on an oligopoly-oligopsony view of the market in the 1950s but noted that there were external upper and lower bounds on the price that the industry might set.

The most detailed examination is undoubtedly the 1981 study of the Canadian petroleum industry by the Director of Investigation and Research of the (federal) *Combines Investigation Act* (Bertrand, 1981). Vol. iv of the *Bertrand Report* considered the Canadian crude petroleum industry in detail, finding that (pp. 211–14):

[W]hile production was not highly concentrated, the disposition of crude production was controlled by a small number of firms.

... The high level of concentration in 'controlled' crude discouraged the entry of other companies who wished to purchase crude oil....

The monopoly situation which was produced by the control possessed by the leading firms was exploited in several different ways. First, it was used to establish a crude pricing formula which resulted in prices that were higher than they would otherwise have been. In addition complementary devices were used to maintain the prices of other hydrocarbons

such as condensate and heavy crude and to prevent the price structure for light crude from deteriorating....

... The major firms which possessed control were able to wielded [sic] their power in such a way as to entrench their market position downstream from production....

This practice lessened competition from small and large competitors who lacked crude control.

We will not report in detail on the Bertrand analysis, in part because the follow-up federal government study by the Restrictive Trade Practices Commission (RTPC) concluded that in its view "the Director failed to establish his allegations against the producing companies" (Canada, RTPC, 1986, p. 140). The RTPC (p. 132) did note:

[T]here is little doubt that, as the Director has argued, the Alberta Government's prorating scheme and the Federal Government's National Oil Policy had the effect of raising the price of domestic crude oils and hence petroleum products, for many Canadian consumers. On the other hand, there is no doubt that both programs produced many benefits as well.

This ascribes the higher prices to the government policies, not monopolistic behaviour. At a more pragmatic level, the RTPC pointed out (in 1986) that Canadian crude oil prices had been set by governments since 1973, so detailed investigation of crude oil pricing was not warranted.

However, despite the lack of evidence in support of the hypothesis that the oil industry has exercised market power over crude oil prices, there has been significant interest in the structure of the Canadian petroleum industry. Attention has focused largely on two issues – the degree of concentration of production and the level of foreign ownership in the industry.

B. Structure of the Canadian Crude Oil Industry

1. Concentration

Crude Oil. The lower the concentration of output, the less likely the exercise of monopolistic behaviour by producers. Further, if entry and exit into the industry were relatively easy, it would be difficult to maintain

Table 6.6: Concentration in Canadian Crude Oil Output (8 Largest Producers)

	Percentage Shares of Output					
	1957	1970	1980	1990	2000	2009
Imperial (Esso)	19.2	13.4	12.9	17.5	13.0	6.4
British American (Gulf)	7.1	7.3	8.0	3.9	3.8	
Texaco	6.9	8.9	8.6			
Mobil	4.6	7.6	5.8	4.1		
California Standard (Chevron)	4.5	5.0	5.6	4.1	3.7	
Hudson's Bay Oil and Gas	4.5	4.8				
Shell Canada	2.3	5.4				4.5
Pan American (Amoco)	1.9	4.5	5.1	6.5		
PetroCanada			4.1	7.0	3.8	
Dome			4.1			
Pan Canadian ^c				4.8	5.5	
Suncor Energy				3.2	5.9	9.9
Canadian Natural Resources					7.7	10.9
Husky Energy					5.8	6.4
Alberta Energy Co. ^c						3.7
Encana ^c						9.7
ConocoPhillips						6.3
Devon						4.5

	Concentration Ratios					
	1957	1970	1980	1990	2000	2009
4-Firm	37.8%	37.2%	35.3%	35.8%	32.4%	36.9%
8-Firm	51.0%	56.9%	54.2%	51.1%	49.2%	58.6%
HHI	566 ^a	528 ^b	507 ^b	516 ^b	432 ^b	524 ^b

a It was assumed that the next 13 largest firms all produced 1.5% of industry output and that all the other firms in the industry were too small to add anything to the HHI. Once the production share is less than one, each extra firm adds a minimal amount to the HHI.

b Based on the top 20 producers. (The 20th largest in 1970 and 1980 produced 1.3% of output; in 1990, the 20th largest produced 0.8% of output, in 2000, it produced 0.9% of output, and, in 2009, 1.1%.)

c PanCanadian and AEC merged in 2002 to form Encana. In 2009, Encana separated into Conovus (oil operations) and Encana (focusing on natural gas).

Sources: *Oilweek*, May 15, 1972, p. 24; June 15, 1981, p. 42; June 17, 1991, pp. 22-25; July 2, 2001, p. 32. The 2009 data was provided by Dale Lunan of *Oilweek* and appears in a July 2010 issue.

high monopolistic prices for any great length of time. Significant entry and exit would imply that the relative size of firms changes over time, rather than remaining stagnant. Specific corporate information on Alberta oil production is not readily available, but data for Canada is (and, recall, Alberta provides a large majority of Canadian crude oil). Table 6.6 provides data on corporate production of Canadian crude oil, for select years: it shows the eight largest crude oil producers for the year 1957 and similar values for 1970, 1980, 1990, 2000, and 2009 as drawn from *Oilweek* magazine's annual tabulation.

The level of concentration is measured in two ways. Four (eight) firm concentration ratios give the percentage of total oil output from the largest four (eight) producers. It is, of course, hard to interpret such numbers. One prominent expert in industrial organization suggested (Bain, 1968, p. 464) that "[T]entative indications are that if seller concentration exceeds that in which the largest eight sellers supply from two-thirds to three-fourths of the output of an industry ... there is a strong disposition toward significant monopolistic price-raising and excess profits." By this criterion, Canadian crude oil production is

relatively unconcentrated. The rising concentration ratios for 2009 reflect the growing importance of the large oil sands mining operations.

The second measure of concentration is the HHI (the Hirschman-Herfindahl Index), which is the sum of the squared output shares (percentages) of all firms in the industry. A monopoly would show a value of 10,000 (i.e., 100^2), while a very unconcentrated industry would have small value (e.g., if 100 equal-sized firms made up the industry, the value would be 100 – i.e., 100×1^2 , while 1,000 equal-sized firms would have an HHI of 10). The HHI is harder to calculate than the concentration ratio, since the output of all firms in the industry must be known; in practice, firms that produce less than 1 per cent of the industry's output add very little to the HHI. Once again, no precise interpretation can be attached to particular values of the HHI. The most prominent use of the HHI has been since 1982 in the *Merger Guidelines* of the U.S. Department of Justice. The precise criteria of the Department are quite complex, but mergers would clearly be challenged if the industry HHI were above 1,800, and would not be if it were less than 1,000. Once again, by this standard, the Canadian crude oil production industry appears quite unconcentrated.

However, as many observers have noted, the degree of output concentration may not be the only, or the most, relevant measure in a vertically integrated industry. Bertrand's report, for instance, emphasized the role of the major oil producers, especially Imperial Oil, as builders and equity shareholders in the major pipelines (especially Interprovincial Pipe Line).

Pipelines. By the late 1940s, as discussed above, Imperial Oil had begun initial plans to construct an oil pipeline east of Edmonton. In April 1949, a special act of Parliament incorporated Interprovincial Pipe Line (IPL), and Imperial was the first subscriber for shares, with a 50 per cent equity holding by 1950 (Bradley and Watkins, 1982, pp. 105–6). Imperial also guaranteed minimum shipment volumes and agreed to make up debt repayments if IPL were in default. Trans Mountain Pipeline was incorporated in 1951, also with major oil companies as majority shareholders and guarantors of debt. These two main (trunk) lines were connected to Alberta oil pools by a system of local gathering pipelines linked to a number of main feeder lines running to Edmonton; these local pipelines were usually owned and built by the first oil companies to generate significant discoveries in that part of the province.

The key question of concern is whether the relatively concentrated control of essential pipeline links

by the major oil companies was utilized to their competitive advantage. This might have happened in a number of ways including:

- (i) excessively high pipeline tariffs;
- (ii) denying access to facilities to crude oil from competing oil producers;
- (iii) restricting total facility throughput to keep oil prices artificially high.

Bertrand (1981, vol. iv) discusses these and other possible practices, but most observers have not found the evidence convincing (e.g., Lawrey and Watkins, 1982; Restrictive Trade Practices Commission, 1985). Why not?

- (i) The effective controls on Alberta crude oil production were the government prorationing regulations, and these were designed to ensure a 'fair' allocation to all companies. (The situation was somewhat different for heavy crude oil, which came from Saskatchewan to a large degree and was not subject to market-demand prorationing in Alberta.)
- (ii) The pipelines, certainly the two trunk lines, seem to have operated essentially as 'common carriers' and there are few recorded complaints from non-owner producers. (A common carrier pipeline is one which is open to all potential users on an equal basis; it does not discriminate in favour of its owners by offering them preferred access or lower tariffs.)
- (iii) The 1959 *National Energy Board Act* gave the NEB the authority to regulate tariffs of the trunk lines. While this power was not exercised until 1977, it was potentially available, and rates did have to be filed with the NEB. The sections of IPL and Trans Mountain which were in the United States were rate regulated by the U.S. government. Regulations, and the threat of regulations, will inhibit excessive tariffs.
- (iv) Lawrey and Watkins (1982) find the IPL and Trans Mountain tariffs before NEB regulation in 1977 to be somewhat higher (12–16% greater) than they would have been under the NEB rules. However, they note that the tariffs seem to be consistent with the rate procedures established by the U.S. Interstate Commerce Commission and suggest that a higher risk premium may have been called for in the earlier years of operation of the pipelines.

On balance, then, there is little evidence that the major oil companies' control of pipeline facilities was used to generate significant excess profits.

Refiners. One might suppose that oil refiners are interested in the highest possible price for refined petroleum products (RPPs) and the lowest possible price for the crude oil they purchase. As discussed in Chapter One, there are economies of scale in refining – by the 1960s an efficient refinery producing the light-end slate of products typical in North America would need a capacity of 100,000 barrels per day or more. However, this is a relatively small share of the RPP market in highly populated parts of the continent. Moreover, a refiner charging high prices would have to worry not only about new competitive refineries in its market area but also about imported products from other areas. Therefore, some observers have suggested that an oligopolistic refining industry, consisting mainly of vertically integrated companies, might prefer to pay high prices for crude oil. This would generate high profits for their crude oil affiliates, necessitate high prices for refined products, but not offer an incentive to new refining companies to enter the market. The strategy makes particular sense for a company that produces a large amount of crude oil relative to its total refining operations and is especially attractive if income tax laws favour crude oil profits over refining and marketing profits. (The latter was generally true, at least up to 1980, as Chapter Eleven discusses.)

There is no doubt that the purchases of Alberta crude oil exhibit higher concentration than do sales. Table 6.7 shows the nominations for Alberta crude oil for the month of August (a seasonally high demand month) for a number of years from 1955 through 1986. Nominations are the volume that buyers (usually refiners) indicate to the ERCB that they plan to purchase and serve as the basis for market-demand prorationing allocations. All buyers who asked for one percent or more of total Alberta nominations (in any of the indicated months) are shown in Table 6.8, as well as the number of smaller buyers. In total, buyers ranged in number from 6 (in 1955) to 31 (in 1976). It will be recalled that producers of crude oil in Alberta number in the hundreds. The concentration ratios and the HHI are higher than on the seller side, and particularly high for 1956. It can be seen that the lowest concentration occurred in those years (1971 and 1986) when access was open to U.S. markets and in 1976 before the U.S. market was severely restricted and when the Montreal link of Interprovincial Pipe Line was open. Note that the year 1986, with deregulation

of North American energy markets, saw the emergence of several crude oil purchasers who were not refiners (e.g., the Alberta Petroleum Marketing Commission [APMC] and Northridge Petroleum) but operated as crude oil-marketing middlemen.

However, claims that refiner-buyers were able to generate artificially high prices for Alberta crude oil must remain suspect. Output control came, not from the refiners themselves, but from the Alberta government market-demand prorationing scheme. For the years 1973 through 1985, governments also set the oil price. Up to the National Oil Policy of 1961, and since 1985, the Alberta oil price seems to have been set by competitive interface with other North American crude oil. The NOP years, 1962 through 1972, are the most difficult to assess, with Canadian prices relatively fixed, lying between falling international and higher relatively stable U.S. prices. We suggested above that this reflected oligopolistic price rigidity, where the Alberta Oil and Gas Conservation Board administered quantities, and refiners, aware of the political uncertainties associated with the NOP, simply refrained from altering oil prices. Thus, the level of Alberta crude oil prices has reflected government policies at least as much as the market power of crude oil buyers.

Other structural features of the Alberta crude oil industry, such as the changing relative importance of the major integrated companies, the other large crude oil producers and the small ('junior') companies, are not discussed in this book. Nor do we examine the reasons for and extent of merger activity in the industry, or why mergers occurred so much more frequently in some time periods rather than others.

Performance. Industry profitability is a key indicator of market 'performance.' (Differences between individual companies or types of companies will not be discussed here.) High levels of profit are often taken as evidence of market power, although careful interpretation is necessary. Profits, for instance, tend to be sensitive to cyclical fluctuations in the economy so that a single year's high profit is not necessarily meaningful. Moreover, the preponderance of fixed costs means short-run profits are highly levered by price variations, up or down. Beyond this, there are difficulties in measuring profit rates, especially in terms that the economist finds meaningful. Reported measures of profit typically are annual rates (for an entire corporation) derived using a variety of accounting conventions regarding things such as historic costs and capital depreciation rates. Economists are inclined to view profits as the present value lifetime return

Table 6.7: August Nominations for Alberta Crude Oil (10³ m³/d)

	1986	1981	1976	1971	1966	1961	1955
PetroCanada	45.6	0.6	-	-	-	-	-
Imperial Oil ^a	41.5	45.6	39.4	31.4	21.2	22.0	5.6
Shell	27.1	30.4	30.7	27.0	20.6	7.3	-
Texaco ^b	18.5	20.6	16.0	20.9	19.4	12.3	1.4
Koch	13.1	3.0	2.9	-	-	-	-
Sun Oil	11.2	12.2	9.9	5.3	1.7	2.0	-
APMC	8.4	-	-	-	-	-	-
Petrosar	7.7	14.5	1.2	-	-	-	-
Husky	7.5	3.2	1.9	0.9	0.7	0.2	-
Dome	6.3	-	4.3	0.7	-	-	-
Northridge	5.7	-	-	-	-	-	-
Turbo	5.4	1.0	-	-	-	-	-
Chevron	4.5	4.8	4.6	2.5	2.5	1.8	-
Consumers' Co-op	4.3	3.8	2.7	3.3	2.5	1.7	-
Amoco	3.7	-	1.0	2.7	-	-	-
Union Oil	3.5	-	0.8	0.3	-	-	-
Gulf ^c	2.9	32.6	31.2	21.2	16.9	10.9	1.9
Mobil	2.9	0.2	5.4	14.3	4.9	3.2	-
Murphy	2.5	1.9	5.9	4.9	1.4	0.3	-
BP	0.3	13.9	11.8	2.5	2.5	-	-
Ultramar	1.6	6.1	-	-	-	-	-
Petrofina	-	4.6	2.5	-	-	-	-
Hudsons Bay	-	-	9.7	13.5	2.5	-	-
Ashland	-	-	7.3	10.4	2.1	1.6	-
Consumer Power	-	-	2.2	-	-	-	-
Atlantic Richfield	-	-	2.1	1.9	-	-	-
Sohio	-	-	1.8	6.0	3.2	2.1	-
United Refinery	-	-	0.7	2.7	-	-	-
Clark	-	-	-	4.2	-	-	-
Bay	-	-	0.2	2.2	1.5	0.7	-
Cities Service	-	-	-	1.5	-	2.1	-
International	-	-	-	-	0.9	2.3	-
Northwestern	-	-	-	-	0.5	-	-
Canadian	-	-	-	-	-	3.6	-
Anglo American	-	-	-	-	-	0.4	0.5
Wainwright Prod.	-	-	-	-	-	-	0.2
# of Other Cos. ^d	(5)	(1)	(7)	(6)	(4)	(2)	(1)
Total	229.3	198.4	148.4	184.5	104.9	75.2	9.8
<i>Concentration Ratios (%)</i>							
4-Firm	57.9	65.1	59.2	54.4	74.5	69.9	96.8
8-Firm	75.6	87.6	80.3	78.2	87.0	84.7	100.0
HHI	1060	1312	1111	953	1463	1525	3951

Notes:

- a Includes nominations from one Royalite refinery (in 1961) and a U.S. Humble Oil Refinery from 1971 on.
- b Includes McColl-Frontenac and Regent in 1956.
- c Includes BA Oil before 1971.
- d All nominators who took 1% or more of Alberta oil in any of the years are listed separately.

Sources: Various issues of Oil in Canada and Oilweek.

associated with particular projects, using replacement cost criteria to value assets. Moreover, there are ambiguities involved in assessing the profits expected under effective competition in natural resource industries since economic rent over and above normal profits is to be expected. Unusually high profits might, in this case, say more about the ineffectiveness of government rent collection schemes than the degree of competition in the industry! Effective competition requires only that the marginal project does not generate excessive profits (that is profits above normal profits and marginal user costs, as discussed in Chapter Four). We will not provide information on the industry's profitability over the historical period but will briefly refer to several studies of the petroleum industry's profits.

Jenkins (1977) examined rates of return to Canadian industries; accounting data was adjusted to reflect economic valuation of assets. He reports rates of return for the "mineral fuels and petroleum" industry for private companies for years 1965 through 1974. For the first eight years of this decade, annual returns on capital varied from 3.6 per cent to 5.9 per cent, averaging 5.0 per cent; for the final two years, the return rose to 7.0 per cent and 7.3 per cent, in line with rising energy prices. Over the entire decade, the rate averaged 5.4 per cent as compared to 5.9 per cent for all Canadian manufacturing and all non-manufacturing industries. DataMetrics Limited estimated annual real rates of return on capital for oil and gas production from 1972 to 1980, a period of rapidly rising prices. Two series were reported, the second incorporating an allowance for rising costs in the petroleum sector relative to the economy at large (DataMetrics, 1984, Tables 2.1 and 2.2). The latter series showed an average rate of return of 5.5 per cent for the nine years; the rate was at its lowest, at 1.9 per cent, in 1972, and then rose sharply to 4.3 per cent in 1973. It fell the next year, and then rose again to a peak of 9.4 per cent in 1979, before falling back to 6.6 per cent in 1980. The average real return was higher than in the utility or manufacturing sectors (at 3.7% and 4.6%, respectively); however, these sectors exhibited much more stable rates of return, indicating somewhat less risk. Mining (exclusive of petroleum), like oil and gas, showed more variability in returns over this period and also a somewhat lower average rate of return (at 4.7%).

The *Annual Reports* of the Petroleum Monitoring Agency (set up on August 1, 1980, by the federal government) give more conventional accounting measures of profitability. The rate of return on total

capital for upstream (crude petroleum) industry activities can be compared to that of all non-financial Canadian industries, for the years 1980 through 1990. Annual differences are great; for example, in 1980, the petroleum industry earned 14.1 per cent while other industries averaged 10.3 per cent, while in 1986 the respective values were -1.0 per cent and 9.1 per cent. From 1981 to 1985, oil averaged 8.3 per cent, and other industries 7.7 per cent; from 1986 to 1990, oil was at 3.4 per cent, others at 8.8 per cent. Crude oil may have been slightly more profitable than average during the late 1970s and early 1980s when international oil prices were high but became much less profitable once oil prices tumbled. These averages cover a wide range of values for individual companies.

Overall, this brief review of profitability does not support the claim that the Canadian crude oil industry has generated large oligopoly profits.

2. Foreign Ownership

A second structural feature of the Canadian petroleum industry that should be addressed, if only briefly, is the relatively high level of foreign investment. The presence of foreign-owned capital in Canada's oil industry can be placed in context from two somewhat broader perspectives:

- (i) Many sectors of the Canadian economy have high foreign investment, and some people have seen this as a major problem.
- (ii) In most parts of the world, except where oil is nationalized, development of the oil industry has depended heavily on foreign (largely U.S., British, or French) capital from major oil companies, and many people have seen this as a major problem.

Most people would likely accept that there is nothing inherently wrong with the international mobility of capital. Economists, in particular, have suggested that it is an important part of the process of economic development. Inflows of capital allow regions to finance imports in excess of exports, thereby providing a net inflow of goods and services that can, potentially, spur greater economic development. Of course, the owners of the capital expect that they will recover their investment plus a return (profit) at least as high as they could obtain in the next best alternative investment of equal risk. Foreign capital flows in the form of official government assistance or charitable donations will not usually have the same expectations about

repayment and return. Some economists and business leaders have also stressed that international capital flow, especially in the form of 'direct investment' that carries ownership of (equity participation in) projects, may also bring valuable technical and management skills that are not indigenous to the region. But the benefits of foreign investment are not necessarily without cost.

There is a large academic and popular literature in Canada on the benefits and costs of foreign investment; no clear resolution of the debate has occurred, or is likely. Some flavour of the main issues can be obtained from Levitt (1970) and Safarian (1973); Baldwin and Gellatly (2005) and Baldwin et al. (2006) provide an historical overview. Six separate issues might be highlighted. Our discussion is cursory.

- (i) **Necessity of Foreign Investment.** Critics have argued that, at least in part, foreign investment simply displaced Canadian capital, entrepreneurial talent, and technological skills. In other words, foreign capital simply was not needed. Others respond that foreign investment responded to opportunities available in Canada which Canadians were not undertaking, often when there was little unemployment or spare capacity, and Canadians were unwilling to reduce consumption in order to invest more. Further, they argue, it is unfair to blame foreign investment for failures in Canadian macroeconomic policy.
- (ii) **Profitability.** Critics of foreign investment argue that foreign investors received higher rates of return than were required or fair, thereby reducing the standard of living of Canadians. Excess payments may have occurred partly through transfer pricing practices, in which artificially low prices are paid on exports from Canada to affiliates and/or artificially high prices are paid on imports from the foreign affiliate. They also note that if excessive profits are reinvested in Canada they become almost impossible for Canadian governments to claim for Canadians, since this would involve expropriating the newly acquired assets (or their depreciation payments). Those more supportive of foreign investment often say that these arguments are less against foreign capital than they are in support of Canadian government policies to encourage workable competition and corporate income taxes which capture a significant share of profits for Canadians. Both policies are desirable in their own right.
- (iii) **Decision-Making.** Critics suggest that sectors with high foreign investment may make decisions differently than they would if Canadian-owned corporations dominated. Common examples include a reluctance to invest in R&D in Canada, failure to train Canadian staff for high-level technical or management positions, and failure to process raw materials in Canada. Furthermore, in sectors with some, but not complete, foreign ownership, Canadian-owned companies may be forced to behave in the same manner or be at a competitive disadvantage. In response, others have expressed scepticism that companies would deliberately forego potentially profitable investments, and argue that importing R&D from abroad may be the lowest cost way to obtain new knowledge.
- (iv) **Extraterritoriality.** This occurs when a firm in Canada acts in a particular way because it is foreign-controlled and the home government of the foreign investor requires certain action. For example, the U.S. government has, on occasion, ordered U.S. corporations, including their affiliates, to restrict trade with certain communist and Middle Eastern countries. Another possibility is that state-owned oil companies from other countries might devise policies for political rather than commercial reasons; for example, might Chinese state-owned oil companies who have recently invested in the oil sands attempt to ship bitumen or synthetic oil to China at lower than market prices to ensure it is competitive with Middle Eastern crude oil? Others argue that such an exercise of extraterritoriality has been rare, and that, if it occurred, the Canadian or Alberta government may wish to pass counter-vailing regulations applicable to companies operating here. A related argument is that Canada's openness to foreign companies may not be matched by the same degree of openness to Canadian investors in the home country of the foreign interests.
- (v) **Resource Depletion.** Critics of foreign investment have sometimes argued that foreign investors have been particularly prone to come into a country and produce large volumes of a depletable natural resource for export markets (often in the company's home country), thereby accelerating depletion of the country's valuable and limited natural resources. Those

more favourable to foreign investment usually note that, if valuable export markets exist, domestic corporations usually behave in exactly the same way and that the government always has the right to control levels of output and exports.

- (vi) **Cultural Sovereignty.** High levels of foreign investment, critics argue, tend to lead to changing social and cultural norms, often with greater homogenization and adoption of foreign values. The process may be direct, with the influx of foreign management and workers, or more indirect through the influence of a foreign corporate ethos, or very indirect through the loss of political resolve on the part of local governments who come to feel dependent on the goodwill of foreign firms and their governments. (Urquhart, 2010, in this vein, discusses whether Alberta might be considered a 'Petro-state'.) Others, in response, argue that social values are not all that fragile, that governments can do many things to encourage national cultural institutions, and that the higher standards of living derived from foreign investment should increase the governments' options in this regard.

Before returning to the Alberta petroleum industry, we should discuss the distinction between foreign 'ownership' and 'control'. Ownership relates to the distribution of equity shares in a corporation; it is the prime determinant of the distribution of dividends from current income and claims on the net assets of the firm. An emphasis on equity capital, rather than debt capital, is consistent with the tenor of the six arguments above. Foreign debt capital does entail an obligation to transfer the capital borrowed plus interest to the foreigner making the loan, but it is normally at a fixed rate of interest and does not transfer decision-making power to the foreign lender.

Foreign control refers to the ability of foreign equity interests to control decision-making in the corporation. Since outsiders do not have a window on decision-making procedures in corporations, control is difficult to assess. The most common criterion was that developed for CALURA, the *Corporations and Labour Unions Return Act* (now CRA, the *Corporate Returns Act*). From 1962, CALURA required most corporations and unions to file data annually with Ottawa, including details on the degree of foreign involvement. (The *Petroleum Corporations Marketing Act* gave the Department of Energy, Mines and Resources the responsibility to gather information on

petroleum companies' activities and resulted in the annual report of the Petroleum Monitoring Agency [PMA]). CALURA defined 'foreign control' as occurring when more than 50 per cent of the voting shares in a corporation were owned by non-Canadians (or by some other corporation that in turn is foreign controlled). Weaknesses in this convenient definition are easy to find. If the 50 per cent or more foreign shareholding is dispersed, effective control could lie with Canadian shareholders or management. Conversely, a large, but minority, foreign shareholder could effectively control decision-making.

There is also the question of what is controlled. A crude oil company builds up a stock of assets (land, oil and gas reserves, employees, capital) in order to produce physical output to generate sales revenue that gives the company profits. Foreign ownership and control shares of an industry will vary depending what dimension of the industry is measured.

High levels of foreign ownership and control in the Canadian petroleum industry have long been indisputable. By 1890, Standard Oil had acquired a majority interest in the first large Canadian crude oil producer and refiner (Imperial Oil). Royalite Oil was an Imperial subsidiary; Royalite acquired the assets of one of the first discoverers in the Turner Valley gas field in 1914 (the Calgary Petroleum Products Company), was responsible for the deeper 1924 gas discovery, and helped finance the 1936 Turner Valley oil find (Hanson, 1958, chap. 5; Gray, 1970). Foat and MacFadyen (1983) looked at seven of the largest Alberta crude oil plays; in all of them, the discovery well was by a foreign-controlled corporation (e.g., Imperial Oil for Leduc in 1947, Socony-Mobil for Pembina in 1953; Banff-Acquitaine for Rainbow West in 1965). The major vertically integrated companies, in particular, were foreign-owned and controlled, until the creation of Petro-Canada in the 1970s.

The federal government's comprehensive 1973 study, *An Energy Policy for Canada* (EMR, 1973) included a detailed discussion of foreign ownership in Canadian energy industries. In 1970, the Canadian petroleum industry (including crude petroleum, refining, and marketing operations) had assets that were 77 per cent foreign-owned and 91 per cent foreign-controlled (EMR, 1973, vol. v, pp. 219–29). Foreign control was also 91 per cent for industry equity, 93 per cent for reported (accounting) profits, and 96 per cent for the value of sales. These percentages had held during most of the 1960s, with slightly rising foreign control shares of profits and sales. Foreign control was somewhat lower as far as crude petroleum activities were concerned, and somewhat

Table 6.8: Foreign Ownership and Control in the Canadian Petroleum Industry, 1971-2007
(% of petroleum industry revenue)

	<i>Ownership</i>	<i>Control</i>
1971	79.5	94.4
1975	76.1	92.9
1979	73.8	82.5
1985	56.2	62.6
1989	55.1	63.9
2000	n/a	51.1
2007	n/a	48.3

Note: 2000 and 2007 are for oil and gas extraction and related activities.

Sources:

Canadian Petroleum Monitoring Agency *Monitoring Reports* for 1971-91. Statistics Canada catalogue #61-220 (*Report of findings under CRA*) for 2000 and 2007; available from CANSIM as table 179-0004.

higher for refining and marketing. EMR reported foreign ownership and control at around 20 per cent for the oil and gas transportation industry. In 1974, the government established the Foreign Investment Review Agency (FIRA) to monitor foreign acquisitions to ensure that they provided 'significant benefits' to Canada. (Eden, 1994, pp. 14-16, provides a summary history.)

After the 1973 EMR Report, continued statistics on foreign ownership in the Canadian petroleum industry were available through CALURA and PMA surveys. Table 6.8 shows the evolution of Canadian ownership and control percentages as reported by PMA for select years from 1971 through 1991, and from CALURA (CRA) reports for 2000 and 2007, based on the total revenue earned by the industry; the early years are for both upstream and downstream activities, while 2000 and 2007 include petroleum extraction only. The very high levels of foreign involvement in the 1970s had fallen by the 1980s, particularly with the rapid growth of Petro-Canada and Dome. Mergers and acquisitions have been common in the Canadian petroleum industry (PMA, 1990, provides a list of the main takeovers from 1976 through 1990). With this activity, the foreign share of the industry fluctuated, but generally it has stayed around 55 per cent for ownership and 60-65 per cent for control through to 1990, after which foreign control fell to near 50 per cent. The apparent decline to 2000 reflects the exclusion of downstream activities in these numbers.

Foreign control of assets has continued to be lower than of revenues.

As was discussed earlier, the share of the industry held by foreign firms varies depending upon the type of firm and industry activity considered. For example, in 1985, the year that FIRA was disbanded and monitoring of foreign investment shifted to Investment Canada, petroleum industry exploration expenditures were only 31 per cent by foreign-controlled firms, and upstream petroleum revenues by non-integrated firms were 49 per cent under foreign control, while upstream revenues earned by integrated firms were 61 per cent foreign-controlled (Canada, PMA, 1986). These contrast with the 57 per cent foreign control for all petroleum industry revenues as reported in Table 6.8. By 1990 the foreign control percentages corresponding to those of the previous two sentences were 47 per cent, 49 per cent, 80 per cent, and 52 per cent (Canada, PMA, 1991). Rising levels of Canadian ownership and the closer integration of the U.S. and Canadian economies under the Free Trade Agreement led to a relaxation of regulations regarding foreign acquisition of Canadian oil and gas assets in 1992. Petroleum would henceforth be treated like most other industrial sectors (Globerman, 1999, p. 19). Investment Canada was eliminated in 1994 and the Department of Industry took over responsibilities for overseeing foreign investment; acquisitions of Canadian-owned assets above certain values would be monitored to ensure they offered 'net benefits' to Canada.

The high level of foreign investment in the Canadian petroleum industry is likely to continue to be of concern to some Canadians, who view the petroleum industry as a particularly critical one and who suspect that a foreign-dominated industry will behave differently than a Canadian-owned industry would. Those more accepting of foreign investment in the Canadian petroleum industry emphasize the benefits of the greater access to financial capital and technology and note that foreign-owned corporations are subject to regulation by Canadian governments if their actions are perceived to be harmful. Moreover, physical assets, in the form of oil-production equipment and developed reserves, cannot be removed from the country, so remain subject to Canadian laws and regulations.

Both views are likely to persist, so that the foreign-ownership issue will likely be a recurring one on the Canadian political agenda. We would suggest that the persistent disagreement stems in part from differing views on the two sides of the debate about the role

in society of economic markets and the corporate sector in particular. Most economists adopt an 'economic' focus in which corporations, for example, are generally viewed as working to maximize profits within whatever regulatory environment they operate. Governments are free to initiate policies that they believe to be in the public interest, and individuals are similarly free to pursue whatever objectives they feel are important. In this view, foreign investment is not in itself undesirable, but governments have a responsibility to introduce regulations ensuring that after-tax corporate profits are not much in excess of 'normal' levels, with the additional profits captured for the public benefit. In addition, governments always have the ability, and responsibility, to introduce laws and regulations to control any corporate behaviour that is not in the public interest. However, other analysts, and some economists, have taken a different perspective on foreign ownership, from a 'political economy' point of view, generally with a leftist slant. In this view, the corporate sector is important, not primarily for the allocative economic functions it performs, but as a social power structure that imposes its values on the broader society and subverts the government's willingness to act in the broader public good. From this perspective, foreign investment is seen as problematic for the economy because it is not only tied to the corporate sector but because it imports foreign values and culture. Barrie (2006) does not deal with the foreign-investment question but does provide interesting comments on Alberta's political culture.

Our view is the 'economic' one that, subject to appropriate government regulations, the international flow of capital – and the inevitable foreign ownership that results – is a desirable component of a dynamic and growing world economy. We do not view foreign investment in the petroleum industry as being, or having been, detrimental to Canadian interests. We will return to the issue of foreign investment in Chapter Nine when we discuss the impact of government regulations to control the price of oil. It is also one of the issues lying beneath the analysis in Chapter Eleven of the efficiency of the regulations devised by the government to capture a 'fair' share of the economic rent from producing oil for the government.

5. Conclusion

In this chapter, we have reviewed the history of prices and output for Alberta conventional crude oil. (The

market outcomes reflect as well the production of bitumen and synthetic crude oil from the oil sands. The unique features of the oil sands are discussed in Chapter Seven.) We argued that our focus has been largely from a 'private' perspective, as seen through the activities of crude oil producers and refiner purchasers in the crude oil market. However, throughout the period, the activities of private market participants played out against a backdrop of government regulations: petropolitics was ever-present.

Private market behaviour was sometimes more constrained, and sometimes less, by government regulations. Of the four main periods into which we divided the history of the Alberta oil industry, the first and the last were relatively more loosely regulated. From the early days of production, and especially after the 1947 Leduc discovery, up to the end of the 1950s, the key issue was the expansion of the market for Alberta oil, in competition with imported crude oil. Market growth fell behind increases in reserves additions, but major price declines were contained by the market power of the large integrated oil companies and, most critically, the government of Alberta's market-demand prorationing regulations. With deregulation of the crude oil market in 1985, and high U.S. demand for imported crude oil, Alberta production was once again facing a relatively unregulated market in which it had to meet competition from other sources in the world. The welcome reception of non-OPEC oil in the U.S. market (so long as competitively priced) meant that the market for Alberta crude oil was large; after 1989, market-demand prorationing no longer constrained production. The main new government regulations in this later period were the two free trade agreements. Their impact was not to constrain Alberta oil production or prices but to offer some certainty to the private industry that the Canadian government was committed to the relatively unimpeded operation of a free market for crude oil.

The years bracketed by these two periods of relatively free markets saw government regulations aimed at affecting the price of Canadian-produced crude oil. Initially, from 1960 through to the early 1970s, the main concern was low world oil prices, and the federal government's National Oil Policy operated indirectly ('covertly') to keep Alberta oil prices above world levels. From the early 1970s through to 1985, Ottawa was concerned by the high level of international oil prices, and explicit ('overt') price controls kept Alberta crude oil prices below world levels; at times, the prices were set unilaterally by the federal government, but most often federal-provincial agreements applied.

As with the degree of government regulation, the range of crude oil prices since the end of World War II has been large. Nominal prices have been as low as \$2.00/b and as high as over \$130/b, and have, especially since 1970, varied considerably within a relatively short period of time. This price instability has posed considerable problems for decision-makers in energy industries, especially since many of the factors causing the instability – Middle East crises, the degree of stability within OPEC – cannot be forecast with any precision. Thus decision-makers have been forced to find ways to live with oil price instability and

uncertainty. One can interpret the price regulation periods of 1960 through 1985, in part, as governmental responses to this problem. And, in Chapter Thirteen, we will see that the price instability for crude oil also raised macroeconomic policy issues for the province.

Before turning to governmental regulation of the oil industry, we will review the history of the Alberta oil sands (Chapter Seven), and briefly summarize some of the literature that has attempted to build economic models of Alberta conventional crude oil supply (Chapter Eight).

CHAPTER SEVEN

Non-Conventional Oil: Oil Sands and Heavy Oil

Readers' Guide: Alberta's gigantic non-conventional oil sands resources have been known to exist for over a century. In this chapter, we review the long history of the evaluation of this resource and the development of production techniques thought to be commercially viable. The initial projects of the 1960s and 1970s are discussed in detail, including the important public policy issues raised by the prospect of large oil sands output. We then discuss the absence of large new projects in the 1980s and 1990s, with smaller bitumen projects appearing, and the two existing mining ventures engaging in moderate expansion. Finally, the resurgence of interest in the oil sands at the turn of the millennium is discussed.

1. Introduction

The difference between the conventional and the non-conventional is hazy and changeable. Some lifestyles progress from unacceptable to tolerated to conventional within the space of a generation. A similar transition is occurring for the so-called 'non-conventional' oil from the Alberta oil sands and very heavy oil deposits. The non-conventionality of these resources lies in the fact that they cannot be produced by the techniques that have conventionally been used in the oil industry. The hydrocarbons (bitumen) in the ground are so heavy and viscous, and so firmly attached to the rock pores, that the oil will not easily flow to and up the well bore, even with the 'primary' inducements that the industry commonly uses

(fracturing the reservoir rock around the well and pumping). Loosely put, commercial primary recovery rates are very low, and the EOR techniques required are not those that the industry has developed for conventional oil pools. The ERCB has defined crude bitumen as "a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentanes, that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well" (ERCB, 2010 *Reserves Report* ST-98, p. A1). The resources discussed in this chapter include more than those shallow oil sands deposits around Fort McMurray that are amenable to strip-mining. There are also extensive oil sands deposits that are too deep to be effectively strip-mined, and from which oil must be recovered by *in situ* processes that typically inject heat into the reservoir to make the viscous heavy oil more fluid and allow it to flow beneath the surface to a well bore. Early prospectors attempted this in the shallow Athabasca sands, but much of the experimentation has been more recent, relying on new technologies such as horizontal drilling.

There are four very large areas in Northern Alberta on which bitumen deposits are recognized to exist: Athabasca, Wabasca, Peace River, and Cold Lake. (See Figure 5.1, in Chapter Five.) Recently the Athabasca and Wabasca sands, which border one another, have often been combined. There are also other smaller deposits of a similar bitumen nature in Northern Alberta, for example in the Buffalo Hills area. Typically, there are a number of heavy oil or bitumen formations in each of these deposits. Overall, as of 2012, the ERCB recognizes fifteen separate bitumen sand deposits in these four areas. On balance,

the distinction between conventional and non-conventional heavy oil resources is somewhat arbitrary, perhaps best viewed as involving a division along a continuum of heavy oil pools. The non-conventional resources are usually considered to be those very large accumulations of heavy oil in Northern Alberta that were not historically producible by conventional techniques. However, the ERCB shows a number of heavy oil projects that are ascribed primary production. Moreover, there are undoubtedly smaller 'conventional' heavy oil deposits that hold oil in formation in a manner very similar to a deposit such as Cold Lake. Such conventional heavy oil pools often exhibit increased recovery rates with EOR schemes that are similar to the *in situ* production techniques used in the non-conventional heavy oil pools. We suspect that the crucial difference, which will soon be commonly accepted, is between mining and *in situ* production techniques, though it will still be of interest whether an *in situ* scheme is located in one of the huge bitumen sand 'fields.'

By 2012 crude bitumen made up 78 per cent of Alberta's oil production (ERCB, *Reserves Report ST-98*, 2013, p. 2), as conventional output continued to exhibit production decline and non-conventional output expanded. Most analysts see the share rising. The non-conventional is becoming commonplace! The reasons for this lie in a mix of natural, technological, economic, and political factors. Alberta's bitumen resource base is huge. Higher oil prices beginning in the 1970s served to attract more attention to higher-cost energy sources such as the oil sands. Companies and government research agencies have long investigated new production techniques explicitly for Alberta's oil sands and heavy oil resources, and there was significant 'learning by doing' along with production. Governments offered encouragement to oil sands projects and came to believe that the special features of this petroleum resource warranted different royalty and tax treatment than conventional oil.

2. Early History

Alberta's oil sands were probably the first of its hydrocarbon resources to be discovered. (Carrigy, 1974; Chastko, 2004; Ferguson, 1985; Fitzgerald, 1978; Gray, 1970, chap. 14; Pratt, 1976, chap. 3; NEB, 2000, Section 3 and Nikiforuk, 2008, provide historical detail on the oil sands.) In 1778, Peter Pond, an early white trader, remarked on the shows of oil in the banks

of the Athabasca River north of the present town of Fort McMurray. Pond noted that the local aboriginal population used the bitumen in a number of ways. However, the difficult nature of the bitumen – heavy, viscous and high in sulphur – discouraged its development, even after the start of the modern petroleum industry about 1860. The federal government's geological service turned its attentions to the oil sands in 1882. Robert Bell ascertained the Lower Cretaceous age of the Athabasca sands, suggested that the bitumen might be separable from the rock by a hot water process, and argued that the bitumen in the sands had originated in Devonian era rocks. Three years later, Robert McConnell provided further geological analysis and estimated that the oil sands area was at least 1,000 square miles with at least 30 million barrels in place. In the Ottawa labs of the Geologic Service, G. Hoffman had discovered the asphaltic nature of the bitumen. He demonstrated that, by heating the bitumen-laden rock, the concentration of bitumen could be increased from under 15 per cent to about 70 per cent.

Attention focused initially on the presumed presence of deeper large conventional oil deposits from which seepages to the surface must have occurred. In the late 1890s, a series of wells was drilled by the Geologic Service in the oil sands region; several gas strikes occurred, but no underlying oil reservoirs were located, a result confirmed by private sector drilling early in the century. However, the non-conventional bitumen sands themselves were so obvious, and large, that numerous prospectors and scientists were drawn to speculate on, and experiment with, ways of producing the bitumen. After World War I, both private and public enterprises were involved, most notably Sidney Ells with the Mines Branch of the federal government, Karl A. Clark with the provincial government-funded Alberta Research Council, Robert C. Fitzsimmons, who founded the International Bitumen Company, and Max Ball, who founded the Abasand Oil Company.

Ells first became convinced of the potential of the oil sands when commissioned to undertake a survey in 1913. For the next three decades, he became a firm proponent of the oil sands, suggesting production methods and actively pursuing uses for the bitumen. Ells was especially active in demonstrating the utilization of concentrated bitumen for paving projects (in Edmonton in 1915 and Jasper in the 1920s). Ferguson (1985) suggests that Ells's difficult personality slowed federal involvement in the oil sands and encouraged the government of Alberta to take a more active role.

Clark began work in the early 1920s, based on hot water extraction methods, which had been applied since before the turn of the century to petroleum from heavy oil deposits in California and elsewhere. Laboratory work and pilot plants at the University of Alberta (1923), Dunvegan (in Edmonton, 1924), and on the Clearwater River near Fort McMurray (1930) confirmed the technological feasibility of Clark's hot water process. Clark also demonstrated the possibility of using bitumen for paving purposes, but, unlike Ells, emphasized that it was more costly than the usual materials. While researchers like Ells and Clark established a firmer understanding of the resource and technological potential of the mineable Athabasca oil sands, commercial viability had not been proved. With falling oil prices and the Great Depression in the early 1930s, government interest in the oil sands waned.

Private entrepreneurs continued to pursue commercial development. Fitzsimmons headed the International Bitumen Company (1927, successor to the Alcan Oil Company, a drilling company funded by a group of New York policemen in 1922). Fitzsimmons initially drilled for conventional oil in the Athabasca area, where his self-promoting claims of success seem to have been derived from bitumen that flowed into the well bore as a result of the heat of the revolving drill bit. He turned his attention to a mining and separation facility and in 1930 constructed a hot water separation plant at Bitumount, near Fort McMurray. International Bitumen struggled along with a mix of high promises, technical problems, and management and financial crises until bankruptcy occurred in 1938. In 1942 a Quebec investor, Lloyd Champion, bought International Bitumen, re-organized it as Oil Sands Limited, and approached the Alberta government about the possibility of government funding to complete and re-open the Bitumount plant. Alberta refused to provide loans or loan guarantees to the company, but in late 1944 it entered into a joint venture. This decision reflected advice from experts such as Karl Clark, who argued that the private sector could not be expected to invest heavily in the oil sands in light of their uncertain commercial viability, especially when technical issues about separation and upgrading had still to be resolved. The provincial government took over sole operation of Bitumount in 1948 when Oil Sands Limited proved unable to continue its financial share. There were numerous technical problems and accidents, but Bitumount did operate for part of 1948 and 1949. In September 1949, the plant was closed, issues of technical feasibility having been substantially addressed. The government hosted the First

Athabasca Oil Sands Conference in 1951 and used this as a forum to make available to the public the technical information that had been gained at Bitumount.

Max Ball was an American engineer who became interested in bitumen sands in the 1920s while working at a lab in Denver. In 1930 he founded Abasand Oils Limited (originally the Canadian Northern Oil Company) to operate a separation plant in the Athabasca oil sands. (See Comfort, 1980, for a history of Abasands.) Ball consulted with Karl Clark, and by 1936 Abasand was in production using a hot water separation process. There were numerous technical problems, many of them involving mining difficulties, since the sands quality was poorer at the Abasand site than at International Bitumen's. Abasand was, however, much more effective than International Bitumen in its financing, management, and operation. In 1941, Abasand finally began to operate consistently, only to burn down in November. In April 1943, the federal government, concerned about war-time oil supplies, decided to finance the rebuilding of the Abasand plant. A restructured Abasand Oil would run the facility and have the right to purchase it from the government at a later date, at market value. Numerous construction delays and unexpected cost increases plagued the re-building, with the separation plant beginning sporadic production in the fall of 1944. Experiments were undertaken in 1945 with a second separation plant using a cold water process. But in June 1945, a fire destroyed part of the project including both separation plants. The federal government delayed in committing more funds to the project, in part because the war pressures had ended and also because much of the desired technical information had been gained. In June 1946, Ottawa formally announced what most people had come to expect; it was out of the Abasand project. Abasand Oil took over the remaining assets but was essentially inactive until the mid-1950s when it sold its oil sands leases to Sun Oil.

What conclusions can be drawn from this brief early history of the Athabasca oil sands? The period from 1880 to 1950 was primarily one of knowledge generation. It was soon clear that the natural resource base was huge, but time had been needed to demonstrate that the resource was the Lower Cretaceous bituminous sands themselves, not an underlying conventional oil play. The bitumen content of the sands varies, averaging around 12 per cent (by weight) in the Fort McMurray area, but rising to almost 20 per cent at some locations. While some investors attempted *in situ* recovery methods, it was commonly accepted by

the 1930s that strip-mining of shallow sand deposits was the most promising production approach. By 1950, it was also pretty clear that the initial commercial production of oil sands oil would involve the three stages that Clark, Fitzsimmons, and others had been advocating for at least twenty years. A mining process would strip-mine the bitumen-laden rock that lay near the surface; a hot water flotation process would free the bitumen from the rock; and a refining process would upgrade the bitumen from very heavy and high sulphur crude to sweet, light crude or into specific light refined petroleum products.

In their 1927 *Report* for the Scientific and Research Council of Alberta, Karl Clark and Sidney Blair summarized the view prevalent amongst many early oil sands researchers (vol. II, p. 35).

It will require but a small diminution in the supply of crude oil or increase in the demand for gasoline to render possible the development of the Alberta bituminous sands for the production of motor fuel. If, as appears to be the case, separated bitumen can be produced for a dollar a barrel, and can be turned into a forty-five per cent yield of cracked gasoline, conditions in the near future should cause a profitable basis for an industry. On the other hand, prospecting may reveal extensive petroleum pools in Western Canada which would cause a delay in bituminous sand development. The results of the search for oil fields to date does not give strong hopes that this will happen. It is not improbable that the great bituminous sand deposit represents Nature's major gift of crude oil to Western Canada, and that it must be turned to as the source of supply of mineral oil products for the Prairie Provinces.

Clark and Blair were quite correct to remark on the connection between the conventional oil industry and the likely appeal of the oil sands and were not alone in suggesting that the oil sands were not quite commercially attractive.

From an economic point of view, there are a number of issues of interest, though data is somewhat sketchy. Commercial viability is one issue, and some information is available from the pilot projects and from reports by such careful analysts as Karl Clark. (Most of the data we use are drawn from Ferguson, 1985.) The desirability of an upgrading stage, for example, is evident in the finding that separated

bitumen was not competitive as a paving material. (Clark noted that one seller charged Camrose \$1/square yard for paving with bitumen, and probably lost money; the City of Edmonton costed paving by more conventional means at \$0.66/square yard.) However, the likely cost of synthetic (upgraded) crude is harder to estimate. For one thing, the cost is a function of project-specific factors such as the grade, depth, and location of the bituminous sands being mined and the separation and upgrading techniques. Further, both learning-by-doing and economies of scale are likely to be significant. The former implies that costs fall as more is produced and that new plants may be cheaper than older ones. The latter implies that per unit costs may be significantly less for larger plants than for small pilot projects. The 'hardest' data on synthetic crude costs comes from the two large pilot projects, Bitumount and Abasand. The experience of both projects suggested that unanticipated technical difficulties, including equipment failures and long shut-down times, would be likely to affect commercial ventures, at least in the early years, and these, of course, increase the cost of the synthetic crude. (Costs that are incurred even when there is no output must be spread over the output when it does occur; also, delayed output has a lower present value than earlier output, and so increases the effective capital cost of a unit of output.) On both these projects, the capital costs turned out to be higher than initially projected. This was especially true for the war-time Abasand project, which was projected to cost \$500,000 to rebuild and which by 1945 had absorbed more than \$1,900,000. (Bitumount was initially budgeted at \$250,000 in 1942 and had spent \$750,000 by 1949.) However, since both projects were pilot projects, and neither produced for long, no reliable unit costs can be derived from them.

Another source of synthetic crude oil costs came from estimates made by those involved in the bituminous oil business. Such estimates have the advantage of allowing for factors such as economies of scale and utilization of the (presumed) best production technique. But they have the disadvantage of being hypothetical, a major problem when virtually all the actual projects undertaken exhibited unexpected technical problems and cost overruns. Further, the cost estimates of promoters are particularly suspect, since they were often attempting to raise capital from investors. They may also have been drawn to reduce the cognitive dissonance they felt as their cash dissolved in unprofitable investments; if they could convince themselves, however inaccurately, that

profitability was just around the corner, they would feel less unhappy about the money they had already lost. For example, Fitzsimmons estimated a synthetic crude cost in the mid-thirties of \$0.72/b, even as his company was slowly going bankrupt. Contrast this with Karl Clark who, in his detailed *Report* on the oil sands for the Research Council of Alberta, had estimated mining and separation costs at \$1.00/b for bitumen alone (Clark and Blair, vol. II, 1927, chap. III). However, Clark and Blair had noted (p. 31) that this 'is evidence that the separation process besides being efficient is also economically possible.' Finally, it is often difficult to compare cost estimates since they do not always include the same elements. For example, it is not always clear how the cost of capital is treated, some estimates are for only one of the three processes (e.g., separation) and some estimates included the cost of shipping the synthetic crude out of the Athabasca region while others did not.

Ferguson (1985) notes a number of independent studies, especially in the 1940s as governments considered investing in oil sands operations, which suggested that if a few of the technological uncertainties could be resolved, synthetic crude production costs would be in the vicinity of light crude oil prices. However, these cost estimates varied considerably. For example, two federal government studies in the early 1940s estimated bitumen costs (mining and separation but not upgrading) at \$1.31 (G. Hume of the Geologic Survey) and \$2.00 (Federal Oil Controller G. Cottrelle) per barrel, when bitumen was selling for about \$1.60/b. G. Webster of Abasand estimated that a 1,000 b/d separation plant could produce bitumen at a cost of about \$2.50/b, when crude at that time (September 1945) was selling for about \$1.00/b.

In 1949, the government of Alberta commissioned Sidney Blair, a former Research Council colleague of Clark's, to write a report on the oil sands. Blair undertook a detailed examination of all the technical tasks involved in producing synthetic crude and came up with a cost estimate (Blair, 1950, p. 75). He estimated the cost of light oil from a 20,000 b/d oil sands project at \$3.10/b; Blair also estimated that the oil would sell for at least \$3.50/b (delivered to Lake Superior) to yield a return on capital of 5.5%/year. The \$3.50 value was considerably higher than the price of conventional Alberta light (Redwater) crude, reflecting the very light, high quality of the upgraded bitumen. In 1950 Blair noted that Alberta Redwater crude delivered to the Lakehead sold for \$3.00/b, which is just under his estimated \$3.10/b cost. Since his cost estimates do not appear to include a cost of capital nor any taxes

or royalties, and given the constant technical problems the pilot plants had consistently experienced, it is hardly surprising that no commercial ventures followed immediately on the Abasand and Bitumount closures. Falling Alberta oil prices after 1949 offered further discouragement, as did the rapid acceleration in both production and excess production capacity of conventional Alberta oil. Some observers (e.g., Pratt, 1976) suggest that the major oil companies acted to tie up leases in the oil sands and deliberately refrained from production in order to maintain output from their conventional oil reserves in Alberta and elsewhere. Commercial production of oil sands oil did not commence until 1967.

The question of whether synthetic crude should obtain a value appreciably higher than Alberta light conventional oil has been controversial. The upgrading process is, in very simplified terms, a coking and distillation procedure. Bitumen, as a very heavy hydrocarbon, has a relatively high proportion of carbon relative to hydrogen. In upgrading, some of the carbon is removed as coke (a by-product, along with sulphur) and the remaining hydrocarbons are separated by distillation. For example, Fitzgerald (1978, p. 3) notes that four main products result from the Suncor plant: gases (used internally by the plant), naphtha (which is readily processed into motor gasoline), kerosene and light fuel oil (gas-oil). These light products (other than the gases) typically have prices higher than crude oil. However, to obtain such prices it would be necessary to ensure that the products meet consumer specifications and that they are transported to market in a pure form, which is not inexpensive given the distance from Fort McMurray to major petroleum product markets. In fact, the practice for existing oil sands mining plants (e.g., Suncor and Syncrude) has usually been to blend the three liquid products together and ship the mix, which is then valued as a light sweet crude.

Early government policy with respect to the oil sands was much more active than that with respect to conventional oil, where exploration, development, and production decisions were left to the private sector, subject of course to a regulatory framework (e.g., mineral rights and taxation/royalty policies). However, both the federal and provincial governments saw the oil sands deposits as unique in at least two important respects. The first was geological, their non-conventionality, their apparent size, and unusual nature. In part this piqued the curiosity of government scientists such as Bell, McConnell, and Ells. The second was an engineering problem, how to treat the bitumen in

such a way as to produce valuable products, and this too attracted the attention of university and government scientists such as Clark. There is an economic argument for a government role in generating basic engineering and geologic knowledge. Since the information, once gathered, has very low marginal costs of transmission, it should be provided to prospective buyers at a very low price. However, if this were the case, private companies would have very little incentive to invest in the production of such knowledge. If private companies do undertake such research but charge high prices for their information, then society at large may not benefit as much as would be desired; high prices can be a particular problem since the firm producing the new, valuable information may be in a monopoly position. Of course, this problem of the 'public good' nature of information is a ubiquitous one in society and is handled in a variety of ways. (Information is a public good in terms of its non-exclusivity – my consumption of a bit of knowledge does not prevent you from also consuming it, quite unlike my consumption of Skor bars.) If the knowledge is of a narrow and specific nature, it is most frequently left in the hands of the private sector with the innovator offered patent protection to encourage investment in generating new knowledge. However, for more 'basic' research, which may have no immediate apparent commercial use, or for which the possible uses are so broad as to be hard to define, it is common for governments to play an active role in generating or funding the production of knowledge. Of course, there is no clear demarcation between these two classes.

The federal government was particularly active in oil sands research prior to 1920 and with the Abasand plant during World War II. The provincial government was heavily involved in the 1920s with Clark's hot water process and then in the Bitumount plant from 1945 to 1949. By 1950 the Alberta government had decided that further oil sands development would be left to the private sector, using the 1951 Athabasca Oil Sands Conference as a venue for conveying to private entrepreneurs the information it had gathered. (The government continued to offer some support for basic oil sands research through its universities and bodies such as the Alberta Research Council. In 1974 it created AOSTRA, the Alberta Oil Sands Technology and Research Authority, which undertook joint research with industry on oil sands, heavy oil, and EOR technologies. AOSTRA was later incorporated into the Alberta Energy Research Institute, which in 2010 became part of Alberta Innovates.)

Another significant policy responsibility of governments was in managing the leasing of mineral

rights on oil sands lands, which are largely Crown owned. As with conventional oil and gas, such lands were under the jurisdiction of the federal government until 1930, in which year most were transferred to the province. (Ottawa continued to hold control of some mineral rights in Alberta, for example on Indian reservations and in National Parks; in the oil sands area, small acreages were still federally held, including the plot on which the Abasand plant was built.) However, there were relatively few bituminous sand leases issued. By March 31, 1946, the province had only four outstanding leases covering 3,952 acres, and by March 1949 there was only one outstanding. (Data in this chapter on mineral rights and oil sands royalties and taxation come largely from the *Annual Reports* of the provincial government departments responsible, i.e., Mines and Minerals, Energy and Natural Resources or Energy, depending on the year.)

3. Resources, Reserves, Production and Costs

In this section, we discuss oil sands projects from a 'private' point of view, largely that of the oil producer. In the next section, we review government policies.

A. Resources and Reserves

The word 'reserves' is often used rather loosely, as has been the case in oil sands analysis. (Chapter Five included discussion of this terminology). The ERCB *Reserves Reports* (ST-18 and ST-98) set out criteria used in determining estimates of producible volumes. Dunbar et al. (2004, chaps. 2 and 3) provide a good review of the resource characteristics of Alberta heavy oil deposits and the production technologies currently under consideration. See also NEB (2000); Engelhardt and Todirescu (2005); and the ERCB *Reserves Report* ST-98. Some have used the word 'reserves' to mean 'resources,' that is, the amount of bitumen or synthetic crude in place. (The produced natural resource is bitumen, which may then be upgraded to light synthetic crude, or 'syncrude.' The first two commercial oil sands mining plants, for instance, produce a little over 0.8 of a barrel of syncrude per barrel of bitumen.) More careful analysts restrict the use of the word 'reserves' to an estimate of recoverable volumes, but this is often an amount assumed to be eventually recoverable under hypothetical (and often undefined) technical and economic conditions. We

prefer to label such estimates 'ultimate potential.' Reserves (initial or remaining) are volumes known with a reasonable degree of certainty to be producible under current technologies and anticipated economic conditions. Until recently, this meant that bitumen volumes recognized as oil reserves were restricted to projects currently in production. Almost all such reserves come from large commercial projects, though small amounts may be credited to experimental pilot projects. However, since the early 2000s, Alberta and Canadian statistics have accepted large volumes of oil sands resources not currently in production as qualifying as reserves, and in 2003 the U.S. Energy Administration Information (EIA) accepted these estimates. Thus, for example, BP estimated end of 2004 Canadian crude oil reserves as about 16 billion barrels, in contrast to the EIA's 174 billion; by 2010, BP had raised its estimate of Canadian oil reserves to 33.2 billion barrels by including 27.1 billion barrels of oil sands 'under active development' and, in 2011, it reported 175.2 billion barrels. However, even those sources that now place Canada a not-so-distant second to Saudi Arabia in oil reserves acknowledge that the quality of the two countries' reserves differ by many orders of magnitude, with the Saudi production costs a fraction of those for Alberta heavy oil.

It is also important to realize that Alberta's oil sands and heavy oil deposits are not homogeneous. The natural product is a mix of hydrocarbons (bitumen), water, sand, and other earth materials like clay. Amongst the important ways in which deposits differ are: specific gravity (some crudes are heavier than others), bitumen concentration (the proportion by weight or volume that is bitumen), and depth (where shallow deposits, usually up to 75 m deep are regarded as amenable to mining operations). The concentration of bitumen, by weight, may range from 1 to 18 per cent. The physical chemistry of the Alberta oil sands is such that bitumen encases sand particles with a film of water between the sand and the oil; this separation between sand and bitumen seems to make commercial production somewhat easier than for other non-conventional oil resources such as U.S. oil shale. Deposits of intermediate depth may be the most difficult to produce since they are too deep to be mined, but so shallow that injection fluids leak quickly to the surface.

As discussed above, it was soon recognized that Alberta's heavy oil and bitumen resource base was huge, though it was not until after the turn of the nineteenth century that the idea of large underlying lighter oil pools was abandoned. The mapping and drilling programs of the federal Geologic Service prior to 1900 had made clear that the deposits occurred

over a very large area, and examinations of specific sites in the Fort McMurray region had allowed assessment of the characteristics of shallow deposits at those locations. Allen, in his 1920 report to the Alberta Legislature, said that there were 10,000 to 15,000 square miles in the Athabasca region underlain by bitumen, and repeated an estimate by T. Davidson of Imperial Oil that they might hold 30 billion barrels (Allen, 1920). In their extensive Report on the bituminous sands for the Alberta Research Council, Clark and Blair simply noted that outcrops of oil sands in the Athabasca area covered at least 750 square miles, but that actual bitumen deposits covered a much larger area; they provided no estimate of total oil accumulations (Clark and Blair, vol. I, 1927). Sidney Blair's 1950 Report to the Alberta government noted that "outcrops and drillings proves a vast deposit" but that "the evidence is inadequate to appraise the total bitumen" (Blair, 1950, p. 13). The federal government undertook a drilling program of 291 wells on federal leases during World War II, and a consortium of 11 companies completed 91 wells on provincially issued leases from 1952 to 1954, clearly demonstrating the richness of the sands on those leases.

Estimating petroleum reserves was one of the tasks undertaken by the OGCB (later ERCB and EUB), and one can follow the evolution of its estimates through various board publications, including its annual *Reserves Report* (Reports ST-18 and later ST-98). By 1962 the board was basing its estimates on 600 wells and a further 1,200 observational drillings in the bituminous sands areas and, excluding Cold Lake, estimated in-place volumes at 710.8 billion barrels (625.9 billion in the Athabasca deposit) and potentially recoverable volumes at 300.9 billion barrels (266.9 Athabasca). In 1967 the board estimated Cold Lake in place bitumen 'reserves' at 75 billion barrels. By 1981 the ERCB estimated in place bitumen in Alberta at 1,163 billion barrels (including 862 in the Athabasca and 187 in the Cold Lake deposits). However, the estimated ultimate potential had been cut to about 150 billion barrels. Initial established syncrude reserves of 24.5 billion barrels were associated with deposits similar to those underlying the two producing oil sands mining projects.

In 2003, the board began to update resource and reserve estimates for 15 separate oil sands deposits. By the time of the 2013 *Reserves Report* (ST-98), 11 deposits, including the largest, had been reviewed. As of the end of 2012, the ERCB puts in-place bitumen at 1,844 billion barrels (293.1 billion cubic metres), with over 1,500 billion barrels in the Athabasca-Wabasca deposits, over 180 billion barrels in the Cold Lake

deposits, and 135 billion barrels in the Peace River deposits. Initial established reserves of bitumen are estimated at 176.8 billion barrels (28.1 billion cubic metres), of which 39 billion barrels is mineable and 138 billion barrels recoverable by *in situ* means. However, only 33.7 billion barrels of this was under active development in 2011, 82 per cent of it in mining projects, including several projects that had not begun yet, but were, in the board's judgment, likely to proceed. The mining projects exhibit an expected recovery factor (recovered syncrude as a proportion of bitumen in-place) of 29.6 per cent, while the *in situ* projects average 10.4 per cent, usually including 5 per cent credited to primary recovery techniques.

These numbers might be compared to the ERCB's estimate for year-end 2012 of Alberta's initial reserves of conventional crude of 18.0 billion barrels (2,863.2 million cubic metres) and remaining conventional crude oil reserves of 1.5 billion barrels (245.9 million cubic metres). The current and potential significance of the oil sands and heavy oil deposits is evident.

B. Production

In the 1930s and 1940s, various small pilot projects produced small amounts of bitumen and syncrude, but in a very sporadic manner as projects began and folded, going through numerous financial and technical problems. With the closing of the Bitumount plant in 1949, production of non-conventional oil ceased. Interest in the oil sands picked up again in the mid-1950s, and once again small pilot projects began to operate, including a mining venture run by Cities Service Athabasca and *in situ* experiments by Shell and Pan Canadian. In 1960, Great Canadian Oil Sands Ltd. (GCOS) applied to the OGCB to build a 31,500 b/d mining plant; permission was given in 1962 and the plant (now known as Suncor) began production in 1967. (George, 2012, provides a recent history of Suncor and the oil sands by one of Suncor's CEOs.) There were a number of other proposed mining projects in the 1970s, but by 2000 only one other plant had been built. In 1967, Syncrude (owned, at the time, 30% each by Imperial Oil, Atlantic Richfield Canada, and Canada-Cities Service and 10% by Gulf Canada) applied to the OGCB for an 80,000 b/d mining plant; in 1972, permission was given, and, in 1977, production began. Both Suncor and Syncrude amended their applications to a larger size. By 2013, both Syncrude and Suncor had expanded considerably, Syncrude to a capacity of 350,000 b/d and Suncor to over 300,000 b/d. Both companies experienced start-up difficulties

in the early years of operation and have had occasional shut-down periods for maintenance or due to accidents. Reliability since about 1990 has been better than earlier, although unexpected closures still occur. A third mining venture, Shell's Albian Sands began production in late 2002. The Albian-mined bitumen is shipped to a Shell Canada upgrading plant near Edmonton, rather than being upgraded on site. In September 2008, the Horizon project, owned by Consolidated Natural Resources Limited, commenced production. As of the end of 2012, these were the only mining operations in production, although the ERCB regards three other projects as under active development, including Fort Hills (owned by Suncor, Teck, and UTS Energy), Jackpine (Shell) and Kearl (Imperial and ExxonMobil). The Kearl project was slated to begin production in spring 2013, at the time of the final editing of this volume, with initial output of 110,000 b/d and an eventual capacity of 345,00 b/d. A number of other mining projects have been proposed, including planned expansions by existing operators.

Experimental *in situ* projects have continued to produce small volumes of oil, but there have been an increasing number of commercial *in situ* ventures, the largest of which is Esso Resources' Cold Lake cyclic steam project, which began in the mid-1980s (with a rated capacity of 140,000 b/d of bitumen). The EUB (in its *Alberta Crude Bitumen Production Report*) listed 9 'commercial schemes' operating in 1997, with an average daily bitumen output of 149,350 b/d (23,706 cubic m/d); 72 per cent of this came from Esso Resources' Cold Lake project. In addition, in December 1997, there was 101,400 b/d (16,099 cubic m/d) from 55 'primary recovery schemes', 5,610 b/d (891 cubic m/d) from 'conventional bitumen recovery not associated with an approved oil sands project', and 1,600 b/d (255 cubic m/d) from experimental schemes. The relative importance of the smaller primary recovery schemes increased during the 1990s. For instance, in December of 1993, the ERCB had reported only 13 such ventures with a total output of 5,580 b/d (887 cubic m/d). The impetus in oil sands development had shifted from the mining and *in situ* megaprojects to smaller ones, many relying on primary recovery. Many of these small projects draw on new horizontal drilling techniques and may have been encouraged by Alberta royalty regulations, which offered some relief to horizontal drilling projects (and to new EOR schemes, in some cases).

The Alberta Department of Energy reported that, by August 2009, the number of *in situ* projects in operation had risen to 87. The ERCB's 2013 *Reserves Report* (ST-98) noted that the number of producing

Table 7.1: Alberta Oil Sands Production, 1967-2012 (10³ m³ per year)

Year	Suncor	Syncrude	Total Synthetic Crude	Bitumen	Year	Suncor	Syncrude	Total Synthetic Crude	Bitumen
1967	72	0	72	42	1996	3,895	11,752	16,318	9,505
1968	835	0	835	64	1997	3,808	12,152	15,960	13,806
1969	1,601	0	1,610	69	1998	4,062	12,322	16,384	16,364
1970	1,904	0	1,904	38	1999	3,712	13,059	16,771	14,171
1971	2,451	0	2,451	15	2000	4,416	11,946	16,362	16,781
1972	2,963	0	2,963	71	2001	4,537	13,142	17,679	17,954
1973	2,906	0	2,906	71	2002	8,050	13,537	21,587	17,560
1974	2,654	0	2,654	73	2003	12,563	12,296	29,522	20,248
1975	2,506	0	2,474	199	2004	12,807	14,085	34,841	22,455
1976	2,810	0	2,779	440	2005	9,936	12,412	31,709	25,553
1977	2,641	0	2,611	486	2006	15,080	14,964	38,093	27,161
1978	2,629	624	3,239	453	2007	13,665	17,689	39,860	29,230
1979	2,425	2,827	5,329	581	2008	13,230	16,820	38,008	33,047
1980	2,760	4,691	7,410	556	2009	16,863*	16,248	44,406	33,047
1981	1,548	4,732	6,446	753	2010	14,999*	17,316	45,918	39,453
1982	1,011	4,989	6,958	1,281	2011	17,690*	16,722	50,042	44,209
1983	2,320	6,319	9,258	1,455	2012	18,792*	16,617	51,105	52,086
1984	2,822	4,961	7,738	1,943					
1985	2,175	7,394	9,746	3,030					
1986	3,271	7,487	10,728	5,410					
1987	2,503	7,918	10,472	6,750					
1988	2,972	8,719	11,643	7,540					
1989	3,343	8,631	11,901	7,482					
1990	3,044	9,086	12,091	7,856					
1991	3,552	9,675	13,121	7,113					
1992	3,369	10,445	13,778	7,362					
1993	3,326	10,736	14,123	7,685					
1994	3,579	11,173	15,191	7,810					
1995	3,967	11,885	16,328	8,630					

Note: * Excludes the Suncor share of Syncrude output following the August 1, 2009 merger of Suncor and Petro-Canada.

Sources: Mining project output from ERCB *Alberta Oil Sands Annual Statistics* (series 43, various years) for 1975-96; mining output from *Alberta Oil Plant Statistics* (ST-39) for 1997-2004, 2010. Other data from ERCB *Alberta Oil and Gas Annual Statistics* (ST-17, various years), and ERCB, *Alberta Energy Resource Industry Monthly Statistics* (ST-3, various years). For years 1967-69 data in barrels was converted to cubic metres by assuming 6.3 b per cubic metre. For 1967-74 it was assumed that all synthetic crude came from the Suncor plant. The 2003 and 2005-12 data for Suncor and Syncrude come from the companies' web sites.

wells had increased from 2,300 in 1991 to 11,500 in 2012 (p. 3-13). In 2012, 25 per cent of bitumen production was credited to 'primary' recovery techniques (which include 'water and polymer injection'); cyclical steam stimulation (used by Esso in its 1980s Cold Lake development) contributed 26 per cent, while the steam-assisted gravity drainage (SAGD) techniques, which became popular in the early 2000s, generated 49 per cent (p. 3-14). According to the ERCB (2009 Reserves Report, p. 2-23), the average SAGD well produces about ten times as much bitumen as wells using either of the other techniques.

Table 6.1 in the previous chapter included synthetic crude production in Alberta, showing it rising from less than 1 per cent of the total in 1967, when the Suncor plant opened, to 3.7 per cent in 1977, to 13.4 per cent in 1987, 17 per cent in 1997, and 36 per

cent in 2012. In 2012, almost all the mined bitumen output, and 7 per cent of *in situ* produced bitumen, was upgraded to synthetic crude oil at the five Alberta upgrading facilities. (The mining projects, Suncor, Syncrude, Shell, and Consolidated Natural Resources, have all built their own upgrading facilities; in 2009, Nexen opened an upgrader at Long Lake, just outside Fort McMurray.) Table 7.1 shows yearly synthetic crude and bitumen output since the Suncor plant began operation in 1967. The lengthy start-up periods, and unpredictability of shut-down times, are evident for the two mining projects (especially Suncor). Bitumen output was about one quarter the size of synthetic crude output in 1984 but had risen to almost 60 per cent by 1996, and 108 per cent by 2012, indicating the growing importance of *in situ* heavy oil projects without associated upgraders.

Prospects for future oil sands production are good. Of course, such forecasts are subject to a wide range of uncertainty, but they illustrate the prevailing optimistic expectations regarding oil sands production. Chapter Six, commented briefly on the necessity for market expansion as oil sands output rises. In 2013, the ERCB (*Reserves Report*, ST-98) projected mined crude bitumen output of 1,602,000 b/d by the year 2022 (up from 930,000 b/d in 2012). Since 2006, the board had reduced its medium-term mined bitumen output forecasts somewhat. On the other hand, in recent years, the board has increased its estimates of future *in situ* bitumen production; the 2013 Reserves Report saw output rising from 992,000 b/d in 2012 to 2,207,000 b/d in 2022. As noted, mined bitumen is currently upgraded. The precise nature of the upgrading varies somewhat (pp. 2–24 in the 2010 Reserves Report):

Suncor produces light sweet and medium sour crudes plus diesel, while Syncrude, CNRL Horizon, and Nexen Long Lake produce light sweet synthetic crude, and the Shell upgrader produces intermediate refinery feedstock for the Shell Scotford Refinery, as well as sweet and heavy SCO.

In early 2013 it was announced by Suncor and Total that their projected Voyager upgrader had been cancelled. Even before this announcement, the ERCB had expected the proportion of bitumen sold, relative to syncrude, to rise.

The sharp rise in world oil prices after 2004 was undoubtedly a factor encouraging expansion of oil sands output. At the same time, a number of newspaper reports indicated that companies were also revising their expected costs in an upward direction. Such cost inflation had been seen in the earlier construction boom, with Suncor and Syncrude, and seems to reflect a combination of design modifications, errors in cost estimation and rising input costs (spurred in part by the increased industry activity due to higher oil prices). In the following section, we examine the costs of oil sands production.

C. Costs

In our discussion of costs, we will focus mainly on costs for the mining projects, for which individual project costs are more readily available and may exhibit somewhat greater consistency across projects

than do costs for the greater number, and generally smaller scale, of *in situ* ventures.

As discussed above, the 1960s saw the beginning of large-scale private production of bitumen deposits in Alberta. Profit expectations have not always been realized as the investor hoped, in part because project costs have often escalated and in part because it has been harder to attain and maintain output levels than was expected. This is especially apparent with oil sands mining projects. The unexpected rapid increases in world oil prices after 1972 were a great help to high cost oil projects and played a role in the increased interest in *in situ* recovery starting in the late 1970s.

Per barrel cost estimates for oil sands oil are difficult to derive, in part because much of the actual cost information is confidential to the companies concerned. However, some information has been provided in company annual reports and applications to governments and in public statements from company officials. It is useful to divide syncrude costs into at least three components – capital costs, operating costs, and ‘government take’ (taxes and royalties). The last of these will be discussed below and has frequently been subject to negotiation between companies and governments. The operating cost can be calculated on an annual basis as operating expenditures divided by annual output. It is often considered to include a ‘fixed’ and a variable component. The fixed component consists of expenditures that must be undertaken as soon as the decision is made to run the plant this year instead of shutting it down, whereas the variable operating expenses are those extra costs incurred each time an extra barrel is produced. The unit operating cost will be particularly high in those years in which there are technical operating difficulties; this is because the fixed operating costs must be spread over a smaller annual output and because operating expenditures on maintenance and repair will likely be higher. Economists usually calculate the unit capital cost as a ‘supply cost’ that spreads the total capital cost over the lifetime output of the plant and which includes a normal profit allowance as a cost. (Formally the supply cost is the present value of capital expenditures divided by the present value of output, where the present values are calculated on the basis of the ‘marginal opportunity cost of investment’ (the normal profit rate of return). The supply cost is, therefore, a unit charge on output that will generate a present value total just equal to the present value of the capital costs.) An unexpected breakdown that shifts output into the future has the effect of raising the capital cost

of production since the present value of output will be reduced. Expressed in other terms, per unit capital cost estimates are dependent, not only on the accuracy of the capital cost numbers, but also on the accuracy of the output estimates for the project.

As discussed above, in 1950 Sidney Blair had estimated that a 20,000 b/d mining, separation, and upgrading project would be able to produce synthetic crude delivered to Edmonton for \$2.08/b excluding a normal profit allowance. Allowing for general inflation (the GDP price deflator) and assuming a 1950 cost with normal profit of \$2.20, this would imply a cost in 1965 of \$3.18/b. The actual price of Redwater crude at Edmonton in 1965 was \$2.62/b. This simple calculation would suggest that oil sands oil was not economic in the 1950s or early 1960s. However, two commercial ventures were initiated in the 1960s, Suncor and Syncrude. Can we say anything about their costs?

When Suncor was announced, it was expected to have a capital cost of \$110 million and a capacity of 31,500 b/d. A conservative estimate of the implied per unit capital cost can be calculated by asking what the supply cost would be for an infinite life project, costing \$110 million this year and commencing production this year at 11,500,000 b/year. The cost depends on the normal profit rate chosen. At a 10 per cent rate, the implied capital cost is \$0.96/b. (This combines a variety of errors. Since the \$110 million is spread over time, its present value will be reduced slightly lowering the capital cost. However, the supply cost would be higher if it took account of the fact that present value output is overstated by this calculation. It would be lower than this cost since output too is delayed, since the project will likely have a 25- or 30-year life rather than an infinite one and since the project will not run at capacity all days in the year. On balance, the \$0.96 understates costs.) The OGCB Feb.1964 *Report* on the Suncor (GCOS) application noted that cost escalation had increased the estimated capital cost to \$137 million (an implied per barrel cost of \$1.20 on our rough estimate). Estimated operating costs had also increased. Both GCOS and the board now viewed the 31,500 b/d project as uneconomic. Hence GCOS was applying for a capacity increase to 45,000 b/d of bitumen, at a capital cost of \$171 million (\$1.04/b on our basis). Camp (1976, p. 63) reports that Suncor ended up spending \$230 million for a capacity of 45,000 b/d. Calculating as before, this implies a capital supply cost of \$1.40/b. (In 1974, Suncor applied to increase capacity to 65,000 b/d, without any further capital expenditures. This would give a lower implied

per barrel capital cost.) Suncor began producing in 1967 with a rated capacity of 45,000 b/d but did not attain that output level until 1972, as a result of significant start-up difficulties.

Reports by company spokesmen in the mid-1990s suggest that operating costs for both Suncor and Syncrude had been over \$20/b in the late 1980s. However, they were falling, presumably as a result both of increased plant reliability and also due to efficiency improvements (due in part to what many call 'learning-by-doing'). Syncrude reported that operating costs in 1997 were \$13.78/b and could fall as low as \$10/b by the early years of the twenty-first century (Syncrude Canada, *Annual Report*, 1997; note that, with inflation in the economy, real operating costs per barrel are falling even more than these numbers indicate). If we assume a \$13/b operating cost for Suncor and increase the \$1.40/b capital cost for GDP price inflation from 1967 to 1997 (the investor would need payments to compensate him for rising costs over time due to inflation), we would find a total cost of production of \$19.65/b (\$13 + \$6.65), as compared to an average price for synthetic oil in 1997 of \$27.84/b. (However, from the viewpoint of 1967, if that year's price of \$2.80/b had increased by the GDP deflator, the 1967 real price would have been only \$13.30/b. That is, it was the rising real price of oil that would have allowed profitable operations by the late 1990s.) Hence, it would seem that crude oil prices since the early 1980s would have been high enough to cover the costs of a 'Suncor,' given the operating-cost savings that have been realized, but it is not at all clear that the prices anticipated in 1967 would have done so.

Syncrude's capital costs were much higher, for reasons that are not entirely clear. Among factors leading to higher costs are: (1) high inflation in the mid-1970s, (2) higher cost increases for the petroleum industry than other sectors of the economy as oil and gas activities increased with the OPEC-induced price rises beginning in the early 1970s, and (3) unexpected design adjustments as the Syncrude project came closer to completion. In its first guise, a consortium including Cities Service, Atlantic, Imperial Oil, and Royalite filed an application with the OGCB for a 100,000 b/d mining project to produce syncrude with an expected capital cost of \$356 million (\$0.98/b on our rough calculations). For reasons to be discussed below, OGCB permission was not granted. In 1964, the group re-constituted itself as Syncrude and filed in 1968 for an 80,000 b/d plant, which the OGCB authorized in 1969. In 1971, Syncrude filed an amended

application to increase capacity to 125,000 b/d, with an estimated capital cost of \$500 million, implying a cost per barrel (using our approximation) of \$1.10. By the time production began in 1977, actual capital expenditures had escalated to \$2.2 billion (\$4.82/b).

Syncrude was the last oil sands mining venture in Alberta in the twentieth century. A number of other proposals were advanced, most notably the Alsands project in the 1980s (25% owned by Esso Resources, 20% by Canadian Occidental, 20% by Gulf Canada, 15% by Petro-Canada, 10% by Pan Canadian, and 10% by the Government of Alberta). The 1991/92 *Annual Report* of the Alberta Department of Energy estimated that it would produce 80,000 b/d of syncrude at a capital cost of \$5.4 billion or \$18.50/b! In 1982, Brandie et al. (1982, p. 158) reported likely costs for a 140,000 b/d syncrude plant. Operating costs were estimated at \$16/b (excluding taxes and royalties). Capital expenditures included a low estimate of \$5.1 billion (\$9.98/b) and a high estimate of \$8.5 billion (\$16.63/b). Eglington and Uffelman (1984) estimated the cost of upgraded crude from the proposed Alsands project at \$33/b to \$48/b and suggested it would not be economic at anticipated world oil prices.

However, the expansion of Suncor and Syncrude apparently allows the realization of economies that lower unit capital costs for the incremental output. Presumably, it is possible to fit in new facilities that utilize spare capacity in existing facilities and to integrate new capital with old in ways that realize efficiencies. For example, the 'Syncrude 21' expansion was estimated to involve capital expenditures of \$6 billion from 1999 to 2010, while increasing output from 220,000 b/d to 425,000 b/d. Our rough method of cost estimation shows a capital cost of \$8.01/b for the incremental output. Combined with operating costs of about \$12/b, this expansion would be profitable at oil prices over \$20/b, apart from royalties and taxes.

Given the cost estimates of the 1980s, and the fall in world oil prices after 1985, it is hardly surprising that Syncrude was the last mining project opened before the millennium. In the early 1980s, however, many were optimistic about the possibilities for additional oil sands mining projects, partly because of the persistent, and long-standing, tendency to underestimate costs, and partly because of overestimates of oil prices. For example, Volume III of Foster Research's 1980 report for the Alberta government on *A Re-assessment of the Elements of an Economic Strategy for the Province of Alberta* offered a 'reference case scenario' in which mining plant capacity in the year 2000 was over 1,100,000 b/d, including expanded Suncor and Syncrude plants, the Alsands

plant, and three large new mining projects. On the other hand, the National Energy Board in its June 1981 *Supply-Demand Report* showed a 'base case' in which only Alsands came on stream prior to 2000. The 1992 NEB *Supply-Demand Report* showed no new oil sands mining projects by the year 2010, estimating supply costs in the \$22 to \$30 per barrel range. (Chapter Eight, Table 8.3, includes more information on the NEB's cost estimates for syncrude and bitumen.)

In the late 1990s, a number of companies began to express renewed interest in large-scale oil sands projects, although the fall in oil prices in 1998 injected a note of hesitancy into some of these announcements. (In mid-February 1999, Alberta light crude was selling at under \$17/b.) In February 1998, the EUB gave approval to a 140,000 b/d Shell project, the Albion Sands project, which would mine bitumen north of Fort McMurray, then ship it by a slurry pipeline to an upgrader just outside of Edmonton. The expected capital cost of \$3.2 billion translates into approximately \$6.26/b. As was noted above, beginning in the early 2000s, a number of companies revised their cost estimates in an upward direction, indicating sharp cost inflation, a process that continued over the next five years. By 2007, many were suggesting that integrated oil sands projects would be just economic at oil prices as high as \$50/barrel. To illustrate the higher cost estimates, the December 18, 2010, *Globe and Mail* (p. B10) reported on an agreement between Suncor and Total in which the two would cooperate on investment in two bitumen mining projects, with capital costs of \$6 billion and \$9.5 billion and output levels of 100,000 b/d and 160,000 b/d, respectively. Also proposed was a 200,000 b/d upgrader at capital cost of \$6 billion. Using our approximation of per unit capital costs, this translates into \$16.44/b for mined bitumen and \$8.22/b to upgrade it to syncrude, for a total capital cost of about \$25/b; with the recent levels of operating costs discussed below, total per barrel costs for syncrude would come close to \$45/b, and higher once royalties and income taxes are included. (Since the royalty/tax component is price dependent, it is difficult to include them in a cost estimate.) Costs may have been rising since then. The ERCB, in its 2013 *Reserves Report* (ST-98, p. 3-25), estimated that bitumen from *in situ* SAGD would require a WTI price of U.S.\$50-80/b; mined bitumen would need WTI at U.S.\$70-85/b.

As can be seen, cost estimates for mining projects have varied dramatically over the years. We suspect that costs for smaller-scale *in situ* ventures show at least as much variation, both in initial estimates and in actual outcome. The industry expenditure data

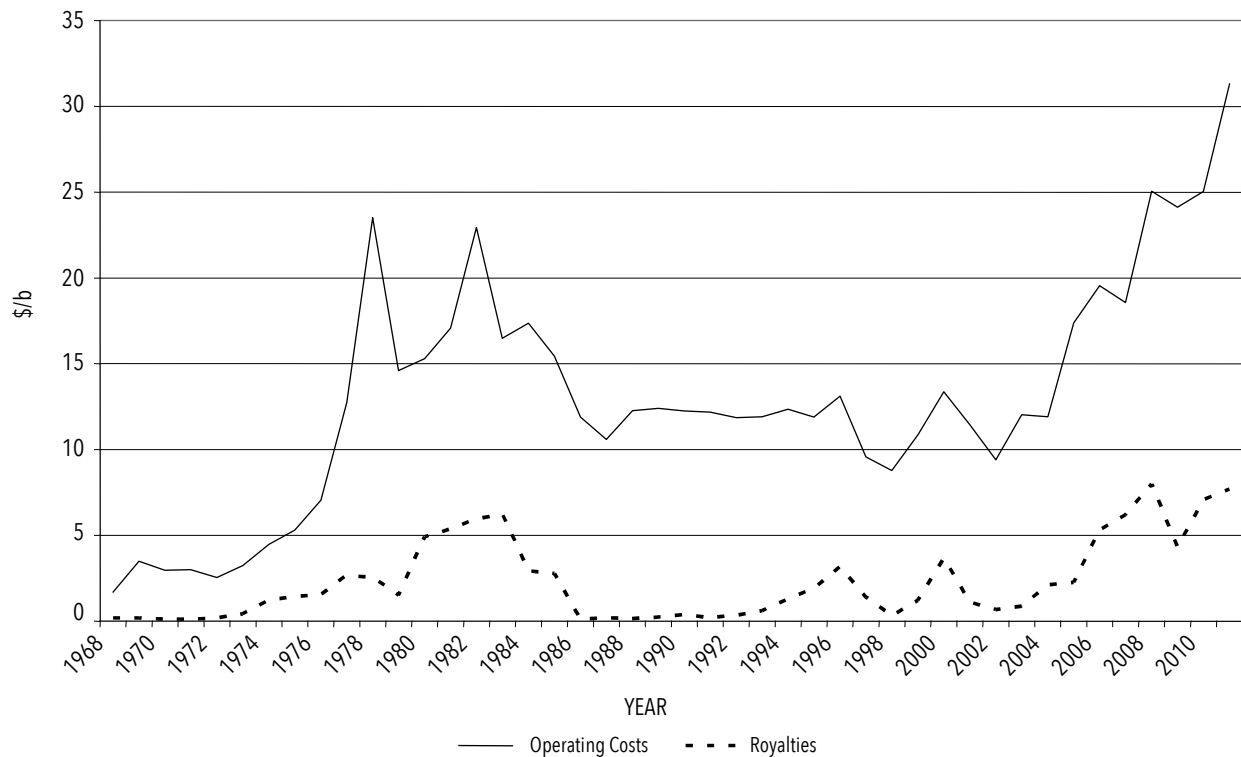


Figure 7.1 Unit Oil Sands Operating Costs and Royalties, 1968-2011

Source: CAPP, *Statistical Handbook*, 2012, Tables 3.2a and 4.16a.

reported by CAPP allow estimates over time of the unit operating costs and royalties for oil sands production (from both mining and *in situ* production). Figure 7.1 shows per barrel operating costs and royalties for the years 1968 through 2011. Operating costs started at under \$5/b in 1968, and then rose dramatically to over \$20/b in the years 1978 and 1982. They fell after that, hovering around \$12/b after the mid-1980s until rising sharply again after 2005. Syncrude's *Annual Reports* show its operating costs falling to around \$12/b in the late 1990s, but then rising above \$16/b in the early 2000s, apparently reflecting a number of operating problems and shut-down periods. (Royalties will be discussed below.)

Two components of operating cost are particularly critical, since oil sands projection techniques (particularly mining projects) are energy- and water-intensive. Hence costs are sensitive to the prices of these resources, and the policy issues and uncertainties related to each.

Thus far, natural gas has been the major energy source utilized. A CERI oil sands study (Dunbar et al., 2004, pp. 60 and 67) suggests that one barrel of bitumen from a mining project requires between 250 and

300 feet of natural gas, while an integrated mining, separation, and upgrading project uses between 400 and 750 Mcf per barrel of synthetic crude. Using the average values, this implies that a two dollar per Mcf rise in the price of natural gas would increase the annual operating costs of a 100,000 b/d bitumen mining venture by some \$20 million (about 0.55 cents per barrel); the operating cost for a synthetic crude operation of the same size would rise by over \$40 million per year (or a little under \$1.20 per barrel). The CERI study notes a rule of thumb for *in situ* bitumen ventures of 1,000 cubic feet of natural gas per barrel of bitumen, but reports a range of 510 to 1610 cubic feet, depending on the required steam to oil ratio. The rule of thumb value implies that a \$2/Mcf increase in the natural gas price would raise the bitumen cost by \$2/barrel.

Rapidly rising gas prices in the early 2000s increased operating costs for the oil sands and spurred interest in alternative energy sources. There were occasional presentations of the argument that costs might be reduced if the oil sands operators were able to self-generate the required energy, for example by using bitumen itself as fuel or by gasifying

hydrocarbons from the heavy oil. The argument is curious because the appropriate cost of an input is its 'opportunity cost.' Hence gas produced from the heavy oil resource is not costless but has an economic cost equal to the price one might sell it at; if natural gas prices rise, the value of the self-produced gas also increases. The decline in North American natural gas prices after 2009 would, of course, reduce oil sands operating costs.

A further complication relates to the controversial question of whether energy and water inputs are bearing their full social costs (Nikiforuk, 2008). If not (for example, because energy prices fail to include environmental costs such as those associated with global warming, or water is underpriced), then oil sands operating costs could increase appreciably in the future as government programs are introduced to address such inefficiencies. Of course, such input price rises encourage input substitution, which can be particularly effective for new ventures. Thus, use of alternative energy sources such as nuclear power or coal (which could produce hydrogen as an injection fluid), increased use of carbon dioxide as an injection substance, and greater water recycling could well result.

There can be no doubt that output from the oil sands is costly, frequently more costly than has been anticipated, often due to unexpected technical problems. Operating costs fell somewhat from the mid-1980s, especially in real terms, but development and operating costs are still high, and there are continuing uncertainties attendant to the cost estimates. Escalating costs may reflect ever-present design problems and may be providing some incentive to companies to phase in projects more gradually, and in smaller increments. The high costs have meant that anticipated oil prices play a major role in project planning. Moreover, costs must be considered from both a project and an industry perspective, since oil sands production is concentrated in a relatively small regional economy. Greater construction activity puts pressure on local input supplies and requires greater in-migration of workers and materials. The labour and goods markets react through price increases that attract more workers and supplies from outside the region. Price increases also raise costs to local producers, thereby discouraging some projects and freeing inputs for other projects (such as the oil sands plants). This can raise major problems for the local community; for instance, the projects squeezed out by rising input costs might be local government services and community and recreational facilities (Nikiforuk, 2008).

These broad-based regional economic effects raise the possibility that a more active government role is desirable to address inefficiencies in market reactions and/or to help smooth adjustment costs. Examples of the former might be government investment in vocational training for specific skills in short supply and provision of information in other regions of job opportunities in northern Alberta. Examples of the latter might include financial aid from Edmonton to local governments for infrastructure such as roads and schools.

More controversial, as government policy, would be a requirement that the licensing of projects take into explicit account the 'optimal timing' of construction in light of socio-economic adjustment costs. Thus far, the ERCB has noted some of these problems but has not explicitly taken them into account when issuing approvals for expansions or new facilities; this has led some to suggest that it is failing to uphold its responsibilities to assess the extent to which projects are in the public interest (Fluker, 2005; Nikiforuk, 2008). The government, as much as market forces, would then be playing an active role in selecting which project would proceed and when. Growth pressures on the local economy, including input price inflation, could be moderated. However, the government, or its regulatory representative, would have to develop criteria to distinguish amongst competing projects to see which would be approved first, and it must be recognized that some local workers, homeowners, and businesses might prefer to see their services rise in value.

4. Government Policy in the Oil Sands

A. Mineral Rights

As noted, Alberta decided in 1950 that oil sands development would be undertaken by the private sector. Bitumen leases were generally issued following application to the government, rather than through the competitive bidding process used for most conventional petroleum mineral leases. This reflected the uncertain economics of the oil sands, and the desire to encourage companies to develop and test new technologies. More recently (since 1992), bonus bids have been solicited on leases on oil sands lands, but bids per hectare have been low compared to much land more promising for conventional oil or natural gas; this is not surprising given the relatively high expected costs, and low prices, of bitumen. Bitumen

and oil sands leases have also incurred annual rentals. (For example, the 1978 regulations for oil sands leases specified an annual rental of \$2.50 to \$3.50 per hectare.)

Oil sands leases have generally applied only to the geologic formations that hold the oil sands, thereby allowing the government to issue conventional petroleum mineral rights for other formations on the same land area. In the late 1990s, some potential oil sands operators were questioning the wisdom of this policy since they felt that the production of natural gas from formations adjacent to oil sands formations might serve to reduce recovery of *in situ* bitumen. The EUB held hearings on this issue, and in 2004 the EUB issued an interim order that a significant number of natural gas wells in the oil sands area be shut in. A final decision, EUB Decision 2005-122 of November 2005, reaffirmed the shut-in of 917 natural gas wells.

By the mid-1950s companies were beginning to take up bitumen leases (starting in 1961 the leases were issued as 'oil sands leases'). These were 21-year leases, renewable for another 21-year term, and then for a third 21-year term, so long as the lease had attained a minimum output level specified in the lease. (In the mid-1990s, the government amended these regulations so that third-term renewals were possible so long as the operator and the EUB had agreed upon a plan to commence production.) From 1 lease at March 31, 1946, covering 3,834 acres, the number of outstanding leases rose to 9 (17,788 hectares) in 1956, 86 (1,254,409 ha) in 1962, 138 (1,686,815 ha) in 1970, 197 (2,023,000 ha) in 1979, and 345 (2,032,000 ha) in 1994. By March 31, 1996, a total of 526 leases covered about half of Alberta's estimated bitumen in place; 118 of these leases were in their second term, some nearing the end. By fall 2003, a total of 1,807 leases were in operation covering 32,000 square kilometres (3,200,000 ha), and from then until March 31, 2010, another 5 million hectares were issued. (Data are from the *Annual Reports* of the provincial government department handling mineral rights; outstanding lease areas were not reported for 1996 or subsequently; new leases after 2003 are from the *Annual Summary of Oil Sands Public Offerings* on the Department of Energy's website.)

B. Approvals

Before commercial syncrude production can commence, provincial government approval is required for the project. An initial report (usually following a

public hearing) by the ERCB (previously OGCB, and EUB) makes a recommendation to the Lieutenant Governor-in-Council. After the provincial government gives approval, the ERCB issues an order allowing production. Approval depends on the project being in the 'social interest,' but the critical question is what this means. The ERCB has, at various times, considered a number of factors including the technical efficiency of the project (does it use a viable technology? does it recover a sufficient proportion of the bitumen in place? is the upgrading procedure efficient?, etc.), the economic and financial viability of the project, the social and regional impact, environmental effects, the impact on government revenue, and others. (See Atkins and MacFadyen, 2008. Fluker, 2005, McCullum, 2006, and Nikiforuk, 2008, argue that the ERCB has been negligent in failing to take a broad enough view of the Alberta public interest.)

In the 1960s, however, the key issue was the impact that a large oil sands project would have on the conventional petroleum industry. Two factors made this an important matter. The first was the high cost and large scale of oil sands mining projects. It was assumed that economic viability depended on their operation at full capacity (so that the high capital costs and significant 'fixed' operating costs could be recovered as quickly as possible), and large plants were needed to realize economies of scale. The second factor was the provincial market-demand prorating scheme, which, in the early 1960s, fixed the output of the conventional Alberta oil industry at only about 50 per cent of productive capacity. (Chapter Ten looks in detail at prorating. Simply put, prorating regulations restricted oil production to estimated market demand at current prices.) If a new oil sands project were to provide oil to customers who would otherwise buy conventional Alberta crude, prorating regulations would have to cut back conventional production even further. The government faced an obvious dilemma. On the one hand, it wished to encourage development of technologies that would unlock the large bitumen resource base. On the other hand, this would mean displacing relatively low-cost conventional crude with high-cost syncrude.

The issue was recognized as early as 1955, when the *Bituminous Sands Act* was passed with a key provision ensuring that the *Oil and Gas Resources Conservation Act* of 1950 did not apply to surface mining oil sands projects or the sale of the resultant products. We shall trace the evolution of the Alberta policy with respect to oil sands development through the historical applications for approval.

GCOS 1960 Application. As discussed above, Suncor (then known as Great Canadian Oil Sands, GCOS) applied for a 31,500 b/d integrated mining project in 1960. GCOS indicated that almost all the output would be sold to two Sarnia refineries, owned by Sun and Canadian Oil Companies, largely using conventional Alberta crude. The OGCB estimated that 80 per cent of the oil displaced would come from Alberta and that ‘proratable market demand’ for conventional oil would fall by 20–30 per cent (OGCB, 1960, pp. 5, 73–74). (Proratable market demand was total market demand less the well based economic allowances and was the basis for the variable output allowable production levels under the province’s market-demand prorating regulations.) The size of this impact on the conventional industry, along with its doubts about project economics, led the OGCB to defer its decision and invite GCOS to submit further evidence by June 1962.

GCOS 1962 Application. The board cited three factors to aid in assessing the impact of oil sands production on Alberta’s conventional oil industry: (1) trends in the life index (R/P ratio); (2) capacity utilization; and (3) the market-demand prorating allocation factor (OGCB, 1962, p. 39). (The prorating factor was essentially the proportion of productive capacity a well was allowed to use under market-demand prorating.) On October 2, 1962, the OGCB approved the GCOS (Suncor) project for a 31,500 b/d capacity plant. It argued that the impact of the project on the market for conventional oil, the allocation factor, and the ratio of output to capacity was not sufficient “to have any serious detrimental effect on the conventional oil industry” (OGCB, 1962, p. 42).

Oil Sands Development Policy of 1962. The provincial government accepted the OGCB recommendation, but Premier Manning took the occasion in October 1962 to announce a provincial policy on oil sands developments. The policy statement is reprinted as Appendix B in the February 1964 *Report* of the OGCB on the GCOS application for expansion (OGCB, 1964a). The statement noted that

the Government has an obvious responsibility to regulate the timing and the extent of oil sands production to protect the interests of the public as the owners of the resource....

Obviously it would be detrimental to the public interest to permit unregulated development of an alternative source of supply to impair the economic soundness of the conventional oil industry by further reducing its already limited market.... Having regard

to these circumstances, the policy of the Government will be to so regulate oil sand production that it will supplement but not displace conventional oil. At the same time, an opportunity will be provided for the orderly development of the oil sands within the limits dictated by the Government’s responsibility to the public interest in preserving the stability of conventional oil development....

The Policy Statement suggested that there were two categories of oil sands oil. “For such production from the oil sands as may be able to reach markets clearly beyond present or foreseeable reach of Alberta’s conventional industry, there is no need to restrict the rate of production.” However, three criteria were imposed for oil sands oil that did compete with conventional oil in “present or foreseeable markets”:

- (a) in the initial stages of oil sands development, by restricting production to some 5 per cent of the total demand for Alberta oil – i.e., at a level of the order of that recently approved for Great Canadian;
- (b) as market growth enables the conventional industry to produce at a greater proportion of its productive capacity, by permitting increments in oil sands production as recommended by the Oil and Gas Conservation Board, and on a scale, and so timed, as to retain incentive for the continued growth of the conventional industry; and
- (c) by relating the scale and timing of increments of oil sands production also to the life index of proven reserves of conventional oil allowing the index to decline gradually from present levels but ensuring that it does not drop below 12 to 13 years.

1963 Applications by Cities Service et al. and Shell.

In early 1963, the OGCB held hearings on two new mining project applications, one by a group led by Cities Service Athabasca (including also Imperial Oil, Richfield Oil, and Royalite Oil) for a 100,000 b/d mining plant, and a second by Shell Canada for a 97,000 b/d project. The board interpreted the 1962 government policy as favouring the sharing of any market growth in excess of that which would maintain the conventional industry’s level of capacity utilization. So long as this capacity utilization grew by at least one percentage point per year, the ‘excess’ market growth could be shared between conventional and oil sands production. However, the board

argued (OGCB, 1963, pp. 231–32) that these projects would violate the provincial policy: synthetic crude output would exceed 5 per cent of the market; the R/P ratio wasn't likely to fall below 12–13 years within the forecast period the board was using; and even synthetic crude of 100,000 b/d commencing in 1971 (let alone what these two projects planned) would deny growth opportunities for conventional oil until 1973. Both projects were denied, but the board would allow reconsideration of the projects up to the end of 1968.

Additional GCOS Application, 1963. In September 1963, GCOS filed an application to increase the capacity of their project to 45,000 b/d, arguing that a larger capacity was economically essential. Clearly the 1962 government Policy Statement provided a rough guideline that the OGCB had to interpret in a specific manner. From an economic point of view, the two-fold market distinction was strange. Why should there be markets for high-cost oil sands oil that were not accessible to lower-cost conventional oil? If there were significant buyer power in the crude oil market, a refiner might refuse to buy oil from conventional producers in Alberta but be willing to switch from non-Alberta producers to its own oil sands oil. However, in a reasonably competitive market, conventional light Alberta oil and syncrude should be equally appealing to a prospective buyer. The OGCB seems to have accepted the competitive market view as it took “the position that the boundaries to such markets are geographical, and would not be defined according to individual company policies” (OGCB, 1964a, pp. 60–61). Hence, the three criteria (a), (b), and (c) were the critical ones. In essence, the OGCB undertook forecasts of consumption of Alberta oil and conventional reserves additions and then saw what conventional oil output would be at different hypothetical syncrude production levels; this allowed assessment of syncrude's share of demand (was it close to 5% as (a) required?), of spare capacity in the conventional industry (was the percentage of spare capacity falling as (b) required?), and of the R/P ratio (was it around 13% as (c) required?). In 1964, the board approved the GCOS amended application, even though at startup the project was expected to absorb 7.5 per cent of the market for Alberta oil. While this was seen as beyond “a narrow interpretation” of the five per cent limit, the project was seen as falling “within the intent of the policy for the initial development of the oil sands” (OGCB, 1964, p. 80).

Oil Sands Development Policy of 1968. A new oil sands policy was issued by the government in February 1968 (reprinted as Appendix A, Part 2 in OGCB, 1968) in response to several developments since 1962.

These included the 1964 modifications to the prorationing plan that had reduced incentives to develop extra conventional crude oil production capacity. In addition, the market for Alberta oil had grown more slowly than the OGCB had expected, and several new oil plays had added to conventional reserves, so that the R/P ratio in 1968 was at 31 years, much higher than the 21 years the board had forecast. A number of modifications were made to the oil sands policy:

- The oil sands provisions were extended to heavy oil deposits like Cold Lake.
- ‘Beyond reach’ markets (definitely accessible to oil sands output) were not to be interpreted in a purely geographic sense. Rather, they were to be interpreted as any markets, including ‘specialty markets,’ not served, nor expected to be served in the foreseeable future because of price, quality specifications, or other reasons.
- For ‘within reach’ markets, the capacity utilization requirements were dropped, leaving the trend in the R/P ratio as the prime criterion. In addition, if an applicant could demonstrate provision of additional growth in demand by developing a ‘new’ within reach market, then 50 per cent of the new market could be granted to the applicant. A ‘new’ market was “one not being served today; one over and above growth in existing markets; and one representing a net increase in the total market.” However, up to 1973, oil sands production in such ‘new’ markets was limited to 150,000 b/d including the 45,000 b/d from GCOS.

Syncrude (Cities Service) Application, 1968. In 1968, an amended application was made by the Cities Services group for an 80,000 b/d oil sands project. The operating company would be Syncrude Canada. Each Syncrude member proposed to market its share of the project's oil in ‘new within reach’ and ‘beyond reach’ markets. The board, in its decision, fleshed out the 1968 government policy distinction between ‘within reach’ and ‘beyond reach’ markets (OGCB, 1968, pp. 73–74):

- ‘Within reach’ markets were defined geographically by the current and prospective pipeline network available to Alberta producers; ‘beyond reach’ markets lay outside this geographic area. However, the board did allow for specialty markets in the ‘within reach’ geographic area which were not serviceable, now or in the foreseeable future, by the conventional industry; such specialty markets would be classified as ‘beyond reach.’

- The board set out its interpretation of the three criteria for ‘new within reach’ markets. This would include ‘within reach’ requirements not served by Canadian sources of supply. ‘Markets over and above normal growth’ had to allow for increased penetration by conventional oil over the medium term, so would involve accelerated market acquisition and could involve serving a market which otherwise would be unlikely to use oil from Alberta. The board felt that corporate proprietary interests could be important for such ‘new’ markets. ‘Normal growth’ included growth in feedstock requirements for refineries heavily dependent on Canadian supplies, increased penetration of refineries which were showing a trend of rising reliance on Canadian oil, and requirements of any refineries with no alternative supply sources. A ‘net increase in the total market’ would not be satisfied if absorption of Canadian supplies in a ‘new within reach’ market displaced Canadian supplies to other portions of ‘within reach’ markets, or precluded normal growth of sales in such markets.

With respect to the Syncrude application, the board found that the marketing plans aimed largely at ‘new within reach’ export markets were valid and that proposed specialty market sales of syncrude and naphtha would satisfy the ‘beyond reach’ criterion. However, the board felt that for the export sales to qualify as representing a ‘net increase in the total market,’ the U.S. restrictions on imports of Canadian oil would have to be removed. (The U.S. Oil Import Quota Program is discussed in more detail in Chapter Nine.) Since it was uncertain whether this would happen, especially given the developing oil supplies from the North Slope of Alaska, the board refused approval of the Syncrude application. It did invite a reconsideration of the application in late 1969 if the applicants could provide information to allay the board’s concerns about the impact of Alaskan supplies in reducing the markets for Canadian oil.

Syncrude’s March 1969 Appeal. In February 1969, Syncrude applied to the Alberta government, appealing the OGCB decision and requesting a new hearing. Syncrude argued that uncertainties about Alaskan oil supplies could not be resolved at this time. Syncrude alluded to new evidence that U.S. oil consumption was growing faster than earlier studies had estimated and proposed deferring the start-up date of the project three years to 1976. Syncrude argued that these factors should assuage the board’s concerns about the impact

on oil imports of a rapid build-up of Alaskan oil production. The government referred these matters to the OGCB, which invited an amended application from Syncrude.

Syncrude’s Amended Application, 1969. After a May 1969 hearing, the board issued a September Decision Report approving the amended Syncrude application. The decision was not unanimous, but the majority agreed that Syncrude’s plans now met the ‘net increase’ criterion. The dissenting board member disagreed with this conclusion but saw the proposal as “appropriate” in light of the declining trend in the R/P ratio and the expected need for oil sands oil to supplement conventional oil around the year 1980.

This dissenting opinion was prescient: following approval of the Syncrude application, neither the government nor the board expressed much concern with the question of whether oil sands production would reduce the market for conventional Canadian oil. The U.S. import quota program was eliminated in the early 1970s, and the unsettled world oil market led the Canadian and U.S. governments to favour North American oil supplies, including oil sands production.

Alberta’s Conservation and Utilization Committee.

In 1970, the Social Credit government, which had been in power since 1935, was defeated by the Progressive Conservatives under Peter Lougheed. The new government established an internal Conservation and Utilization Committee to prepare an oil sands development strategy. In a statement of its ‘primary objective,’ the Committee noted (p. 5):

Alberta is not under any pressure to develop synthetic crude oil from the bituminous tar sands for the purpose of meeting either Albertan or Canadian petroleum requirements. The pressure to develop synthetic crude from the tar sands emanates from markets external to Canada...

... [I]t becomes axiomatic that Alberta’s primary objective should be to regulate, guide and control the bituminous tar sands development in order to meet the growing socio-economic needs of Albertans as well as Canadians.

The authors noted that this left a variety of relevant concerns (provincial economic development, conservation, stimulus to Canadian businesses, government revenue, regional economic development, manpower training, environmental protection) which were not all mutually consistent but did provide the guiding

principle that “foreign energy demands should not be the only force influencing development” (p. 6). The “pro-Canadian and pro-Albertan flavour” (p. 27) of this approach made itself manifest in suggestions that the Canadian engineering and design input should be maximized, that the local Fort McMurray region should be heavily involved in the planning and implementation process, and that “[t]he oil sands offer a unique opportunity to change the historical trend of ever-increasing foreign control of non-renewable resource development in Canada” (p. 16). Research was suggested to study the feasibility of channelling private and public Canadian investment into the oil sands. Under the heading “Suggested Dimensions of Development Model” (p. 24), it was noted that, while “the actual rate would depend on Alberta’s and Canada’s capability to generate sufficient capital as well as our requirements for socio-economic development,” their “projection is based on approximately 1,000,000 barrels capacity per day by the year 2000.”

Underlying this policy document is a common, but debatable, view of the oil sands as an almost limitless constant cost resource. Once the price rises high enough that they are economic, they would become a perfect substitute for other crude oil supplies. Consumers anxious to reduce dependence on OPEC, and unstable Middle Eastern suppliers in particular, will turn en masse to the oil sands. From such a perspective, it is natural that the government should be concerned with the orderly development of the resource. A more realistic view casts some doubt on this vision. In the first place, the oil sands are not a constant quality resource; the depth of the overburden, the bitumen content, the serviceability of the deposit, the closeness of process water, and other factors vary for mineable deposits. There is probably even more variability for *in situ* sources (Ruitenbeek, 1985). However, it does seem likely that the long-run supply curve is relatively elastic once the oil price is high enough. Moreover, the resource base is so large, and the quality of deposits is consistent enough over the area necessary to support a single project, that the user cost of bitumen production is undoubtedly very low. A second problem with this view of the oil sands is that it ignores the strategic and dynamic nature of world crude oil markets. OPEC is acutely aware of the necessity of pricing oil in such a way as to maintain markets and would not tolerate a large loss of market share to a competitor such as the oil sands. In a reasonably well-functioning crude oil market, one would expect that potential investors in oil sands projects would be aware of this and regulate investment accordingly. (Such commercial caution

could be overridden by some government policies, such as, for example, a minimum price guarantee high enough to cover capital and operating costs.)

The Conservation and Utilization Committee’s report was quite properly concerned with the development of Alberta’s oil sands resources in a manner consistent with the public interest. It is likely that the oil sands and heavy oil deposits raise potential problems beyond those associated with the conventional crude oil industry. The huge resource base is regionally concentrated, mining mega-projects have relatively high manpower requirements during both construction and operation, and the separation and upgrading processes pose special environmental problems. These were, in fact, not entirely new concerns in the early 1970s, many of them having been considered by the OGCB in the 1960s under the guidelines established by Manning’s Social Credit government. The 1971 Progressive Conservative government under Peter Lougheed may be seen as offering an oil sands policy that differed in two main respects. One was the high emphasis placed on the regional economic impact of syncrude production. The other was the suggestion that direct government investment in oil sands ventures might be desirable. The latter did become an important factor, although not for the reasons that the Conservation and Utilization Committee suggested.

Syncrude’s Construction. The story of the building of the Syncrude project is complicated and overlaps in part with negotiations about government take. (Pratt, 1976, provides a detailed review of the history of Syncrude, although one that is coloured by distrust of the major oil companies.) As discussed above, in September 1969, the OGCB approved an 80,000 b/d Syncrude plant. In December 1971, it approved an expansion to 125,000 b/d capacity. The market for Alberta oil was growing rapidly, and additions to conventional reserves were slowing with the result that the board foresaw continuing declines in the Alberta conventional oil R/P ratio (or ‘Life Index,’ as the board preferred to call it). Hence the output from Syncrude could be absorbed in the market without a significant negative effect on the conventional Alberta industry.

By 1973, conflicting pressures were evident. On the one hand, escalating costs were inhibiting the private Syncrude investors. On the other hand, the 1973 international oil crisis, and the OPEC price rises in 1973 and 1974, increased the value of Alberta oil and its attractiveness as a North American supply source. The Conservation and Utilization Committee had implied that there might be such high demand to invest in the oil sands that the government would have to limit

investment and that both the provincial and federal governments might desire to invest themselves in order to maintain Canadian control over the resource. Rising cost estimates for the Syncrude project changed this picture dramatically. It became unclear whether *any* mining projects would be economic, and government involvement became a possible means of ensuring that Syncrude went ahead. By 1973, the capital cost estimate for Syncrude had escalated from \$500 million to \$2.4 billion. Planned capacity had also been raised to 125,000 b/d, but the 56 per cent increase paled beside the almost 400 per cent cost rise. Intense negotiations between the Syncrude consortium and Canadian governments ensued, covering tax/royalty, pricing and investment issues, the resultant agreements proving to be very controversial. (Pratt, 1976, chaps, 8, 9, 10, and 11, provides a very interesting review of the process, while arguing that the governments caved in to demands of the multinational oil companies. Fitzgerald, 1978, chap. 11, reports much more favourably on the governments' roles, suggesting that the project would not have proceeded without their involvement.) Alberta and Syncrude had reached an initial agreement in September 1973, which established a new royalty regime unique to Syncrude, a provincial-government-established oil company (Alberta Energy Company) providing utility and transportation infrastructure and taking a minority equity share in Syncrude and government guarantees of some stability in environmental and trade union regulations.

However, the taxation and pricing provisions required the agreement of the federal government as well. (As will be discussed in Chapter Nine, Ottawa had imposed a freeze on the price of crude oil in Canada in September 1973, holding it below the international price, whereas Syncrude and Alberta had agreed that Syncrude should obtain the international price. Also, the unusual royalty arrangement had to be recognized in the corporate income tax regulations.) Negotiations were proceeding with Ottawa when, in December 1974, Atlantic Richfield announced its withdrawal from the Syncrude consortium, necessitating a reassessment of the project.

A new agreement was reached in Winnipeg on February 3, 1975. This affirmed the international pricing and royalty provisions of the earlier agreement with Alberta, the provincial infrastructure provision and investment in utilities by the Alberta Energy Company, and the exemption of Syncrude output from prorationing restrictions. The governments would step in to replace Atlantic Richfield.

The Winnipeg agreement left equity ownership in Syncrude as follows: Imperial Oil, 31.25 per cent; Cities Service, 22 per cent; Gulf, 16.75 per cent; Ottawa (Petro-Canada), 15 per cent; Alberta, 10 per cent; and Ontario, 5 per cent. In addition, Alberta agreed to loan \$100 million each to Gulf and Cities Service (with an option to convert to equity, which was exercised 1982), and the Alberta Energy Company was given an option to buy from 5 per cent to 20 per cent of the project, an option that could be exercised before cumulative Syncrude output hit 5 million barrels and was taken up in 1979. Hence Syncrude, the last oil sands mining venture before the turn of the century, proceeded with significant direct government investment. After 1975, the ownership of Syncrude changed somewhat. As of 2013, it is as follows: Imperial Oil Resources, 25 per cent; Suncor (which acquired the Petro-Canada share when the two companies merged in August of 2009), 12 per cent; Sinopec Oil Sands Partnership (a Chinese state oil company, effective April 2010, acquired the ConocoPhillips share, which it had gained when it took over Gulf Canada in 2002), 9.03 per cent; Nexen Oil Sands Partnership (formerly Canadian Occidental), 7.23 per cent; Murphy Oil, 5 per cent; Mocal Energy (a subsidiary of Nippon Oil from Japan), 5 per cent; and Canada Oil Sands Limited, 36.74 per cent. (The latter is a royalty trust that makes payments to its investors on the basis of Syncrude operations.)

It is difficult to undertake detailed economic analysis of the Syncrude project from either the private or social points of view. Private analysis is hard, given the changing corporate ownership and the lack of detailed cost data. In part, this difficulty extends to the government sector as well since the governments were equity participants. But analysis for the governments is further complicated by uncertainty about exactly what governments were trying to achieve with their oil sands investments. Was it security of supply (higher Canadian oil production and reduced imports)? Was it improved knowledge about oil sands production techniques? Broader spreading of commercial risks? Economic diversification? Regional economic development in north eastern Alberta? Canadian participation in the development of oil sands technologies? All of these may have been obtained to some extent by the governments' investments in Syncrude, but there is no clear indication of the value that ought to be placed on such benefits.

The sale by the Alberta Government of its equity interests in Syncrude in the early 1990s provides some

basis for assessing economic returns associated with the plant. In December 1993, Alberta sold a 5 per cent share in Syncrude to Murphy Oil for \$150 million (or \$30 million for a 1% equity share). In November 1995, Alberta sold 11.74 per cent to Torch Energy for \$352.2 million (again \$30 million for 1%, a slightly lower value, allowing for inflation over the two years since 1993). If we take \$30 million as the value of expected discounted profits to an investor in Syncrude for each 1 per cent ownership share, we can derive a rough estimate of the expected profitability of a barrel of Syncrude production as seen by market participants in the mid-1990s. If we assume that output would continue for twenty more years, that Syncrude had a capacity of 220,000 b/d, and that the requisite rate of return on capital is 10 per cent, then the anticipated per barrel profit (after taxes and royalties) would be \$4.32/b. (The life of the plant is hard to determine. Syncrude is now over thirty years old but may be able to maintain its separation and upgrading equipment for many years and simply mine new parts of the sands; moreover, more efficient use of existing equipment has apparently allowed both Syncrude and Suncor to expand output somewhat beyond rated capacity with minimal new investment. Further, both Syncrude and Suncor have undertaken large expansions.) This estimated return is an implicit function of the tax/royalty regulations, expected oil prices, expected operating costs, and the past depreciation and capital cost provisions that dictate how much of past capital has been 'recovered.'

It might be tempting to compare Alberta's share of Syncrude investment to the return from its sale of ownership, but it is hard to know how to interpret the resultant figure. If Syncrude had a capital cost of \$2.4 billion, a 16.4 per cent cost share would be \$394 million spent in the mid-1970s, making a return of \$502 million after almost twenty years seem relatively small. (\$394 million invested at 5%/yr would give over \$1 billion after twenty years.) However this calculation fails to account for the payments made to the government over the years as a partner in Syncrude. These would have been relatively small in early years when operating costs were very high but became more significant as operating costs fell. (The 1997 Syncrude *Annual Report* shows operating cash flow, i.e., revenue less operating costs and royalties, rising from \$6.39/b in 1993 to \$11.34/b in 1997.) *Annual Reports* of the provincial government's Energy Department show total equity payments to the province from 1980 to 1992 of \$496.2 million, making the total return to the province over the twenty years on its equity investment almost

\$1 billion. (This calculation allows for neither the province's share of Syncrude's incremental investment costs after the first stage nor the time value of money in the time flow of these receipts.)

In retrospect, it appears that high risks probably necessitated active government involvement in Syncrude, while recognizing that some of the risks were government generated (e.g., risks of changes in regulations). An integrated oil sands mining project involves a very large capital commitment, and the high per unit capital and operating costs mean that the project is very vulnerable to falling oil prices.

The other large proposed mining venture in the 1980s was the Alsands project (or OSLO, Other Six Lease Owners project), which was reportedly expected to produce 70,000 b/d of syncrude at a capital cost of \$4.1 billion (\$16/b by our rough estimates, based on numbers in the 1988/89 *Annual Report* of the Alberta Department of Energy). Another estimate put production at 80,000 b/d of syncrude at a capital cost of \$5.4 billion (\$18.50/b). In September 1988, the private participants reached an agreement similar to that with Syncrude, including federal (10%) and provincial (10%) government equity participation. But in February 1990, Ottawa withdrew, and work officially stopped two years later. Costs were simply too high, given world oil prices in the 1990s.

On the other hand the commercial *in situ* projects of the 1980s (e.g., Esso's Cold Lake and BP's Wolf Lake, since sold to Amoco, but re-acquired when BP and Amoco merged internationally) were undertaken without government financial contributions, even though one of them (Cold Lake) was also very large and costly. The large oil sands projects proposed in the late 1990s, some proceeding after the turn of the century, came from private participants with no indication that they required government equity participation or loan guarantees, nor any hints that governments were considering this possibility. While the involvement in Syncrude might be justified on grounds of learning or higher private than social risk, the judgment now appears to be that oil sands projects must stand on their own in commercial terms. Alberta still requires that such projects be approved by the ERCB after demonstrating that they are in the public interest by making efficient use of available technologies, meeting environmental standards, and not placing undue burdens on regional economies and infrastructure. Subject to these conditions, the Province expects that commercial exploitation of the oil sands and heavy oil deposits will proceed under private development.

C. Pricing

As has been noted, Alberta syncrude is a light, low sulphur crude and hence is priced a little higher per barrel, delivered to Edmonton, than a typical reference crude such as Redwater. In general, syncrude prices have tracked the light crude oil prices shown in Chapter Six. It should be noted that there are unique characteristics of synthetic crude oil from the oil sands that prevent a typical refinery from running entirely on this oil; currently synthetic crude can provide up to about 30 per cent of the oil input for such a refinery.

As will be discussed in Chapter Nine, from 1973 until 1985, there were government price controls on Canadian crude oil. These arose after the international price rises engineered by OPEC beginning in the early 1970s and served to keep oil prices in Canada lower than international prices. A key issue for potential investors in the oil sands was how their oil was to be priced under the government price control regulations. As it happened, it was agreed that Syncrude's output would be allowed the international price, even while much conventional Alberta crude received lower domestic prices. This reflected the presumption that syncrude was high cost so would be produced only if it were allowed a high price and the realization that it would be preferable for Canada to produce syncrude rather than importing oil so long as the production cost of the syncrude was less than the cost of the imported oil. This decision did raise an issue of fairness with respect to Suncor. Starting in 1978, it too was allowed the world price. Thus from 1978 to 1985, synthetic crude was at the world price, rather than the domestic controlled price.

If the oil from the oil sands is not upgraded, the value of the oil is much less. While bitumen prices have tracked the broad trends in lighter crude oil prices, the correlation is not perfect; in other words, the light oil-bitumen price differential changes over time. Part of this reflects the changing relative values of light and heavy oil prices. From 1987 through 2001, the posted price for Lloydminster Heavy oil at Hardisty averaged \$6/barrel below the Alberta light par price; but the differential varied considerably as well, from as little as \$2/barrel to over \$20/barrel. In addition, the differential between heavy oil and bitumen also changes. Precht and Rokosh (1998) present a figure (their Figure 8) plotting Lloydminster Heavy and Cold Lake bitumen prices from 1994 to 1998 in which bitumen prices are consistently lower than the Lloydminster price by amounts varying from \$2 to \$7 per barrel. Bitumen prices are not regularly posted,

but the Alberta Energy and Utilities Board does obtain some bitumen price data from producers. Figure 7.2 shows crude oil price differentials in Alberta from 2002 to 2011, where the differential between bitumen and light oil can be seen as comprising two components: (1) the differential between light and heavy oil (as represented by the Alberta 'par' price less the price of heavy oil at Hardisty), and (2) the differential between the Hardisty price and that for bitumen. As can be seen, the light/bitumen differential over this period has varied from as little as \$9/b (in summer 2009) to \$60/b (in spring 2008). In general, the differential rose from 2002 to 2005/6, then declined, before hitting the spring 2008 peak; after this, it fell back to the levels of 2002-4. In 2011, the heavy/bitumen differential widened again; in addition, as was discussed in Chapter Six, a significant differential opened up between Alberta and International oil prices. As can be seen in Figure 7.2, until 2008 changes were more due to the fluctuating light/heavy differential than the heavy/bitumen differential.

The light oil-bitumen price differential is a prime determining factor in the level of bitumen upgrading in Alberta. So long as the expected differential is higher than the unit cost of upgrading the bitumen into a light crude oil, there is an economic incentive to build upgraders. Reflection shows that the future development of Alberta's heavy oil industry could involve one of a number of rather different paths, or some mix thereof. The result will reflect all of the following:

- the level of future world light crude oil prices and the price differentials between lighter crudes and both bitumen and the very light hydrocarbons that are used as diluents when shipping heavy crude;
- current and future techniques and costs for shipping light oil and bitumen, and the decline in price needed to sell Alberta bitumen or synthetic crude in more distant markets;
- current and future techniques and costs for refining heavy oil and the prices of heavy refined petroleum products;
- current and future techniques and costs of upgrading bitumen into light synthetic crude;
- current and future techniques and costs of refining synthetic crude oil; and
- current and future techniques and costs of shipping refined products.

Given the cost disadvantages of shipping refined petroleum products (RPPs), as compared to crude oil, it

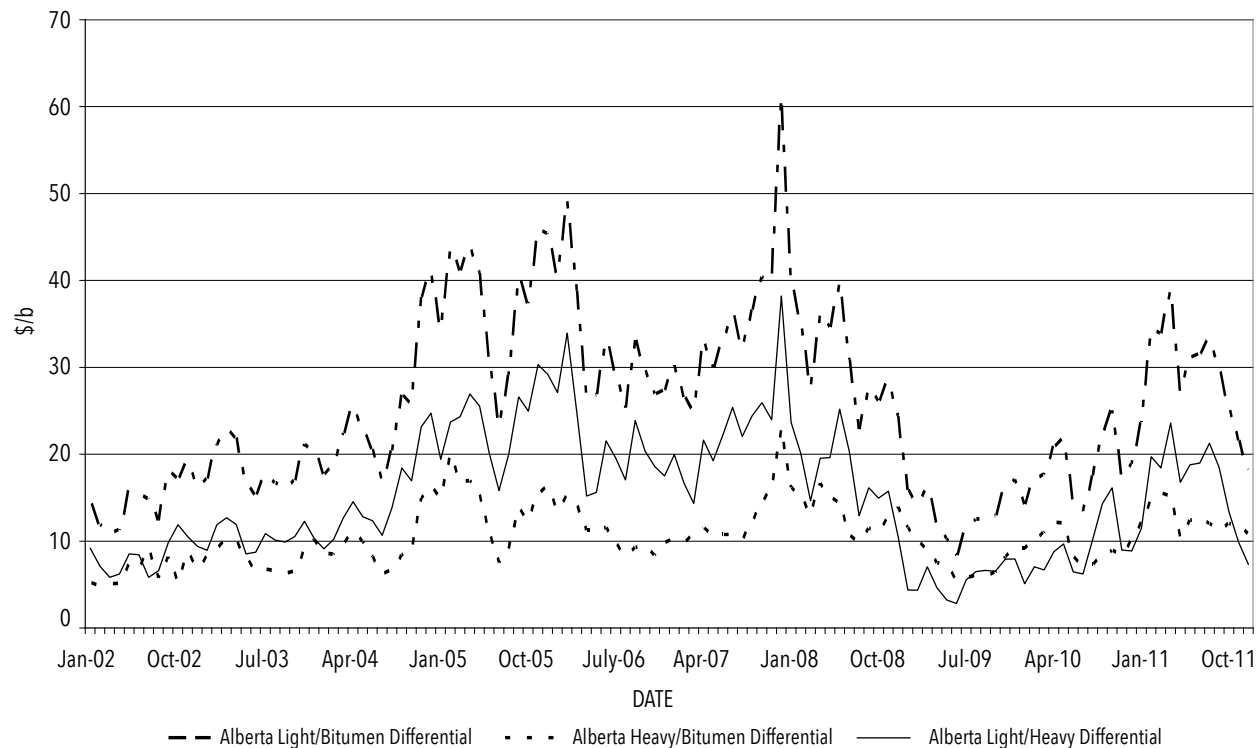


Figure 7.2 Bitumen Price Differentials Jan 2002–Dec 2011

Source: From data in CAPP Statistical Handbook, Table 5.5 and ERCB, *Alberta Energy Resource Industries Monthly Statistics*, ST-3

is unlikely that large volumes of bitumen would be upgraded and refined in Alberta for export as refined products. However, increased growth in the Alberta economy may translate into higher local demand for RPPs. Combined with the expected falling conventional oil production, this would mean a retooling of existing refineries and some expansion in capacity to handle a growing volume of upgraded synthetic crude.

A more critical question is whether it will be more attractive to upgrade the bitumen in Alberta and ship the lighter synthetic crude to export markets, or to export bitumen for refining (or upgrading and refining) elsewhere. One might suppose that the former is favoured by the relative difficulty in shipping the exceptionally heavy bitumen. However, if the bitumen is mixed (diluted) with a lighter hydrocarbons, which are slated to be exported anyway, this shipping cost disadvantage may disappear; currently pentanes plus, in a proportion of about 30 per cent, are normally used as the diluent. The diluent might even be upgraded synthetic crude (in a proportion of about 50%, according to the ERCB 2010 *Reserves Report*, ST-98, p. 2-18), which would imply a need for some

upgrading within the province. It would also require long-run planning to ensure that the purchasing refineries in the export market are constructed so as to handle the heavier oil. Extension of the Alberta oil market as far as the Texas Gulf Coast, as has been planned since 2011, would open potential markets for bitumen from refineries that have been importing heavy oils from Venezuela and Mexico. While export of bitumen might be economically feasible, Alberta interests have generally favoured the ‘value-added’ approach of upgrading bitumen in the province, with the associated expansion in economic activity and, from some points of view, economic ‘diversification.’ (We return in Chapter Thirteen to this issue of diversification.) It is obvious, however, from a shorter-term perspective, that exporting bitumen, without upgrading, would be one way to reduce the regional economic inflationary pressures of rapidly expanded oil sands production. Whether Alberta should reply on relatively unfettered markets to handle these investment options or look to a more activist government policy in scheduling the timing and type of facilities built is likely to generate lively debate.

D. Government Take

We use the term 'government take' to refer to the payments made by the oil company to the government; governments derive these payments in part through their role as the owner of mineral rights and in part through their powers of taxation. On both grounds, the government of Alberta has been concerned that a 'fair' share of the value of petroleum goes to it, as representative of the public. Chapter Eleven contains an extensive discussion of objectives of government with respect to payments it assesses on the petroleum industry and the instruments that might be used to collect revenue. In brief, the government simultaneously pursues objectives of revenue generation, risk sharing, equitable treatment of all parties, and administrative simplicity. The industry might make payments to the government in the form of bonus bids to obtain mineral production rights, land rental payments, taxes based on the value of production (usually called 'royalties' or severance taxes), corporate income taxes, and/or the government share of profits if it is a part-owner of the company. In the oil sands, companies have obtained mineral rights through competitive bonus bidding and face annual rental payments on the area under which they own the rights. However, the most controversial parts of government take have been the provisions applied to projects once they have begun to produce bitumen or upgraded synthetic crude oil. (Plourde, 2009, provides a useful review of government take in the oil sands up to 2008).

Experimental oil sands projects have typically been assessed a gross royalty of 5 per cent. When Suncor began production in 1967, it was governed by the prevailing royalty and income tax regulations on conventional oil, as discussed in Chapter Eleven. In 1978, the royalty was set at 8 per cent on production below 143,019 cubic metres/month (30,000 b/d), at 20 per cent on output above that up to 217,389 cubic m/month (45,000 b/d), at 8 per cent again on output to 258,704 cubic m/month, and at 20 per cent again above that. (The second tier at 8% applied to the Suncor expansion of the late 1970s.)

With Syncrude, the Esso Cold Lake project and the BP Wolf Lake projects, the royalty and tax regimes became subject to negotiation on a project-by-project basis with the provincial and federal governments. This recognized that oil sands projects were not 'like' conventional crude oil projects. They were very high cost and involved unusual technological risks since they used untested processes. At the same time, governments want to ensure that they derive a fair share

of the profits from the oil sands. The picture was complicated with the new taxes on petroleum introduced by Ottawa with its National Energy Program of October 1980. (These taxes were removed with the federal-provincial 'De-regulation' Agreement of 1985, so were of concern only to Suncor and Syncrude.)

The approach agreed to by Syncrude and the Alberta government was a new royalty arrangement based largely on the profitability of the project. This was attained through a 50 per cent net royalty arrangement, where Syncrude would pay 50 per cent of net operating profits (that is, after operating costs were deducted from revenues) once the project had recovered its investment costs and an agreed-upon (8%) annual return on unrecovered capital costs. To ensure that the province would receive some revenue in all periods, there was a minimum 5 per cent gross *ad valorem* royalty. In the mid-1980s the net royalty was modified to require amortization of remaining unclaimed capital expenditures (although expansion investment undertaken in the mid-1980s could be written off immediately). Alberta had a non-reversible one-time option to replace the 50 per cent net royalty with a 7.5 per cent gross royalty, but this option was never exercised. In the Winnipeg Agreement, Syncrude and the governments agreed that this net royalty would be deductible as an expense in calculating the federal/provincial income tax owing. They also agreed that companies would be allowed to 'flow through' capital expenses to the parent companies, so that they could be deducted from the parent's revenues for income tax purposes without having to wait until Syncrude itself generated sufficient revenue to allow deduction of these costs. (The sooner a company can deduct expenses in calculating taxable income, the earlier the tax savings are earned, and the more valuable they are to the company.) In addition, under the corporate income tax regulations, mining expenses could be deducted immediately, rather than expensed over time. As a result, Syncrude's royalty payments per barrel of oil were relatively small as compared to payments by most conventional oil production, and the owners gained a significant corporate tax advantage.

In situ oil sands projects were assessed royalties based on the Esso Cold Lake project, which paid a 1 per cent gross royalty initially, rising to 5 per cent over six years. After recovery of capital expenses, payment was to be the maximum of a 5 per cent gross royalty or a 30 per cent net royalty. (However, unlike bitumen mining, *in situ* investments had to be expensed over time for corporate income tax purposes.) A fairness issue arose with respect to Suncor after these special

Table 7.2: Oil Sands Royalties, 1968-2012

<i>Fiscal Year Ending</i>	<i>Royalties (\$millions)</i>	<i>Fiscal Year Ending</i>	<i>Royalties (\$millions)</i>
1968	1.0	1993	64.9
1969	2.3	1994	66.4
1970	3.1	1995	209.1
1971	2.4	1996	311.6
1972	3.0	1997	512.2
1973	3.8	1998	192.4
1974	8.2	1999	59
1975	13.9	2000	426
1976	15.4	2001	712
1977	19.1	2002	185
1978	23.8	2003	183
1979	30.6	2004	197
1980	46.2	2005	718
1981	224.9	2006	950
1982	299.7	2007	2,411
1983	362.3	2008	2,913
1984	303.8	2009	2,973
1985	185.5	2010	3,160
1986	24.8	2011	3,723
1987	11.2	2012	4,513
1988	22.6		
1989	19.0		
1990	27.7		
1991	39.0		
1992	30.6		

/continued

Note: Values from 1968 to 1972 include oil sands rentals and fees.

Source: Annual Reports of the Alberta Department of Energy and of Energy and Natural Resources.

deals were negotiated for large mining and *in situ* projects. Effective in 1987 the Suncor royalty was changed to the greater of a 2 per cent gross royalty or a 15 per cent net royalty, with these percentages increasing to 5 per cent and 30 per cent respectively in 1992.

Table 7.2 shows Provincial receipts from syncrude and bitumen royalties for fiscal years ending March 31 from 1968 to 2012. The jump in the early 1980s reflects a combination of the start of Syncrude production and the very high international oil prices that determined the value of Syncrude's output. The sharp decline in royalties after 1985, as international crude oil prices plummeted, illustrates the sensitivity of a net royalty to oil prices. The move to 'profitability' of the mining ventures is the main factor leading to the rapid increase in payments after 1990, with the large decline in 1998 and 1999 once again demonstrating the sensitivity to oil price declines. Payments rose markedly after 2004, as output and oil prices both increased. In the 2006/7 fiscal year, oil sands royalties for the first

time surpassed conventional oil royalties; in 2009/10, they also exceeded natural gas royalties, due largely to falling natural gas prices.

In the 1990s, potential investors and the government both found the absence of an agreed-upon royalty for oil sands projects to be less than satisfactory, since it meant that project-by-project negotiations were needed, and companies could not assess the commercial viability of their project until the negotiations were concluded. In 1995, a 'Task Force,' including both government and corporate representatives, recommended that Alberta implement a 'generic' oil sands royalty regime that would apply to all new projects (National Task Force on the Oil Sands, 1995). The task force had been set up in 1993 under the chairmanship of Dr. Erdal Yildirim to examine the lack of interest at the time in expanded oil sands production. Alberta accepted the recommendations with respect to royalties, announcing on November 30, 1995, that oil sands projects would be subject to a minimum 1

per cent gross royalty and would be assessed a 25 per cent net royalty after capital costs, including an interest allowance, had been recovered; the interest charges would be determined by the long-term Government of Canada bond rate. Oil sands investments, whether for mining or *in situ* projects, could be written off immediately against income from the project. (Alberta Energy, 2006, Plourde, 2009, and Mitchell et al., 1998 summarize the new regulations, which became effective in September 1997.) For the net revenue royalty, most 'project' costs would be deducted, including any gross royalties paid, but not bonus bids or pre-investment start-up costs. This royalty is quite different from that assessed on conventional oil (a sliding-scale gross royalty). It recognizes that oil from the oil sands is now, and is likely to continue to be, high cost, and hence very dependent on the level of oil prices and the size of the tax burden. By assessing payments to the government (both royalties and corporate income taxes) largely on the basis of the project's profits, the commercial risk is shared by the company and the government, and any disincentive to invest due to the necessity to make payments to the government is minimized.

Recognition of the significance of this new royalty regime, and the efforts of the National Task Force, was made manifest in a ceremony at Fort McMurray in June 1996; the governments of Canada and Alberta and executives of almost twenty oil companies signed a document expressing their commitment to expanded oil sands development. It is important to note that the generic royalty could be applied to either the bitumen or the synthetic oil produced; since bitumen prices were lower than synthetic crude prices, companies had a clear incentive to reduce the size of the royalty by electing to pay on the basis of bitumen prices, as has been the case. (The issue is more complicated than this suggests. If bitumen were chosen as the product to which the royalty applies, upgrading costs could not be deducted as a cost for royalty purposes. Therefore, until payout, companies would likely prefer to base the royalty on the upgraded product. After that, as long as upgrading is expected to be profitable, companies would prefer not to pay a royalty on upgrading as well as bitumen operations. Suncor and Syncrude, covered by royalty arrangements agreed to before the generic regime, had the option to switch from a royalty on syncrude to a royalty on bitumen anytime prior to 2009. Both companies exercised this option, Syncrude in late 2008.) (Alberta Energy, 2003, 2007a, 2007b reviews Alberta petroleum royalty

provisions. The department now maintains a webpage with ready links to relevant royalty documents: www.energy.alberta.ca/About_Us/Royalty.asp.)

The generic royalty regime removed some of the political uncertainty faced by prospective oil sands producers, as well as the additional project costs involved in negotiating specific tax/royalty regulations for each project. As was noted above, reliance on a net royalty provided an explicit sharing of economic risk. For instance, if prices were insufficient to cover costs (including an allowance for return on capital invested), payments to the government would be relatively small (mainly the 1% gross royalty, much less than the average rate of nearly 20% assessed on conventional oil and gas production); however, once prices were high enough to generate profits, the government and company would split them on a 25/75 basis. That is, in order to encourage investment in the oil sands, the province was willing to allow the companies a significant proportion of price-related upside profit potential. (Plourde's simulations [Plourde, 2009] suggest that the companies' share of anticipated economic rent did increase on mining projects as the oil price rose up to about \$70/b. It is not clear whether *in situ* projects showed similar price sensitivity.) From a public policy perspective, this might be justified in several ways, for example, to offset high corporate risks (e.g., risks with still developing technologies, risks of high cost inflation or risks of world oil prices collapsing). If the government foresaw little chance of very high oil prices, the chance of foregoing large amounts of royalty revenue would be seen as low.

In comparison to the conventional royalty formula, the generic oil sands royalty involved two main elements of increased administrative complexity. First, it involves accounting for the specific costs of the project. Since companies would pay lower royalties if they absorb higher costs, there would be an incentive to inflate reported costs or pass on benefits to the company and its managers in the form of higher costs; hence, the government would be expected to incur incremental monitoring costs. A second complexity relates to the relative lack of 'transparency' in bitumen markets, which are less well-developed than North American markets for conventional light and heavy crude oil. The tax base for the net royalty depends on the price paid for bitumen, so companies would have some incentive to report relatively low prices, especially if the sales are made to an affiliate company (which would then receive relatively high profits on the subsequent processing and sale of the

oil products). Hence, in assuring it is receiving its fair share of profits, the government would incur additional costs of monitoring the North American bitumen market.

The generic regime was explicitly designed to encourage oil sands development. In part, this was attained by the introduction of a net royalty based on project profits, rather than a gross royalty. But it also stemmed from the relatively low rate of the net royalty. This became an issue of concern to many as international oil prices rose in the early years of the new millennium; the net royalty would capture only 25 per cent of the increased profits due to price increases, although it should be remembered that the 75 per cent accruing to the companies would be subject to the corporate income tax. It is difficult to separate the effect of higher price expectations from the impact of a royalty regime designed to encourage investment, but, as was discussed above, by the year 2013, three major new oil sands projects were already in production, both Suncor and Syncrude had undertaken expansions, and numerous other projects had been announced, a number of which had received approval from the EUB/ERCB.

Smaller heavy oil projects in the oil sands area (known as Township 53), which are capable of producing heavy crude by primary techniques, were initially subject to conventional oil royalties. These projects were particularly encouraged by some of the oil royalty relief measures introduced in Alberta beginning in the mid-1980s. Of special importance were the EOR-tertiary project and the horizontal production well royalty relief programs of the early 1990s. As part of the 1995 generic royalty regulations for the oil sands, projects that produce heavy oil in the oil sands part of the province were given the option of selecting the generic oil sands royalty instead of the conventional crude oil royalty, an option most companies have taken.

Suncor and Syncrude, who were still producing the majority of the mined oil in the first decade of the twenty-first century, were not covered by the generic royalty regulations but by the deals they had negotiated earlier, which lasted up to the year 2015.

Figure 7.2, above, included per barrel royalties for syncrude and bitumen from 1968 to 2011. These varied considerably, from a high of \$8/b to almost nil. The high per barrel values came with high crude oil prices such as during the early 1980s and after 2006, the low royalties with low prices. Since the introduction of the generic royalty scheme, based mainly on a measure of

profitability, the royalty per barrel has fluctuated considerably as world oil prices rise and fall.

Petroleum corporations are also subject to federal and provincial corporate income taxes. From 1972, the mining portion of oil sands plants were allowed rapid write-off of capital costs. As part of the 1995 revisions to the oil sands royalty regulations, the mining portion of oil sands projects and *in situ* ventures were granted an accelerated capital cost allowance that allowed immediate deduction of the costs up to the full amount of income from the sale of the oil from the project. In effect, corporate taxes could be delayed until all investment costs were recovered. This also generated some support for projects to include an upgrader since the upgraded synthetic crude has a higher value than bitumen and therefore allows earlier write-off of the capital costs of the mine. Taylor et al. (2005) argued that such measures provided an unfair advantage to oil sands investors compared to those in other Canadian industries. The March 2007 federal budget announced that the accelerated allowance would be phased out entirely by 2015, at least as far as the federal share of the corporate income tax was concerned.

In September 2007, the Alberta Royalty Review Panel released its *Report* (Alberta Royalty Review Panel, 2007). (Plourde, 2009, who was a member of the Royalty Review Panel, presents a detailed summary and some simulation results.) The panel reported that, as of the end of December 2006, a total of sixty-six projects were covered by the generic oil sands royalty regulations, of which thirty-four were past the payout stage (p. 76). The panel reported on simulations of project profitability undertaken for and by the Department of Energy, which suggested that the share of economic rent (profits) captured for the government on oil sands projects was significantly less than what other jurisdictions in the world were gathering on oil investments. Across a number of different cost and price levels, they estimated that Alberta would receive about 47 per cent of the economic rent under the present regulations, a significantly lower share than the 60 per cent or so that had been anticipated when the generic royalty was introduced in late 1995 (pp. 7 and 11). Plourde's simulations suggest that the share of expected profits accruing to government (provincial and federal) over the entire life of an oil sands project would be relatively stable under the generic royalty regime, for oil prices of \$70/b or more (\$50/b or more for an *in situ* project) (Plourde, 2009). He argues that the lower than expected share

under the generic regime reflects changes to corporate tax provisions, including reductions in the rates after 1995. (In 1995, the combined federal–Alberta corporate income tax rate was 43.62%; by 2007, it had been reduced to 30%.)

Accordingly, the panel recommended a number of changes to the oil sands royalty regulations, including an increase of the net royalty rate from 25 per cent to 33 per cent, the introduction of a new price-dependent ‘severance tax,’ and making the 1 per cent gross royalty payable in all years and an expense in calculating the net revenue tax. The new severance tax would be based on bitumen revenues less base and net royalties and rentals and would be set at 0 per cent for oil prices (WTI) at \$40/b or less and rise linearly to a rate of 9 per cent on oil prices of \$120/b or more; the severance tax would not be an allowable deduction for either net royalties or the corporate income tax. The panel also urged the government to take steps to ensure that bitumen prices are fair market values and recommended a tradable credit against oil sands royalties for companies undertaking oil sands upgrading investments (pp. 85–89). From an economic perspective, the severance tax seems likely to be more distortionary than a larger increase in the net revenue royalty but may have been appealing since a new tax could be more easily applied to Suncor and Syncrude as well as those producers covered by the generic royalty system. The panel’s report also expresses obvious concern about the efficiency of synthetic crude and markets, as evidenced by both the desire for an assessment of bitumen prices and the apparent unwillingness to allow investment in bitumen upgrading to be handled solely by market forces.

Late in 2007, the government announced its response to the recommendations of the Royalty Review Panel (Alberta Department of Energy, 2007c). The government said that new royalties on bitumen values would become effective at the start of 2009. It did not introduce the new severance tax recommended by the panel. Instead, the 1 per cent gross royalty would be revised to a price-sensitive sliding-scale fee, at 1 per cent for oil prices less than \$55/b, rising to 9 per cent when the oil price reached \$120/b; the net revenue royalty rate would continue to be 25 per cent at oil prices of \$55/b or less but would increase with higher prices to a maximum rate of 40 per cent at prices of \$120/b or more. The gross royalty would be paid up to the time costs (including a normal return) were recovered and then the higher of the base or net royalty would be paid. Negotiations would be undertaken with Suncor and Syncrude to revise their

agreements with the government prior to the expiry date of 2016. (In 2008, Suncor and Syncrude both agreed to increase royalty payments starting in 2010 until they became subject to the new regulations in the year 2016.) The government also announced that it would follow Ottawa’s plans in making oil sands capital expenditures deductible over time for the corporate income tax rather than being immediately expensible. Plourde’s simulations (Plourde, 2009) suggest that the new regulations would generate a share of profits for the provincial and federal governments (combined) in the range of 60 per cent, about what had been projected under the generic royalty regime in 1995 and about 12 to 17 percentage points higher than actually occurred. However, the share is significantly lower than that which would have resulted from the Royalty Review Panel recommendations (though there is a shift in share under the government’s announced regulations from the federal government to the Alberta government).

The government did not adopt the Royalty Review Panel’s recommendation for a royalty credit against new upgrading investments. In late June 2008, it announced a proposal for the determination of bitumen values in the absence of a clear fair market (arms-length) value (e.g., for bitumen retained by the producer for upgrading or for intercorporate transfers). Subject to a floor value based on heavy Mayan crude from Mexico, the value would be determined by the price for heavy crude at Hardisty, Alberta, with quality adjustments (Alberta Department of Energy, 2008). It also announced plans to take delivery of bitumen in place of royalty payments (a ‘bitumen in kind’ royalty).

5. Conclusion

Alberta’s non-conventional oil resources are huge, even by global standards, and dwarf the province’s conventional oil reserves. They are often seen as a part of the world’s ‘backstop’ to conventional crude oil: that is, a large-volume but high-cost perfect substitute for conventional crude. Producers have been holding out high hopes for significant oil sands production since the start of the twentieth century. Many of the main technical innovations needed to allow production of shallow deposits through strip-mining and upgrading were made in the first half of that century, and the evolution of EOR technologies for conventional oil offered knowledge for use in *in situ* production from

the deeper oil sands. However, commercial production proved elusive.

The first mining/upgrading venture, now known as Suncor, started in the 1960s. It was seen by many as a precursor to rapid development of the oil sands, but only the 1970s Syncrude mining/upgrading and Cold Lake *in situ* projects materialized. Costs of these projects exceeding initial estimates and falling world oil prices after 1985 inhibited further investment. Syncrude and Suncor began some cautious expansions in the 1980s, suggesting that there might be economies that they could capture as existing operations. In addition, the continuing development of horizontal drilling technologies encouraged a number of small-scale *in situ* projects. But it was rising oil prices around the turn of the millennium that appears to have been the main factor leading to a surge in oil sands investments at that time. By 2005, most forecasters were projecting rapid output growth from the oil sands of both bitumen and light upgraded synthetic crude; output has been expanding and, as of March 2013, several new projects are underway, have received approval, or have been announced.

The significance of the oil sands to the province can hardly be overestimated. By the year 2012, syncrude and bitumen provided over 75 per cent of Alberta's crude oil and had more than offset the decline in conventional oil production. Forecasts of rising oil output depended entirely on expanded oil sands production. However, this involves major changes since oil sands output differs in a number of important respects from conventional crude oil. Some of the changes are largely 'physical' and technical. Thus, for example, the oil resource in the oil sands is bitumen, a very heavy viscous hydrocarbon which is difficult to move and handle and which has had a limited market. Thus, the expansion of oil sands production saw the growth of a large upgrading industry to transform bitumen into light syncrude; it has also seen a rising demand for very light oil products in pipeline transmission to mix with and dilute the bitumen, and development of plans to extend the pipeline network

from Alberta to the U.S. Gulf Coast where refineries are equipped to handle very heavy oil. Mining, upgrading, and *in situ* production technologies are very energy intensive, leading some to expect that large amounts of natural gas will have to be diverted from export markets to oil sands production. Further, growing environmental concerns are raised by the large water requirements of the mining operations, the strip-mining itself, and the sulphur content of the bitumen.

There are also economic differences between the oil sands and conventional crude oil production. Conventional production has been spread broadly across Alberta, but expenditures on the oil sands have been concentrated in a small geographical area in east central Alberta, with further potential to the west in the Peace River region. The costs in the oil sands are high, and the prospective economic rents seem to be smaller, though this will obviously hinge on the price of oil. Thus, the impacts on the province seem likely to come through the economic activity directly associated with oil production and somewhat less from the 'surplus' revenues collected by the government. Finally, the operating phase of oil sands production is much more labour-intensive than the operations phase of the conventional industry, especially for mining and upgrading activities. This also implies a more direct and regionally concentrated impact from oil sands than was seen with the conventional petroleum industry in Alberta. That the government has come to recognize the problems this might raise is suggested by its appointment of a committee to investigate the impacts of increased oil sands production; the committee's final report focused on regional planning and infrastructure investment needs in the oil sands area (Oil Sands Ministerial Strategy Committee, 2006). The *Alberta Land Stewardship Act*, proclaimed on October 1, 2009, may provide a framework within which many regional planning issues can be addressed, but the hard work of financing and building new facilities remained to be addressed.

CHAPTER EIGHT

The Supply of Alberta Crude Oil

Readers' Guide: Supplying crude petroleum is a complex process. In this chapter, we review a number of attempts to build models of this process, or, as is more frequently the case, some part of the process, for the province of Alberta. Rather than a history of the Alberta petroleum industry, this chapter might be seen as a history of Alberta oil-supply modelling. Readers with a limited interest in the details of oil-supply modelling will likely find Section 3 of most interest; it summarizes the conditional forecasts of oil production made by the National Energy Board from about 1970.

1. Introduction

This chapter summarizes various studies of the supply of conventional crude oil in Alberta. Rather than building our own model of crude oil supply, we provide an overview of the broad range of published models. Also relevant are the studies of Alberta crude oil potential set out in Chapter Five, especially the 'discovery process' models.

We will first briefly review what economists typically mean by the 'supply' of a product.

As was discussed in Chapter Four, the 'supply of crude oil' is ambiguous. For example, it could be used to refer to the size of the total resource base in a region, or to the quantity of reserves additions added in a particular period, or to the volume of oil lifted to the surface in a particular period. However, for

the economist, 'supply' typically has a much broader meaning, referring to the constellation of factors that might influence production. Formally, this broader use of the term 'supply' is called a 'supply function'; it is best seen as a formulation that documents all factors potentially affecting oil production, as well as the strength of impact of each. In a more restricted manner, economists often speak of the 'supply curve' for crude oil (or more simply 'the supply of oil'), which shows how the production of crude oil will change as the price of crude oil changes. This aspect of supply is of particular interest to economists, who focus on the way in which the oil market determines prices. It is important to realize that only one level of price and production will actually occur at any point in time; in other words, only one specific point on the supply curve is actually observed in any time period, and the other possible price/output combinations are hypothetical. It is also important to recall that the concept of a supply curve does not say that *only* the price of oil is important in determining production. Rather, it says that out of all the factors that have influence, price is the one upon which analysis will focus. One can define a meaningful price/output relationship only for fixed values of the other variables that influence output. If other things change, then a new price/output relationship will occur. A change in supply can be associated with a change in price (which leads to a 'change in quantity supplied,' or a movement along a supply curve) or a change in other factors affecting supply (which leads to a 'change in supply' or a new supply curve).

Chapter Four provided a list of the main factors that might be expected to enter into the supply

function for conventional crude oil in Alberta. Included are: the price of crude oil; the underlying natural resource base; knowledge about the resource base; the technologies currently governing production; the costs of various inputs into production (wage rates, interest rates, the prices of types of capital equipment, the cost of hiring a drilling rig, the price of electricity, etc.); the extent to which the quantity of capital equipment can be varied; government regulations (such as tax and royalty rates, rules for the issuance of mineral rights, drilling requirements on mineral rights, price controls, export limits, production controls, well-spacing regulations, gas-flaring regulations, etc.); the determinants of oil companies' behaviour (i.e., company objectives including risk preferences); and expectations about the future. A complete supply function would specify exactly how all these variables impact upon the level of production of crude oil.

Estimation of such a comprehensive supply function must remain an unattainable ideal. The number of variables influencing supply is large, especially when it is realized that each individual oil company will have its own objectives, current knowledge, and expectations about the future. Beyond this, some variables are difficult to know. We cannot know for certain what the underlying resource base looks like (the number, size, and location of all the oil pools that nature has given us). We may not even be able to define all the possibilities. If we can't do this, we can't include all of the possible expectations companies might have, nor how these expectations will vary in response to changing circumstances. Thus, the estimation crude-oil-supply functions is another example of the 'art of the possible,' and, as with all the arts, what is beautiful lies very much in the eye of the observer.

The essential first step in crude-oil-supply modelling is simplification. Simplifications may or may not be explicitly acknowledged by the analyst. A common assumption is that certain variables, which might theoretically be expected to affect oil production, simply are not relevant and therefore will not be included in the analysis. This clearly reduces complexity. The assumption may reflect the analyst's judgment that the variable is not significant enough that it is worthwhile expending time and effort to gather the data. Or it may reflect the belief that the variable did not change very much over the period and therefore changes in output cannot be due to this variable. Analysts often report only the variables that they include in their analysis and not the ones that they exclude. Simplification frequently involves explicit assumptions that the analyst realizes are not necessarily true, but which

it is believed (or hoped) will allow the major factors affecting supply to be assessed. The analyst is aware that the model will not capture all aspects of reality but hopes that it will come close and that errors will be random (so, for example, a forecast will be equally likely to over- or underestimate oil production). An example of such a simplifying assumption relates to the determinants of companies' behaviour. Economists often assume that all oil companies are profit-maximizers; therefore, companies will always pursue the lowest cost methods of production and will exploit all profitable investment opportunities. In this case, as argued in Chapter Four, the supply curve is a marginal cost curve, which ranks possible units of crude oil production from the lowest cost unit to the highest cost unit. Thinking of a supply curve as a marginal cost curve is a useful way to see how various crude oil 'products' differ from one another; thus, undeveloped oil reserves require development investment to become developed reserves, and these require operating expenses to become oil in the field, which require pipeline expenses to become oil at a main gathering point. It also follows that the price that elicits oil supply differs in each case as well; that is, the price of oil in the ground (reserves) differs from the price of oil as lifted. If we further assume that all companies have the same knowledge and expectations, it is not necessary to treat the industry as consisting of many different firms, each influenced by different factors. Instead, we can treat the industry as if it were a single large profit-maximizing firm. Other simplifying assumptions commonly adopted are to assume: that current conditions (for example, prices) reflect expected future conditions; that all pools, once discovered, tend to be depleted in the same manner; that future reactions to prices and other variables will mimic past reactions; and that the supply function takes a particular mathematical form.

This chapter includes five main sections. Section 2 offers a more detailed discussion of the framework for oil-supply modelling. Section 3 summarizes the results from the most well-known and accessible estimates of Western Canadian crude oil supply, those undertaken on a regular basis by the National Energy Board (NEB) since the 1970s. We refer briefly to similar analyses from the Canadian Energy Research Institute. Section 4 discusses studies that assess Alberta oil supply by attempting to directly measure the cost of oil production. Section 5 turns to research that provides 'indirect' estimates of oil supply by attempting to estimate various forms of an oil-supply function. We conclude with some general comments in Section 6.

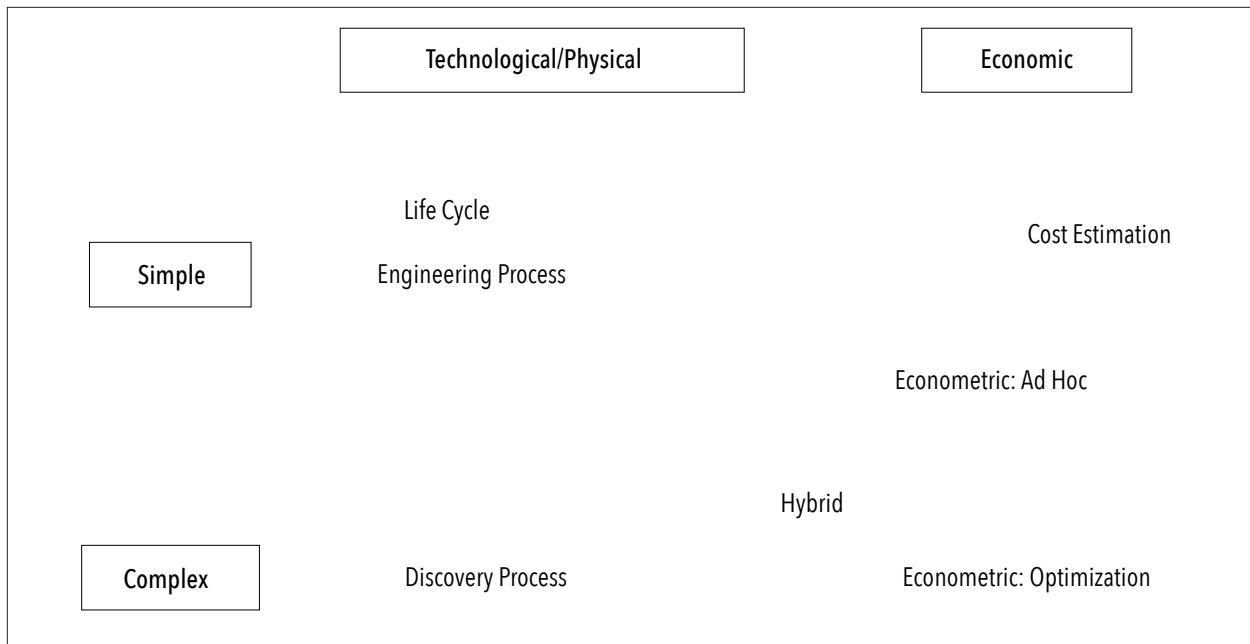


Figure 8.1 Models of Oil Supply

2. Concepts of Crude Oil Supply

As mentioned in the Introduction to this chapter, the term ‘crude oil supply’ has a number of different meanings. (Bohi and Toman, 1984, provide a useful review.)

The ‘product’ **crude oil resources** is of a qualitatively different order than the others. Here economists often speak of a ‘Resource Stock Supply Curve’ (RSSC), which, on the basis of an assumed set of underlying conditions (regulations, input prices, technology) ranks, by marginal cost, the total quantity of crude that it is thought lies in the ground. This is quite unlike the economists’ usual supply notion, which is a flow concept; that is, it refers to the quantity of oil supplied in a particular period – **discoveries** in 1967, total **gross reserves additions** in 1987, or **oil lifted** in 1992. However, the idea of an RSSC is often the starting point for detailed oil-supply analysis in a region such as Alberta. Exploration and development activities translate the resource stock into reserves in the ground, and production facilities translate reserves in the ground to production at the surface.

We would also remind readers that oil is found in separate ‘pools’ (‘deposits’ or ‘reservoirs’) and that these pools tend to accumulate within a relatively small number of geological plays. A grouping

of nearby pools in the same geological formation is called a ‘field.’

A number of authors review different approaches that have been used in crude petroleum supply modelling (for example, Adelman et al., 1983; MacFadyen and Foat, 1985; Kaufman, 1987; Power and Fuller, 1992; Walls, 1992; Adelman, 1993b; Brandt, 2009). We will provide a brief summary of some of the main approaches. As we shall see, many of them have been applied to the Alberta crude oil industry.

Following Kaufman (1987), Figure 8.1 provides a simple classification of these modelling approaches along two key dimensions: the extent to which the models are primarily ‘economic’ or ‘technological’ and the extent to which the model utilizes relatively ‘simple’ as opposed to ‘complex’ quantitative or statistical procedures. It is important to realize that the approaches are not mutually exclusive. They can overlap and researchers may utilize more than one approach.

Cost Estimation. Estimates or reports of expenditures are tied to the resultant output to derive a measure of the unit cost of oil.

Engineering Process. A relatively simple relationship affecting oil supply is assumed, based on the physical activities involved in oil production. Sometimes this is a purely ‘engineering’ relationship. It

might be assumed that all oil reserves are developed and depleted in identical fashion; for example, development occurs in equal stages over three years, output commences at a reserves to production ratio of 10, and the pool exhibits constant exponential decline at a 7 per cent annual rate. Another engineering approach posits a consistent relationship between the discovery rate of oil (or average discovery size, or reserves added per foot drilled) and the passage of time (or cumulative footage drilled); this relationship is often based on historical experience, and, in mature regions, normally shows 'depletion effects' where oil becomes increasingly hard to find.

Life Cycle. This approach assumes a regular relationship between the passage of time and the rate of oil discoveries and production; it is a specific example of an engineering process model.

Econometric: Ad Hoc. Econometric approaches argue that economic variables are a prime determinant of crude oil supply and that one can utilize regression techniques applied to historical data to estimate the precise relationship between oil supply and the underlying variables that affect it. The model may also include non-economic variables, for instance representing different geological plays. The 'Ad Hoc' approach begins with a 'conceptual' model that suggests the variables most likely to affect crude oil supply and then utilizes statistical estimation procedures to see how strongly these variables are connected. The investigator may assume a specific functional form for the relationship amongst the variables (e.g., a linear relation) or try a number of possible functional forms and select the one that appears to 'fit' best.

Econometric: Optimization. Optimization models begin with a formal analytical model of industry behaviour, which is utilized to generate the list of variables that are expected to affect oil supply, as well as constraints on the precise mathematical relationship amongst the variables. Normally a number of simplifying assumptions are necessary in order to make the theoretical model and its operationalized version tractable. Thus, for example, all firms may be assumed to be effective profit-maximizers, with identical expectations based on the current values for key variables, and the underlying production functions may be assumed to have specific 'regularity' properties.

Discovery Process. These models assume that the discovery of oil pools involves a non-random sampling process without replacement from an underlying distribution of crude oil pools. Given assumptions about the nature of the underlying pool distribution in nature (e.g., that the size distribution of pools is log-normal) and the sampling process (e.g., the

probability of discovery for a pool of size 's' is proportional to the volume of oil still in the ground in pools of that size), it is possible to calculate the probability that the next discovery will be of size 's', and the expected size of the next discovery. In Chapter Five, results of the Geologic Survey of Canada's discovery process model were summarized.

Hybrid. Hybrid models typically combine aspects of the engineering, economic, and discovery process approaches. Thus, for example, the level of exploratory drilling and anticipated success rates might be estimated econometrically while the volumes of discoveries are drawn from a discovery-process model. Many of these modelling approaches have been applied to the Alberta crude oil industry, often in combination. In Chapter Five, we reviewed some of the estimates of the total availability of crude oil in Alberta. In this chapter, we will emphasize studies that assess the flows of oil supply, specifically reserves additions and production (or productive capacity). Recall that the two are connected, since production comes out of reserves.

The next section will review the crude-oil-supply scenarios of the National Energy Board (NEB). Beginning in 1969, and periodically since then, the NEB has issued conditional forecasts of Canadian oil supply. These studies have drawn on many modelling approaches, including cost estimates, engineering process analysis, discovery process analysis, and econometrics. They provide a very useful review of how expectations about Canadian crude oil supply have changed over the past three decades.

3. NEB Supply Studies

In providing information about its regulatory responsibilities, the NEB has produced a number of reports that forecast the future production of Canadian crude oil. These reports are of interest for a number of reasons. They are the most visible forecasts of Canadian energy production and consumption (or 'Supply' and 'Demand,' as they are usually labelled). They also depict how prevailing expectations about Canadian energy industries have changed over time. It is tempting, in this regard, to emphasize the ways in which the forecasts have been 'wrong,' but this is not the most profitable way to view them. The NEB forecasting procedures have evolved over time, learning from new information and modelling techniques. And the NEB studies have usually been at pains to point out how and why the forecasts have changed from one

report to the next. Failure to revise forecasts in light of changing circumstances would be a much more serious concern than the continual revision of the forecasts. The more interesting question is why the forecasts have changed.

The Appendix to this chapter (Appendix 8.1) provides a number of tables showing oil-production (or productive capacity) forecasts from NEB reports, which we will refer to simply by the year in which they were issued. We consider reports issued from 1974 through to 1999, and look at oil output projected up to the year 2010. (The NEB 'Supply/Demand' Reports after 1999 include numerical values for total oil output, rather than the disaggregated categories we utilize; some graphs for disaggregated output are included in the reports, but the precise output values are difficult to determine from the graphs.) In what follows, we briefly review the various types of crude-oil-supply models utilized by the NEB, the forecasts of conventional crude oil reserves additions in the Western Canadian Sedimentary Basin (WCSB), and the forecasts of light and heavy crude oil output (or potential production) in the WCSB. (The NEB does provide detail by province, but the main reports are for the entire WCSB. Alberta is the source of most of this oil, although less so for heavy crude oil.) The NEB has not usually labelled its projections as 'forecasts,' instead using terms such as 'cases' or 'scenarios.' Our preference is to label them as conditional forecasts, that is, forecasts of future output conditional on a number of underlying assumptions.

A. The NEB Modelling Procedure

The first NEB report in 1969 utilized a simple aggregate engineering approach based on the estimated availability of oil reserves; these in turn were drawn largely from relatively simple geological-volumetric estimates provided by the Canadian Petroleum Association. As discussed in Chapter Five, the geological-volumetric approach estimates the total volume of potential oil-bearing rock in a sedimentary basin and applies an assumed average amount of oil found per unit volume of rock. Often, this average oil volume is based on experience from other petroleum basins elsewhere in the world.

Since the 1969 report, the NEB has built up a considerable bank of data that allows much more detailed forecasting. Some of these data consist of detailed reserves and output information on all significant oil pools in production in Canada. Cost and planned output data is obtained from many of the main oil

producers. The NEB also draws extensively on the play-based models of the Geological Survey of Canada (GSC). Beginning as early as the 1974 report, this allowed the NEB to make disaggregated forecasts of crude oil producibility.

The 1994 report provides extensive detail on the modelling procedures. A number of the approaches discussed in Section 2 are utilized. Some of the forecasts are largely engineering or technical in approach. For instance, already discovered pools normally are assumed to produce following specified depletion paths; oil sands output is based to a significant extent on announced projects; reserves additions follow assumed time paths of development and depletion. Production of pentanes plus and condensate falls out of the NEB's natural gas forecast through assumed liquids to gas ratios. Cost estimation is often used. Thus 'supply costs' are estimated or assumed for large oil sands mines, for bitumen and frontier projects, and for the potential reserves additions. Reserves additions are normally separated into those added through new discoveries, those added through extensions and revisions of extant discoveries, and those added through enhanced oil recovery (EOR) projects. The resource potential for conventional oil is derived from the GSC discovery process and subjective probability models (discussed in Chapter Five). The NEB recognizes that future production is conditional on many factors that cannot themselves be forecast with certainty. Hence, a number of different forecasts are usually provided to indicate how oil production might change as underlying conditions change; such 'sensitivities' may relate to variations in the price of oil, in technologies, in the size of the resource base, or in government regulatory policies.

The NEB has undertaken a very difficult task. The crude oil industry is complex, and to provide detailed and frequent forecasts of the total Canadian output of crude is a major undertaking. The openness of the NEB to a variety of modelling approaches – the eclecticism of its approach – is probably one of its main strengths. Yet it is quite different to the modelling procedure most common in academic studies, which is to select a more restrictive problem and apply a relatively sophisticated technique to this smaller issue.

B. Potential Reserves Additions

A key determinant of the future producibility of Canadian crude oil is the volume of conventional crude oil that remains to be added to reserves. The production from reserves additions depends not only on their

volume but also on the rate the reserves are added and developed, which in turn reflects the willingness of producers to undertake the necessary investments. Readers may recall our argument that resource limits are not absolutely binding since the real issue is what volumes from the indeterminate underlying physical resources will ultimately prove to be economic. The NEB, like many oil-supply modellers, has felt it necessary to recognize the exhaustible nature of conventional oil by incorporating in their model some estimate of the volume of oil that may ultimately prove to be economic. If all else were equal, one would expect to find that the volume of potential reserve additions would fall over time since reserves additions over time would reduce the total amount remaining in the ground still to be added to reserves, making additions more difficult. However, while such 'depletion effects' will reduce reserves addition potential, changing knowledge and technology could increase it by making larger volumes commercially accessible.

Table A8.1 in Appendix 8.1 shows that declines in reserves additions potential have not been the norm in the NEB reports. In fact, for both light and heavy crude, and for both new discovery and EOR reserves, the NEB has become much more optimistic since the mid-1970s. For light oil discoveries, the latest report considered here (1999) shows the highest potential (666 million m³). For heavy oil, estimated potential was increased sharply to 1991 but has since been lowered for both new discoveries and EOR reserves additions. The potential for light crude EOR reserves was also cut in 1999, although this may partially reflect the application of economic criteria to the 1999 figures. In general, the data in Table A8.1 suggest that there is a tendency for the passage of time to generate improved expectations about possibilities for reserves additions. This may well be a common occurrence in disaggregated models since the ability to foresee entirely new techniques or geologic plays is necessarily limited and the willingness to extrapolate trends in these supply components may be constrained by the presumption of depletion effects in discovery.

Rising estimates of potential reserves additions cannot be tied to rising oil prices. Table A8.1 shows the approximate level of the crude oil price at the time the report was issued. (These prices are in nominal dollars, so the earlier prices are actually understated in real terms compared to more recent prices.) As can be seen, the highest reserves potential does not occur in the year with highest prices; for example, the January 1981 report had the highest price (\$38/b), but the light crude potential is significantly higher for all years

since then, even at prices 50 per cent lower. Changing knowledge must be the most significant factor in the revisions of the NEB forecasts, and the knowledge changes must tend to be 'positive' (that is, leading to more optimistic forecasts over time).

C. WCSB Crude Oil Producibility

Appendix 8.1 includes four tables showing the NEB forecasts of crude oil producibility in the WCSB: conventional light oil (Table A8.2), conventional heavy oil (Table A8.3), syncrude (Table A8.4), and bitumen (Table A8.5). In each table, actual output is also shown for years from the mid-1970s to 2010. Where a number of scenarios were reported, we normally show the 'Base' or 'Reference' case, selecting the case that seems most accurately to reflect actual world prices in the years immediately following the forecast. We shall discuss, briefly, each of the four crude oil categories. The first NEB supply/demand report of 1969 did not report estimates for these separate grades of crude oil. It did forecast rapid increases in Canadian crude oil output. (The report did not distinguish between production and producibility.) Thus, for example, Table 17A(1) of the 1969 report showed Canadian petroleum production rising from 161,000 m³/d in 1966 to 361,000 in 1975, to 522,000 in 1980 and to 654,000 by 1990. Actual production of conventional and non-conventional crude oil in 1991 was 243,500 m³! These extremely high production forecasts presumably reflected the high resource potential stemming from the volumetric estimation procedures.

1. Conventional Light Crude in the WCSB

Each of the eleven forecasts exhibits pronounced decline over time. This reflects decline rates in individual oil pools, which apply to the sizable number of pools already in production at the time the forecast was made. Since the forecasts are usually for productive capacity, they may tend to overstate the amount of production anticipated in those years from 1974 to 1985 when there were government limits on the volume of exports from Canada. (See Chapter Nine.) Note, also, that the 1974 and 1975 reports include all WCSB crudes, not just light oils. It is therefore not surprising that these two reports forecast higher oil output than actually occurred for light and medium crude in the 1970s. But, by 1984, actual production exceeded the forecasts of both the 1974 and 1975 reports.

The year 1993 is instructive, since this year included forecasts for all the preceding reports. Forecast production tended to be higher the later the report was issued. (The 1991 report is an exception; the 1977 report also appears to be, but remember that the 1974 and 1975 reports included all crude, not just light and heavy.) Actual production in 1993 exceeded the forecast from all reports for 1974 through 1991. In line with these revisions, the 1994 report was more optimistic about future production than the 1991 report. A comparison of 1999 to 1994 is more ambiguous, with the more recent forecast lower for the first decade but higher from 2005 on.

These results are quite consistent with the changes we mentioned for estimates of reserves additions, where the additional information garnered over time led to more optimistic projections. It also highlights the dangers in emphasizing the exhaustible nature of conventional oil since there seem to be persistent tendencies to underestimate future availability. These probably stem from the difficulties imposed by (or the conservative reluctance to go beyond) the constraints of current technology and knowledge. This raises a classic induction problem, however: the fact that virtually all the historical forecasts have been overly pessimistic does not mean this pattern exists of necessity.

2. Conventional Heavy Crude in the WCSB

Table A8.3 shows NEB forecasts of conventional heavy crude production in its reports from 1977 through 1999. We see the same pattern as for light and medium crude oil. Forecasts have underestimated the actual growth in heavy oil production, and later forecasts have tended to be more optimistic. Thus, for example, the 1977 report foresaw heavy crude oil production in 1995 of 19,000 m³/d, whereas output was actually 73,000. The 1991 report put the level in 1998 at 48,700 m³/d; that year output hit 85,000.

3. Synthetic Crude

NEB reports from 1974 through 1999 provided future output paths for syncrude, as did the NEB's three later reports on the oil sands. (See Table A8-4.) The 1974 report provided the most optimistic forecast, and all three reports from the 1970s substantially overestimated the future syncrude output. These reports all reflected the siren call of the huge synthetic crude resource base and optimistic estimates of the associated production costs. However, as was discussed in Chapter Seven, it soon became apparent that the oil

sands were much more difficult and costly to bring into production than had initially been thought. The NEB reports after 1978 reflected this information and also a change in estimation methodology in which the projected paths of syncrude output mainly reflected announced projects or expansions. Given the long lead times in constructing integrated mining projects, this meant that the forecasts were relatively accurate for a period of five or maybe ten years, but the reliability had to be suspect beyond that. As it happens, up to 2000, no new mining projects had been commenced, but addition to capacity in the Suncor and Syncrude plants has been greater than was anticipated in the NEB reports from 1981 through 1991. The 1999 report anticipated that one large new project would begin production by 2005, which was accurate as the Albion Sands project began production in late 2002.

4. Bitumen

Table A8.5 shows that the NEB estimates of future bitumen production exhibited the same pattern as for conventional crude. The forecasts underestimated future production. Later forecasts were more optimistic, but still tended to be too conservative.

D. Implied NEB Supply Elasticities

As we mentioned, the NEB often provides a number of 'conditional' forecasts in its reports; that is, the specific forecast is conditional on particular assumptions. The previous section looked at the NEB forecasts that assumed prices closest to those that actually occurred and found that, except for synthetic crude, the NEB tended to underestimate future production. In this section, we consider a different dimension of the NEB forecasts. In those cases, where the NEB provided forecasts at different prices, and price was the only variable that changes, it is possible to look at the responsiveness of the forecast to the price difference; that is, there is an implied elasticity of supply given by the two estimates. (Remember from Chapter Four that the elasticity of supply is the percentage change in output divided by the percentage change in price that brings it about, all other factors affecting supply held constant.) These are 'arc' estimates of the elasticity of supply, since the two output values are typically estimated at prices that are quite distant. (As such, they contrast with 'point' elasticity estimates, which indicate the responsiveness of output to very small price changes. A number of varying 'paths' of point

Table 8.1: Implied Oil Supply Elasticities in NEB Reports, 1984-99

	1984	1986	1988	1991	1994	1999
Established Reserves, Light and Heavy	0.8/ 0.15					
New Discoveries, Light and Heavy	1.48/ 0.67					
EOR, Light and Heavy	2.68/ 1.12					
Established Reserves, Light		0.04	0.04			
EOR, Light		0.28	0.50		0.9/ 1.94	
New Discoveries, Light		0.96	0.02		0.33/ 0.17	
Light and Medium				0.83/ 1.5		1.03/0.32*
Established Reserves, Heavy		0.08	-0.84			
EOR, Heavy		0.98	0.90		1.03/ 2.46	
New Discoveries, Heavy		0.96	-0.5		0.4/ 0.26	
Heavy Crudes and Bitumen				1.07/ 1.73		
Conventional Heavy						0.52/0.59*
Bitumen		5.62	2.68		5.27/ 2.43	2.21/2.77*
Syncrude		1.00	1.60		1.17/ 0.34	1.31/2.23*

Notes: Most elasticities reflect the supply response to higher prices; numbers in bold are elasticities with respect to price declines. In 1999, the values marked with an asterisk (*) are from the "Low-Cost Supply Case," which assumes that greater volumes of low-cost resources are available.

supply elasticities are all compatible with any particular arc elasticity.) The values that we calculate below are not always true supply elasticities because in some cases the difference between the two NEB forecasts involves more than simply two prices of crude oil; we have noted the most important differences. It is also important to note that there is usually no single supply elasticity involved in comparing two cases since the relative difference between outputs typically varies depending how long into the future one is looking. Since the NEB production forecasts tend to exhibit short-run price inelasticity (as is entirely appropriate), we have normally picked a year for comparison at least ten years into the forecast. And, finally, not all price assumptions involve constant prices over time, so that the percentage change in price is not necessarily constant between two forecasts; once again, we try to take note of exceptions in this regard.

The 1969, 1974, and 1975 reports included no explicit price assumptions. Appendix A8.6 has tables showing the ranges of forecasts for the subsequent NEB reports. We shall briefly review the price assumptions of each report and make comments on the implied elasticities where appropriate. Table 8.1 summarizes the estimated price elasticities from the 1984 to 1999 reports.

1977 Report. A constant real price (at the 1980 international level) was assumed in the 'expected' case; in the 'maximum price' case, the real price rises by 5%/

yr, while in the 'minimum price' case, the real price falls by about 5%/year (the nominal price is constant). The NEB estimates show significant price response for both conventional and synthetic crude, especially if prices fall.

1978 Report. The base, high, and low price assumptions are the same as for the three cases in the 1977 report, but with greater supply desegregation. Production from current established reserves was completely unresponsive to price differences. Presumably this oil has only to recover operating costs, so the effect of different prices is on the abandonment date, when output rates are small. Bitumen production is low and is shown as responding asymmetrically to price changes; a higher price does not call forth any more production, but output falls dramatically if the price declines. Synthetic crude is also shown as particularly affected by lower prices. Conventional light reserves additions are particularly responsive to higher prices.

1981 Report. The 1981 report showed sharply rising nominal (and real) prices, as international prices were assumed to continue to rise, and Canadian prices increased under the various schedules of the National Energy Program. The sensitivity cases shown in this report do not reflect price differences but, rather, differences in geologic and technological potentials and in fiscal regimes. Of course, reduced government take is like a price increase as far as producers

are concerned. The modified base case allowed for reduced taxes or royalties. The low case assumed somewhat higher government take and poorer geological potential. The high case assumed higher geological potential and more rapid approach to international oil prices. Specific price effects cannot be estimated since price is not the main variable changing between cases and the netback changes assumed are not explicitly described. This report shows bitumen as completely unresponsive to changes between cases, while synthetic crude production is highly responsive to improved conditions. Conventional crudes are clearly regarded as also sensitive to changing conditions; of course, this is true pretty well by definition as far as changes in geological potential are concerned.

1984 Report. The report showed high and low prices relative to the reference case. In 1983, U.S. dollars/b, the reference price in 2005 was \$37.60, the high price was \$50.10 (or 33% higher) and the low price was \$28.10 (or 25% lower). These price differences were not constant across time, so the implied elasticities of supply are only approximate. We have estimated elasticities of supply by taking the percentage change in quantity between cases and dividing it by the percentage change in price. For example, as Appendix A8.6 shows, at higher prices, output from currently established reserves is 5 per cent higher (20/19); since the price was 33 per cent higher the elasticity of supply implied is 0.15 (5/33). As Table 8.1 shows, higher elasticities are implied for output from new discoveries than for established reserves, with EOR output even more responsive to price changes.

It will be noted that these estimates show supply as being more responsive to lower prices than higher. This is true even for already established reserves; by 2010, the output from these reserves has fallen dramatically due to production decline, so small changes in production appear more significant. It is not clear why supply should be less responsive to price rises, although this could reflect a higher government take as prices increase. Another possibility is related to the tendencies we noted above to underestimate reserves additions. Forecasts tend to be conditioned by the existing knowledge gained at prevailing prices, so tendencies to underestimate resource potential may be particularly pronounced for cases that assume prices higher than we have seen. Alternatively, it may reflect a judgment that additions to volumes of recoverable oil become smaller as prices rise.

1986 Report. By 2005, the high price of US\$27/b (real 1986 dollars) is 50 per cent higher than the low price. The implied elasticities in Table 8.1 show that

output from current established reserves is minimally sensitive to price changes, which is not surprising. Light oil output from EOR projects is estimated to be relatively inelastic. Unlike the 1978 and 1981 reports, bitumen is highly responsive to price increases. The other output categories all exhibit about unitary elasticity.

1988 Report. As in the 1986 report, the high price (at US\$30/b in 1987 dollars) is 50 per cent higher than the low price. Using the same procedure as before, the elasticities shown in Table 8.1 are derived. The negative supply price elasticities for two of the heavy oil categories stand out. Why would higher prices reduce output? The reason seems to lie in the exhaustibility implications of the NEB's models, where higher prices induce increases in reserves but may also speed up production so that, by the year 2005, heavy established reserves and reserves additions actually show less production at higher prices. (This highlights the difficulty of deriving precise supply elasticities when what is really being compared is production paths over time.) As in the 1986 report, non-conventional supply sources are shown as particularly price responsive; large volumes are waiting, if only the price gets high enough. From the mid-1970s to the mid-1990s, however, it seemed that the 'magic' price was always above prevailing market prices! The production possibilities for light oil in 2005, due to higher prices, have flipped in the 1988 report as compared to the 1986 report, with EOR now offering most of the incremental output.

1991 Report. The control case had a price of US\$27.00 in 2010 (1990 real dollars). The other cases are described in slightly vague terms but seem to involve a price 26 per cent lower and 30 per cent higher. Supply elasticities (Table 8.1) are generally elastic and are higher for heavy crudes than light.

1994 Report. The reference price in 2010 is US\$23.00/b (in real 1991 dollars). The low price is 35 per cent lower, and the high price is 30 per cent higher. Table 8.1 includes implied supply elasticities based on the production amounts for 2010. EOR is quite price sensitive, especially to price declines. On the other hand, this report shows conventional crude as being particularly sensitive to price rises, though the supply response is still inelastic. The high supply elasticity of bitumen is evident.

1999 Report. This report gave two price sensitivities, a 29 per cent higher price in a case involving 'current supply trends,' and a 22 per cent higher price in a case with a greater volume of low-cost oil available. Once again, the NEB analysis implies particularly high supply elasticities for non-conventional crude, as Table

8.1 shows. Conventional heavy oil is seen as supply inelastic. The sharp fall in the supply elasticity for light oil between the two cases suggests that a significant portion of the expected reserves additions for light oil are booked at the lower price, leaving relatively small incremental volumes to draw under the stimulus of higher prices: the supply curve gets steeper.

E. Conclusion

We have reviewed the NEB supply forecasts from the early 1970s through to 1999 in some detail because they are the most widely reported and accepted supply estimates in Canada. They incorporate all types of crude, have been revised and published on a regular basis, and have seen the gradual development of a large data base and increasingly sophisticated modelling. The modelling approach is eclectic, involving a variety of techniques ranging from 'rules of thumb' through to elaborate statistical estimation. Because the techniques are so varied, and the underlying data so extensive, it is not always obvious what factors are of most significance in giving changes in forecast oil production from report to report. The NEB reports have tended to become increasingly optimistic about the oil production capabilities of the Western Canadian sedimentary basin. The disaggregated supply estimation methods imply that crude oil supply is price responsive to some degree. Supply from already established reserves normally appears as very price inelastic, and the various categories of reserves additions, EOR potential, and non-conventional crude show widely varying implicit supply elasticities in different NEB studies, but the clear, emerging message is that 'price matters.' The NEB has generally found that price is particularly important for non-conventional crude oils. Underestimates of supply for the conventional oil may reflect a tendency to underestimate the impact of changes in technology and knowledge (for example, with respect to new geological plays or new recovery techniques). But this could also stem from underestimation of the price elasticities of conventional crude oil supply since much technological change is, in fact, induced by expectations of profit that is, clearly, enhanced by higher prices. That is, higher prices will induce increased crude oil production because higher cost oil (under current technologies) becomes profitable; they also induce more production as a result of the new technologies and knowledge that the price rises stimulate. Our sense is that the NEB forecasts of the 1970s and 1980s tended to be insufficiently

optimistic about these new technological possibilities. This in turn may reflect a natural conservatism in making forecasts that manifests itself in the difficulty in allowing for truly novel possibilities. However, that this has been the case in past forecasts is not a guarantee that it will prove to be so for the most recent forecasts, which may be more accurate as forecasting procedures have improved. In addition, it may well happen that the tendency to resource 'pessimism' turns out, at some point in time, to be correct!

The NEB is not the only research organization to build a disaggregated model of Alberta oil supply, although it is the only body to provide continually updated forecasts over an extended period of years. Both the ERCB and the Canadian Energy Research Institute (CERI) have also provided forecasts of Alberta conventional crude oil production, using relatively detailed supply models. The ERCB forecasts have appeared in the series of publications to which we have made frequent allusion entitled *Reserves and Supply/Demand Outlook* (ERCB, ST-18 and, since 2001, ST-98) and will not be reviewed here. We will summarize some of the CERI work.

Heath (1992) and Heath, Chan, and Stariha (1995) set out the **CERI conventional-oil-supply model**. It is difficult to disentangle all the details, which involve numerous assumptions to go from separate oil pools to total Alberta supply. We will provide a brief outline of the model as we understand it. To some extent, they rely on data and assumptions from the NEB models. For geological information, they draw on analysis from the Institute of Sedimentary and Petroleum Geology (ISPG), which set out a total of 45 crude oil plays in Alberta (39 of them light and medium crude, and 9 heavy crude). CERI researchers added a 46th play to represent small and unclassified pools and oil from natural gas pools with high condensate content. The ISPG data was largely drawn from discovery process modelling, which provided estimates of the size distribution of pools in the 45 plays and, by deducting historic discoveries, gave a distribution of the number and expected sizes of as-yet-undiscovered pools. The ISPG model also estimates a parameter that indicates the extent to which pools have been discovered in a strict largest-to-smallest sequence; this variable can be used to indicate the likelihood that the next discovery in the play will be of any specific size. Drawing on a number of sources, CERI assumes exploration success ratios for each play. In addition, play-specific depletion paths are assumed, as are two abandonment quantities, one for larger pools and one for smaller. Heath, Chan, and Stariha also discuss economic

criteria for determining the abandonment date for oil pools and the willingness to invest in pools, but it is not clear how these criteria interact with the more deterministic rules they also discuss. The economic criteria appear to be used largely for a separate cash flow and profitability analysis of the oil pools available in each play; in effect, these involve the estimation of ‘resource stock supply curves,’ which indicate the volumes of oil available at various possible costs. The estimates of Alberta production to 2014 are apparently assumed to be drawn from the economic pools. The CERI study also assumes that results from Saskatchewan for increased recovery factors due to new EOR and horizontal drilling (Chan et al., 1994) can be generalized to Alberta.

The CERI production model incorporates short-, medium-, and long-run perspectives. In the short-run, existing established reserves are run down using established production decline relationships and 1995 economic and fiscal conditions. The analysis assumed a WTI price of US\$19.50/b at Cushing, netted back to Alberta, with quality and local transmission cost adjustments appropriate to each oil play.

In the medium-run, oil pools are developed up to some level for primary production and are also assessed for EOR potential. The EOR is assessed as waterflood potential but draws on EUB data for all types of EOR. Considerable judgment was used in defining the number of development wells required in an oil pool, based on four factors: an assumed 80 per cent success rate; the provincial average, for each pool size, of reserves divided by the estimated lifetime production of an average well; an assumed average well spacing (e.g., 64 hectares for a well in a light oil pool); and the historic average number of wells in each pool size. Planned development is usually the smaller of that suggested by the latter two of these criteria and is assumed to take five years, following an ‘S’-shaped curve, with assumed maximum numbers of wells possible each year in a pool. Within any play, development is assumed each year to start with the largest pools and progress through to smaller pools, in so far as development expenditures allow. (See below for the determination of these expenditures.)

In the long-run, new pools can be discovered from the 46 plays, based on the estimate of the size distribution of undiscovered pools and the likelihood of finding each pool. At any time, the relative appeal of different oil plays is based on each play’s share of as-yet-undiscovered reserves in the province.

The level of investment activity, and hence the actual amount of development and exploration that

Table 8.2: CERI Alberta Oil Model: Forecast Oil Production (m³/d)

	<i>Existing, fully developed pools</i>	<i>Existing pools, not completely developed by 1992</i>	<i>New pool discoveries</i>	<i>Total</i>
1995	87,758	4,088	58,187	150,032
2000	33,051	1,087	51,359	85,497
2005	17,221	391	27,310	44,923
2010	11,002	174	14,960	26,093
2014	8,306	130	9,045	17,439

takes place, is said to be based on econometric estimates that CERI derived from the Alberta Department of Energy. Heath, Chan, and Stariha (1995) provide insufficient data to understand this model clearly. Their Appendix A.6 suggests that the model estimates constant dollar expenditures on exploratory drilling, G&G expenses, land rental costs, and development drilling as a function of variables such as interest rates and oil netback values (price net of operating costs including taxes and royalties). However, Appendix A.4 describes the independent variable as “the producers’ probability of reinvesting” (p. 259) and says that the reference cases assume a constant reinvestment rate of 88 per cent (p. 260) with 62.5 per cent of this going to development and the rest to exploration. Thus, the key factor is the reinvestment of the net operating income of the industry (which we assume is revenue less operating costs, royalties, land rentals, and taxes). Exploration and development expenditures are then allocated across the plays on the basis of each play’s share of undiscovered oil volumes. In this model, reserves additions fall off rapidly. For example, in 1995, in millions of barrels, there are new discovery reserves additions of 220.5, but in 2014 there are only 2.8. Less drastically, EOR reserves additions fall from 32.0 to 7.1.

Table 8.2 (with data from Heath, Chan, and Stariha, 1995, p. 29) shows forecast Alberta conventional crude production for several years from 1995 to 2014 in cubic metres per day. The extremely rapid forecast decline in Alberta conventional oil production is apparent, much more rapid than the declines forecast by the NEB in 1994 and 1999 for WCSB conventional light and heavy crude (Appendix Tables A8.2 and A8.3). CAPP shows conventional Alberta oil production in 2000 as 119,188 m³/d, almost 40 per cent higher than the CERI forecast for that year; in 2005, CAPP reported 90,804 m³/d as compared to 44,923 for

CERI; for 2010 the numbers were 72,957 m³/d (CAPP) and 26,093 m³/d (CERI) (CAPP *Statistical Handbook*).

Thus, the CERI forecast seems to share the under-estimation characteristics of the NEB forecasts.

4. Direct Cost Estimation

A. Introduction

Recall that, if we are willing to assume that the industry is dominated by profit-maximizing companies, then the supply curve for crude oil can be interpreted as the marginal cost curve of crude oil. From this perspective, one way to assess the supply of Alberta crude oil would be to directly estimate the actual and potential costs of production. This procedure is often used, both in cost assessments for specific projects and in industry-wide studies of 'Finding' and 'Replacement' costs. And the profitability analysis internal to most companies either explicitly or implicitly incorporates the unit costs of the oil associated with specific investment proposals; of course, these analyses are usually kept confidential as propriety information to the company.

In this part of the chapter, we will review some studies that directly estimate the cost of Alberta crude oil. In estimating the costs of oil production, only variable costs are relevant. This leads to the distinction between 'full-cycle' costs (when new exploration, development, and lifting costs must be incurred) and 'half-cycle' costs (in already discovered pools, when only new development and lifting costs are needed).

Direct cost estimation normally relates quantities of crude oil production (Q) to the expenditures (E) undertaken to produce those quantities. In the simplest format, we could define an average cost of oil production as E/Q . But this is not the marginal or incremental cost that economists think of as defining a supply curve of oil. Complications abound, including the following seven:

- (i) Care must be made to distinguish between oil-in-the-ground (for example, additions to oil reserves) and oil as it is lifted (crude oil production).
- (ii) The time value of money must be considered. In practice, a base year must be defined (usually the current year or a recent one), and expenditures after this year assigned a smaller

value than the actual expense since their present value is reduced by the advantage of being able to wait before incurring them and investing the capital funds in the intervening period. Mathematically, if r is the annual rate of 'discount' or time value of money, expressed as an annual interest rate, then the present value of $\$I$ spent a t years from the base year is:

$$Z = \frac{I}{(1+r)^t};$$

that is, $\$Z$ invested today at $r\%$ per year would give $\$I$ in t years time. Let us suppose that $\$I^*$ is the present value of the investment expenditures needed to add R barrels of oil to reserves. Then I^*/R would be a measure of the average cost of the additional oil-in-the-ground.

Timing is also important for the process of oil production since reserves are depleted over many years and much of the revenue will not be received until far into the future. If the analyst is estimating the cost of oil as lifted, it is therefore necessary to adjust production for timing as well. This involves the concept of the 'supply cost' or 'supply price' or 'levelized cost' of oil, which is the present value of costs divided by the present value of production, or, in symbols, where $q(t)$ is output in year t , and year T is the last year of production:

$$\frac{I^*}{\sum_{t=0}^T q(t)(1+r)^{-t}}$$

If output follows an exponential decline relationship, falling at annual rate of $a\%$ per year, and $q(0)$ is the initial annual output rate, and continuous rather than discrete time is used, then the supply cost is:

$$\frac{I^*}{\int_{t=0}^T q(0)e^{-at}e^{-rt}dt} = \left(\frac{I^*}{q(0)} \right) \left(\frac{a+r}{1 - \frac{1}{e^{(a+r)T}}} \right)$$

These timing factors must be kept in mind when estimating the costs of oil.

- (iii) Determination of the appropriate rate of discount (r) is not easy. From the start, care must

be taken to ensure that both expenditures and r are in the same 'units,' that is either nominal (current or 'as spent') dollars or real (constant or 'inflation free') dollars. A number of different inflation rates are potentially available to translate nominal into real discount rates.

- (iv) The supply curve is a ranking of potential units of oil production from low cost to high cost, where the cost is the incremental, or *marginal*, cost of that unit of oil. However, reported cost data is normally an *average* cost for an aggregated volume of oil. This may be all the costs in a region for a particular time period, or it may be the total costs for an entire project. Relating these costs to the associated reserves or output will, therefore, yield an average cost. For a specific project, the data may reflect indivisibilities ('lumpiness'), in the sense that one cannot typically vary capital expenditures in such a way as to change production on a unit-by-unit basis. Hence, the calculated cost might be interpreted as a marginal cost since it does represent the incremental cost per unit of the next 'lump' of output. However, even for individual projects, the data are often not in an appropriate form to calculate a marginal cost, since it represents the *total* investment plan of the producer and does not include the sequence of smaller investment options that preceded the one selected. It is the sequence of these incremental projects that really defines the marginal costs. In certain circumstances, this may not pose much of a problem. Thus, for example, in a reservoir that has homogeneous physical characteristics – porosity, permeability, thickness, water-to-oil ratio, etc. – extra units of production from extension drilling will exhibit relatively constant returns, where average and marginal costs are equal as production expands. However, activities like infill drilling and EOR projects are more likely to involve diminishing returns as the scale of the project is increased. Thus, the average cost of the entire development investment will understate the marginal cost of the last units produced.

It may be possible to approximate marginal costs from average cost data. Suppose that we know the equation for the average cost curve. We also know that total cost (TC) is the average cost (AC) multiplied by quantity (Q);

marginal cost (MC) is the first derivative of the total cost curve with respect to quantity. For example, suppose that we assemble average cost data that suggest that the average cost curve is a straight line that starts at zero. That is, costs begin at a minimal level for the very first unit of production, then increase so that $AC = bQ$, where b is the slope of the average cost curve. Then total cost is $(bQ)(Q)$, and $MC = 2bQ$; the marginal cost curve is twice as steep as the average cost curve.

- (v) Direct estimation of the cost of oil production is plagued by joint-product problems since much expenditure is not clearly tied to specific units of output. Remember that in a joint-product process a single activity necessarily generates more than one output. Petroleum exploration is an outstanding example since exploration expenditures almost invariably yield knowledge that is useful in the location of both oil and natural gas deposits and also for both current and future discoveries. How, then, can a particular exploratory investment be tied to specific units of output? One point of view is that it cannot and that attempts to directly estimate 'finding' (or exploration or discovery) costs are futile and meaningless (Adelman, 1992). Other analysts disagree, suggesting that simplifying assumptions allow us to derive meaningful cost measures in joint-product cases. Often the argument is not so much that the specific value is a 'true' measure of cost, but that, so long as we always make the same assumptions, these costs may serve a useful comparative purpose. For example, trends across time in costs for a region may be calculated, or cost comparisons may be made between different companies in order to assess their relative performance. The assumptions required are of two main types, one related to *timing* and one to the *types of products* produced.

For the first, it is normally necessary to make some assumption about the timing of the output tied to a particular expenditure. Thus, for example, it might be assumed that geological and geophysical (G&G) expenses are tied to oil discoveries one year later (and therefore include one year's interest cost), while exploratory drilling costs relate to discoveries in the same year. It is also

necessary to decide whether discoveries are the reported 'new discoveries' in the year of the exploratory expenses, or whether an attempt should be made to estimate 'appreciated discoveries,' including the reserves that will be added through subsequent development activities. Presumably, exploration discovers the whole oil pool, but some of the reserves subsequently added may reflect later economic or technological conditions, especially where EOR schemes are concerned. However, if only year-of-discovery 'new discovery' reserve estimates are used, then these reserves will be allocated a relatively high cost of exploration, and the subsequent reserves added in the pool will not show any exploration cost at all.

Exploration normally generates both oil and natural gas discoveries. In any region where both products are valuable, it is necessary to: (a) model oil and gas discoveries together, (b) divide the expenditures between the two products, a cost allocation process, or (c) combine the two products into a single one (e.g., barrels of oil equivalent), an output aggregation process. In the cost allocation or output aggregation cases, a 'reasonable' criterion will be selected, but there are a number of such criteria and no firm basis for thinking that any one is *the* valid method. For example, total exploratory drilling costs may be allocated on the basis of the relative number of successful oil and gas wells, or some measure of the 'intent' of companies when drilling the exploratory wells, or the relative footages of successful oil and gas wells. Oil and natural gas could be combined into a single product on the basis of their respective energy contents or their relative market values. The absence of any obviously valid solution to the joint-product problem leads some to deny the validity of any direct cost measures where joint-product problems are significant. Adelman and Watkins (2002) note the range of different results depending on the method used and argue that no one approach is more meaningful than any other. The contrary view is that, once a specific assumption is made about how to treat joint-product cases, trends in the value calculated are meaningful.

Readers may recall that, if the proportions of the joint products can be varied by varying the types of expenses undertaken, then it is

possible to calculate marginal costs for the separate products, even though the average costs are still arbitrary. The marginal cost is the 'full' opportunity cost per unit of the incremental output, where the opportunity cost includes the incremental investment expenditures to produce the extra product plus the net operating profits given up on any units of the other product which are sacrificed. For example, a company might redirect its exploration away from wells that have a higher probability of locating natural gas and toward wells with a higher probability of finding oil. One would expect to see a net increase in oil discoveries from the new wells drilled, but there would be an additional opportunity cost in terms of reduced discoveries of gas. In practical terms, however, cost data are rarely available in sufficient detail to allow the estimation of such marginal costs.

- (vi) It is also important to realize that expenditures (even including allowance for the time value of money) do not account for all costs that go into the supply curve. Both user costs and any costs associated with the foregone value of future options will also enter marginal costs. That is, direct estimation of a marginal cost curve on the basis of industry expenditures will normally underestimate the marginal costs of production and therefore overestimate supply.
- (vii) Finally, when time series data are used to directly estimate unit oil costs, there are 'identification problems' in interpreting the resultant values (one per year) as a supply curve. This is because, as time passes, the factors underlying the supply curve change so that it is not clear whether the cost has changed across time because there has been a movement along a supply curve or because the supply curve has shifted.

Despite these problems, direct cost estimates of oil are frequently made. They can be very useful when data are available for specific projects, as they can provide a check on whether that project is potentially profitable at the current level of oil prices. The project will not necessarily be undertaken even if this condition is met, since the willingness to invest depends not only on the current price of oil but also on expected

Table 8.3: NEB Supply Costs for Non-Conventional Oil (\$/m³)

NEB Report	Integrated Mining (mining and upgrading)	Bitumen	Bitumen and Upgrading
June 1981	\$260	N/A	N/A
October 1986	\$185-\$275	\$70 and up	\$140-\$230
September 1988	\$170	\$65-\$100	\$150-\$185
June 1991	\$200	\$65-\$90	N/A
December 1994	\$157-\$189	\$57-\$100	N/A
1999	\$94-\$151	\$50-\$107	N/A
2000	\$94-\$114	\$44-\$88	N/A
2003	\$138-\$176	\$63-\$120	N/A
2006	\$226-\$251	\$88-\$138	N/A

prices. And even were it profitable based on expected oil prices, the company might find it profitable to delay production for ‘user cost’ or ‘option value’ reasons. Also, a company might be willing to undertake a project even if it did not generate expected profits itself, if, for example, it was expected to generate geological information that would help the company make better exploration decisions in subsequent periods.

We will not attempt to summarize all the published direct cost estimates for Alberta oil, but we will provide several examples falling into two broad classes. The first involves cost estimation for specific projects, while the second involves time trends in costs for the entire industry.

B. Costs of Specific Projects

Companies undertake project evaluations all the time, which could be readily translated into unit cost estimates. These could be either for oil in the ground (i.e., the present value of exploration expenditures divided by the volume of oil reserves expected to be discovered) or for crude oil as produced (i.e., the present value of expenditures divided by the present value of the output that is expected to result). However, companies rarely make this information public.

There are several examples of studies that have used this approach to analyze the supply of crude oil in Alberta. We will see a detailed example in Chapter Ten, where Watkins estimated the costs in the 1950s of developing a number of particular oil pools in Alberta under three possible sets of regulatory conditions. Cost estimation has also formed a part of the NEB’s

analysis in their ‘Supply/Demand’ reports. Starting with the June 1981 report, the forecasts of bitumen and oil sands production summarized above, for instance, derived in large part from direct estimation of supply costs and their size in relation to anticipated oil prices. There seems to be a common presumption that the resource base of the oil sands is so large that per unit development and operating costs are constant and the user cost component of marginal cost is minimal. This may well be reasonable for mining type operations, where it seems to be relatively easy to move on to a new piece of land to strip mine more ore without appreciably impacting production opportunities in the near future. For *in situ* ventures, the assumption of zero user costs may not be as appropriate since current production may deplete reservoir energy and therefore increase future production costs, much as happens in a conventional oil pool. Table 8.3 summarizes the varying supply costs reported by the NEB for syn-crude from combined oil sands mining and upgrading projects and for bitumen from heavy oil projects. The costs are in dollars per cubic metre and have not been adjusted for inflation. As can be seen, current dollar cost estimates for upgraded synthetic crude oil tended to fall from 1981 to 2000 (and real costs would have fallen even more dramatically), but then rose again after that. In 2011, the NEB was estimating that new mining and upgrading projects would require a price for WTI of US\$535-600/m³ (NEB, 2011). Estimated bitumen costs showed less variability, but also rose after the year 2000.

The NEB has also used the supply cost approach to assess the likely future production from enhanced oil recovery (EOR) projects. An extensive data base was built up and used to screen major oil reservoirs

to see which had technical characteristics that might be amenable to particular types of EOR; from this, the NEB estimated the supply costs of the various possibilities to see if they would be economic at various oil prices. The NEB reports do not give detailed estimates of these supply costs. Supply cost analysis of EOR projects in Alberta was also undertaken by the Canadian Department of Energy, Mines and Resources (1977), Watkins (1977b), Prince (1980), and Eglington and Nugent (1984).

Watkins (1977b), for example, examined thirteen EOR projects in Alberta. At the time there were 370 such schemes in place in the province, but these thirteen accounted for about 40 per cent of the reserves credited to EOR. Most of the projects were water-floods, with one solvent flood, and one combined water and solvent flood. The data were supplied by the firms involved in the EOR projects and included actual development and operating expenditures (excluding taxes and royalties) and output to 1974; costs incurred after 1974 were projections. All values were in real 1973 dollars; the deflator used was a U.S. oilfield equipment price index. The supply costs of crude ranged from \$0.25 to \$2.35/b, with an average reserves-weighted cost of \$0.83/b, supply costs evaluated at a 12 per cent rate of discount. Ten of the projects had unit development and operating costs below \$1/b, and the highest cost project was the solvent flood in the Swan Hills South pool. Field prices in these pools in 1973 were in the \$3–\$4/b range. Supply prices less than market prices would be anticipated since the investors in the EOR projects presumably anticipated that they would earn profits over and above a normal rate of return – that is, they would enjoy some economic rent. Of course, this expectation is not necessarily met since an EOR project may function less well than anticipated and/or the actual market price could turn out to be lower than was anticipated.

Prince (1980) undertook an extensive study of Canadian EOR potential based upon economic analysis of Alberta oil pools. He considered ‘tertiary’ EOR, after waterflood recovery. Prince looked at the potential for eight different EOR processes in 1,372 individual Alberta oil reservoirs. An initial screening of reservoir characteristics eliminated a number of these reservoirs as suitable for any of the EOR techniques but left a total of 1,536 possible EOR projects. (Some reservoirs could potentially support more than one type of EOR project.) Economic analysis (based on the implementation of projects over a ten-year period, an 8% required real rate of return and an oil price of \$20/b) reduced the number of reservoirs with

positive expected profit to 460. (This also involved selecting the most attractive project in reservoirs where more than one EOR scheme was feasible.) His analysis allowed construction of a reserves additions supply curve, showing the supply cost associated with the various projects. The lowest cost project began at about \$14/b (\$88/m³) and showed approximately 2.4 billion barrels accessible through the 460 projects, at a cost of \$20/b (\$126/m³) or less. Prince’s results show much higher EOR costs than in the previously established projects analyzed by Watkins but also show a flat supply curve for a large supply addition.

Supply costs studies also formed a part of the research funded by the Economic Council of Canada in its extensive review of Canadian energy policies in the early 1980s. Eglington and Nugent (1984) undertook extensive analysis of hydrocarbon miscible flood projects in three Alberta oil reservoirs. They estimated both ‘social’ supply costs (which excluded the effects of taxes and royalties) and ‘private’ supply costs (which included the payments to governments, on the basis of 1983 tax and royalty regulations). These costs were estimated using a 10 per cent real discount rate and are in 1983 dollars; they include no formal allowance for risk. Table 8.4 summarizes some of their results.

The three EOR projects are of quite different size and are in three different reservoirs. Costs do not vary strictly with the size of the project, though the smallest project is the most costly. At the prices in effect in 1983 (for oil from new EOR projects), the Violet grove project was marginal, but the other two appeared profitable. However, all three would have been unprofitable, if the costs including royalty/tax payments had stayed the same, at average prices from 1986 through 2000. It should be noted, however, that the costs of the hydrocarbon flooding agent would likely fall along with oil prices. The size of the tax/royalty burden is apparent, even though there were a number of special incentives for EOR investments. The Eglington and Nugent study suggests that oil from hydrocarbon miscible flood projects is quite expensive and appreciably more costly than Prince found. (Prince shows an average cost of about \$96/m³ for hydrocarbon miscible flood projects.) Eglington and Nugent’s study considered only three projects and was designed largely to allow an assessment of Canadian oil policies in the mid-1980s.

Taken together, these studies demonstrate the reservoir-specific nature of EOR, both with respect to the technical viability of different schemes and the costs of the oil produced.

Table 8.4: Eglington and Nugent Supply Costs for EOR Projects

<i>EOR scheme, Reservoir, acres</i>	<i>Recoverable Reserves before Scheme (10⁶ m³)</i>	<i>Recoverable Reserves in Scheme (10⁶ m³)</i>	<i>Private Supply Cost (\$/m³)</i>	<i>Social Supply Cost (\$/m³)</i>
Violet Grove AB Lease, Pembina Cardium, 640 acres	0.81	0.27	261.24	161.30
Nipisi Gilwood Unit 1, Nipisi Gilwood Middle Devonian A, 3,840 acres	6.07	2.73	206.71	99.26
West Waterflood Area, S. Swan Hills Beaverhill Lake A&B, 11,000 acres	18.15	7.25	160.29	124.85

Note: Costs are in 1983 dollars.

C. Province-Wide Supply Costs

Some studies have estimated the average cost of oil produced in Alberta by relating reported industry expenditures to the resultant oil volumes. *Oilweek* magazine, for instance, has frequently reported annual average oil costs but using a suspect methodology that combines values for oil in the ground (investments divided by reserves additions) with values for oil as produced (operating costs divided by production).

One of the earliest estimates of the cost of Alberta's conventional crude oil was **Watkins and Sharp (1970)**, which used expenditure and production data for all pools discovered in the province from 1947 through 1968. A variety of allocation factors divided total expenditures between oil and gas. They also forecast future operating costs, development costs for pool extensions and production to the year 1990. (Remember that a supply price estimate shows the present value of expenditures divided by the present value of output.) A number of different sensitivities were undertaken, but their 'normal case,' assuming a 10 per cent rate of discount, generated a 'social' cost for Alberta crude oil of \$1.20/b; adding payments to landowners (including the provincial government) increased the cost to \$1.91/b, and adding projected income taxes generated a 'private' cost of \$2.24/b. (The three costs just given, if transformed to a cost per cubic metre, would be \$7.55, \$12.02, and \$14.10.) This compared to a 1969 market price of \$2.55/b. Watkins and Sharp suggested that on average oil companies were earning approximately a 15 per cent rate of return over this period. The two governments' policies seemed quite effective in capturing a large share of the profits on this oil. Using a 10 per cent rate of discount as representative of the marginal opportunity cost of

investment, the governments were estimated to capture 77 per cent (that is, \$1.04/\$1.35) of the economic rent on an average barrel. Of course, such an average cost covers an unknown range of marginal and average costs for different pools.

While the Watkins and Sharp study examined the cost of all conventional Alberta crude found from 1947 through 1968, others have looked at the year-to-year variation in the average cost of oil. One early study was Blackman and MacFadyen (1974), but we will focus on work done for the Economic Council of Canada in the mid-1980s (Eglington and Uffelman, 1983) and after that by the Canadian Energy Research Institute (Slagorsky and Pasay, 1985; McLachlan, 1990, 1991; Kolody, 1992; Chan, 1993; Heath, Chan, and Star- iha, 1995; and Quinn and Luthin, 1997).

The **Eglington and Uffelman (1983)** analysis considered the capital cost of oil reserve additions in Alberta for the years 1957 through 1979; the cost was a cost of oil-in-the-ground in 1981 dollars, for the most part using the Canadian Industrial Selling Price Index as the price deflator. Expenditure data came from the Canadian Petroleum Association (CPA, now CAPP), and a number of factors were used for different expenditure categories to allocate costs between oil and natural gas. Reserves data were the Energy Resources Conservation Board's reported annual 'booked' reserves. It was assumed that bonus payments were those that occurred three years before the reserves were booked; geological expenses were those incurred two years previously, and exploratory drilling expenses those incurred the previous year. In each case, an interest factor was added to costs to allow for the required return on capital during the delay between the expenditure and the reserves additions. Development expenses were assumed to be tied

Table 8.5: Eglington and Uffelman Supply Costs of Reserves Additions

	<i>Social Cost (\$/m³)</i>	<i>Private Cost (\$/m³)</i>	<i>Social Supply Cost (\$/m³ of lifted oil)</i>	<i>Booked Reserves (10⁶ m³)</i>
1957	11.82	13.94	23.64	51.8
1958	12.25	15.56	24.50	47.9
1959	13.96	17.27	27.92	43.0
1960	13.24	16.66	26.48	43.8
1961	10.76	13.33	21.52	100.0
1962	5.14	6.32	10.18	104.0
1963	4.97	6.00	9.94	106.3
1964	4.40	5.33	8.80	131.7
1965	4.17	5.09	8.34	142.0
1966	4.09	5.20	8.18	154.5
1967	7.03	9.07	14.06	95.8
1968	7.57	9.98	15.14	89.4
1969	10.11	13.62	20.22	65.7
1970	12.50	17.14	25.00	50.6
1971	20.49	27.00	40.98	28.5
1972	20.30	26.35	40.60	25.3
1973	22.98	29.01	45.96	19.4
1974	33.34	41.13	66.68	11.2
1975	31.66	37.78	63.32	11.0
1976	29.45	34.71	58.90	10.3
1977	42.20	48.58	84.40	13.2
1978	53.92	63.79	107.84	16.4
1979	44.43	53.68	88.86	21.7

Note: Costs are in 1981 dollars.

to the booked reserves in that year. The per barrel 'social' cost excluded bonus bids, which were considered to be part of the economic rent transferred to the government. The 'private' cost included the bonus bids. Eglington and Uffelman noted that the cost of oil-in-the-ground could be transformed into a supply price per barrel of oil produced by multiplying it by an appropriate factor that reflected the time value of money and the expected timing of lifting the oil; for example, with an annual percentage decline rate of 8 per cent per year in production over a production life of thirty years, and an annual discount rate of 10 per cent, this factor would be about 2. (The equation to make this adjustment is shown in Section 4.A.) Due to the tremendous year-to-year variability in booked reserves, Eglington and Uffelman preferred to use five-year moving averages of expenditures and booked reserves. Several sensitivity cases were run, but the main results are seen in Table 8.5.

The table shows private and social costs for oil-in-the-ground and a social supply cost for lifted oil (assuming a factor of two to go from oil-in-the-ground to produced oil) with all costs in dollars per cubic metre. The table also shows the five-year moving average of booked reserves in millions of cubic metres. It should be noted that the social supply costs are much higher than Watkins and Sharp's \$7.55/m³, which includes an operating cost of \$2.25. This is true even if only the earlier years (1957 to 1968) covered by the Watkins and Sharp study are considered. The oil found prior to 1955 may have been particularly cheap. But there may also be major differences in the ways in which the data were treated. Thus Eglington and Uffelman include implied interest costs on top of the exploratory spending to account for lags between expenses and reserve additions, and they have put all values in terms of 1981 dollars. The latter adjustment is significant, due to the high inflation felt in the 1970s. (If the Watkins and Sharp capital cost of \$5.30/m³ [= \$7.55-\$2.25] is inflated by the Industrial Selling Price Index from 1969 to 1981, the average exploration and development cost of Alberta oil becomes \$15.14/m³, which is more in line with the costs reported by Eglington and Uffelman for the period before 1970.)

An obvious question of interest is what meaning one might give to the annual costs derived by Eglington and Uffelman. It is important to note that neither the social nor the private costs trace out an average cost curve for reserve additions. This is because an average cost curve is a ranking of reserve additions from low cost to high cost; thus, in any year, if there are more reserves additions, more higher-cost projects will have been undertaken, and the average cost of reserves additions in that year will be higher. But the average costs reported in Table 8.5 tend to be lowest in the period of highest reserves additions and highest in times of the smallest reserves additions. One might argue that this simply reflects the great uncertainty in the process of reserves additions, so that when oil companies are unusually lucky their costs tend to be low, and vice versa. While this is true, one might expect that over a number of years things would tend to average out, and, if the yearly values were tracing out an average cost or marginal cost (supply) curve, the expected positive relation between costs and the volume of reserves additions would be apparent. However, this is not seen. Rather, as economic logic would suggest, the reported average costs reflect a mix of movements along the curve and shifts in the curve. Presumably movements along the curve are driven largely by increases in the expected level of

oil prices, while shifts in the curve reflect a variety of factors, including the following three: (1) technological changes and knowledge generation, including the discovery of new oil plays, which increase supply and allow more reserves to be added at any given cost; (2) depletion effects, which reduce supply as oil becomes harder and harder to find; and (3) shifts in the curves due to uncertainty, that is, good or bad luck. Since real oil prices were relatively low and falling in the 1960s, when reserves additions were at their highest, and real prices increased markedly in the 1970s when reserves additions were low and tending to decline, movements along an average cost curve offer little explanatory value. Rather, shifts in the curves seem to be particularly significant, with new knowledge (and good luck?) operating strongly in the 1960s, and the 1970s showing strong depletion effects (and bad luck?). Table 8.5 does indicate that the cost of reserves additions is higher in periods with higher prices, as economics would lead us to expect: that is, higher prices induce companies to search for higher-cost oil.

The Canadian Energy Research Institute (CERI) has also undertaken average cost studies, both of annual costs for the Province, and a comparison of costs for a sample of companies in the early 1990s. McLachlan (1990) estimates both 'short-term replacement costs' (STRC) and 'long-term replacement costs' (LTRC) for Alberta oil and natural gas, from 1970 to 1988. Several cases are presented. The results we will summarize calculate STRC's as the sum of appropriately lagged expenditures divided by total reported reserves additions and so are a cost of oil-in-the-ground. It can be interpreted as "the *weighted average* of the finding cost and development cost components for the **reserves additions from a particular year**" (McLachlan, 1990, p. 45). Reserves added in year *t* are associated with land expenditures two years previously, geological expenses one year prior, and exploratory and development drilling costs in the same year as the reserves additions. The inclusion of land expenditures, which are largely bonuses paid to the provincial government, implies that the costs are from a 'private' rather than 'social' perspective. Early work by CERI included implied interest costs for the expenses from an earlier year, but McLachlan's study did not. LTRC's use appreciated estimates of reserves added, where reserves are credited to the discovery year. McLachlan (1990, p. 45) argues that the LTRC is "the *sum* of the finding and development cost components for the **fully appreciated reserves from a particular discovery year**." It is assumed that

Table 8.6: McLachlan's CERI Reserves Addition Costs

	STRC (\$/m ³)	LTRC (\$/m ³)	Appreciated Reserves (10 ⁶ m ³)	Price (\$/m ³)
1970	na	142.54	4.3	39.27
1971	na	67.66	10.9	42.33
1972	na	117.63	4.8	40.42
1973	na	18.53	30.5	45.39
1974	na	71.99	8.2	65.84
1975	na	148.55	4.2	75.37
1976	na	112.32	6.5	81.22
1977	na	38.88	26.4	91.75
1978	na	25.89	51.1	103.56
1979	37.11	53.46	32.7	101.67
1980	72.04	102.92	17.5	108.20
1981	52.48	173.14	10.1	118.25
1982	248.86	124.71	14.9	148.62
1983	29.11	103.33	21.8	175.48
1984	54.07	119.49	19.9	178.41
1985	43.17	76.09	30.3	177.49
1986	65.06	84.75	20.0	95.37
1987	75.30	64.59	22.9	110.01
1988	32.95	70.50	11.0	78.42

Note: Prices and costs are in 1981 dollars.

reserves in a pool are completely proved up in five years, with the allocation of development expenditures to the five years mimicking the reserves appreciation pattern. The same lags as in the STRC calculations are applied to exploration expenditures, while development expenditures in any year are allocated to pools discovered in the previous five years. This required estimated development expenses for the years 1989 to 1993, so total development costs could be included for reserves found up to 1988. All expenditures are in 1988 dollars, with deflators drawn mainly from the inflation cost indices of the Canadian Petroleum Association. Expenditures are allocated between oil and natural gas on the basis of the relative total drilling footage.

Table 8.6 summarizes the results. The costs are in dollars per cubic metre of oil-in-the-ground. Average oil prices are shown as well, in dollars per cubic metre. Also shown are the appreciated reserves credited to each year (in millions of cubic metres); these are the reserves used for the LTRC estimates. In order to allow some comparability with the Eglington and Uffelman estimates, costs and prices are shown in 1981 dollars; McLachlan's 1988 costs and average Alberta oil prices were adjusted using the Canadian GDP price deflator.

Interpretation of McLachlan's results is difficult, and costs show an erratic pattern over time. The only comment McLachlan offers is that costs seem to have fallen after the early 1980s. Clearly, the combination of reserve volumes discovered and the LTRC does not trace out a single average cost curve. Larger volumes tend to exhibit smaller costs, as might be expected if larger pools imply an unusually lucky year in exploration. (The LTRC and the quantity of reserves move in opposite directions in all years.) But this seems to suggest that shifts in the curve (for example, the new knowledge that a particular pool is large) tend to overwhelm the basic shape of the curve. The chance of discoveries may also help explain the rather strange result that in seven years the LTRC (which is a cost of oil-in-the-ground) is actually higher than the average market price of oil as lifted. Alternatively, this might reflect bad decision-making, expectations of price rises, or flaws in the whole concept of replacement costs. (Eglington and Uffelman suggested that in the late 1970s the cost of oil reserves additions were higher than the expected value of oil-in-the-ground, although their costs were lower than the market prices for lifted oil.)

Perusal of the assorted oil-in-the-ground costs generated so far make clear why it is difficult to place much reliance on any single estimate. The STRC and LTRC costs from McLachlan not only differ greatly in value but do not even change in the same direction in four of the ten years. The McLachlan LTRC and the Eglington and Uffelman private cost estimates also differ greatly and move in opposite directions in seven of the nine yearly changes that they share. In six of ten years, the LTRC is greater than the private cost estimate, usually by large amounts. (The average private cost from 1970 to 1979 is \$36.32/cubic metre, while the average LTRC is \$79.75/cubic metre.) One implication of this is that the particular assumptions made in estimating oil costs are critical. (It should be noted that the two studies utilize mainly the same data sources.) And it is also clear that the changes from one year to the next have relatively little meaning. Broader trends may be more meaningful, but even here it is hard to see similarities in the 1970s between the Eglington and Uffelman and the McLachlan studies. This could mean that direct cost estimate studies are of little value at all. Or it may mean that the form of the reserves data (i.e., whether appreciated discoveries or reported gross reserves additions) is critical to the results. McLachlan, in fact, places relatively little weight on her numerical results, suggesting that she is primarily concerned with issues of methodology.

Heath, Chan, and Stariha (1995) and Quinn and Luthin (1997) continued the CERI cost analysis in a somewhat more disaggregated manner. Quinn and Luthin, for example, calculated unit costs for oil reserves additions for a sample of forty-three Western Canadian oil companies, divided into three size groups. The sample accounted for around 40 per cent of industry activity. Their estimates allocate expenditures between oil and gas on the basis of the relative proportions of successful wells, and they relate exploration and development expenditures in a particular year to proven reserves additions in that year, without any assumed lags. (They argue that the lags between land acquisition and geological expenditures and resultant reserves additions are so variable that one might as well assume no lag.) They generally excluded 'Revisions' from their reserves additions figures since these primarily reflect reassessment of oil flow rates and are not associated with current investments. Table 8.7 summarizes some of their findings; values have been transformed from 1996 dollars per barrel into 1981 dollars per cubic metre to facilitate comparison with the previous tables. The deflator for inflation is the Canadian GDP Price Deflator. The 'social' cost is the 'private' cost less land expenditures.

Oil reserves additions increased over this period, suggesting that there were some improvements in technology and knowledge. (That is, more reserves additions resulted each year, while the average cost showed a tendency to decline.) Quinn and Luthin's private costs are higher than those estimated by Eglington and Nugent for years prior to 1974, but lower than the 1974-79 costs, and lower than McLachlan's STRC's. (Averages are: Quinn and Luthin, 1992-96, \$27.67/m³; Eglington and Nugent, 1957-73, \$13.93/m³; Eglington and Nugent, 1974-79, \$39.76/m³; McLachlan, 1979-88, \$71.01/m³.) Clearly the average cost of reserves additions tends to follow oil prices, with higher prices (as in 1980-85) drawing forth higher-cost oil. There are, it must be noted, two main reasons for oil costs to rise as prices rise: (1) with constant input prices, producers are encouraged to look for deeper, harder to find and smaller pools and to undertake more expensive development projects; and (2) the extra exploratory and development effort attracted by higher prices will tend to push up the prices of drilling rigs and other inputs, making oil industry activities more expensive relative to other activities in the economy. Thus, for example, McLachlan (1990, p. 56) shows drilling costs rising by 289 per cent from 1972 to 1981, when the GDP price deflator rose by 126 per cent. (McLachlan's study

Table 8.7: Quinn and Luthin CERI Reserves Addition Costs by Company Size (1981\$/m³)

	<i>Private Cost</i>	<i>Social Cost</i>	<i>Private Cost Seniors</i>	<i>Private Cost Intermediate</i>	<i>Private Cost Juniors</i>	<i>Market Price</i>
1992	28.90	26.49	26.39	57.66	27.96	96.68
1993	28.05	24.59	25.35	45.59	31.40	91.53
1994	32.20	27.26	31.31	47.46	25.96	88.96
1995	24.62	22.09	22.87	46.82	22.90	84.85
1996	24.56	21.49	23.42	33.70	32.17	88.06

attempted to isolate the first of these effects by deflating exploratory costs by the drilling cost index.) Such cost rises could reflect 'rent seeking' behaviour by input suppliers, as they attempt to gain some of the increased value of oil and gas.

Quinn and Luthin offer no real explanation of why oil companies of intermediate size apparently exhibit such high costs of oil reserves additions. If the forty-three companies are considered separately, there is wide variation in the five-year average costs, the highest cost company having a per unit cost almost 300 per cent higher than the lowest cost company. They suggest that companies may find this sort of information useful for 'benchmarking' purposes, in which a company can see how well it is doing compared to others in the industry. The wide company differentials, like the large range of historical variation in reserves additions costs, point out the great heterogeneity in industry experience with respect to the cost of incremental oil supplies.

Even apart from the conceptual difficulties involved in directly measuring the unit cost of adding oil reserves, it is difficult to weave any but the simplest stories ('Higher prices draw out higher cost oil') out of the costs calculated. Therefore, while 'replacement cost' studies are common in the industry, most economists have tended not to rely on this approach as the main avenue of petroleum supply modelling. Instead, they have generally tried to deduce the position of, and shift in, the marginal cost (supply) curve for crude oil by more elaborate and indirect means.

Lasserre (1985) provides an example of a researcher drawing directly on discovery cost estimates to try to understand the oil-supply process. He looked at the discovery cost of Alberta oil in order to examine the suitability of using discovery cost as a proxy for the user cost of crude oil production. Recall, from Chapter Four, that the user cost is the present value of the future profits given up by lifting a unit of crude oil today, rather than leaving it in the ground.

Consider a simple resource extraction model, which treats exploration as an activity to increase reserves, and which assumes that crude oil lifting costs are a function of the volume of reserves and that there are no 'depletion' effects in the process of adding reserves through exploration. In this model, the marginal benefit of adding reserves is the anticipated profit from a unit of added reserves; this profit is measured by the marginal user cost. (That is, the present value profit of adding one unit to reserves would be the same as the present value profit foregone by producing a unit out of reserves.) The profit-maximizing competitive producer would, then, add reserves through exploration until the marginal cost of new discoveries just equalled this marginal benefit. Hence, marginal discovery cost provides a measure of the marginal user cost. This is a potentially useful result since the marginal user costs depends on such unobservable factors as producer's expectations about future oil prices so is not easily estimated by an outside observer. However, if, contrary to Lasserre's assumption, current discoveries deplete the stock of available reserves and thereby raise future discovery costs (a depletion effect), there is a user cost of discoveries, and the estimated capital cost of discoveries will understate the total cost. In this case, the estimated discovery cost would understate the user cost of production.

Lasserre, drawing on cost information from Uhler and Eglington (1983), calculates the cost of reserves additions per barrel of oil in-the-ground from 1957 to 1981 for various components of cost, and for 'full marginal development cost' (FMDC). There is considerable year-to-year variation in FMDC and its components, as seen in the tables above. Roughly, FMDC rises slightly to the year 1960 from a little over \$2.00/b in 1957, falls to not much over \$1.00/b in the early and mid-1960s, then rises sharply, peaking at almost \$10.00/b in 1978, and ending the study period at about \$8.30/b in 1980. From the late 1960s, exploratory drilling and development costs increased particularly markedly. Lasserre

draws a number of conclusions, including the following (Lasserre, 1985, pp. 480–82): (1) there is considerable stochastic variability in unit reserves addition costs; (2) rising costs in part reflect depletion effects, as the stock of undeveloped reserves declines and reserves additions become harder to make; (3) rising costs may also reflect diminishing returns to effort in any one year as the level of exploration and development increases (independent of depletion effects), reflecting, for example, the problems in spreading fixed knowledge and inputs over more effort, and (4) user costs in the reserves addition process are significant, as indicated by significant bonus bids, implying that discovery costs are not a valid proxy for the user costs of lifting oil.

Lasserre provides an interesting application of direct-cost data. Most economists, however, have been skeptical about the possibility of drawing meaningful conclusions from trends in unit costs alone and have turned to more complicated econometric estimation of oil-supply relationships and functions. We now turn to some of this literature as applied to Alberta crude oil supply.

5. Indirect Supply Estimation

A. Introduction

Since the oil-supply process is so complicated, different studies make quite different simplifying assumptions and focus on different parts of the process. We will begin by reviewing some of the major dimensions of difference.

One is the specific variable that the model is designed to explain. Most models look at oil as the product, but some studies focus primarily on oil in the ground (e.g., reserves additions), while others look at the volume of crude oil lifted. As has been discussed previously, these are related products. Crude oil cannot be lifted unless there are reserves available, and the value of a unit of reserves added is based in part on the expected prices of lifted crude. Other studies, however, set the level of industry activity ('effort') as the variable to be explained. They might, for instance look at total real exploratory spending or at the number of exploratory wells or the exploratory well footage drilled. It is also necessary to decide whether a single variable measures the 'effort,' or whether there are a number of separate activities involved (e.g., land acquired, G&G activities, drilling).

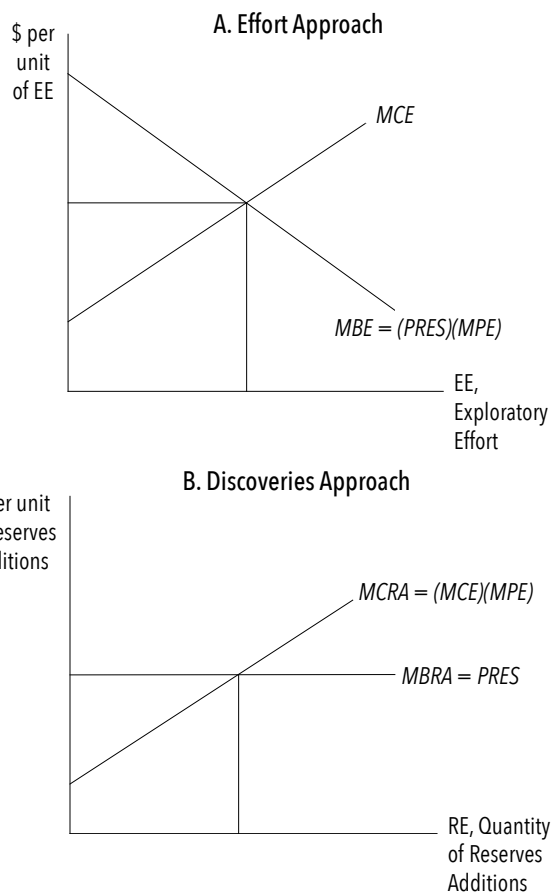


Figure 8.2 Reserves Additions: Discoveries and Effort Approaches

The two types of variables ('oil' and 'effort') are related. The volume of oil added to reserves obviously depends on the amount of exploration undertaken, and the quantity of effort must be a function of expected discoveries. Figure 8.2 provides a simple reconciliation of the 'discovery' and 'effort' approaches for an effectively competitive, profit-maximizing crude oil industry. Figure 8.2(A) is drawn on the assumption that companies will undertake exploratory effort (*EE*) up to the level at which the marginal benefits of exploration (*MBE*) equal the marginal costs of exploration (*MCE*). The *MCE* curve is drawn as upward-sloping on the assumption that more exploration causes price rises in the costs of the inputs used for exploration. (If we were looking at a region that is a small part of the total North American oil industry, these input costs might not change, and the *MCE* curve would be a horizontal line.) The marginal benefit of exploration is the product of two key variables, the value of a unit of

discovered reserves (*PRES*) and the marginal product of exploration (*MPE*, that is, the number of reserves that would be found by one unit of exploratory effort.) The optimal amount of exploratory effort is shown where these two curves intersect. That is,

$$MCE = MBE = (PRES)(MPE) = (PRES)\left(\frac{\partial RA}{\partial EE}\right),$$

where *RA* stands for reserves additions, and the last expression is the change in (the derivative of) reserves with respect to the change in (the derivative of) exploratory effort. In order to understand how exploratory effort changes, it is necessary to look at how the two curves might shift. More exploration could result from anything that causes a fall in the cost of exploration, anything that might increase the price of reserves and/or anything that would increase the marginal productivity of exploration. Remember that the price of reserves is the value of a unit of oil in the ground; it would increase the higher is the expected market price of (lifted) crude, the faster reserves will be depleted, the lower are variable development and operating costs and the lower the rate of discount. The marginal productivity of investment tends to fall as a result of depletion effects, which specify the extent to which new discoveries become more difficult as more and more of the available resource base is discovered. However, the marginal productivity of investment will also increase as a result of technological innovations (like 3-D seismic) that make exploration more efficient, or knowledge changes, like the discovery of a new oil play in a geologic formation that was not previously known to hold oil.

Figure 8.2(B) takes the quantity of reserves additions as the 'dependent' variable instead of the amount of exploration. Rational companies will add reserves up to the level where the marginal benefits of reserves additions (*MBRA*) equals the marginal costs of reserves additions (*MCRA*). The former (for a price-taking industry, which is a small part of the total oil market) is equal to the price (value) of reserves (*PRES*). The marginal cost of reserves additions will be equal to the marginal cost of an extra unit of exploration (*MCE*) multiplied by the marginal exploratory effort required to add one more unit of reserves. Equilibrium will occur where the marginal benefits of reserves additions equals the marginal costs of reserves additions.

That is,

$$MBRA = PRES = MCRA = MCE\left(\frac{\partial EE}{\partial RA}\right) = \left(\frac{MCE}{MPE}\right).$$

Since this is describing exactly the same process as the exploratory effort model, it is not surprising that this equation shows exactly the same relationships amongst *PRES*, *MCE*, and the two derivative terms. Variations in the volume of reserves added will reflect any factors that shift either the marginal costs or marginal benefits of reserves additions. These, of course, are the same factors that might cause a change in the level of exploratory effort!

A second major difference amongst the 'indirect' supply studies relates to what might simply be called the degree of sophistication of the analysis, as illustrated in Figure 8.1. The simplest approach is relatively atheoretical trend extrapolation, where a simple historical correlation is assumed to continue in the future as it has held in the past. This could involve time extrapolation (e.g., production per year or the reserves added per year) or might involve the continuation of the trend in the change of one variable (e.g., the quantity of oil found per successful well) relative to another (e.g., the number of exploratory wells drilled). More complicated statistical modelling can take place through 'reasoned' but informal or *ad hoc* methods. Thus, on the basis of one's understanding of the industry, a list of variables could be set out that might be expected to affect the variable of interest, and then an equation estimated to show the relationships amongst the variables. For example, the volumes of reserves added in a year are specified as a function of the price of oil, the cost of hiring a drilling rig, the cost of money (that is, an interest rate), time (to allow for technological improvements) and the cumulative discoveries up to this time (to allow for depletion effects). At a higher level of complexity, one might build a formal model of industry behaviour and derive a set of equations from it that reflect the anticipated behaviour of the industry, and then estimate this set of equations. We call this 'econometric (statistical) optimization modelling.'

The degree of complexity that may arise in the formal economic modelling approach warrants discussion. Most such models begin at the level of the individual oil company. It is normally assumed that companies make decisions in an optimal way. Thus, for example, a company might be imagined to be looking at the possibility of adding to its crude oil reserves through a joint-product production function, which describes the current state of knowledge and technology. The production function would describe the volumes of oil and natural gas reserves additions (output) that would result from the efficient utilization of various inputs such as land, geological surveys,

exploratory wells, undeveloped reserves, and labour. Given the prices of oil and natural gas reserves and the costs of the various inputs, the company would purchase the optimal quantities of the productive inputs to produce the optimal quantity of oil and natural gas reserves additions. 'Optimal' is most frequently taken to mean 'profit-maximizing.' This model typically leads to a set of interrelated equations describing both the input demands and the supplies of reserves additions. Moreover, since the equations are interrelated, they must normally be estimated jointly and assume a particular form because some of the equations impose constraints on the forms that other equations can take.

A further degree of complication is added by the fact that data are not usually available on a firm-by-firm basis, and, even if they were, it would be too complicated to estimate equations for all of the firms separately. Accordingly, optimization models typically are simplified by assuming that the optimization model (which is normally set out for a single firm) also holds at the aggregate level for the entire industry. This 'aggregation' assumption can come from two quite different premises. The first is a 'true' aggregation process, in which the sum of the optimization procedures of all the separate firms happens to lead to a total that is exactly the same optimization problem at the aggregate provincial level. However, most of the literature on aggregation suggests that the conditions necessary for this to happen are so extreme as to be very unlikely. (For instance, it might require the assumption that all companies have exactly the same knowledge and initial holdings of land.) More frequently, a more *ad hoc* assumption is made that the industry behaves as if it were like a single optimizing decision-maker with characteristics reflecting the aggregate characteristics of the industry; or that the industry operates as if it consists of a number of 'representative firms' who are all identical and behave in an optimizing manner. This representative firm approach might be seen as an example of a simplifying assumption; that is, an industry consisting of a number of different firms, each in a different position, is assumed to behave as if it consisted of a number of identical representative firms.

This issue of simplifying assumptions lies at the heart of many of the disagreements about what is the 'best' oil-supply model. Is it valid, for instance, to build a model that looks at crude oil reserves additions alone, ignoring the joint-product connection with natural gas? Given that different oil pools are so different in characteristics, must the pools be treated separately as sources of reserves additions or lifted

crude, or can a simpler, province-wide, aggregate model of oil supply be built? From a practical point of view, the aggregate models have great appeal since they are simpler and because they have far smaller data requirements. But can one move to the aggregate level and still derive a useful representation of industry behaviour? These are open questions about which different analysts have different opinions, and the response may be different at different points in time or for different types of industry activity.

B. Input Measures: Studies of Industry Expenditures

In 1984, as part of the Economic Council of Canada's study of Canadian energy policy, Scarfe and Rilkoﬀ undertook an econometric analysis of petroleum industry exploration and development expenditures in Alberta. The modelling framework was an inventory adjustment process in which companies are assumed to estimate an optimal level of petroleum reserves and undertake investment in such a way as to move towards this optimum. The optimal size of reserves is a function of expected profitability. Estimation of expected profitability is complicated by the dynamic aspects of industry activity: reserves additions may become more difficult over time due to depletion of the stock of undiscovered reserves, but technological advances may make reserves additions less costly. All monetary values were in 1981 dollars, deflated with the Canadian Industrial Selling Price Index. The major variables that Scarfe and Rilkoﬀ included in their equations were as follows:

- The dependent variables that they were trying to explain were **the industry's expenditures** in Alberta for three categories of exploratory investment and four of development, as reported by the Canadian Petroleum Association (now, CAPP, the Canadian Association of Petroleum Producers).
- A **value ('price') of oil and gas reserves in the ground**, derived from Uhler and Eglington (1983), with the expectation that higher prices generate higher profits and therefore higher industry expenditures. Essentially, this is an estimate of the present-value after-tax profit expected from a unit of reserves. It takes the expected future wellhead price of petroleum and reduces it to allow for future operating and development costs and for the delay involved in the depletion of oil

Table 8.8: Uhler and Eglington Oil Wellhead and Reserves Prices and Development and Operating Costs (nominal \$/m³)

	<i>Wellhead Price</i>	<i>Netback Price</i>	<i>Developed Reserves Price</i>	<i>Undeveloped Reserves Price</i>	<i>Operating Cost</i>	<i>Development Cost</i>
1947-51	18.19	14.36 (.79)	6.42 (.35)	5.59 (.31)	1.98	0.64
1952-56	15.81	10.94 (.69)	4.39 (.27)	3.51 (.22)	2.08	0.59
1957-61	15.71	10.12 (.64)	4.03 (.26)	2.53 (.16)	2.75	1.01
1962-66	15.98	10.65 (.66)	4.59 (.28)	3.15 (.20)	2.46	0.96
1967-71	16.45	11.25 (.68)	4.15 (.25)	2.63 (.16)	2.09	1.02
1972-76	35.07	24.31 (.69)	14.93 (.43)	12.99 (.37)	2.87	0.93
1977-81	88.47	52.20 (.59)	38.25 (.43)	30.20 (.34)	6.37	3.01

Note: Numbers in parentheses show the value as a proportion of the wellhead price.

reserves (since a reservoir is typically drained over several decades). The reserves prices are in nominal dollars. The annual adjustments for operating costs (for the developed reserves price) and operating and development costs (for the undeveloped reserves price) are based on the industry's average costs during that year. Total industry operating expenses are divided between oil and gas on the basis of the proportion of operating wells of each type. Development costs include a development well component based on the average cost of drilling a well and an oilfield equipment component based on average industry expenses in that year. For years prior to 1974, the actual crude oil price is assumed to represent future expected nominal oil prices. For 1974 and 1975, it is assumed that producers expected the nominal price to rise by 5%/year, rising to an expectation of 10%/year from 1976 through 1981. Table 8.8 summarizes Uhler and Eglington's prices; it shows average prices over five-year periods, including a wellhead price, a 'netback' price at the wellhead after operating costs and royalties, and both developed reserves and undeveloped reserves prices. Prices are in nominal dollars per cubic metre; the number in parenthesis shows the price as a proportion of the wellhead price. The last two columns show the estimated operating and development costs per cubic metre. As was discussed in Chapter Six, the average field price of crude fell in the 1950s, as Alberta oil penetrated more distant markets, and only began to rise markedly after international oil prices began to rise in the 1970s. The fall in the netback price as a proportion of the wellhead price after 1951

and in the 1977-81 period reflects the increase in provincial royalties in 1952 and 1974. From 1947 through 1976, average operating costs varied around \$2.00/cubic metre, while development costs rose on average after the first decade but were relatively stable from 1956 through 1976. After 1974, both operating and development costs rose appreciably as wellhead prices increased, but by relatively less; that is, the value of oil in the ground rose somewhat faster than wellhead prices. For industry expenditures that applied to both oil and natural gas, weighted average petroleum prices were calculated with the weights given to oil as opposed to gas based either on a measure of the drilling 'intent' of producers or the relative numbers of completed oil or gas wells.

- **Production of petroleum the previous period**, with the expectation that higher production requires higher expenditures in order to increase reserves back up to the desired level. The variable used was a weighted average of the logarithms of the oil and gas output, the weights being the relative completion rates of oil and gas wells.
- **The previous year's expenditure**, which is expected to correlate positively with this year's expenditures. That is, one of the 'independent' explanatory variables was the one-year lagged value of the dependent variable being explained. This procedure is designed to allow for rigidities in the inventory readjustment process. For example, if a rise in the price of oil induces more investment this year, then this increase in investment will in turn be associated with more investment the year after, and so on. In fact, the size of the influence of the lagged dependent variable can be taken

Table 8.9: Estimated Coefficients in the Scarfe/Rilkoff Oil Expenditure Model

<i>Expenditure</i>	<i>Price</i>	<i>Output</i>	<i>Lagged Dependent</i>	<i>R²</i>	<i>Long-run price elasticity</i>
Geological	.1953*	.1359*	.6583*	.85	.57
Exploratory Drilling	.1657*	.1294*	.8914*	.95	1.53
Land acquisition and rents	.3432*	.1227*	.5376*	.81	.74
All exploration	.2495*	.1282*	.7328*	.94	.93
Development drilling	.1393	.1461*	.8760*	.92	1.12
Field equipment	.2135*	.4198*	.4998*	.95	.43
Enhanced oil recovery	.1853	.2873*	.5460*	.79	.41
All development	.1786*	.2058*	.6077*	.91	.46

* Significant at the 5% level.

as a measure of the speed with which industry behaviour adjusts to a rise in the petroleum price. (A value of zero means that all of the adjustment occurs in the initial year, and there is no effect on current expenditures through past expenditures. The closer the value comes to one, the longer the time it takes to fully adjust behaviour to the higher price. That is, a value appreciably greater than zero implies that the long-run elasticity of expenditure with respect to price changes is significantly greater than the short-run elasticity.)

Equations were estimated by simple Ordinary Least Squares (OLS) regression, using annual data from 1957–81 (1960–81 for exploration expenditures). The equation estimated was of the following form, which is linear in the natural logarithms of the variables:

$$(investment_t) = a_1(price_t)^{a_2}(output_t)^{a_3}(investment_{t-1})^{a_4}.$$

The four ‘a’ terms are the numerical coefficients that are estimated by the OLS procedure to provide the best fit to the data. In this form, the price and output coefficients are estimates of the short-run elasticities of expenditures with respect to that variable. (Remember that elasticity shows the percentage change in one variable – e.g., exploration expenditures – in response to the percentage change in another variable – e.g., the price of petroleum.) The long-run elasticities can be derived by dividing the short-run elasticity by one minus the lagged dependent variable’s estimated coefficient. Table 8.9 shows some of Scarfe and Rilkoff’s results, where coefficients that were significant at a 5 per cent level of confidence are indicated with an asterisk (*). (This means that one can be 95% confident that the coefficient

is not actually equal to zero.) The *R*-square value is the adjusted correlation coefficient, and it provides a measure of the per cent of variation in the dependent variable that is ‘explained’ by the equation.

It is not unusual to find that a large amount of the variation in a dependent variable is captured by a time series equation that includes the lagged value of that variable. Scarfe and Rilkoff note that both price and output are positively related to expenditures, as was expected. They found that they had to try a number of different forms of the price variable to derive what appeared to be reasonable results for the development equations, and two of the price elasticities (drilling and EOR) failed to pass the 5 per cent significance test; the estimated equation tracked the historical data most poorly in these cases. All the exploration equations and the field equipment development equation were based on prices weighted by the intent ratios. However, development drilling and total development expenditures used prices weighted by numbers of completions, and the EOR equation used the netback wellhead price. They noted that their results suggested, in comparing exploration and development, that “reserves prices ... are more important with respect to exploration expenditures, ... expenditure levels are more sensitive to production on the development side, ... [and] the adjustment process is somewhat slower for exploration” (Scarfe and Rilkoff, 1984, p. 21). They also note that, in the long run, drilling expenditures are the only categories that are elastic in response to price.

Two further aspects of the Scarfe and Rilkoff study merit brief attention. One relates to an alternative set of regressions, which included a variable measuring the current ‘cash flow’ to the industry, after allowance for operating expenses (i.e., royalties, well-operating

costs, and land rentals). The production variable was dropped, in part because it correlated very highly with cash flow. The results were generally very similar to the ones reported earlier, although several equations had to be estimated with variants of the cash flow variable before good results were obtained. This version was run because of frequent reports in the industry press that investment in the industry is constrained by available cash flow. In other words, there are capital market constraints that may make it difficult for firms to raise outside capital, so they must rely on their own funds. In general, the cash flow results seem quite unconvincing for a variety of reasons. They are not as strong as those with production as a key variable; Scarfe and Rilkoff had to experiment to find a cash flow variable that seemed to work in a satisfactory manner; a number of Canadian petroleum companies clearly were able to tap financial markets for funds; and the cash flow argument does not imply that all cash flow is spent, but that in some circumstances cash flow may constrain spending, so cash flow would not be a general influence on expenditures.

Scarfe and Rilkoff also found that their model seemed to fit the final year of their sample quite poorly, and, even after a revision in the price series to allow for less buoyant expectations in 1981 than the Uhler-Uffelman numbers, their model mis-forecast the observed expenditures in 1982. Exploration expenditures, in particular, were significantly overestimated (by over 45%), as was development drilling (by over 25%). They noted that total development spending was forecast quite well, and that the trauma of the National Energy Program provided a very unsettled period in which to attempt a forecast.

It is satisfying to find that a simple econometric estimation of industry expenditures in Alberta can generate results that seem plausible theoretically and have a relatively high degree of statistical validity. However, it is important to remind readers that this is only one part of the oil-supply process. It is still necessary to determine how much petroleum production (in this case largely reserves additions) results from the expenditures.

It is also discouraging to see that, while many of Scarfe and Rilkoff estimated equations appeared to fit the historical data well, their results did not serve to provide a good forecast for even the first year after their sample period. This relatively poor forecasting ability has also been found in a number of U.S. econometric petroleum supply models. It is, of course, a rather surprising result, given that the estimated equations typically fit the historical data well. One

interpretation is that the modelling interest of economists tends to be attracted to the industry when unusual events occur, and it is precisely at these times that the historical regularities are most likely to be broken. For instance, in stable times, current prices may form the basis of price expectations for most producers, but this may not be true in more revolutionary times. The economic model suggests that investment should reflect long-term price expectations, but these are largely unobservable.

A key question, then, is whether estimates like those of Scarfe and Rilkoff would regain their legitimacy as a forecasting tool once a more stable industry regime is established again. It is possible to undertake a rough test of this possibility by comparing the actual investment expenditures from the mid-1980s through the 1990s (after the industry had operated a number of years in a deregulated environment) with those implied by the Scarfe/Rilkoff econometric results. It is important to note that the inclusion of the lagged dependent variable will tend to keep the forecast 'on track' to some degree; that is, variables that are of major significance in affecting industry expenditure, but are missing from the model, will influence the actual level of expenditures in any particular year, and then this will influence the following year's estimated expenditures. (That is, inclusion of a lagged dependent variable in the estimating equation, not only accounts for lags in the ability to adjust expenditures, but also serves as a way to 'capture' the effect of missing variables.)

Our out-of-period forecast of total exploration and development spending in 1981 dollars to the year 1992 uses a number of simplifying assumptions that impose obvious limitations on the interpretation of the results. However, it does provide a rough idea of whether the relationship estimated by Scarfe and Rilkoff over the period from the 1950s to the 1970s is reasonably predictive of industry activities once the trauma of the National Energy Program ended in 1985. Our forecast assumes: that the intent ratio data reported by Scarfe and Rilkoff for 1982 (p. 47), and used to obtain weighted petroleum price and production figures, continue through the forecast period; that the average of the 1979–81 ratio of reserves values to average wellhead prices (as reported in the *CAPP Statistical Handbook* for western Canadian crude) holds over this period; and that inflation in the Consumer Price Index (CPI) as reported by CAPP tracks inflation in the Industrial Selling Price Index used by Scarfe and Rilkoff. The differences between forecast exploration and development expenditures (from the Scarfe and

Table 8.10: Out of Period Forecast Based on the Scarfe/Rilkoff Model

	Exploration: Forecast - Actual (\$10 ⁶)	Exploration Forecast Error as % of Actual	Development: Forecast - Actual (\$10 ⁶)	Development Forecast Error as % of Actual
1984	2,473.4	79.9	916.5	45.3
1985	2,506.3	87.5	966.3	49.0
1986	1,490.9	56.4	623.9	55.4
1987	1,718.3	70.8	740.3	59.5
1988	1,353.4	60.4	657.9	69.9
1989	1,550.8	76.3	756.0	73.6
1990	1,705.7	92.2	827.9	76.8
1991	1,454.4	87.7	767.4	88.2
1992	1,381.1	85.8	759.6	93.3
1993	1,329.6	85.6	765.2	99.4
1994	1,373.7	88.8	797.3	100.4
1995	1,523.7	102.7	873.4	101.3
1996	1,705.7	118.7	953.6	100.4
1997	1,577.9	113.3	912.0	105.4
1998	1,208.3	88.3	773.4	117.8
1999	1,610.9	121.8	940.3	109.3
2000	2,080.0	165.9	1,131.1	104.5

Rilkoff equations) and the actual values (in millions of 1981 dollars, and as a per cent of the actual value) are shown in Table 8.10. The forecast errors are very large.

It can be seen that the tendency to overestimate in the years of the National Energy Program (1984 and 1985), remarked by Scarfe and Rilkoff, is present in this forecast, but that this tendency persists throughout the entire period, even after deregulation in 1985. For exploration, the percentage forecast error drops noticeably in 1986, but soon rises again, and shows a general tendency to increase. For development, the percentage forecast error is smaller at the start of the period but rises throughout. Part of the forecasting error may be due to the simplifying assumptions that we have made; our percentage errors of 80 per cent and 45 per cent for 1984 are higher than the errors of 45 per cent and 25 per cent noted by Scarfe and Rilkoff for 1982. Despite this, our simple simulation suggests that there was a persistent shift in the expenditure relationship from that estimated by Scarfe and Rilkoff. Of course, one would expect that the Scarfe/Rilkoff model would forecast much better for this period if it were re-estimated using data up to the end of the 1990s, but we have not undertaken this task. Moreover, the need to re-estimate the model to obtain

valid coefficients suggests that there are some structural elements missing.

Desbarats (1989) provides an extensive critical review of the Scarfe/Rilkoff model. She thinks that the focus on expenditures as the key variable of interest is appropriate. However, her re-estimation of Scarfe/Rilkoff using a different (and longer) series for reserves values finds that the reserve price variable does not appear to be significant and that the estimated coefficients seem to be very unstable. She suggests that the exploration expenditure model needs to be drawn from a more precise theoretical foundation and that more sophisticated econometric techniques for analysis should be used. There are three main foundations of the model that Desbarats constructs. The first relates to the profit-maximizing equilibrium condition for the desired level of reserves, assuming that the production function for petroleum exhibits a constant elasticity of substitution. (The elasticity of substitution measures the ability to substitute between different inputs while holding production constant.) Desired reserves (and also total exploration spending) are a function of the level of petroleum output, the elasticity of demand for petroleum, the input cost of adding reserves, and the elasticity of substitution between resources and other inputs in generating petroleum production. Secondly, Desbarats argues that uncertainty in the exploration process is inevitable, so that the way in which producers form their discovery expectations is critical; this expectation is represented by the producers' expectations regarding the size distribution of oil pools in the region, which may change over time as exploration proceeds. Finally, Desbarats accepts that there will be lags in the adjustment of reserves to the desired level.

The resultant general model is far too unconstrained to be estimated with the limited time series data available: for example, there are no strong guidelines on the functional form that should be used; any number of lag structures are possible; determination of a precise cost of non-resource inputs is not possible given the variable number of inputs that might be used and uncertainty about the extent to which certain expenditures (e.g., geophysical) relate to current or future reserves additions. Finally, the joint-cost problem is present, since exploration expenditures will add both oil and natural gas reserves. Thus, while Desbarats uses sophisticated econometric procedures, the final exploration expenditure equation she generates reflects a certain amount of pragmatic judgment. We will reproduce the estimated equation for which she reports an *R*-square value of 0.99 and which was

based on annual data for the years 1949 to 1982. The dependent variable was real exploration expenditures (E), in 1981 dollars. Explanatory variables included: a two-year average of the real reserves price of oil plus the reserves price of gas (P ; the reserves values are from Uhler and Eglington, and the units are $\$/\text{m}^3$ for oil and $\$/10^3 \text{ m}^3$ for natural gas); the sum of oil and gas output (Q); the inflation rate (IR , as measured by the CPI); the ratio of reserves additions for natural gas to gas output (RAG/QG); this variable summed for natural gas and oil (RA/Q); and the difference between domestic and import oil prices (PD). Finally, some of the variables are lagged values; we use $(-t)$ to represent a lag of t years. We do not report any of Desbarats evaluating statistics in the following equation (Desbarats, 1989, p. 55):

$$\ln(I) = -2.27 + .60\ln(I(-1)) + 1.24\ln(P) - .09IR(-1) + .003RA/Q(-1) + .002RAG/QG(-2) + .13\ln Q(-1) - .21PD(-1) - .87[Q(-1)-Q(-2)] - .20[IR(-1)-IR(-2)].$$

Given the number of variables included in the equation, the estimation possesses relatively few degrees of freedom, and the underlying properties of the time series have not been subject to the tests that are now common in cointegration analysis.

Desbarats suggests that this model explains exploration expenditures better than the Scarfe/Rilkoff model. The estimated coefficients generally have the expected sign; thus, a higher value for reserves additions stimulates more exploration expenditures, as does higher production in the previous year. Several variables are somewhat harder to interpret. Thus, the negative effect of an increase in production for the previous year leads Desbarats to speculate that scarce investment capital may be allocated away from exploration to more intensive development when companies are trying to increase production rapidly. Desbarats also notes that her model underestimates actual 1980 investment spending, if she uses estimates based on the 1949–79 period and uses the results to forecast 1980 expenditures. We suspect that, if the estimated coefficients for this period were applied to events after 1985, including the lower real prices after that date, the model would tend to significantly overestimate actual expenditures, much as did the Scarfe/Rilkoff model.

Helliwell et al. (1989) undertook a detailed econometric analysis of the Canadian petroleum industry, largely with the intent of analyzing the very extensive policy interventions from 1973 to 1985. Amongst other work, they estimated econometric equations for land payments (bonuses) for the crude petroleum industry

in the Western Canadian Sedimentary Basin, an area dominated by Alberta. We include discussion of this equation here because land payments are one type of industry expenditure. However, it is important to recognize that the size of bonus bids made for mineral rights is determined largely by the anticipated profits from the rights acquired; that is, rather than a cost item, land bonuses are best viewed as a part of economic rent.

Helliwell et al. drew on annual data from 1951 to 1985. Costs seem to have been divided between oil and gas on the basis of the relative footages of development drilling. Amongst the variables used to explain the level of expenditures is what is called a ‘profitability’ ratio. It is a little difficult to interpret their descriptions of how the profitability ratio is calculated. Their Figure 8.3 (Helliwell et al., p. 152) describes it as “Net Wellhead Revenue Divided by Marginal Cost,” while the text of the previous page says it is “real after-tax wellhead or field prices divided by the sum of real operating costs and the amortized exploration and development costs.” Neither of these descriptions seems adequate since each involves a ratio between a total and a per-unit measure. The profitability ratio (PR) for oil takes values ranging between about 0.6 to 1.9 over the period from 1951 to 1985, and we interpret it as the ratio of a discounted value per unit of oil sales (after royalty and income tax), over a typical lifetime of a pool, divided by a per-unit ‘supply cost’ for capital and operating costs. The authors assume that wellhead prices remain constant at the level of the initial year. The notion of a supply cost or price was described above. The profitability ratio used was a three-year moving average, the current year and the two previous years, which helps level out extreme values and allows for lag effects in the responses of expenditure to changes in profitability.

With respect to oil land payments (L), the more significant equation (R -square = 0.3091) is:

$$\ln L = 2.2714 + 1.1422\ln PR + 0.4168\ln CF,$$

where CF stands for industry cash flow, defined as revenues net of operating costs, royalties and income taxes. (t -values for the three estimated coefficients are 2.22, 3.75, and 2.73.) In this double logarithmic form, the estimated coefficients are elasticities, so a 10 per cent rise in the profitability ratio implies an 11.4 per cent rise in land payments. Note that factors that increase profits are also likely to raise cash flow, so land bonus payments would actually rise by more than this.

One possible interpretation of the limited forecasting ability of aggregate industry expenditure models like that of Scarfe and Rilkoff is that relatively simple econometric estimation fails to provide a useful depiction of activity for a complex industry in a complex environment. With sufficient effort, and ‘manipulation’ of explanatory variables like price, it will usually be possible to find some equation that seems to provide a reasonably good fit to the historical data. However, the failure to explicitly address the complexities of the industry almost inevitably means that the estimated equation will be of limited value in understanding how the industry actually functions or in forecasting future industry activities.

It may be useful, by way of conclusion, to discuss three somewhat different perspectives amongst economists who utilize econometrics to study petroleum industry behaviour.

- (1) Some believe that it is possible to estimate relatively simple single equations (‘reduced form models’) that are useful for forecasting and understanding industry behaviour. (For example, Moroney and Berg, 1999, have estimated what they argue is a meaningful simple log-linear equation for lower-48 U.S. crude oil production, based on time series data from 1950 to the 1990s. Yu (2003) finds that this model does not perform well for conventional oil in Alberta or western Canada.)
- (2) Other economists believe that much more elaborate models are required if econometric analysis is to be useful. Some of the elaborations are in terms of econometric technique. (Kaufman and Cleveland, 2001, for instance, use cointegration techniques to estimate a crude oil production relationship for the United States that is very similar to that of Berg and Moroney.) Others argue that more elaborate underlying conceptual models are needed, thereby adding more variables to the explanatory equation, and/or moving into more complicated estimation procedures in which a number of related aspects of industry activity (e.g., expenditures, reserves additions, and output) are explicitly treated as co-dependent, and are jointly estimated.
- (3) Others feel that the uncertainties affecting the petroleum industry are so great that it may be futile to try to estimate long-term forecasting equations, which are based on an attempt to capture fundamental causal relationships explaining industry behaviour. Instead, useful

forecasting models must be largely ‘technical’ studies of the path of the dependent variable over time. Pindyck (1999), for instance uses the techniques of cointegration analysis and Kalman filters to try to derive a depiction of how crude oil prices have evolved over time; his model includes no explicit recognition of variables such as GDP, which economists might expect to affect the demand for oil and hence the price of oil.

Examples of all three types of econometric approaches will undoubtedly continue to appear in the literature.

C. Output Measures: Studies of Reserves Additions or Production

Rather than looking at industry activity as the main variable to be explained, some researchers have looked at the results of industry activity in terms of volumes of oil produced. This could involve either oil-in-the-ground (i.e., reserves added) or volumes of crude oil lifted to the surface. The expenditures required to attain this output could be estimated by assuming some particular cost function for oil supply. For example, in a reserves addition model, it might be assumed, following historical trends, that the reserves added per unit drilling effort becomes smaller and smaller as a region matures; this relationship could be used to estimate the amount of drilling required to add the forecast reserves additions, and then the expenditures for this drilling could be calculated.

From an economic point of view, the problem of explaining the volume of oil output is intimately connected to the form of the oil-supply production function, which tells, at any particular point in time, the minimum quantities of various inputs required to produce any given amount of output. There have been different representations of the required inputs. In general, one might suppose that inputs include ‘land’ (i.e., areas over which petroleum rights are held), geological and geophysical (G&G) surveys, labour, materials (e.g., drilling mud), and various forms of capital equipment. The practical question of how to measure these inputs generates a variety of responses. Sometimes authors rely on largely physical measures (e.g., the number of wells drilled, or the number of feet drilled). Other authors use economic aggregates, for example, the real value of expenditures on drilling. Since such measures are not perfectly correlated, it is possible for different studies to reach different

conclusions, even working with essentially the same model.

A production function reflects the existing state of knowledge and, as has been discussed earlier, will change over time as knowledge and technology advance and as the stock of undiscovered resources declines. In the crude oil industry, in any large region, a particularly important source of knowledge change is the continuing discovery of new geological plays. For ease in modelling, it is frequently assumed that knowledge and technological changes are primarily 'exogenous,' perhaps occurring at a relatively regular rate over time. However, technological changes may have a strongly 'endogenous' character, in which economic conditions in the industry affect the amount of new knowledge produced. Thus, for example, increased exploration makes discovery of a knowledge-shifting new oil play more likely. There are also possibilities related to what Leibenstein (1976) has called *X*-inefficiency. Companies may not always exploit all the profitable opportunities available, but some conditions may drive them to be more efficient in this regard; for example, rising production costs, which put downward pressure on profits, may spur application of unutilized cost-reducing technologies.

While the production function sets out current technological constraints, the actual level of production hinges also on the specific point on the production function that is selected. In the conventional economic model, this is a function of the prices of the output produced and the inputs that must be hired.

Without entering into a discussion of the range of possible econometric estimation procedures available or returning to the joint-product problem, it is easy to see that a large number of oil-supply models might be constructed. In what follows, we will summarize some aspects of a number of models of Alberta crude oil supply, treating them in order of publication. The focus here is on equations estimating the quantity of Alberta (or Western Canadian) crude oil output, whether lifted crude or reserves additions. As will be noted, many of the studies also include estimates of other variables, such as the unit cost of oil. (Explanations of expenditures were reviewed in the previous section, and econometric estimates of cost functions will be covered in the next section.)

Russell Uhler's influential work, emphasizing the depletability of oil plays, provides an excellent starting point (Uhler, 1976, 1979, 1981; and Uhler and Eglington, 1983). Uhler's work might be seen as part of economics' negative reaction to the famous earlier research of M. King Hubbert (Hubbert, 1956, 1962).

Hubbert argued that conventional petroleum, as an exhaustible natural resource, would necessarily go from some starting point for production through a life history to zero production at some future date. Drawing on the history of oil reserves additions (and production) in the lower-48 states, he proposed that they would exhibit a period of increase, followed by a mirror image path of decline, with the reserves addition curve preceding the production one by about ten years. He proposed that the curves would look much like normal curves; formally, he proposed that cumulative output or reserves additions would follow a logistic curve. Initially, he fitted these curves by eye, but subsequent analyses used statistical curve-fitting procedures. Apart from the simplicity of Hubbert's approach, and its appeal to notions of resource exhaustibility, his model derived great popularity from the fact that Hubbert was dead on in his forecast of 1970 as the peak year for U.S. lower-48 oil production. Critics have pointed out, however, that production since 1970 has fallen off less rapidly than would be implied by Hubbert's symmetric model and that it underestimated recoverable oil volumes.

Hubbert's model struck many as far too simple. Some, for instance, pointed to the importance of geological plays in the crude oil industry and argued that the general pattern of reserves additions that Hubbert suggested might be appropriate for a single play, where accumulating knowledge and drilling effort initially allowed rising reserves additions, but where depletion of the play would eventually mean falling additions to reserves. Even within a single play, many thought that the more likely pattern was a short period of rising reserves additions as the best prospects were explored, followed by a lengthy decline period, rather than Hubbert's symmetric rise and fall. But why would the same pattern be observed across all of industry activity, which would depend on the pattern of sequencing of oil plays? More fundamentally, it was argued that discoveries and production reflect a variety of factors, including changing economic conditions, government regulations, technological and knowledge changes, etc., which would make any number of production histories possible, not just Hubbert's logistic one. Ryan (1973a,b) provided a cogent early criticism; his paper includes estimates of changing discovery patterns for a number of Alberta crude oil plays, with a tendency to falling reserves additions as plays mature. Falling reserves additions can be connected to the asymmetry in pool sizes within an oil play, with a small number of large pools and a large number of small pools. (There is some discussion of this issue in Chapter Five; Allais,

1957, was among the first to note the skewed size distribution, hypothesizing that the distribution was log normal, and McCrossan, 1969, provided evidence for Canadian oil and gas fields. Smith, 2010, provides a recent assessment of Hubert-type ‘peak oil’ models from an economic perspective.)

Uhler follows in this line of work by emphasizing the importance of geological plays in oil discoveries and accepting that the total amount of oil in a play is not unlimited. As is common in discovery-process models, the discovery process is viewed as an uncertain process that involves sampling (i.e., discovering new pools) from an underlying distribution of pools that is log normal in size distribution.

Uhler’s 1976 paper develops such a stochastic model and sets out to estimate it empirically for two sets of regions in Alberta; results are reported for only one region, an area of about 13,300 square miles in Central Alberta. Strictly speaking, Uhler argues, the model should be applied separately to separate plays, but he notes that the major plays in Alberta are geographically distinct to a considerable degree. Uhler is concerned both with the nature of the production function for oil and gas discoveries and the associated cost functions. We will focus here on the reservoir discovery model, setting out a brief, non-technical, overview, commenting on some of the measurement problems and giving a flavour of the results. The initial part of the model is concerned with the number of petroleum deposits that exploratory effort might locate in any specific time interval. Uhler reports results for both ninety-day and annual time intervals. Discoveries reflect three stochastic variables: the number of potential drilling sites available at any time; the likelihood that any particular site will be drilled; and the likelihood that a drilled site will hold a deposit. Uhler argues that the latter component reflects opposing tendencies. As drilling proceeds, more knowledge is gained, which enables an improved selection of drilling sites; however, as drilling proceeds and more pools are discovered, there are fewer pools left to be located, making new discoveries more difficult. It is likely, he argues, that the first of these effects will be strongest in the initial phases of exploration and the second later on.

The specific form that he assumes for this process is as follows, where $P(N = n)$ is the probability that the number of reservoirs discovered is equal to n :

$$P(N = n) = \exp(-l)(l)^n/n!$$

where

$$l = aD^\alpha \exp[-b(C_{t-1}-K)^2].$$

In this equation, D measures the amount of exploratory effort undertaken in the period, so that more exploration increases the number of discoveries. The variable C is the ratio of the cumulative exploratory footage drilled to the size of the area; it obviously increases as exploration proceeds. (The variables a , α , b , and K are parameters that are estimated by econometric maximum likelihood procedures, so that the model best fits historical data.) Initially, C is very small, and as it rises the gap between it and K becomes smaller and smaller, so that the negative effect of the $(C-K)$ term on l becomes smaller; that is, any given amount of exploratory effort (D) has more effect as C rises. But, after C exceeds K , the opposite is true, and as drilling proceeds, any given amount of exploratory effort generates fewer and fewer discoveries.

The final phase of Uhler’s model is estimating how much oil lies in the n discoveries made in any time interval. This could be defined as the number of discoveries (i.e., n) multiplied by the expected size of an average discovery (y). But what will determine the average discovery size? Uhler argues that the uneven pool size distribution and the tendency to find larger pools first drives the average discovery size lower, as captured in the following functional form:

$$\log y_t = \log b - gC_{t-1}.$$

There are a number of practical difficulties that arise in applying this model empirically, specifically that of defining what is meant by exploratory effort (D), and how to handle the joint-product problem since exploration generates both oil and gas discoveries. Uhler elects to measure exploratory effort by the exploratory drilling footage undertaken in a period. He suggests that one would ideally like to separate drilling into oil-drilling and gas-drilling, based on the intent of the company undertaking the drilling, although he notes that drilling directed towards one product may still find a reservoir of the other. He does not credit oil pools with their associated or solution gas, or gas pools with the condensate present. In the absence of reliable intent data, and the rather arbitrary methods that might be used to separate exploratory footage into the oil/gas categories, he uses total exploratory footage in both the oil discovery and gas discovery equations. Finally, he notes that his discovery volumes “have not been adjusted for any expected appreciation, and these sizes are *initial*, not recoverable, magnitudes.” This means that the size of more recent discoveries may be

understated relative to earlier finds since there may be significant appreciation in these pools as development occurs, although the tendency to falling average discovery size may reduce the significance of the failure to allow for appreciation. The reference to the size of discovery volumes is somewhat ambiguous about whether it means that oil-in-place is used or simply makes clear that initial reserves are used, rather than a later estimate of remaining reserves.

In his 1976 paper, Uhler does not report oil-supply results for the entire province of Alberta, so his paper is best understood as presenting a new petroleum supply modelling technique, which happens to have been applied to parts of Alberta for years up to 1972. The equations he has specified seem to fit the data reasonably well. The results show a pronounced tendency in Alberta towards falling reserves discoveries over time for both oil and gas. For example, in the area studied, estimated oil discoveries based on his equations totalled 62,117 thousand barrels from May 12 to August 10, 1951, but only 2,786 thousand barrels from April 21 to July 20, 1972.

Uhler's 1979 study builds on concepts from his 1976 research in an application to the entire Alberta industry for years from the Leduc discoveries of 1947 to 1975. He notes that, while it would be ideal to consider separate oil plays, the absence of play-specific data for exploratory effort makes this difficult in practice; however, if each separate play tends to exhibit falling discoveries, and the sequence of plays itself exhibits a tendency to declining size, then the industry aggregate discovery data will also exhibit declining size. Since it is possible to accumulate reserves and successful well data by play, he proposes two discovery models, one using entirely aggregate provincial data, and a second that looks at total Alberta discoveries but retains some play-specific drilling information. Uhler suggests that discoveries in any period (y) might be seen as the separable product of a function ($h(x)$) of exploratory effort (x) and a function for discoveries ($g(R)$) based on cumulative discoveries (R) up to that date; the discovery part of this relationship could be set up for the entire province or for separate geological plays. This approach differs from the 1976 paper in a simplifying manner by not separating the effects of number of finds and average discovery size. A complicating difference from the 1976 paper is the explicit inclusion of a translog production function ($h(x)$) to capture the effects of three different components of exploratory effort: exploratory drilling footage; land holdings; and geophysical crew-weeks. The $g(R)$ function in this model is designed to capture the impacts

of growing knowledge and depletion, and uses a function of the form:

$$g(R) = A \exp(-\beta R)$$

where A and β are parameters to be estimated. Note that this equation implies a steady tendency to declining discoveries as cumulative discoveries grow. (It is interesting that in his natural gas model, Uhler does not select this form, but one like the D function of the 1976 study, allowing for a positive initial effect of cumulative discoveries on this year's discoveries due to greater knowledge.) He also discusses the possibility of a separate price effect on discoveries, although the reasons for including this are not as obvious as might be thought since one would expect that the main effect of petroleum prices is felt through the level of exploratory effort (x), which is already included in the model. Uhler notes that higher prices will tend to shift the classification of deposits from the non-commercial to the commercial category, including previous discoveries; hence, higher prices will tend to have an effect on reserves additions in addition to the impact through current exploration.

Uhler, of course, faces data problems. Discoveries can be separated relatively easily into oil and gas categories (with some complications raised by the presence of condensate in gas pools and associated and solution gas in oil pools), based on the official categorization of reservoirs as oil or gas. However, there is ambiguity on how many reserves to credit to any one year; as in his 1976 research, Uhler uses the most recent ERCB estimates of initial reserves by year of discovery, with no attempt to increase recently discovered reserves for possible appreciation in subsequent years. Exploratory effort of necessity raises joint-product problems, as discussed earlier in this book. These joint-product problems are both product-related (dividing activities between oil and gas) and temporal (relating an activity at one date to specific reserves additions). Uhler draws on data that separated exploratory drilling from 1947 through 1970 by intent ('oil,' 'gas,' or 'both oil and gas'). The 'both' wells were treated as oil-intent. The ratio of oil-intent to total exploratory wells was then multiplied by the measures of total industry activity to derive oil-directed exploratory footage, geophysical activity, and land holdings. For years after 1970, it was assumed that the oil-intent well-drilling proportion in the years just before 1971 continued to hold. With respect to the timing issue, Uhler generally assumes that the current-year activities are associated with the

current-year discoveries; for land, he assumes that the amount 'used' in reserves additions is the average of the start-of-year and end-of-year acreages.

The separable multiplicative form of the reserves addition process (discoveries = $h(x)g(R)$) is linear in its logarithmic form. Rather than jointly estimating the equation, Uhler uses a two-stage estimation procedure, initially estimating the production function ($h(x)$), and then inserting the estimated annual values for h into the discoveries equation, and estimating the coefficients of the g relationship. It is this latter relationship that is of most interest here, the relationship that shows the negative impact on current reserves additions of rising cumulative reserves additions. Uhler estimates three versions of this equation. The first incorporates the separate impact of four major Alberta oil plays – Leduc, Pembina, Swan Hills, and Rainbow-Zama. Uhler suggests that the estimated equation fits the observed pattern of reserves additions quite well. As with actual reserves additions, the volumes estimated by the model exhibit significant year-by-year variability; in addition, the estimated equation tends to show pronounced peaks in the same years as the actual data. Such peaks typically reflect the emergence of a new oil play, which, of course, this equation captures quite well. He notes that the estimated equation seems to miss spurts in reserves additions in 1952 (when significant Leduc discoveries took place), 1959 (Swan Hills successes), and 1964 (with the Gilwood play, which was not included as a separate play). In addition, actual discoveries from 1968 on were less than predicted by the model. In part, this might reflect the failure to apply appreciation factors to the more recent discoveries. However, it would also seem to stem from the apparent dearth of significant new oil plays in this period and the inclusion of only four oil plays in the estimation. That is, the effects of other oil plays in the period prior to 1968 will tend to be captured by the estimated coefficients for the four plays included, and hence these coefficients will tend to understate the rate of decline in discoveries within the typical play.

The other two equations that Uhler estimates are based on cumulative reserves additions for the entire province rather than for specific plays, one of the equations adding the wellhead oil price as a variable. It turns out that the oil price is not significantly related to reserves additions. This does not mean that the price of oil has no effect on discoveries; remember that the oil price has already entered Uhler's model indirectly through its impacts on the level of exploratory effort. As noted earlier, Uhler's equation is set

up so that current reserves additions are a declining function of cumulative reserves additions (R), and the estimated negative coefficient for R is significant. However, the equation will obviously fail to show the assorted upward shifts in actual reserves additions that were captured by the equation that included the four separate oil plays. On the other hand, Uhler finds that the aggregate model generates estimated reserves additions that are closer to actual values for the last years under study (1968 to 1975) than the play-inclusive equation.

It is tempting to interpret Uhler's findings as a good news/bad news story. On the one hand, it suggests that our understanding of oil discoveries in the Alberta oil industry can be greatly aided by explicitly recognizing two relatively simple factors: the majority of the many separate oil discoveries occur in a small number of discrete plays, and each of these plays tends to exhibit strong depletion effects, with falling reserves additions over time. However, while such a model can be of great value in understanding past developments, it is problematic as a forecasting model since "it is my belief that a model cannot be constructed which can forecast exactly the point in time and the magnitude of a new play" (Uhler, 1979, p. 63).

Uhler and Eglington (1983). Uhler continued his research on Alberta oil reserves additions in work undertaken with Eglington for the Economic Council of Canada's major evaluation of Canadian energy policies in the early 1980s. The 1983 study continued to contrast play-specific and aggregate Alberta approaches, this time incorporating eight 'geological formations and areas' that accounted for 98 per cent of the conventional oil that had been discovered in Alberta up to 1981. The eight categories do not exactly correspond to separate oil plays but are typically dominated by such a play. As in the earlier research, this study continues to emphasize the significance of depletion effects, but it also moves towards a more explicit incorporation of the impact of economic circumstances.

In general, it is argued that producers can be seen as profit-maximizers operating under the constraints of resource limits and current production technologies, and therefore reserves additions will be positively affected by factors such as a higher price for oil and technological improvements, and negatively affected by things like higher oil royalties or increases in the costs of inputs. The main focus of the 1983 study is on discoveries (reserves additions, D) in relation to drilling effort (E) and cumulative drilling (CE), which is hypothesized to fit the following functional form:

$$D = A_0 E^{A_1} e^{-A_2 CE}$$

The A 's are coefficients to be statistically estimated.

As in Uhler's 1979 study, this equation shows depletion effects with no allowance for initial rising finding rates as knowledge grows. Reserves additions are measured differently in this study; reported reserves additions for each year are used, which includes new discoveries plus appreciations in that year from discoveries in previous years. From this perspective, reserves additions are due to both exploratory and development drilling, so drilling effort includes both types of wells. Drilling effort (annual and cumulative) is measured by the number of wells penetrating the formation under study, whereas Uhler's earlier work used footage drilled. Unlike the 1979 study's three-input production function, only the single measure of reserves addition effort is used. Uhler and Eglington argue that one would ideally like to use the number of well penetrations that were *targeted* at that particular formation and therefore measure wells by the number of wells that hit the particular formation and did not go any deeper. This will obviously fail to count wells that were targeted at a shallower formation but went deeper, either because the well accidentally was drilled deeper, or because the company was simultaneously interested in finding out about a deeper formation. There is a joint-product complication since there will typically be some non-associated gas pools found within any one of the eight specified formations/regions. Thus some wells may be drilled with a primary intent of finding gas rather than oil, and the total number of wells drilled with the intent of testing this formation will be affected by both oil and gas prices.

The net result is that Uhler and Eglington run a number of different cases for each of the eight formations/regions. These include two cases based on total well penetrations, one 'unrestricted,' based on the equation given above, and a second 'restricted' case in which the coefficient on the current drilling variable is set equal to one; this implies a unitary elasticity of reserves additions (D) to drilling effort (E), forcing changes in the efficiency of the reserves addition process entirely onto the resource-depletion variable of cumulative drilling (CE). In most cases, the coefficient of the current drilling variable in the unrestricted model is relatively close to one, and it could be argued that constraining this variable to the same elasticity across all areas allows more direct comparisons of the depletion effects in different areas. For each region, they also estimate equations that show the discoveries

of non-associated gas as a result of the drilling.

Another set of estimates is based on separate oil-well and gas-well penetrations, where the total number of wells drilled are allocated between oil- and gas-intent wells on the basis of the proportion of oil-well completions to total well completions. Finally, factors unique to a particular area sometimes lead to another set of estimates. For example, the Upper Devonian category consists in large measure of the D-2 and D-3 plays, which began with Leduc in 1947 and were therefore quite advanced by the 1970s; however, in the later 1970s, a new play began in the Nisku formation, leading to a sharp increase in reserves additions. If the analysis were truly play-specific, one could treat this new play separately, but the use of broader groupings means that its impact is lumped in with the earlier plays in the Upper Devonian group. Uhler and Eglington report equations both including and excluding the new Nisku discoveries.

There are obviously a large number of estimated equations in Uhler and Eglington, so their study is best seen as presenting ranges of likely results for the oil-producing areas. Table 8.11 gives a flavour of their findings. It shows the estimated coefficients in the restricted oil-reserves-additions equation using the total data available without allocating wells between oil and gas. That is, in terms of the equation above, it reports the estimated value for the constant ($\log A_0$) and the coefficient of the cumulative wells variable (A_2); also shown are the coefficient of determination (R^2) and standard errors of the estimated coefficients (in parenthesis; the coefficient has greater significance the lower the standard error relative to the size of the coefficient). Table 8.11 also includes estimates the authors made, on the basis of the reserves additions equations, of possible future reserves additions for each of the seven areas. (The eighth is Upper Cretaceous formations in southeast Alberta, which hold no significant oil volumes.) In brief, they asked what volume of incremental reserves would be economic based on the estimated reserves addition equation, the current (1981) real cost of drilling in that region/formation, and the anticipated real market values of the discovered oil and associated and non-associated gas. The values of oil and gas are reserves values since their model looks at discovered volumes in the ground; as has been discussed above, a reserves price is less than the wellhead price for lifted petroleum since there are still additional costs to be incurred to lift the petroleum, and one must wait to receive much of the revenue since petroleum reserves are lifted over many years. Many estimates of future reserves additions

Table 8.11: Uhler and Eglington: Coefficients of Reserves Additions Equations and Possible Reserves Additions

Formations/Region	$\log A(0)$ Coefficient	$A(2)/1000$ Coefficient	R - squared	1979 Reserves (10^6 m^3)	Reserves additions @\$35.78 (10^6 m^3)	Reserves additions @\$70.00 (10^6 m^3)
Upper Devonian/all Alberta	3.980 (0.052)	-0.146 (0.075)	0.11	554.4	47.7	57.9
Beaverhill Lake and Lower Devonian/all Alberta except area 5 (far NW Alberta)	5.41 (0.68)	-0.84 (0.21)	0.42	236.8	0	0
Mannville/all Alberta	1.67 (0.30)	-0.117 (0.032)	0.31	87.5	Minimal (due to gas-intent wells)	Minimal (due to gas-intent wells)
Beaverhill Lake and Lower Devonian/ Area 5 (NW Alberta)	5.990 (0.533)	-0.378 (0.067)	0.72	118.53	0	almost 0
Upper Cretaceous/Area 8 (around Pembina)	4.503 (0.880)	-0.494 (0.179)	0.23	163.05	0	0
Viking/all Alberta	1.845 (0.555)	-0.41 (0.240)	0.09	29.65	3.95	8.58
Mississippian/all Alberta	3.029 (0.668)	-1.167 (0.291)	0.36	54.47	0.01 (due to gas- intent wells)	0.01 (due to gas- intent wells)

are possible, depending on the specific reserves additions equation chosen and the drilling cost and prices assumed. The results that we show assume a gas reserves price of $\$11.65/10^3 \text{ m}^3$; oil reserves prices of $\$35.78/\text{m}^3$ and $\$70.00/\text{m}^3$ are shown. This $\$70.00/\text{m}^3$ for developed reserves is about $\$11.10/\text{b}$. It is doubtful that the real value, in 1981 dollars, of developed oil reserves attained this level for any extended time in the 1980s and 1990s. The gas price and the lower oil price are the estimated reserves prices for 1981, based on Alberta wellhead prices of $\$117.12/\text{m}^3$ (about $\$18.60/\text{b}$) for oil and $\$98.74/10^3 \text{ m}^3$ (about $\$2.80/\text{mcf}$) for gas.

It is striking that this analysis generates valid results for the model in all seven formations/regions but also suggests that the prospects for additional conventional crude oil reserves additions in Alberta in established oil plays are very restricted, except for the Upper Devonian plays. The Uhler/Eglington results cannot easily be related to more up-to-date Alberta statistics, but it is apparent that reserves additions have been significantly larger than was indicated in their analysis. In Table 8.12, we show ERCB initial oil reserves by geological formation for the years 1976, 1999, and 2007; where possible, geological categories as close as possible to the Uhler/Eglington ones have been noted.

It can be seen that the geological formations as listed here generally hold somewhat more oil than

similar formations in the Uhler/Eglington study. It can also be seen that the actual reserves additions from 1976 through 1999 were quite significant, even though oil reserves prices in real terms were below the $\$70/\text{m}^3$ assumed in the earlier table. (The decline in Beaverhill Lake reserves additions over the period reflects downward 'Revisions and Extensions,' mainly associated with modifications in the estimated effectiveness of EOR projects.) While some of the reserves additions over this period will reflect new oil plays, and small plays as of 1980 that were excluded from the Uhler/Eglington study, it would also appear that actual reserves additions within established plays exceeded those estimated by their model. In most of the plays, reserves additions, albeit generally rather small, occurred after 1999.

Uhler and Eglington go on to estimate two aggregate models of oil reserves additions in Alberta. The first estimates the simple oil reserves additions equation for the entire province, with wells allocated between oil and gas on the basis of the proportion of completed wells that were classified as oil wells. The estimated coefficients are 4.278 for $\log A(0)$, and -0.069 for $A(2)/1000$; the respective standard errors are 0.419 and 0.021, and the equation has an R -square of 0.25. (Inclusion of dummy variables for the starting date of four successive oil plays, as might be expected, increases the R -square considerably to 0.47 and allows more rapid depletion effects as the $A(2)$ variable

Table 8.12: ERCB Oil Reserves by Formation, 1976 and 1999 (10⁶ m³)

	1976 Reserves	1999 Reserves	Change in Reserves, 1976-99	2007 Reserves
Upper Cretaceous: Cardium	284	297	13	294
Viking	49	62	13	68
Mannville	100	407	307	544
Mississippian	71	100	29	92
Upper Devonian: Wabamun, Nisku and Leduc	547	708	161	732
Upper Devonian: Beaverhill Lake	421	393	-28	408
Middle Devonian: Keg River	158	195	37	197
Other	183	350	167	400

Source: ERCB (and EUB) Reserves Reports (ST-18 and ST-98).

becomes -0.323 .) However, in this model (without the oil-play dummy variables), no further reserves additions at all in Alberta are estimated to be economic at reserves prices of \$70 or less per cubic metre. In other words, this model, while not restricted to existing oil plays, is even less optimistic than the findings from the separate established plays!

Their second aggregate model utilizes a different data set, closer to that used by Uhler in his earlier work. Reserves additions are measured by estimated appreciated reserves discovered, and the variables used to explain oil discoveries (OD) are the prices of oil and gas ($P(o)$ and $P(g)$, undeveloped reserves prices), a cost of drilling (c) and the cumulative number of oil discoveries (d , the variable used to capture depletion effects). The estimated equation (R -square = 0.27) is:

$$\log OD = 4.416 - 0.440 \log P(o) + 2.82 \log P(g) + 0.373 \log c - 0.0046d.$$

There is a strong depletion effect, but the oil price variable shows *fewer* reserves discovered the *higher* the oil price. The coefficient on the gas price variable (2.82) suggests a very high elasticity of oil discoveries to gas prices. However, neither the price nor the drilling-cost variables are particularly significant. Overall, this model is not very satisfactory, and the lack of a reliable relationship between price and discoveries makes it impossible to estimate possible reserves additions as a function of the price of oil.

In summary, Uhler provides one of the most detailed approaches to modelling Alberta oil supply. His research generated a mix of useful and discouraging results. The presence of strong depletion effects in the oil reserves additions process was clearly

demonstrated, as was the value of seeing reserves additions as embedded within a succession of geological plays. However, as Uhler noted, the emphasis on oil plays poses major problems for forecasting models since it is impossible to predict when new plays will occur. In addition, much as in the NEB reserves estimation models of the 1980s, it would appear that actual reserves additions in plays under study turned out to be larger than was estimated. There could be a number of reasons for this, including: (1) technological developments that reduced the costs of adding reserves; (2) a tendency of the model to underestimate the volumes of oil in smaller oil pools, perhaps because the data available provided less information about this part of the reserves base; and (3) the likelihood that, while the model projects new discoveries of progressively smaller size, a few of the new finds in any play will actually turn out to be relatively large.

Other Models. Foat and MacFadyen (1983) also looked at oil discoveries from a geological-play perspective, for nine Alberta oil plays. A geographical area was defined for each play, and reserves (R) were the reported appreciated reserves as of 1976. The cumulative number of wells that penetrated the formation prior to the current year ($CumPen$) was used to capture depletion effects. Reserves additions were also argued to be determined by the number of formation penetrations in that period (Pen). The specific form of the equation estimated was a simple one:

$$\ln R = A + B(\ln PEN) + C(CumPen),$$

where A , B , and C are estimated coefficients; B is expected to have a positive sign and C a negative sign. This assumes a negative exponential depletion effect. A number of different equations were estimated for

Table 8.13: Foat and MacFadyen Model of Oil Discoveries in Nine Alberta Oil Plays

<i>Play and year of first discovery</i>	<i>1976 initial reserves (10⁶ b)</i>	<i>Number of pools discovered</i>	<i>A (estimated constant)</i>	<i>B (estimated coefficient for In Pen)</i>	<i>C (estimated coefficient for CumPen)</i>	<i>R-square</i>
Leduc, D-3, 1947	2,262	71	16.511*(5.37)	.99111*(1.72)	-.00891*(-8.49)	0.71*
Keg River, 1964	1,099	407	6.525 (1.20)	2.7592*(2.72)	-.00320 (-1.40)	0.60*
Beaverhill Lake, 1957	1,000	20	19.610*(2.43)	0.65982 (0.32)	-.01479*(-4.95)	0.55*
Cardium, 1953	966	59	1.0122 (0.10)	3.4651 (1.33)	-.00396*(-1.94)	0.20
Nisku, D-2, 1947	559	58	4.9649 (0.80)	2.6347*(1.94)	-.00248*(-3.86)	0.36*
Viking, 1949	173	39	4.1920 (0.29)	1.6794 (0.60)	-.00063 (-1.42)	0.01
Granite Wash, 1956	43	15	15.125*(4.78)	-1.1705 (-0.98)	-.01952*(-1.84)	0.14
Slave Point, 1958	24	9	2.3409 (0.60)	1.4520 (1.60)	.00081 (0.77)	0.08
Sulphur Point, 1967	3	13	14.05 (1.63)	-0.2292 (-0.19)	-.00632 (-1.00)	0.03

* Significant at the 5% level.

different oil plays, including estimates for oil-in-place as well as reserves, and with the use of moving averages to smooth the data somewhat. A flavour of the results can be garnered from Table 8.13, which is for initial reserves for the annual (unsmoothed) data; 1976 initial reserves are shown for each play in millions of barrels. The Cardium equation also included a 'Dummy variable,' which took the value of 1 in 1953, the year of the initial Pembina discovery; the coefficient for this variable was 9.5, and it was highly significant.

A play-specific approach seems to capture some aspects of the reserves addition process. The coefficients on the penetrations and cumulative penetrations variables have the correct sign in fifteen out of the eighteen estimates, and for four of the five largest plays the equation exhibits significance at the 5 per cent level, as does the tendency to negative reserves additions as cumulative reserves additions increase. The fit is not good for the smaller plays. Similar regressions were also run for the average size of a discovery in an oil play, and, similarly, depletion effects were found for all plays, and at a 5 per cent significance level for four of the five largest plays.

These results are entirely consistent with the somewhat ambiguous conclusions we have drawn from Uhler's work: our understanding of past discoveries of oil in Alberta is greatly enhanced by utilizing a play-specific analysis, but the inability to foresee the appearance of new plays limits this as a forecasting method.

The emphasis on depletion effects in oil plays in the Uhler and Foat and MacFadyen studies is consistent with sophisticated discovery-process modelling in

the 1988 study of Western Canadian oil potential by authors from the **Geological Survey of Canada (1987)**. The GSC analysis was discussed in Chapter Five. One advantage of this modelling approach is that it generates results that show the tendency towards reduced reserves discovered as the play is depleted and also generates an estimate of the underlying distribution of oil pools in the play. Hence, one can match past discoveries with pools in the estimated distribution to derive a size distribution of *undiscovered* pools, some of which may be relatively large. This differs from the Uhler and Foat and MacFadyen approaches in which new finds are all progressively smaller. As will be recalled, the authors of the GSC study suggested that a different modelling technique had to be used for new and potential oil plays; they applied subjective probability techniques in these cases.

Another example, applied to Alberta, is found in **MacDonald et al. (1994)**. They approximate a general discovery-process model for three Western Canadian oil plays (two in Alberta) by an equation in which cumulative discovery volumes are related to the number of discoveries in the play and the square of the number of discoveries. They too find noticeable depletion effects. Their approximation, however, unlike the GSC discovery-process model, forces smaller discovery sizes onto forecast reserves additions.

Siegel (1985) includes an Uhler-type oil discovery equation in his study of the 'information externality' in oil exploration, as seen in the Rainbow-Zama play in northwestern Alberta. In brief, this externality applies when there is a depletion effect in exploration; that is, there are a limited number of oil pools,

which tend to be discovered in order of size, so that a new discovery depletes and degrades the stock of remaining undiscovered pools, creating a user cost of exploration in the process. (That is, exploration today, by depleting the stock of undiscovered prospects, increases the cost of future exploration.) The individual company will have no reason to consider the negative effect that its (successful) exploration has on the exploratory prospects of other firms; therefore, from a social perspective, there will tend to be more exploration in any period than is socially desirable. (This and other possible externalities in exploration are discussed in Chapter Eleven.) Siegel uses quarterly data for the years 1965 through 1970, excluding three quarters where no discoveries were reported. As independent variables, he includes the number of exploratory wells drilled this year (W), and both the cumulative number of wells (CW) and this value squared (CW^2); including the two terms for cumulative drilling allows a nonlinear relation with both 'depletion' and 'learning' effects. The dependent variable is the volume of new discovery reserves (D), in thousands of barrels. Siegel's equation has an adjusted R -square value of 0.68 (t -statistics in parenthesis):

$$\ln D = 7.4347 + .6557 \ln W + .00102 CW - .0000009 CW^2$$

(10.258) (3.488) (1.268) (-2.435)

Siegel notes that the depletion effect, generating diminishing returns from cumulative exploration, begins to offset the increasing returns from 'learning' when about 550 exploratory wells have been drilled. The nonlinear cumulative drilling relationship, which was not included in the Foat and MacFadyen analysis of this play, appears to have been important. Siegel also estimates similar equations for real exploratory costs in the Rainbow-Zama play, presumably exploratory drilling costs. He finds a unitary elasticity for the number of wells, and that the CW term is significant, with costs falling as cumulative drilling rises, indicative of a learning effect in drilling costs, although technical changes or some time-related fall in real input costs would generate a similar result. There is no reason why depletion effects should influence total exploration costs, though such an effect would lead to increased per unit costs, as exploration activities find progressively less oil.

A somewhat different approach to estimating oil reserves additions (discoveries) is found in the extensive econometric research of Helliwell et al. (1989). Their analysis covers the Western Canadian sedimentary basin but is dominated by Alberta. The discovery

variable (D) that they use is not reported reserves added but a variable they have created by dividing the total expenditures devoted to adding reserves by an estimated 'adjusted' marginal cost of adding reserves. (Their marginal cost estimate will be discussed below. This cost was 'adjusted' by reducing the estimated marginal cost somewhat to allow for the impact of regulations that encouraged investment in existing reserves rather than in new reserves additions.) To illustrate the discovery variable: if the (adjusted) marginal cost of adding reserves were \$10.00/m³, and a total of \$50 million were spent, then there would be 5 million cubic metres of reserves added: \$50 million/\$10.00/m³ = 5 million cubic metres. It is not altogether clear what went into the oil expenditures: it includes real exploration and development expenditures, presumably excluding expenditures on gas plants; it is not clear whether exploration includes land acquisition costs, and there is a statement that costs are allocated between oil and gas on the basis of proportionate drilling footages for oil and gas development wells.

Results are shown for three equations, estimated in a double log form. All three include a constant and the same two explanatory variables, a 'profitability ratio' (P), and a 'ratio of estimated to adjusted capital costs' (CR), but differ with respect to the third variable, which is either output (Q), cash flow (CF), or lagged land payments (L). As it happens, only the last of these three variables (L) had a significant effect, which is interpreted as reflecting the necessity of holding land before drilling, plus the exploration requirements on newly acquired land. The profitability ratio was discussed above, and, as noted, is a three-year moving average. The ratio variable (CR) is the ratio of the estimated marginal cost to the 'adjusted' marginal cost. The preferred form of the oil discoveries equation (R -square = .9053) is:

$$\ln D = 3.0821 + 1.1957 \ln P + 0.4839 \ln CR + 0.5585 \ln L.$$

(t -ratios are 8.66, 9.88, 5.59, and 7.88, for the four estimated coefficients. Appendix 8.1 in Helliwell et al. provides a number of alternative econometric estimations of the oil-discovery equation.) It can be seen that oil discoveries are estimated as being very elastic (1.2) with respect to the profitability ratio. The estimated elasticity of the cost ratio variable of 0.4893 shows an inelastic impact on discoveries; that is a smaller 'adjustment' (implying a higher CR value) has a less than proportionate impact on reserves additions. Of course, the equation does not provide a perfect fit

to actual discoveries; Helliwell et al. note that their equation overestimated reserves additions from 1974 to 1978 but underestimated them from 1979 to 1981. Overall, however, they view the fit as good, though their Figure 8.2a shows that the model significantly underestimated discoveries in 1985. So far as we know, there has been no report comparing their discovery model's forecast to actual discoveries after 1985, and the complexity of the cost ratio and profitability variables do not allow us to do so with any degree of reliability.

Finally, **Livernois and Ryan (1987)** addressed the reserves-discovery process for Alberta in a model that explicitly recognized the joint-product nature of exploration. They studied reserves of oil and natural gas by the year of discovery for the years 1948 to 1979. Their model is complex, both theoretically and in terms of the econometric estimation. Alberta oil producers are assumed to be price-takers in both input and output markets. The production function involves the production of oil and gas discovery reserves through the utilization of four 'inputs': land acquisition and exploratory drilling, which can be varied by a producer, and two fixed factors, 'the state of depletion,' measured by the cumulative number of wells drilled so far, and geological knowledge, measured by cumulative geophysical crew-months. Under the assumption of profit-maximization, expected industry activity can be set out in terms of a profit function, and estimated 'share' equations showing revenues for the two outputs, and costs of the variable factors as a share of profits. As the extent of 'separability' and 'jointness' varied amongst the two outputs and the various inputs, there would be differences in the anticipated relationships between the variables in these equations. Separability, in this context, means that the output part of the production function can be separated from the input part, as is normally assumed by economists when they write a production function in the form $X = f(L, K)$ where X is output, L is labour, and K is capital. Livernois and Ryan note that if, but only if, separability is true, one can legitimately model industry output as if it consisted of a single aggregate product, although problems do exist in constructing such an aggregate and its price. Several types of non-jointness exist, the most frequently cited form implying that the output of a product (e.g., crude oil) is affected by its own price but not that of the other product (i.e., natural gas).

Livernois and Ryan's results are tantalizing, partly because of their ambiguity. At the broadest level, they are able to reject the hypothesis of separability,

but they cannot reject that of non-jointness; however, despite this, they find significant and positive cross-price elasticities, implying that higher prices for one of the products will stimulate more discoveries of the other. Their results warrant further research and suggest that the results of much of the research on conventional crude oil supply, which assumes non-jointness and/or separability, must be accepted with caution.

Thus far, we have reviewed econometric studies that focus on either the total expenditures undertaken by the oil industry or on the additions of oil reserves in Alberta. We will now summarize several econometric analyses that focus on the costs of adding reserves.

D. 'Indirect' Estimation of Costs

In Section 3, above, we looked at direct estimates of the cost of oil in Alberta in which the analyst divided actual expenditures by the actual amount of output that resulted. We noted that it is difficult to know how to interpret the results. The costs are an after-the-fact measure and therefore reflect the ongoing interplay of shifting supply and demand factors, as well as the inevitable stochastic dimension of oil discoveries. Thus, simple time trends in costs rarely convey unambiguous information: are costs rising because low-cost conventional oil resources are depleting? Or is it because higher prices make the higher-cost resources look more attractive? Or a combination of these factors? One way to begin to address this issue is by undertaking more elaborate econometric analysis to see what factors affect the estimated costs; we call this an 'indirect' cost-estimation process.

Helliwell et al. (1989), discussed above, relate annual 'marginal costs' (C) of oil reserves additions to the cumulative volume of oil discoveries (CD). In their analysis, marginal costs appear to be annual real expenditures on exploration (drilling and G&G) and development divided by the reserves added through new discoveries and revisions and extensions. Years from 1952 to 1985 are included (except for 1976, which saw negative reserves additions, due to a significant downward revision of reserves in several pools). Their preferred equation also includes a variable (EP) from 1982 to 1985 that shows the excess of the 'new' oil price in Alberta above the 'old' oil price; 1982 saw the extension of the higher price to certain development activities such as EOR. The estimated equation (Helliwell et al., 1989, p. 147) with the t -statistics in parentheses is:

$$C = 0.4517 + 0.07807CD + 16.067EP.$$

(0.80) (1.51) (4.42)

The adjusted *R*-square value is 0.4846. This equation suggests that ‘depletion’ effects have been significant in pushing up the unit cost of reserves additions, and that a move to higher-cost reserves additions through development followed the extension of higher oil prices to such reserves in 1982. However, it is notable that the estimated coefficients are relatively unstable as the equation specification changes, such as by using a different time period. Also, the cumulative discovery variable is not highly significant.

We will briefly review two other studies of the costs of Alberta oil supply.

Livernois and Uhler (1987) are primarily concerned with models of natural resource extraction that view exploration as a process to reduce extraction costs by increasing the size of available reserves. They argue that the resource base should *not* be viewed as an aggregated whole, the size of which is inversely related to lifting costs. By way of analogy, think of a region’s reserves as being held in a giant cistern. Suppose that the greater the volume of oil present, the greater the pressure pushing down on the oil and the higher the output flow rate is through the spigot at the bottom of the cistern (and the lower the unit cost of production). Then adding more reserves will reduce per-unit lifting costs. But Livernois and Uhler argue that this picture does not fit the oil industry since reserves are not in fact an aggregate but the sum of many separate reservoirs. There is strong reason to assume that the industry faces depletion effects in the addition of reserves, in the sense that at any point in time the lowest-cost potential reserves tend to be the ones that are added, while those left undiscovered and undeveloped are those expected to be of higher cost. Such depletion effects in the reserves-addition process mean that the incremental reserves added tend to be of higher cost; adding reserves in this model would not tend to reduce average lifting costs. What is required is a disaggregated model. Here the reduction of reserves in any single deposit (the ‘intensive margin,’ as they label it) will tend to increase extraction costs, as in the usual aggregated model. However, the addition of reserves (the ‘extensive margin’) may also lead to higher costs as more costly reserves additions take place.

Livernois and Uhler illustrate their model with data for Alberta oil costs over the years 1951 to 1982. Initially they estimate an ‘aggregate’ cost equation, which shows that the sum of real operating and capital

costs (*C*) was positively related to the size of reserves (*R*), rather than exhibiting the negative connection suggested by the aggregate resource-depletion model. The equation also included the annual output level (*Q*), and, with an adjusted *R*-square of 0.83, was (with *t*-statistics in parenthesis):

$$C = -33.48 + .00000206Q + .000000316R - .029338(R)(Q).$$

(-1.3) (3.4) (2.9) (-1.1)

They then draw on data for 166 oil pools discovered between 1950 and 1973 to do a cross-sectional estimate of oil extraction costs per pool (*C*(*i*)) in 1976. (These data were presumably generated as part of Livernois’ interesting study of pressure maintenance water injection procedures in Alberta oil pools; Livernois, 1987.) The estimated equation assumes that costs are related to the pool’s output rate (*q*(*i*)), the proportion of initial reserves yet unproduced (*r*(*i*)) and the cumulative number of oil discoveries made in Alberta prior to this pool’s discovery (*N*(*i*)). The estimated equation, with an *R*-square of 0.93, and *t*-statistics shown as before, was:

$$C(i) = -1,800,000 + 61.86q(i) - 4,300,000r(i) + 47.47N(i).$$

(-1.5) (47.1) (-2.0) (3.3)

As can be seen, costs rise as reserves in the pool are depleted, and costs are higher the later the pool was discovered, indicating significant depletion effects at both the intensive (pool) level and the extensive (discovery) level.

Livernois (1988) undertakes a joint econometric estimation of the marginal discovery costs of crude oil and natural gas in Alberta, using annual data from 1955 to 1983. His interest, in part, is to address the joint-cost problem in exploration: producers searching for petroleum in Alberta find both oil and gas and are unable to separate their activities into a search for one of the products only. Hence, it may be inappropriate to estimate a discovery-cost relationship for oil alone; one would expect, for instance, that natural gas prices influence oil discoveries, and the strength of depletion effects for one of the products would affect discovery of the other.

Livernois begins with an optimization model in which producers operate to produce the joint products of oil and gas discoveries using three competitively produced inputs (land acquired for exploration, geophysical activities, and exploratory drilling). Cumulative past exploratory drilling effort is included as an ‘input’ variable, to capture the cost-reducing effect of

technological change and the cost-increasing effect of the depletion of the resource base as discoveries proceed. Discoveries are measured by the 1985 estimate of appreciated reserves by year of discovery. (That is, as discussed above, discoveries in any year are based on the 1985 estimate of the size of the pool, not the estimate that was made in the year of discovery.) The basic problem is one of minimizing the cost of the discoveries, given the prices of the inputs and a production function relationship tying the quantities of oil and gas discoveries to the quantities of the four inputs used. Livernois draws on economic theory that shows that this problem can be rephrased as the estimation of a cost function and of cost-share equations derived from that function. He assumes a 'translog' cost function, a flexible functional form capable of capturing a wide variety of interrelationships amongst the variables. The model is complex, as are the econometric estimation procedures. Autocorrelation (serial correlation) was found to be a problem; that is, there was a positive (rather than random) tie between year-to-year differences between the observed values of variables and the values estimated in the equation. Including a dummy variable to capture the new Keg River play starting in 1965 reduced this serial correlation somewhat, suggesting that the Keg River play had characteristics somewhat different from earlier plays. The results showed that, in twenty-one of the twenty-seven years, the cumulative drilling effort variable acted to increase costs, suggesting that depletion effects were more significant than technological improvements. The exception was six consecutive years from 1973. Livernois notes that the negative effect had been small for several years prior to this, and that the widespread adoption of new computer techniques in geophysical analysis began in the late 1960s.

From his estimated cost equations, Livernois is able to calculate the marginal costs of finding additional units of oil and gas each year from 1956 through 1983 (Livernois, 1988, p. 389). Both costs show considerable variation from year to year but also a general tendency to increase. A simple time (t) trend for oil marginal finding costs (MC , measured in 1985\$/ m^3) yields an R -square value of 0.71 for the following equation (standard errors, rather than t -statistics in parenthesis):

$$\ln(MC) = -415.4 + 0.211t \\ (50.3) \quad (0.025)$$

That is, oil finding costs were rising at 21%/year. (For natural gas, the annual average cost increase was about

17%.) Finding-cost estimates generally smaller than estimates of the in-ground value of new reserves indicate that the marginal finding cost is not a good proxy for the user cost of oil and gas; this is consistent with the resource models reviewed above, which include a depletion effect in the discovery process. Livernois notes that his finding-cost estimates do approach the in-ground value around 1970, then fall lower again. As a possible interpretation, he suggests that the most profitable exploration opportunities available at the low price level of the late 1960s had been pretty well exploited by 1970 and that it was only the sharp price rises after 1970 that made significant discoveries economic again and therefore 'resurrected' the importance of exploration depletion effects.

6. Conclusions

This chapter (along with the sections of Chapter Five reviewing discovery-process models like that of the Geological Survey of Canada) has surveyed much of the empirical economic literature on Alberta conventional crude oil supply. The details are overwhelming and must leave the reader wondering whether any firm conclusions can be drawn from the forest of individual results! However, the complexity of the findings reflects the complexity and inevitable uncertainties of the crude-oil-supply process. With the exception of the NEB, which has a government mandate to provide regular progress reports on the supply of and demand for energy in Canada, most analysts respond to the complexity of the oil-supply process by restricting their research to a small part of the activities of the total crude oil industry. As a result, there is no single model that stands out as providing the best description of Alberta oil supply.

On the basis of the literature we have reviewed, the following conclusions seem warranted:

- Crude oil supply (industry activity and resultant reserves additions and production) are responsive to economic signals. All else being equal, higher real prices net of royalties do generate more output.
- Resource-depletion effects have been apparent over time; there has been a general tendency for the real costs of producing oil in Alberta to increase, and most models that explicitly include some type of degradation effect find that it is significant. This is not to say that technological

progress has been unimportant, but the industry does seem to work its way through the underlying resource base by exploiting the lower-cost deposits first and then moving on to the higher-cost deposits.

- Notwithstanding this ranking procedure, there is a great deal of stochastic instability in the reserves addition process. In any year, reserves additions may turn out to have been considerably less expensive or more expensive than was anticipated.
- Alberta oil supply is difficult to model as a process of tapping a single aggregate resource base. A number of the supply models point out the importance of recognizing the development of the industry in Alberta as progressing through a sequence of geologically distinct oil plays. However, while the oil play may be a critical unit for understanding oil supply, the problem arises that there seems to be no reliable way of anticipating as yet unrecognized new plays. This is a case in which the most useful way to understand the history of discoveries in Alberta is of limited value for forecasting purposes.
- There seems to be a persistent tendency for historical models of oil supply (which includes pretty well all models) to underestimate longer-term oil supply. This tendency has been marked in the NEB's work and also seems to have held for the burst of econometric modelling in the late 1970s and 1980s. As mentioned, most of these models found relatively strong depletion effects in reserves additions and/or strongly rising unit costs. Particularly in light of the large fall in real oil prices after 1985, one might have expected that reserves additions since then would be minimal. While production of conventional crude oil since

the mid-1980s has exceeded reserves additions most of the time, there have been continuing additions to reserves. This suggests that there has been some tendency for econometric models to underestimate the impacts of changing technologies and, perhaps, to fail to pick up new oil plays. The newer technologies could be major new techniques like horizontal drilling and 3-D and 4-D seismic but might also include the cumulative impact of many small new innovations in all aspects of industry activity, including the electronic revolution, which some observers cite in the productivity increases in the United States in the 1990s. We are unaware of any recent studies that have addressed in a formal way the importance of such technological changes in the Alberta crude oil industry. Technological and knowledge change is a difficult variable to include in supply models since some of the changes lie in the minds of the companies supplying oil, and others may be embodied in a wide number of specific capital assets: how can this complex mix of tangibles and intangibles be measured? (Cuddington and Moss, 2001, look at U.S. petroleum supply and include a technological change variable measured by patent applications.) Of course, there is no way of being sure that the tendency to produce more than various oil-supply models have forecast will continue through the future!

This chapter concludes the part of the book that deals primarily with the 'private' sector's role in the Alberta petroleum industry. We will now turn to a detailed examination of the role of governments, in other words to public policy analysis of the industry.

Appendix 8.1

National Energy Board: Western Canadian Sedimentary Basin Oil Supply Forecasts

1. WCSB Potential Reserves Additions

Table A8.1: National Energy Board Reports: WCSB Potential Reserves Additions (10⁶ m³)

<i>Report</i>	<i>Light: New Discoveries</i>	<i>Light: EOR</i>	<i>Heavy: New Discoveries</i>	<i>Heavy: EOR</i>	<i>Approximate Oil Price (US\$/m³)</i>
October 1974	270**				11.00*
September 1975	270**				12.00*
February 1977	77	156	99	173	14.00
September 1978	207	156	64	345	18.00
January 1981	225	302	80	169	38.00
September 1984	404	280	140	381	28.00
October 1986	308	367	125	378	18.00
September 1988	563	295	250	370	16.00
June 1991	521	295	270	320	17.50
December 1994	519	395	260	300	19.00
1999	666	253	229	187	18.00

Notes:

* Approximate price in the year the report was issued of WTI at Cushing Oklahoma. Prices are in nominal dollars (unadjusted for inflation). It should be noted that reserves additions depend on forecast prices, which vary from report to report. This price is taken as representative of the anticipated price of oil in each report.

** Reserves additions over two decades of light and heavy crude.

2. Productive Capacity of WCSB Conventional Light Crude

Table A8.2: National Energy Board Reports: Productive Capacity of WCSB Conventional Light Crude (10³ m³/d)

	Actual	1974*	1975*	1977	1978	1981	1984	1986	1988	1991	1994	1999
1974	230.1	321.8										
1975	194.7	324.2	294.8									
1976	174.1	318.6	280.5	239.6								
1977	169.3	308.9	270.1	227.9								
1978	165.6	289.2	252.7	212.0	222.9							
1979	188.2	266.2	230.7	191.6	209.8							
1980	173.7	247.1	209.8	169.7	193.7							
1981	154.5	225.6	191.5	150.3	175.9	167.6						
1982	150.7	205.0	174.3	133.3	159.5	156.4						
1983	153.3	185.1	172.4	118.9	144.8	135.7	165.1					
1984	164.5	166.1	139.0	106.6	131.6	123.6	167.7					
1985	159.8	147.8	129.5	96.3	120.3	114.3	157.0	168.1				
1986	149.3	131.9	116.1	87.9	111.1	109.8	144.5	168.0				
1987	152.3	118.4	104.1	80.4	102.2	104.0	134.5	158.2	159.9			
1988	158.1	106.5	98.5	74.3	94.7	99.1	125.4	143.0	159.7			
1989	148.2	96.1	90.4	68.8	87.7	94.8	116.8	130.0	152.2			
1990	141.2	87.4	85.8	64.2	82.0	90.3	109.1	118.4	143.8	144.7		
1991	137.7	79.5	82.2	60.2	77.4	86.2	102.3	108.4	135.3	137.4		
1992	139.2	72.3	77.1	55.6	73.1	81.9	96.1	100.0	127.6	126.2		
1993	143.9	65.9	72.8	52.9	69.4	78.2	90.6	93.0	120.6	117.2	142.1	
1994	148.5		69.1	49.9	65.8	74.0	85.8	86.9	113.9	110.1	144.9	
1995	145.1		68.0	46.9	62.1	68.1	81.7	81.6	107.4	104.4	150.9	
1996	140.0					66.6	77.9	76.5	98.2	99.4	148.9	
1997	135.1					64.9	74.0	72.4	94.7	94.7	143.5	132.0
1998	140.4					59.4	71.0	68.8	91.0	90.4	137.9	
1999	140.2					56.0	68.1	65.1	85.7	86.4	131.9	
2000	134.6					52.7	65.7	61.1	82.3	82.6	125.8	111.5
2001	127.3						63.5	57.7	78.8	80.4	118.9	
2002	119.4						61.1	54.7	75.4	76.0	112.5	
2003	91.8						58.9	51.7	72.2	73.0	105.5	
2004	87.6						57.0	49.0	69.3	70.3	99.9	
2005	83.9						55.1	46.6	66.5	67.9	94.6	101.1
2006	83.1									65.8	89.3	
2007	82.4									63.9	83.9	
2008	86.2									62.0	78.6	
2009	82.2									60.7	73.2	
2010	83.5									59.5	69.1	82.2

Note:

*Includes light and heavy crude and pentanes plus. The 1975 values were read off two graphs, so are approximate.

1988 and 1989 actual output from CAPP *Statistical Handbook*.

3. Productive Capacity of WCSB Conventional Heavy Oil

Table A8.3: National Energy Board Reports: Productive Capacity of WCSB Conventional Heavy Oil (10³ m³/d)

	<i>Actual</i>	1977	1978	1981	1984	1986	1988	1991	1994	1999
1974	30.3									
1975	25.2									
1976	24.6	33.1								
1977	30.8	32.9								
1978	32.2	32.4	34.5							
1979	31.7	31.3	34.5							
1980	31.7	30.0	33.5							
1981	28.0	28.8	31.9	27.4						
1982	28.7	27.8	31.1	23.6						
1983	33.0	26.9	29.9	22.0	34.4					
1984	37.6	26.1	29.1	20.6	37.6					
1985	39.1	25.3	28.6	26.9	36.5	40.7				
1986	39.9	24.6	29.1	28.4	34.2	41.2				
1987	43.1	23.7	29.6	30.1	32.5	38.1	44.1			
1988	45.4	22.9	30.5	31.6	31.4	34.5	44.9			
1989	46.2	22.4	31.1	32.5	30.1	31.9	42.2			
1990	49.8	21.8	31.5	33.7	28.7	29.5	40.6	49.6		
1991	50.5	21.1	31.8	34.5	28.7	27.6	38.4	48.8		
1992	55.4	20.5	32.3	34.6	28.3	25.9	36.3	48.1		
1993	61.5	19.9	32.3	34.2	27.9	24.6	34.4	47.8	65.4	
1994	65.7	19.2	32.4	33.5	27.5	23.7	33.1	48.3	73.9	
1995	73.4	18.8	32.3	32.7	27.1	22.2	31.7	49.0	86.1	
1996	82.3			31.5	26.8	22.1	30.5	49.5	89.6	
1997	89.3			30.2	26.6	21.4	29.2	49.5	90.0	88.4
1998	85.2			28.8	26.2	20.5	28.0	48.7	88.2	
1999	82.9			27.5	25.8	19.3	26.9	47.5	85.3	
2000	89.0			26.0	25.6	18.7	26.0	46.2	80.7	82.5
2001	90.7				25.5	18.3	25.1	44.7	76.0	
2002	88.0				25.4	17.7	24.1	42.3	71.8	
2003	86.7				25.4	17.2	23.0	42.0	67.7	
2004	86.5				25.4	16.9	22.1	40.5	64.0	
2005	83.3				25.4	16.6	21.3	39.4	60.8	81.4
2006	82.0							39.0	58.0	
2007	79.4							38.5	55.5	
2008	73.6							38.0	53.5	
2009	68.6							38.0	51.7	
2010	67.2							38.0	50.4	60.0

Note: 1988, 1989 and 1990 actual from CAPP *Statistical Handbook*.

4. Production of Synthetic Crude

Table A8.4: National Energy Board Reports: Production of Synthetic Crude (10³ m³/d)

	<i>Actual</i>	1974	1977	1978	1981	1984	1986	1988	1991	1994	1999
1974	7.3	8.7									
1975	6.8	9.5									
1976	7.6	10.3	7.9								
1977	7.2	10.3	7.9								
1978	8.9	10.3	7.9	11.1							
1979	14.6	18.3	16.7	21.5							
1980	20.3	24.6	23.8	23.0							
1981	17.7	31.0	27.0	24.6	20.0						
1982	19.1	35.0	27.0	26.2	25.0						
1983	25.4	45.3	28.6	28.6	28.0	23.5					
1984	21.1	54.8	29.4	30.2	29.0	24.2					
1985	26.7	63.6	30.2	35.8	29.0	25.0	26.1				
1986	29.4	80.2	30.2	38.1	29.0	25.0	28.5				
1987	28.7	93.0	34.2	47.7	29.0	25.0	28.5	28.5			
1988	31.9	105.7	42.1	65.9	29.0	28.5	29.0	28.8			
1989	32.6	115.2	50.1	75.5	29.0	28.5	29.5	30.5			
1990	32.9	132.7	54.0	82.6	29.0	28.5	29.5	31.2	32.2		
1991	35.9	146.2	67.5	89.0	29.0	28.5	29.5	32.5	33.4		
1992	37.2	164.5	76.3	95.3	29.0	33.5	29.5	33.9	33.9		
1993	38.6	183.5	81.0	103.3	29.0	38.5	29.5	34.9	34.8	38.9	
1994	41.6		85.0	108.9	29.0	38.5	30.0	34.9	36.6	41.7	
1995	43.2		89.0	115.2	29.0	38.5	30.5	34.9	36.4	43.8	
1996	42.7				29.0	38.5	30.5	35.0	36.4	44.3	43.2
1997	45.5				29.0	38.5	30.5	35.0	37.6	45.2	
1998	48.2				29.0	38.5	30.5	35.0	37.6	45.2	
1999	45.9				29.0	43.5	30.5	35.0	37.6	45.2	
2000	44.8				29.0	48.5	30.5	35.0	37.6	48.2	59.2
2001	48.4					48.5	30.5	35.1	37.6	54.2	
2002	59.1					48.5	30.5	35.1	37.6	54.7	
2003	80.9					48.5	30.5	35.1	37.6	55.2	
2004	95.5					48.5	30.5	35.1	37.6	56.5	
2005	86.9					48.5	30.5	35.1	40.0	57.0	87.3
2006	104.4								47.1	57.0	
2007	108.3								49.7	57.0	
2008	103.8								49.7	57.5	
2009	121.7								52.1	58.0	
2010	125.7								59.2	58.0	103.1

5. Production of Bitumen

Table A8.5: National Energy Board Reports: Production of Bitumen (10³ m³/d)

	<i>Actual</i>	1977	1978	1981	1984	1986	1988	1991	1994	1999
1976	1.2	0.8								
1977	1.2	0.8								
1978	1.2	0.8	1.1							
1979	1.5	0.8	1.6							
1980	1.5	1.0	1.6							
1981	2.0	1.3	2.4	2.0						
1982	3.2	1.6	2.4	3.0						
1983	4.0	1.6	3.2	4.0	4.0					
1984	5.3	1.6	4.0	4.0	5.5					
1985	8.1	2.4	4.8	5.0	7.0	8.3				
1986	14.8	2.4	4.8	5.0	9.0	14.5				
1987	18.4	2.4	4.8	5.0	11.0	16.0	18.4			
1988	20.7	2.4	4.8	5.0	13.0	15.7	20.1			
1989	20.5	2.4	4.8	5.0	15.0	16.0	25.2			
1990	21.5	2.4	4.8	5.0	17.0	19.3	30.2	20.6		
1991	19.4	2.4	4.8	5.0	19.0	20.0	30.8	20.9		
1992	19.9	2.4	4.8	5.0	21.0	20.8	30.8	23.0		
1993	20.9	2.4	4.8	5.0	23.0	21.5	30.9	24.6	21.4	
1994	21.2	2.4	4.8	5.0	24.0	22.0	30.5	25.4	22.8	
1995	23.7	2.4	4.8	5.0	25.0	22.5	30.2	26.5	24.7	
1996	26.2			5.0	26.0	22.5	30.2	27.2	28.1	
1997	37.8			5.0	27.0	22.5	30.9	27.5	33.4	37.8
1998	45.7			5.0	28.0	22.5	30.9	28.4	37.0	
1999	38.8			5.0	29.0	22.5	31.3	31.9	41.3	
2000	46.0			5.0	30.0	22.5	31.8	36.5	44.5	48.8
2001	49.2				31.0	22.5	35.0	39.1	44.2	
2002	48.1				32.0	22.5	36.4	44.0	44.1	
2003	55.5				33.0	22.5	37.8	47.9	43.8	
2004	61.5				34.0	22.5	38.2	53.3	42.8	
2005	70.0				35.0	22.5	39.4	55.9	42.2	68.8
2006	74.4							56.6	41.2	
2007	80.3							57.3	40.9	
2008	87.5							62.3	40.9	
2009	90.5							67.5	40.8	
2010	108.0							76.8	40.8	78.9

6. Price Sensitivity Cases

Table A8.6: National Energy Board: Price Sensitivity Cases

<i>I. FEBRUARY 1977 REPORT</i> 1995 production in 10 ³ b/d			
	<i>Expected case</i>	<i>Maximum case</i>	<i>Minimum case</i>
All oil	1032	1425	500
Syncrude	575	855	180
Oil excl oil sands	457	570	320

<i>II. SEPTEMBER 1978 REPORT</i> 1995 production 10 ³ b/d			
	<i>Base case</i>	<i>High case</i>	<i>Low case</i>
Light from est. res.	196	196	196
Light from res. add.	195	388	111
Syncrude	725	1175	170
Heavy from est. res.	37	37	37
Heavy from res. add.	166	236	91
Bitumen	30	30	5

<i>III. JUNE 1981 REPORT</i> 2000 production in 10 ³ m ³ /d				
	<i>Base case</i>	<i>Modified base</i>	<i>High</i>	<i>Low</i>
Conventional light	52.7	61.6	89.0	32.4
Conventional heavy	26.0	34.5	46.4	17.2
Syncrude	29.0	158.0	158.0	29.0
Bitumen	5.0	5.0	5.0	5.0

<i>IV. SEPTEMBER 1984 REPORT</i> 2005 production in 10 ³ m ³ /d			
	<i>Reference</i>	<i>High</i>	<i>Low</i>
Established reserves	19	20	16
New discoveries	27	33	21
EOR	35	48	16

<i>V. OCTOBER 1986 REPORT</i> 2005 production 10 ³ m ³ /d		
	<i>Low</i>	<i>High</i>
Light established reserves	17.0	17.4
Conventional light EOR	14.0	15.9
Conventional light, discov.	15.5	22.9
Conventional heavy EOR	9.0	13.4
Heavy established reserves	2.4	2.5
Conventional heavy discov.	5.2	7.7
Syncrude	37.3	56.0
Bitumen	22.3	84.9

<i>VI. SEPTEMBER 1988 REPORT</i> 2005 production 10 ³ m ³ /d		
	<i>Low</i>	<i>High</i>
Light established reserves	22.2	22.7
Light EOR	13.0	16.2
Light discoveries	31.2	31.5
Heavy EOR	6.5	9.4
Heavy established reserves	2.9	1.7
Heavy discoveries	12.0	11.7
Syncrude	50.1	90.2
Bitumen	39.4	92.3

<i>VII. JUNE 1991 REPORT</i> 2010 production 10 ³ m ³ /d (Approximate values, read from a graph)			
	<i>Control</i>	<i>High</i>	<i>Low</i>
Light and medium	188	235	115
Heavy	121	160	55

/continued

Table A8.6/continued

VIII. DECEMBER 1994 REPORT
2010 production 10^3 m³/d

	<i>Reference</i>	<i>High</i>	<i>Low</i>
Light established res.	13.1	13.1	13.1
Light EOR	45.1	57.1	14.3
Light new discoveries	10.9	12.0	10.2
Heavy est. reserves	2.9	2.9	2.9
Heavy EOR	37.7	49.3	5.4
Heavy new discoveries	9.8	11.0	8.9
Syncrude	58.0	78.1	47.5
Bitumen	40.8	105.1	5.8

IX. 1999 REPORT
2010 production in 10^3 m³/d

	<i>\$14, current supply trends</i>	<i>\$18, current supply trends</i>	<i>\$18, low cost supply</i>	<i>\$22, low cost supply</i>
Conventional light	62.8	82.2	86.2	92.6
Conventional heavy	52.3	60.0	63.9	72.0
Synthetic	74.7	103.1	111.1	165.7
Bitumen	48.0	78.9	74.5	119.6

Part Three: Overview

Part Two of this volume dealt primarily with the geological underpinnings of the Alberta oil industry, the operation of oil markets, and the attempts by economists to build models to help us understand the workings of the oil-supply process and make better forecasts of future petroleum production. That is, the perspective was largely from the 'private' viewpoint of non-government decision-makers. (The main exception to this was in Chapter Seven, on the oil sands and heavy oil, where a number of government regulations were discussed in some detail.)

Part Three focuses on governmental regulation of the oil industry. Of course, this separation into the 'private' and the 'public' is artificial; for example, the oil prices discussed in Chapter Six were affected by (and sometimes actually set by) government regulation. This means that there is some overlap of material in Parts Two and Three, particularly between Chapters Six (Crude-Oil Output and Pricing) and Nine (Government Regulations: Trade and Price Controls).

The oil industry operates within a web of governmental regulations. The purposes of such regulations are multifarious. Some, of course, are part of the necessity for government to establish an environment conducive to a complicated economic system: laws governing the ownership of private property and its use; safety and work regulations for labour; regulations for banks and other capital markets; etc. We take this broad economic environment as given and focus on specific regulations related to the oil industry.

By way of introduction, there have been two quite different perspectives taken by economists on the purpose of government regulation. A standard approach

in conventional 'welfare' economics has been to suggest that governments impose regulations in their position as representative of the public interest. Two broad objectives are then ascribed to governments. The first is increasing economic efficiency (which is often described as correcting problems of 'market failure' such as controlling the exercise of excess market power, offsetting assorted 'externalities' [such as pollution] that markets do not recognize or handle inefficiently, and producing goods and services that the private sector cannot provide efficiently). The second government objective is making society more 'equitable' by appropriate policies of taxation and spending across different income levels or groups. In the context of a federal system such as Canada, the efficiency and equity concerns of different levels of government may be quite different, opening up the possibility of inter-governmental conflict.

A second approach to understanding government policies is often called a 'political economy' perspective, which sees individuals, including government decision-makers, as largely self-interested. Government officials are viewed as being highly responsive to the most vocal and powerful interest groups in society. These groups tend to be made up of those members of society who have the most to gain or lose from particular policy measures; conversely, if the individual is not much affected as an individual, then she is unlikely to exercise much political influence even if there are large numbers of people so affected.

We shall adhere in this book to the former, 'public interest' perspective, and bring it to bear on three main types of government regulation of the Alberta oil

industry. Chapter Nine considers regulations directly impacting on the operation of the oil market in the form of price controls or measures affecting the export or import of oil. Chapter Ten deals with 'conservation' in the production of oil in the form of an output control program called 'market-demand prorationing.'

Finally, Chapter Eleven examines regulations aimed at transferring revenue from the oil industry to the government; this might be called 'oil industry taxation,' but we prefer to refer to it as fiscal measures to 'capture' the economic rent earned by the industry.

CHAPTER NINE

Government Regulation: Trade and Price Controls

Readers' Guide: The most obvious examples of petro-politics in the oil market are the instances in which governments elect to interfere with free market prices and the flows of oil in voluntary exchanges between buyers and sellers. From the viewpoint of traditional economic analysis, unless justified by special circumstances such policies are judged to generate inefficiencies in society. Canada, over the years, provides an interesting case study for a variety of government policies that have been designed to change the price of oil and/or to restrict the amount of oil imported or exported. In this chapter we provide descriptions and assessments of two significant policy regimes illustrating quite different market impacts. From the early 1960s to the early 1970s the National Oil Policy served to restrict the flow of oil imports into Canada and to keep the price of Canadian-produced oil above the world oil price. Immediately following this, until the mid-1980s, a set of regulations restricted exports of oil and held the Canadian price below the world level. This chapter discusses the rationale for these policies, the impact on various participants in the oil market, and their economic efficiency.

1. Introduction

In economists' basic model of the economic market for a commodity, supply and demand forces interact to determine an equilibrium in which the market clears. This model, in its simplest form, abstracts from the roles played by the government. In fact, in a

mixed capitalist economy such as Canada's, the presence of the government is ubiquitous. One role is so much taken for granted as to be almost invisible. It is widely accepted that some agent is required to set and enforce the 'rules of the game' that allow coordinated production and exchange in what might otherwise be a chaotic 'state of nature.' This is often seen in terms of a 'social contract': members of society find it to be in their best interest to agree (for the most part) to obey the dictates of a government, which in turn imposes a set of rules and regulations governing the acquisition and utilization of private property and the rights of workers selling labourer services. Robbery is outlawed, so might is no longer always right; slavery is illegal, so employers may buy labour time but not indenture people; contracts become enforceable, so lenders will part with large sums of money and investors undertake productive activities that will not pay back for years. We do not imply unanimity amongst citizens on how far this role of government should extend; admirers of Ayn Rand and other libertarians may debate long and hard with social democrats and those of more collectivist views. For our purposes, however, we shall take the institutions of contract law, labour codes, and property rights (including the rule of capture, under common law) as given and focus on the additional government programs that have been devised with specific petroleum-related objectives in mind.

This chapter deals with regulations that set the price of oil and direct exchange (or trade) conditions. Of course many other programs, such as prorationing regulations (discussed in Chapter Ten) and taxation (discussed in Chapter Eleven), also have had

an impact on the supply of and/or demand for oil and therefore indirectly affect market prices and/or quantities.

Why might the government feel moved to step into the market to affect directly oil prices or the process of exchange? In the Canadian context three main justifications have been employed.

- (i) *Equity concerns.* For obvious reasons, all else being equal, oil consumers prefer lower crude prices and oil producers (and the owners of oil-bearing land, especially the western provincial governments) prefer higher prices. Geographical disparities heighten the importance of these distributional concerns. It is true, of course, that oil consumers are spread throughout the country, as are shareholders in the oil companies, but the weight of crude-oil-producing interests clearly lies in Alberta and adjacent parts of the Western Canadian Sedimentary Basin. It is also noteworthy that a significant proportion of oil company shareholders are non-Canadian. At the same time consumers predominate in the provinces east of Saskatchewan.
- (ii) *Oil as a 'special' commodity.* Oil is not just any other good but an essential input for a modern industrial economy, especially in the short-run when most of our transportation and some of our residential heating and industrial process capability is irrevocably based on refined petroleum products. Moreover, international petroleum supplies, centred so heavily in the unstable Middle East, are subject to unpredictable disruptions (vis., 1948; 1956–57; 1967–68; 1973–74; 1978–80; 1990–91; 2003–4). Can unregulated markets be relied on to make decisions regarding Canadian oil supplies that are in the best interests of the country?
- (iii) *Oil as a depletable natural resource.* Conventional crude oil is available in (unknown) but limited quantities as a resource in nature; it is a depletable and non-recyclable natural resource. Once again, it has been questioned whether unregulated crude oil markets will give adequate recognition to this. Might not producers tend to export low-cost reserves to foreign users at low prices, forcing Canadian consumers later on to rely on high-cost domestic reserves or imports? (See, for example, Laxer, 1970, 1974; Willson, 1980.) In many cases this argument is tied to the interests of foreign-controlled oil producers, though the

connection is not essential to the argument, and most Canadian-controlled firms have been as eager to see high output rates and, usually, exports, as the multinationals.

Chapter Six, in its discussion of output and prices, noted the importance of various government programs. This chapter will follow that one in treating separately three different time periods: the National Oil Policy (NOP) years 1961–72; the price control and National Energy Program (NEP) years 1973–85; and the deregulation and Canada–U.S. Free Trade Agreement (FTA) and North American Free Trade Agreement (NAFTA) years, 1985 until now. In each case, we shall first set out the main regulations and some elements of the policy discussions that preceded their introduction. We then discuss the impact of the regulations with particular emphasis on their economic efficiency. Before the more detailed historical analysis, we shall briefly review constitutional responsibilities over natural resources such as oil and natural gas, which are of such importance in a federal state like Canada.

2. Constitutional Responsibility over Petroleum

The precise division of jurisdiction over energy matters between the federal government and the provinces reflects both legislative acts and ongoing judicial interpretation. (For detailed discussion of the federal division of powers regarding energy, see LaForest, 1969; Helliwell and Scott, 1981; Lucas and McDougall, 1983; and Cairns, 1987. The *Alberta Law Review* each year has a section on oil and gas law, which frequently includes papers reviewing the past year in Canada and which detail any constitutionally significant laws, regulations, or cases.) Up to 1982, the prime determinant of the division of powers was the *British North America (BNA) Act* (1867, with numerous amendments over the years passed by the UK Parliament). Since repatriation in 1982, it has been the *Constitution Act* (or *Canada Act*), as ratified by Ottawa and all the provinces except Quebec. The *Constitution Act* transferred all constitutional authority to Canada; it incorporates the various BNA Acts as part of the Canadian Constitution as well as such new features as the Bill of Rights and formulae for amending the constitution.

The *BNA Act* of 1867 (UK Statutes 30–31 Victoria, chap. 3) set out the basic division of powers between Ottawa and the provinces. Sections 91 and 92 are of

prime relevance. In Section 91 the federal government is assigned responsibility for the “Peace, Order and good Government of Canada in relation to all matters not coming within the Classes of Subjects of the Act assigned exclusively to the Legislatures of the Provinces.” In addition to this residual authority, a list of specific areas of responsibility to the federal Parliament includes: “(2) Regulation of Trade and Commerce” and “(3) The raising of money by any Mode or System of Taxation.” The list of “Exclusive Powers” of the provinces includes (Section 92): “(2) Direct Taxation,” “(5) The Management and Sale of the Public Lands,” “(13) Property and Civil Rights in the Provinces,” and “(16) Generally all Matters of a merely local or private nature in the Province.” Section 91 and 92 dealt with the power to “make laws”; Section 109 held that, for the original four constituents of Canada (New Brunswick, Nova Scotia, Upper Canada, and Lower Canada): “All Lands, Mines, Minerals and Royalties” belonging to the separate constituents would remain under provincial ownership and control. Section 125 of the *BNA Act* prohibits the imposition of taxes on land belonging to Ottawa or the provinces.

Alberta became a province of Canada in 1905, but it was not until the *BNA Act 1930* (U.K. 20–21 George V, chap. 26) that it was given authority over the remaining Crown rights on land and minerals in the province. This act gave constitutional authority to the *Alberta Natural Resources Act* (Canada Statutes 20–21 George V, chap. 3), which in turn recognized an agreement negotiated between Ottawa and Edmonton regarding Crown lands. Crown rights over a small part of the province, in National Parks and on Indian Reserves, remained in the hands of the federal government.

From this description of powers, some possible areas of conflicted jurisdiction over petroleum resources can be seen. To what extent might the federal authority over trade and commerce interfere with provincial responsibilities for property and civil rights? What about the joint sharing of the direct taxation field and exactly what is a direct tax? How far does the provinces’ control of Crown lands, mines, minerals, and royalties extend? Since this is not a study of the legal aspects of Canadian petroleum, we shall not pursue these issues in any depth. We would note that the majority of Alberta’s petroleum has been found on provincial Crown land, and that the province has exercised its powers to govern the conditions of access to such land and payments associated with its use and the royalties assessed on petroleum production. Some oil and gas is produced from freehold

or federal Crown land within the province, and the province has introduced legislation governing activity with respect to this oil and gas as well as that from provincial Crown land. Included here are ‘conservation’ regulations governing production practices, land use, etc., and regulations requiring permits before natural gas can leave the province. The federal government has long acted to regulate pipelines that cross a provincial border (to other provinces or the United States) and natural gas exports. Corporate income taxes on the petroleum industry have been shared between the two levels of governments.

Until the 1970s responsibilities over petroleum resources seem to have been shared between the federal and provincial governments in a largely amiable manner. These friendly relations eroded after 1972 when the federal government moved to exercise direct control over oil and gas prices and to introduce new taxes on crude petroleum production and oil and gas exports. In some instances, the action taken involved joint federal-provincial agreement, but at other times – most notably in the Natural Energy Program of October 1980 – Ottawa acted alone. Eventually the governments agreed on how to handle these areas of shared jurisdiction, though some difficulties in interpretation of the *Canada Act* remained.

The contentiousness of energy policies in the decade after 1972 may also help explain the special attention given to natural resources in the *Constitution Act* of 1982. An additional schedule (“The Sixth Schedule”) was added to the act, which carefully defined “non-renewable and forestry resources,” indicating that the term refers to primary production but does not include refined petroleum products. In addition, Section 50 adds an entirely new section, Section 92(A), to the *BNA Act*. It reads:

- 92A. (1) In each province the legislature may exclusively make laws in relation to
- (a) exploration for non-renewable natural resources in the province
 - (b) development, conservation and management of non-renewable natural resources and forestry resources in the province including laws in relation to the rate of primary production therefrom.
- (2) In each province the legislature may make laws in relation to the export from the province to another part of Canada of the primary production from non-renewable

natural resources and forestry resources in the province ..., but such laws may not authorize or provide for discrimination in prices or in supplies exported to another part of Canada....

- (4) In each province the legislature may make laws in relation to the raising of money by any mode or system of taxation in respect of
 - (a) non-renewable natural resources and forestry in the province and the primary production therefrom ... whether or not such production is exported in whole or in part from the province, but such laws may not authorize or provide for taxation that differentiates between production exported to another part of Canada and production not exported from the province.

In essence this section affirms the very broad nature of the provinces' powers with respect to primary resources (including those not on Crown land), so long as the exercise of powers does not involve prices or taxes that discriminate against other parts of Canada.

3. The National Oil Policy (NOP): 1961-73

A. *The Policies*

1. Background

Recall the discussion of Chapter Six. The 1947 Leduc discoveries stimulated a surge of oil-directed exploration in Alberta that rapidly built up crude oil reserves. New markets were established for Alberta oil by construction of the Trans Mountain Pipeline westward from Edmonton, reaching the Puget Sound in Washington State by 1954, and the Interprovincial Pipe Line (IPL) east from Edmonton reaching Toronto (Port Credit) in 1957. Crude oil prices were set so as to be competitive in the relevant watershed market, necessitating price declines as the market was extended further into central Canada, and, otherwise, following the delivered price of U.S. crude in the watershed market. (Recall, from Chapter Three, that the 'watershed'

market is that market in which the delivered price of oil from two or more different regions is equal, so it serves as the competitive interface for the producing regions.) The operation of the major pipelines as common carriers and market-demand prorating, implemented by the Alberta government, ensured that all producers had access to the market and that market expansion occurred in an 'orderly' manner; it also contributed to a situation in which there was high excess capacity in Alberta, with oil output in the late 1950s at less than 50 per cent of available crude production capacity. By 1959 international crude oil prices were beginning to decline, though U.S. prices were not, therefore shifting the competitive supply source in the Ontario market away from U.S. (e.g., Illinois) crude to Venezuelan and other international supplies. Oil producers, and the Alberta government, were eager to find new markets for Alberta oil, but there was disagreement about where to look – some were drawn to Quebec, others to the Midwest U.S.A. The latter possibility was problematic. The U.S. government, pushed by domestic oil-producing interests, had long been applying pressure on the major oil companies and U.S. refineries to limit oil imports; then, in 1959, the mandatory U. S. Oil Import Quota Program (USOIQP) was implemented.

With the important exception of market-demand prorating (Chapter Ten), the crude oil market in Canada up to the late 1950s had developed in a largely unregulated manner. The two major crude oil pipelines were incorporated under federal statute and subject to federal regulations under *The Pipeline Act* (13 George VI, 1949, chap. 10). Under this act the Board of Transport Commissioners was given responsibility to issue orders governing the construction of pipelines under federal jurisdiction and could, if it wished, declare oil pipelines to be common carriers (Section 39) and regulate traffic, tolls, and/or tariffs (Section 40).

In 1955 Parliament passed the *Exportation of Power and Fluids and Importation of Gas Act* (1955, chap. 14), which gave the Governor in Council authority to require licences from the government in the export of petroleum and the import of natural gas. McDougall (1973) argues that the act was introduced largely due to concerns about natural gas exports from Ontario; it was never used to restrict crude oil shipments out of Canada.

Opposition to a Montreal pipeline was centred in, though not exclusive to, the major oil companies with Montreal refinery operations as well as Canadian crude production. The majors had reason to be concerned about the displacement by western

Canadian oil of Venezuelan and Middle Eastern crude supplied by their affiliates. Opponents of the extension to Montreal stressed the undesirability of both price declines for western crude and new regulatory schemes that would impose costs on Montreal consumers or Canadian taxpayers. Moreover, it was asked “What happens if Middle Eastern or South American crude producers drop their prices to retain this market?” (Canadian Oil Companies, 1958).

2. The Borden Commission and the National Energy Board (NEB)

In October 1957 the newly elected Conservative minority government appointed Henry Borden to head a Royal Commission on Canadian Energy. The Orders in Council establishing the Commission (P.C. 1957 – 1386), noting Canada’s large energy resources base, argued that “the increasing need of energy for the growing industrial requirements of Canada renders it of the greatest importance to assure the most effective use of those resources in the public interest.” It further noted the importance of ensuring “that present and future Canadian requirements for energy are taken fully and systematically into account in granting licences for the export of energy.” Under the Order in Council, the Borden Commission was instructed to make recommendations on four specific matters (as well as any others it saw fit):

- (i) the export of energy;
- (ii) “the regulation of the transmission of oil and natural gas between provinces or from Canada”;
- (iii) the duties of a National Energy Board (NEB), which the government intended to set up; and
- (iv) specific measures regarding Trans-Canada Pipelines Ltd., the natural gas trunk line which government policy had insisted be laid entirely in Canada, instead of looping into the U.S. below the Great Lakes as IPL had done.

In this chapter, the recommendations regarding crude oil will be summarized. (Readers will also wish to refer back to the relevant section of Chapter Six. Breen (1993, pp. 457–65, 468–81) provides a thorough discussion of the Borden Commission and its hearings.) The *First Report* of the Borden Commission was issued in October 1958 and dealt largely with the responsibilities of the NEB and with natural gas. The Commission’s recommendation that oil imports be subject to annual licensing was not adopted (Borden, 1958, p. 26). Nor was the recommendation that it be made “mandatory” for the Board of Transport Commissioners to

regulate the “traffic, tolls or tariffs of oil pipeline companies subject to the jurisdiction of the Parliament of Canada” (Borden, 1958, p. 27). The Commission felt that a different body should be responsible for assessing Canadian energy needs and issuing licences of approval for activities than was responsible for examining shipment tariffs.

Chapter 3 of the Borden Commission’s *First Report* concerned the NEB, with twenty recommendations (Borden, 1958, pp. 43–48). Key recommendations with respect to crude oil were: (i) requirement of an NEB licence for all international or interprovincial oil or oil-product pipelines; (ii) requirement of annual, non-transferable licences for crude and product imports; and (iii) NEB administration of oil export licences. In addition, the NEB would have broad responsibilities for providing information on Canadian energy matters to the public and making energy policy recommendations to the government.

The *National Energy Board Act* was passed in 1959 (Statutes, 1959, chap. 46). (Winberg, 1987, chap. 9, looks at the structure and responsibilities of the NEB.) It established a five-member board, with each member appointed by the Governor in Council for a seven-year term. To some degree, its mandate was patterned on the Alberta Oil and Gas Conservation Board (OGCB) and indeed its first chairman (Ian McKinnon) was formerly chair of the Alberta Board. The NEB was set up as a court of record, with powers to hold hearings, examine documents and witnesses, and issue orders on matters under its jurisdiction. The NEB was given ongoing responsibility to monitor Canadian energy industries and issues of concern to federal policy and to report to and advise the government as “it considers necessary or advisable in the public interest” (Part 2, Section 22). Under Parts II to IV of the act, the board was given the responsibility to issue certificates governing the construction and operation of oil and gas pipelines under federal jurisdiction and the power to issue orders “with respect to all matters relating to traffic, tolls or tariffs” (Part IV, Section 50). While Part VI, Section 81, required licences for the export or import of natural gas, Section 87 allowed that the Governor in Council could extend this requirement to oil. This was not done in the 1960s.

The *Second Report* of the Borden Commission (Borden, 1959) dealt entirely with problems of the Canadian oil industry, particularly those related to the desire for expanded markets. (The discussion that follows is based largely on Bradley and Watkins, 1982.) In 1958, the Canadian oil market and pricing structure appeared to be in equilibrium. Canadian markets were supplied by three main sources – western Canada,

Venezuela, and the Persian Gulf. The Atlantic provinces and Quebec drew from the latter two sources, B.C. and the prairies from the former. Ontario used largely western Canada crude plus some from Venezuela and a significant volume of refined products from Montreal. Flows of U.S. crude into Ontario had become negligible. Alberta oil prices, in 1958, made Canadian-produced crude just competitive with U.S.-produced crude in the mid-continent northern states (e.g., Minnesota) but were not so high as to attract large volumes of foreign crude into the Toronto/Sarnia markets, nor so low as to make Alberta oil competitive with foreign crudes in Montreal. As was summarized in Chapter Six, a report prepared by a U.S. petroleum consulting firm, Walter J. Levy, Inc., for a group of oil companies for submission to the Borden Commission, estimated that Alberta oil delivered to Montreal would cost \$0.12/bbl more than Venezuelan crude (Levy, 1958, p. II-18).

This possibility of extending deliveries of Canadian-produced crude oil to the Montreal market was the most widely discussed option in submissions made to the Borden Commission. It was advocated with particular force by many of the western Canadian 'independents,' crude oil producers without any ownership (either directly, or indirectly through some parent corporation) in refinery operations, and generally without any large crude oil production outside Canada, and certainly not outside North America. It was recognized, as the Levy analysis demonstrated, that Canadian crude was not competitive in Montreal. Levy (1958, p. viii) had concluded that "to establish Canadian crude at Montreal would therefore not only require the efforts of the Canadian oil industry to achieve competitive equality with foreign crudes. It would probably further require an explicit formulation of public policy in support of Canadian markets for Canadian oil." In essence, it was argued that it was desirable to attach western Canadian crude to the Montreal market, but not to reduce the price of Canadian-produced oil. This would require a formal public policy, such as direct subsidies to Montreal refineries purchasing Canadian crude, voluntary or mandatory oil import quotas and/or oil import tariffs. It was also suggested that pricing practices might be implemented that cross-subsidized Canadian oil moving into the Montreal market. For example, the pipeline tariff on oil moving from Alberta to Montreal could be held at the level that made the Alberta oil competitive with foreign crude, and the tariff on other oil shipments (e.g., 'short-haul' crude) increased to recover the full cost of the Montreal line. Alternatively,

price discrimination might be practised on crude oil itself, with a lower field price for sales in Montreal; this would raise formidable administrative problems, however, to ensure that the less-profitable crude oil sales were fairly allocated across all provinces. Most proponents of a Toronto–Montreal pipeline extension argued that such government intervention would be an enlightened move toward Canadian energy self-sufficiency and greater national security.

An alternative strategy was recommended by the majors (e.g., Imperial Oil Ltd., 1958). Under this proposal, the Ontario market would be reserved for Canadian crude oil (backing out some imported oil, mainly, as noted above, refined petroleum products shipped from Montreal). In addition, crude oil exports to the United States would be increased. The latter, as the majors recognized and critics emphasized, would require some special recognition of Canadian crude under the recent U.S. Oil Import Quota Program (USOIQP).

In July 1959 the Borden Commission's *Second Report* appeared, recommending, at least as a first strategy, the proposals of the major oil companies. The *Report* included a detailed review of the development of the Canadian oil industry up to 1959, and summarized the major arguments about a Montreal pipeline. The Commission noted excess oil-producing capacity and concluded "[h]aving regard to the trends in the discovery and growth of reserves in Canada, future Canadian requirements will not be jeopardized, in our opinion, if exports of crude oil are permitted and encouraged. Consequently, we do not feel that such licensing of exports by pipe line as has heretofore prevailed need now be continued" (Borden, 1959, p. 125).

Both the appeal of and the problems with extending Canadian crude oil pipelines into Montreal to secure a larger Canadian market were thoroughly discussed, along with methods to achieve such an objective. For example, (Borden, 1959, p. 130):

In our opinion a customs duty ... would, in itself, be of doubtful value in securing the construction of the pipeline facilities. The vendors of the foreign crude oil to the Montreal refiners might well be prepared to make, either directly or indirectly, substantial reductions in posted prices in order to preserve the Montreal refinery area.... Furthermore, the imposition of a nation-wide customs duty might have the effect of raising, unnecessarily in our view, the internal cost of a vital source of energy to Canadian consumers.

The Commission also considered the suggestion “that a county conserves its resources of crude oil by importing foreign crude ...,” but went on to remark that (Borden, 1959, pp. 130–31):

... the effect of such imports of foreign crude on exploration for and development of Canada’s resources must be considered. The primary ability to make expenditures for exploration and development comes from the actual and anticipated revenues from production. If expenditures on exploration and development are not incurred, the oil reserves may neither be discovered nor developed and therefore would not be readily available for future use...

A healthy, strong and vigorous Canadian oil industry is clearly essential not only from the point of view of its importance to the Canadian economy but because this country should have ample supplies available to enable it, if necessary, to meet its own requirements as well as to supplement those of other countries which, during an emergency, might be dependent upon North American sources of supply.

The existence of high excess capacity undermined continued active exploration and development, so that the “problem is how best to increase the level of production of the oil industry in Canada to the point where such production will sustain a strong and healthy industry without adversely affecting the cost of energy to the Canadian consumer” (Borden, 1959, p. 133). Moreover, (p. 136):

Conditions of uncertainty and over-production in the world oil industry are likely to continue for some years and world oil prices may decline further. If they do and the reduction is substantial and is reflected in lower well-head prices for Canadian crude oil, the results would be very serious for the Canadian industry.

The conclusion was (p. 138):

... that if there were an effective national policy ensuring the use of Canadian crude in domestic markets, now accessible by pipeline, and encouraging the use in those markets of products refined from Canadian crude, and if Canada were successful in the immediate

future in substantially increasing its exports of crude oil to the United States, the production of Canadian crude could be maintained at a level adequate to sustain a strong industry and to provide the incentive for further exploration and development.

We have in mind a target level of production by the end of 1960 approximating 700,000 barrels per day.

Increased Canadian oil output, from the 1958 level of about 460,000 b/d, would, therefore, come from both displacement of crude imports and Montreal-refined products in Ontario and increased exports. The Commission noted that a procedure of import licensing might be needed to achieve this end and that “[t]his system of licensing would lay the foundation for the building of pipeline facilities to transplant Canadian crude to Montreal, if and when it becomes necessary and desirable that they should be built” (Borden, 1959, p. 141).

The government’s receipt of the Borden *Second Report* was followed by declines in the international price of oil later that year, and again in 1960, thereby raising even further the cost of adding a protected Montreal market for Canadian crude producers.

3. The National Oil Policy

On February 1, 1961, Hon. George Hees, the federal Minister of Trade and Commerce, announced the National Oil Policy, basically ratifying the Borden Report recommendations. Adoption of the policy by producers and refiners was voluntary, though the minister reminded industry that the government could always introduce compulsory regulations under Section 87 of the *NEB Act* which gave the NEB the power to require authorization (licences) for imported and/or exported oil (crude and products). The government set a production target level of 640,000 b/d in 1961, rising to 800,000 b/d by 1963, and noted that:

These targets are to be reached by increased use of Canadian oil in domestic markets west of the Ottawa valley, and by some expansion of export sales largely in existing markets which can be reached through established pipelines.

The growth in domestic use is predicated in particular on substituting in Ontario markets west of the Ottawa valley products refined from Canadian crude for those now supplied by foreign crude...

The increase in exports which is integral to the government's program is wholly consistent with the growth of sales of Canadian oil contemplated when exemption from United States oil import controls was established, under which Canadian oil is relatively free to move into the United States by overland means of transportation. (Debates of the House of Commons, 9–10 Elizabeth II, Vol. II, 1960–61, pp. 1641–42).

The NOP was monitored by the NEB. The 1961 to 1963 production targets were successfully met. A target of 850,000 b/d was set for 1964 and surpassed. No further output goals were set, but production continued to rise. The NOP continued until 1973, on a voluntary basis with one exception. Rising movements of motor gasoline across the NOP line induced the NEB, in 1970, to institute licensing of motor gasoline imports into Canada. Bertrand (1981, p. 42) shows imports and transfers of motor gasoline by independent refineries and distributors rising from 1,938 b/d in 1964 to 10,482 in 1970. These figures exclude Gulf, Imperial, Shell, Texaco, and B.P.

4. The U.S. Oil Import Quota Program (USOIQP)

The success of the NOP depended upon the ability of Canadian crude producers to increase exports to the United States, which hinged on the treatment of Canadian oil under the USOIQP. Complete descriptions of the genesis and impact of the USOIQP can be found elsewhere (e.g., Shaffer, 1968; Adelman, 1972; U.S. Cabinet Task Force on Oil Import Control, 1970; Watkins, 1987a). We shall summarize the main provisions as they applied to Canada.

Prior to 1942, crude oil and refined petroleum product prices in international trade were generally based on U.S. Gulf Coast prices, but after that Middle Eastern oil began to become relatively less expensive. By the early 1950s, significant volumes of crude from the Persian Gulf were beginning to move into the United States, much to the alarm of domestic U.S. oil producers. Concern about declining markets and/or prices was often clothed in expressions of concern about U.S. national security. The U.S. government worked with the major oil companies in the mid-1950s to introduce voluntary oil import limits, but without complete success. (Bradley and Watkins, 1982, pp. 78–80, provide an overview of the voluntary program and point out that U.S. oil imports rose from 8 per

cent of U.S. demand in 1950 to 12 per cent by 1956. Also see Adelman, 1972.)

On March 10, 1959, mandatory limitations on crude oil imports were imposed by presidential decree, ostensibly for national security reasons under the *Trade Agreement Extension Act* (Proclamation #3379, 24 F.R. 1781). National security was a legitimate cause for protectionist acts under the multilateral GATT (General Agreement on Tariffs and Trade). The scheme was complex and became increasingly so. The broad outlines will be sketched here.

It is important to recall that the combination of the USOIQP and market-demand prorating in the main U.S. producing states, especially Texas, held domestic U.S. oil prices above international prices from 1957 through 1972. With falling international prices from 1959 through 1970, the discrepancy widened, from perhaps \$0.30 (US) per barrel in the late 1950s to \$1.50/b by the end of the 1960s (Adelman, 1972). Refined petroleum product prices (and crude oil values) were based on the higher U.S. prices, so that anyone allowed to import cheap international crude oil automatically derived an extra profit. Expressed in other terms, the quota limitation prevented international oil supplies from driving U.S. prices down to the international level and meant a windfall gain to those refiners who were allowed to buy international oil.

How, then, were the quota volumes determined, and who was allowed to buy cheap international oil? Under the USOIQP, the United States was divided into two market areas, with different quota regimes. PAD (Petroleum Administration District) V consisted of the West Coast states, and imports were allowed to fill the gap between District V consumption and District V production (presumably at prevailing U.S. crude oil prices). The rest of the continental United States comprised PADs I to IV; here imports equal to 9.6 per cent of consumption (“demand”) were allowed, a value that was changed in November 1962 to 12.2 per cent of PAD I to IV production. The right to purchase imported oil was given to individual refiners in PAD I to IV. All U.S. refineries received such allocations whether they imported oil or not, but particularly large allocations were given to “historical” importers; these were refineries that had been importing oil for a number of years and had been recognized under the earlier voluntary oil import controls. Higher refinery throughput generally meant the right to import more oil, or as it was called, a higher import “ticket.” What, then, happened to tickets awarded to refiners that did

not have a need to use them? The tickets could not be sold directly, so what value would the right to import oil have to a refiner in Montana or Minnesota with no direct access to cheap Venezuelan or Middle Eastern oil? Value was assured since the import tickets could be traded for domestic U.S. crude oil. For example, suppose that the price of U.S. crude oil was \$3.00/b and Middle East oil were available delivered to the East Coast for \$2.00/b. Then Refiner A in Minnesota could trade the ticket for one barrel of oil imports to Refiner B in Philadelphia in return for 1/3 of a barrel of domestic crude. The ticket therefore has a value of \$1.00 (1/3 times \$3.00). Refiner A could now purchase an additional 2/3 of a barrel of domestic crude, thereby receiving a full barrel for an expenditure of \$2.00. Refiner B could import one more barrel of foreign oil for \$2.00, and a total cost of \$3.00 including the cost of the ticket bought from Refiner A. In this way, the benefits of importing low-cost foreign oil could be shared by all refiners, while the actual inflows of foreign oil would be to the most economic markets (farthest from domestic U.S. production and on the east coast).

Now, consider the position of Canadian oil under the USOIQP. The U.S. Cabinet Special Committee, which recommended mandatory oil import controls, did not advocate preferential treatment for Canada but did recommend special allocations for refiners unable to obtain sufficient domestic oil. Preferential treatment for Canadian oil in the Midwest was thus implied. The original presidential proclamation of March 10, 1959, applied to all U.S. oil imports. If Canadian oil were treated like all other imported oil, it would appear attractive to U.S. refiners only if priced competitively with other foreign crudes, allowance being made, of course, for location and quality differentials. (To continue the example of the previous paragraph, why would Refiner A in Minnesota use its crude oil import ticket to buy Canadian oil at \$2.60/b when its ticket plus \$2.00 would give it a barrel of domestic oil?) Special treatment of Canadian oil in U.S. markets was, therefore, essential to the strategy advocated by the majors, the Borden *Second Report* and the NOP.

On April 30, 1959, a presidential proclamation excluded overland imports from Canada and Mexico from the maximum allowable imports into the United States, except if the overall level of imports increased to an extent to seriously affect the intent of the USOIQP (Proclamation #3290 [24 F.R. 3527]).

The reasons for the change in Canadian status were not given, but two plausible ones come to mind.

First, under the national security rationale, Canada qualified as a safe and secure source of supply. At the same time, it did not pose a great threat to domestic production because Canadian oil was not competitive beyond the northern border region. Second, the possibility remained of Canada extending the Interprovincial Pipe Line to Montreal to displace Venezuelan imports in the Montreal market, which would have had serious repercussions for Venezuela. Canada was its second largest customer (16 per cent of Venezuelan crude oil exports went to Canada) (Shaffer, 1968, p. 122). The significance of such a threat to the political and economic stability of Venezuela would not have escaped the notice of the U.S. State Department. The treatment of Venezuela under the import program had always been a sensitive issue. In the original import control proclamation, reference was made to special hemispheric interests involving Canada and Venezuela; it was intended that such interests be accommodated in the program. When exempt Canadian supplies displaced Venezuelan exports to the United States, Venezuela lobbied about what it saw as unequal treatment.

Exemption from mandatory quotas made Canadian oil more acceptable, but an offsetting aspect was an implicit penalty imposed on U.S. refiners using Canadian crude. Any refiner with access to Canadian crude could import it without a licence, but exempt imported crude did not count as refinery input in assigning import quotas. Only offshore and domestic crude qualified for this purpose. Consequently, the loss of import tickets from using Canadian crude constituted a clandestine tariff on it. This penalty on Canadian oil ensured that prices for Canadian crude oil remained below U.S. prices (as Chapter Six showed). However, the exemption from the U.S. import quota meant that the Canadian price could exceed the international price. Canadian oil thus had unique status in the U.S. market, neither like other imported oil nor equivalent to domestic U.S. production. Refiners with access to Canadian oil faced no explicit limits on their purchases, but, because purchase of Canadian oil reduced their import tickets, they were not willing to pay the full U.S. domestic price.

In November 1962, there were several changes to the USOIQP that affected Canada (Proclamation #3509, 27 F.R. 11985). One was a more rapid reduction of historical quotas for those refineries using Canadian crude oil. These refineries used their quotas to send foreign crude oil to coastal refineries

in exchange for domestic crude, mainly from North and South Dakota and Montana, leaving Canada very much a residual supplier of crude oil at such refineries (Shaffer, 1968, p. 160). The more rapid phasing out of historical quotas lowered an important entry barrier to Canadian oil. However, a 1968 decision to set a floor for historical allocations effectively guaranteed a minimum market for United States domestic crude at these refineries via the quota exchange route.

Another change that had a direct effect on Canada was the change in November 1962, noted above, in the basis of setting the overall level of imports for Districts I–IV. The maximum level of imports for any six-month period was changed to 12.2 per cent of U.S. oil production ('supply') from 9.6 per cent of U.S. oil consumption ('demand'). The permitted level of overseas imports was established by deducting the estimated volume of overland imports from total authorized imports. This established a definite, though theoretical, upper limit on Canadian and Mexican imports. More important was the way additional Canadian imports directly displaced offshore imports, raising concern that the curtailment in overseas supply would reduce the supply of crude oil that might otherwise end up in the hands of independent refiners and dealers competing in eastern seaboard markets. Regardless of the merits of this argument, it was significant that Canadian oil was perceived as a threat in certain areas.

The combination of the imports of Middle East oil into eastern Canada and shipment of western Canadian crude to the United States was also seen by some in the United States as a rather costly way of circumventing the import program, especially before the 1962 inclusion of 'exempt' Canadian oil in the overall import umbrella. The argument was that imports of low-cost Middle East oil into eastern Canada released western Canadian oil to be sold at higher prices in the United States market. According to this view, there was still no improvement in security of oil supplies to the hemisphere and, in effect, Canada had served as a conduit for offshore oil to enter the United States market but at the higher Canadian price. Eastern Canadian consumers benefited at no cost to Canadian oil producers. The United States government made it clear that it did not approve of Canada increasing its oil exports to the United States by importing more foreign crude into Canada. Protection of Canadian markets under the National Oil Policy helped assuage these concerns, since markets west of the Ottawa River Valley would be served by Canadian oil despite the appeal of sales in the United States.

During the 1960s the Canadian and United States governments were frequently in contact about exports of Canadian oil to the United States. In 1967, the discussions culminated in an initially secret agreement, before the Interprovincial Pipe Line was extended to Chicago. This agreement sought to allay United States concerns by limiting the growth of Canadian crude oil exports. Canadian crude oil exports were apparently still seen as menacing the goals of the U.S. program in 1970, because in March of that year the first mandatory ceiling on Canadian crude imports to the United States was imposed (Proclamation #3969 [35 F.R. 4321]).

By 1973, rising demand in the United States for crude oil could no longer be met under the quota system and in April of that year the mandatory system of oil import quotas was abolished (Proclamation #4210 [38 F.R. 4645]). It was replaced by a system of licence fees for oil imports. The licence fee was a continuation, at a slightly higher level, of the duty on imported oil that had been in effect during the voluntary and mandatory oil import programs. (The tariff on crude rose from 12.5 cents per barrel to 21 cents.) For the remainder of 1973, exemption from licence fees was granted to certain volumes of Canadian oil imports; the degree of exemption was to decline annually. But these provisions became irrelevant after 1973 as Canada itself increasingly restricted exports of oil to the United States, as the NOP was abandoned.

From this discussion of the terms of access for Canadian oil under the USOIQP, two points should be clear. First, Canadian oil occupied a special position. Second, although Canadian oil was given special treatment, its penetration into U.S. markets was constrained in various ways. The reason for special treatment was simple. The legal justification for the USOIQP was security of supply, and Canadian oil transported overland to the United States was seen as more secure than overseas oil. Hence the decision to exempt Canadian oil from the formal quota provisions. But Canadian oil never enjoyed unrestricted access to U.S. markets. As we have seen, various impediments emerged: hidden tariffs, quota exchange provisions, secret agreements, intergovernmental discussions, and the like. Nevertheless, some lobbies in the United States remained wary of the exempt status accorded to Canadian oil, in view of the fact that world oil had free access to eastern Canada. Over time, the security of supply objective of the USOIQP tended to be neglected and protection per se became the paramount issue.

B. Economic Analysis of the NOP

Initially we shall discuss the effects of the NOP, in 'positive' or descriptive terms; then we shall look at its economic efficiency (i.e., from an evaluative or 'normative' point of view).

1. Effects of the NOP

Analysts sometimes fail to remark on the often difficult first step in describing the impact of a government policy – determining what would have occurred in its absence. It is hard enough to know what has actually happened in the world, without speculating on hypothetical worlds, which, one assumes, have their own virtual reality. In the present instance, the NOP lasted for over a decade (1961–72) in an evolving world oil market with active policy-makers in addition to the Canadian federal government (most significantly, the U.S. government with its USOIQP). No one can know exactly how the Canadian crude oil industry, Canadian and U.S. oil refiners, the Alberta government and Oil and Gas Conservation Board (OGCB) and the U.S. government would have behaved in the absence of the NOP. But the following seems, to us, a plausible scenario.

First, the market-demand prorating regulations of the OGCB would have continued to operate to hold excess Alberta crude oil production capacity off the market, thereby putting primary responsibility for determining the price and output of Alberta crude oil on the purchasing refiners. Second, given the IPL connection from Alberta to Toronto, refiners would establish the posted price for Alberta crude oil at a level just competitive with imported crude oil and refined petroleum products in Toronto. This would have implied declining crude oil prices in the 1960s as international prices fell. Third, especially with Canadian oil priced at the international level, U.S. refiners would increase their imports of Canadian oil. However, it is not at all clear that the level of exports to the United States would have risen beyond that actually observed; the USOIQP was, after all, designed to limit oil imports to protect the domestic industry, and international political concerns of the U.S. State Department imposed limits on the willingness of the United States to see Canadian oil back Venezuelan and Middle Eastern oil out of the U.S. market. Moreover, at lower prices, the U.S. market would have appeared less attractive to Canadian oil producers. And remember that the NOP itself set out explicitly to encourage increased oil

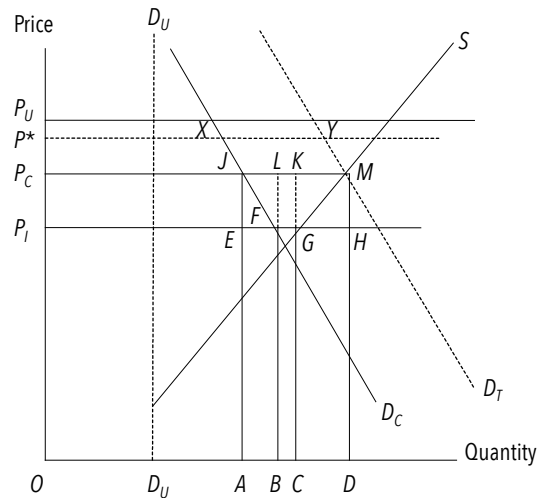


Figure 9.1 Canadian Oil WORV under the NOP

exports to the United States, something that was not occurring automatically. Also, the lower prices would make incremental investment in Canadian crude oil exploration and development less appealing.

Figure 9.1 provides an initial and oversimplified comparative static picture of the impact of the NOP. Presumably there was no impact in Canada east of the Ottawa River Valley (EORV). Consumers imported foreign oil at the international oil price under the NOP, just as they would have without the NOP. We shall not go into the argument that the major international oil companies EORV used their market power in refining to pay more than the prevailing oil price to their international crude-oil-producing affiliates, thereby overcharging Canadian consumers. Bertrand (1981) argues this forcefully, but the Restrictive Trade Practices Commission (1984) was not convinced, and Bernard and Weiner (1992) provide strong contrary evidence. (See also Bradley and Watkins, 1982.)

Figure 9.1 shows the Canadian crude oil market west of the Ottawa River Valley (WORV) in terms of simple supply/demand relationships that abstract entirely from market-demand prorating. P_I is the international price, and P_U that in the United States. D_C and S show the demand for oil by Canadians WORV and the supply of Canadian-produced crude oil. It is assumed that U.S. refiners would find Canadian oil attractive as soon as the price is far enough below P_U but that a maximum of $XY (= D_U)$ barrels of Canadian crude oil would be accepted. The total demand for Canadian oil, then is $D_T (= D_C + D_U)$. The penalties against Canadian oil in the USOIQP

would keep refiners from buying any until the price was P^* or less. Figure 9.1 shows that without the NOP the Canadian crude oil market WORV would have been in equilibrium at point G; Canadian oil would sell at the international price (P_I) and total oil production (OC) would be divided between domestic sales (OB) and exports (BC). Under the NOP, the Canadian oil price rose to level P_C (less than or equal to P^*), with total output of OD divided between domestic (OA) and U.S. ($AD = XY = D_U$) consumption.

The NOP was viewed as beneficial by domestic crude oil producers but imposed costs on some domestic oil consumers. Figure 9.1 can be used to illustrate these effects. Consumers (WORV) under the NOP pay a higher price for oil ($P_C > P_I$) and purchase less ($OA < OB$). Total payments for crude oil change from $OBFP_I$ to $OAJPC$, which will involve an increase so long as the demand for crude oil is inelastic (i.e., the absolute value of the elasticity of demand is less than 1, as is certainly true in the short-run, and probably also in the long run). Under the NOP, producers increase sales of oil from OC to OD , and receive a higher price ($P_C > P_I$). Total receipts rise from $OCGP_I$ to $ODMP_C$. U.S. consumers receive more oil ($AD > BC$), but pay more for it ($P_C > P_I$), while still paying less than for domestic U.S. oil ($P_C < P_U$).

The total increase in payments to Canadian producers, as represented by areas P_IHMP_C plus $CDHG$ can be separated into a number of different components:

- (i) $CDMG$ is the increased cost of production of the incremental oil output, including the various tax and royalty payments made to governments by the crude oil producers, and the user cost of lifting the crude;
- (ii) $P_I E J P_C$ is the increase in payments by Canadian consumers to producers on the oil they buy at the higher price;
- (iii) EFJ is a loss of consumers' surplus due to reduced purchases of oil by Canadians as the price rises (various other measures of consumers' surplus are possible, see Willig, 1976);
- (iv) the remaining area $FGMJ$ is part of the increased payments by U.S. oil consumers for their oil imports, including the higher payments on the oil they would themselves buy at P_I (i.e., area $FGLK$); U.S. consumers also pay for the lost value of oil purchases given up by Canadian consumers (area $AJFB$) and the cost of the increased Canadian production ($CDMG$).

The main weakness in Figure 9.1 is its failure to allow for the existence of large excess producing capacity for Alberta crude oil, and the operation of market-demand prorationing. In effect, there was not a conventional well-defined supply curve for Alberta crude oil. Thus, for example, without the NOP, Canada could easily have supplied the full complement of feasible exports to the United States (i.e., $XY = AD$). Had this occurred, the impact of the NOP would have been to increase Canadian receipts on this oil, but not necessarily to increase the volume of sales. (This implies that some other force, but a temporary one, was limiting expanded oil sales to the United States up to 1961. The obvious candidate is uncertainty about whether Canadian oil policy would force a Montreal pipeline extension. Until that issue was resolved, pipeline companies and Canadian producers might well be unwilling to expand sales in the United States.)

One might also speculate on the investment impact of a price rise, if there is significant excess capacity. Why add new reserves when unused productive capacity is available? Investment stimuli under prorationing will be discussed again in Chapter Ten, but it was certainly a promise of Borden, governments, and the industry that the NOP would serve as a positive stimulus to exploration and development. If it encouraged more output, then any new reserves found were going to be needed sooner. And if the price were higher as well, this was only more inducement to increase investment. It is also important to realize that the market-demand prorationing regulations ensured a market for any newly added reserves, so that, all else being equal, a higher price made investment more profitable, and the producer did not have to wait until excess capacity disappeared before beginning to realize those profits. However, while there was, under market-demand prorationing, an upward sloping supply relationship for additions to reserves, this cannot be translated into a conventional rising marginal cost curve for crude oil production, as Figure 9.1 might initially be interpreted.

How large were the price effects of the NOP? They most certainly varied over time, since international oil prices declined after 1960, and then rose again in the early 1970s. The precise values would, of course, differ for various grades of crude oil. Table 9.1 presents approximate values using exports from the Niagara Peninsula as the interface market. Values are only approximate for several reasons, including the difficulty in obtaining completely reliable data on international crude oil prices at a time when discounts were common and the lack of accurate data on

Table 9.1: Crude Oil Costs under the NOP (36° API Crude to Detroit/Toledo Canadian \$/b)

	Canadian Crude (C)	US Mid-Continent Crude (US)	Persian Gulf Crude (PG)	Differentials		
				US-PG	US-C	C-PG
1961	3.31	3.57	2.46	1.11	0.26	0.85
1962	3.41	3.70	2.55	1.15	0.29	0.86
1963	3.41	3.70	2.60	1.10	0.29	0.81
1964	3.41	3.65	2.26	1.39	0.24	1.15
1965	3.41	3.64	2.11	1.53	0.23	1.30
1966	3.41	3.71	2.19	1.52	0.30	1.22
1967	3.41	3.76	2.13	1.63	0.35	1.28
1968	3.41	3.84	2.74	1.10	0.43	0.67
1969	3.41	3.98	2.16	1.82	0.57	1.25
1970	3.71	3.92	2.25	1.67	0.21	1.46
1971	3.71	4.01	2.40	1.61	0.30	1.31
1972	3.71	3.93	2.54	1.39	0.22	1.17

Notes and Sources: Canadian Crude: Redwater 35° crude as reported in Watkins (1987a), plus \$0.02 quality adjustment plus \$0.77/b shipment cost as implied in Watkins (1987a, p. 48).

U.S. Mid-Continent Crude: Field price as reported in Degolyer and MacNaughton plus estimated pipeline tariff of US\$0.45/b. Watkins (1987a, p. 48) reports delivered costs in Detroit of Wyoming sour crude (with which mid-Continent U.S. crude would have to be competitive); these costs exceeded mid-Continent field prices by \$0.53/b in 1965, \$0.45 in 1967 and \$0.50 in 1969. The year-end Canadian–U.S. exchange rate was used.

Persian Gulf Crude: Saudi Arabia 34° prices f.o.b. the Persian Gulf as reported in Adelman (1972, pp. 183,190) and Griffin and Steele (1986, p. 18) plus Canadian \$0.04/b quality adjustment plus a shipment cost to the North American east coast, which falls from US\$0.78/b in 1961 to US\$0.57/b from 1966 on. These are based on costs from W. Newton reported in Watkins and Bradley (1982, p. 115) of \$0.88/b in 1959, \$0.68/b in 1963 and \$0.57/b in 1968. An additional Canadian \$0.11/b was added for shipment costs from the East Coast; this was the Portland, Maine, to Montreal tariff (as reported in Bertrand, 1981, vol. II, p. 38). The end of year U.S.–Canadian exchange rate is used.

international tanker rates; the need to estimate costs for hypothetical pipeline routes; and the somewhat arbitrary nature of quality differentials. For Canadian and U.S. crude oil, posted field prices have been used. The international oil prices are drawn largely from Adelman's estimate of third-party arms-length prices and reflect such factors as the disruption to oil values during the 1967/68 Arab–Israeli war. All prices have been translated into Canadian dollars per barrel of 36° crude oil, using the year-end exchange rate. U.S. prices were always at least \$1.00/b above international prices, and as much as \$1.80 higher. U.S. prices also exceeded Canadian prices, by as much as \$0.57/b, though usually by \$0.25/b to \$0.30/b. As can be seen, Canadian prices were significantly higher than international prices, by amounts ranging roughly between \$0.80 and \$1.45 per barrel. These differences may overstate the price effect of the NOP slightly, since they are based on the \$0.11/b shipment cost reported by Bertrand (1981, vol. II, p. 38) for the Portland (Maine) to Montreal pipeline link; a hypothetical east coast to

Toronto line for international crude would, presumably, have a cost higher than this.

In conclusion, it is fair to say that, for most of the NOP years, Canadian crude oil prices were \$1.00/b, or more, higher than international prices and about \$0.30/b below the U.S. level.

2. Normative Analysis of the NOP

Evaluation of whether or not the NOP was a desirable policy requires criteria about what generates the 'public good.' Initially we shall use the criterion of microeconomic economic efficiency, considering only the immediate effects in crude oil markets. We shall then offer some thoughts on other possible criteria for evaluating public policy, including equity concerns and possible externalities related to the level of macroeconomic activity and to national security.

It is sometimes not emphasized that normative evaluation of public policies necessitates careful

definition of a reference population. What appears a desirable policy from the viewpoint of Calgary's citizens might or might not so appear for the entire province of Alberta or for all of Canada. Careful specification of the reference group is, perhaps, particularly critical for the objective of economic efficiency, since it is usually assumed that the impacts of a policy are important only insofar as particular individuals directly feel them; that is, no allowance is made for feelings of empathy or altruism that people may possess. (The objective of 'fairness' or 'equity' may presume widespread empathic sentiments.) In our evaluation of the NOP, which was a federal government policy, we assume that all of Canada serves as the referent, not just Alberta.

a. Economic Efficiency of Crude Oil Markets

(i) **Case 1.** Figure 9.1 provides a starting point for our analysis. The economic efficiency of the NOP can be measured by the sum of all gains the policy generated for Canadians less the sum of all costs, or the 'net social benefits' (NSB), which may be either positive or negative. Initially we will work on what might be called a 'domestic' basis, evaluating benefits and costs as they occur within Canadian borders. The comparison involves the NOP in contrast to a non-NOP world where the external environment is 'constant,' that is, as it actually occurred. Hence, international oil prices are accepted as defining the value of oil in Canada, and the USOIQP is taken to exist, with its willingness to accord special treatment to Canadian oil, as part of 'secure' North American supplies. In Figure 9.1, exports to the United States without the NOP are shown as equal to the gap, at the world oil price, between western Canadian production and consumption. It is assumed that, for security of supply reasons, the United States would be more willing to absorb Canadian oil than any other international oil at the world price, so Canada would still obtain special treatment under the USOIQP. This assumption is questionable, as we do not know how Canadian oil might have been regarded had Canada not introduced the NOP. Had Canada not been exempt from the USOIQP, the volume of exports without the NOP might well have been lower than suggested in Figure 9.1.

Some of the effects of the NOP, as presented in Figure 9.1, cancel one another out. For example, area P_iEJP_C is a cost to Canadian oil consumers of higher prices due to the NOP, but it is received by Canadian oil producers as a benefit. Three specific effects in Figure 9.1 should be considered as possible components in the Net Social Benefit. First, area EFJ is a loss of consumers' surplus by oil consumers on the oil they

would purchase at the lower price, but do not buy at the higher. (Recall that a demand curve can be interpreted as a marginal willingness to pay curve.) This is an example of what economists often call a 'dead-weight loss.' Second, some oil is produced in Canada at marginal costs in excess of what it would cost to buy the oil in the international market, as measured by area GHM . Note, however, that some of the additional cost will represent payment to governments, which oil companies see as a cost, but taxpayers as a benefit. In addition, it should be noted that, in this case, the incremental output and reduced consumption under the NOP go as increased exports to the United States. This may overstate export levels under the NOP. The United States would certainly not have allowed Canada to import offshore crude for re-export to the United States, but it also kept a close eye on imports of Canadian-produced oil. At the same time, the reduced export level indicated without the NOP, at the lower international price, also may be overstated, as it assumes that the United States would have been willing to accept all this Canadian oil under the USOIQP. That is, another possible benefit of the NOP may have been its effect in persuading the United States to exempt Canadian oil from the USOIQP. Finally, Canada received incremental revenue as a result of exports to the United States that occur at price P_C under the NOP, instead of P_i . The extra revenue is given by the volume of exports ($XY = AD$) times the price rise ($P_C - P_i$), and is received by the producers. It can be seen that the extra export revenue (area $EHMJ$) covers both loss of consumers' surplus (EFJ) and the incremental Canadian oil production cost (GHM). This leaves a net gain as a result of the NOP, equal to area $FGMJ$. From this view, Canada as a whole benefited from the NOP because it allowed us to move an expanded volume of exports into the higher priced U.S. market, therefore capturing for Canada some of the protectionist producer benefits of the USOIQP. These benefits were captured by Canadian oil-producing interests (i.e., oil companies and shareholders and government taxes on the oil industry). However Canadian oil consumers (WORV) paid higher prices for crude as a result of the NOP, so suffered a cost.

(ii) **Case 2.** Other assumptions would generate different conclusions about what developments in Canadian oil policies would have been if the NOP had not been adopted. Suppose, for instance, that prices for Canadian-produced oil fell to the international level (P_i), that Alberta market-demand prorationing regulations were relaxed to allow growth of exports

to the United States to the maximum level authorities there would tolerate, and that the Canadian government imposed an export tax to capture the difference between the value of Canadian oil to U.S. refiners and the international price. With specific reference to Figure 9.1, one might assume that exports to the United States were allowed to increase to level XY (as did occur under the NOP), with the Canadian demand curve shifting, in effect to the dashed curve D_T . Export tax revenue would be received which was at least as large as the extra revenue on export sales accruing to domestic producers under the NOP (i.e., area $EHMJ$ equal to $(P_C - P_I)(XY)$). If Canadian crude oil sold for $P^*(> P_C)$ in the U.S. market, and Canadian government authorities were able to gauge this value well enough to set the export tax at level $(P^* - P_I)$, then there would be an additional gain to Canada. Recall that while Canadian-produced oil was attractive to U.S. refiners because it was exempt from the USOIQP, refiners did suffer some penalties in using Canadian oil instead of domestic U.S. crude, so that the maximum value of Canadian oil in the U.S. market (P^*) would be less than the domestic U.S. prices (P_U). In other words, we know that P_C is less than or equal to P^* , which is less than P_U , but the exact value of P^* (at each year from 1961 through 1972) within that range is difficult, if not impossible, to determine.

Having defined the second case, let us now consider the net effects on Canada of the NOP. In this case, there is no net gain to Canada on exports to the United States so long as the Canadian oil price (P_C) approximates the price that would have been attained under an export tax. The net revenue gain on exports to the United States at prices above the international price would go to domestic oil producers under the NOP, instead of to the federal government in export tax revenue. However, the NOP, in this case, could be argued to generate two efficiency costs. First, there is the loss of consumers' surplus (area EFJ in Figure 9.1), since Canadian consumers $WORV$ reduce their oil consumption when the NOP lifts prices above the international price. Second, the higher oil price would have induced incremental Canadian oil supplies to some extent, at costs in excess of those that would otherwise have occurred; i.e., in excess of the international oil price (area GHM in Figure 9.1). These two areas, EFJ and GHM would be deadweight losses of the NOP.

(iii) Estimates of the Net Social Benefits (Losses) of the NOP. We have now defined two cases that allow us to look at the economic efficiency of the NOP, each case involving a different assumption about how

Canadian oil policies might have developed without the NOP. Case 1 essentially assumes that there would have been no federal oil policy, so that Canadian oil prices would have been set by international crude at the competitive interface in Toronto. Case 2 assumes this as well, but adds the assumption that the federal government would have utilized its authority to capture for Canada, by an effective crude oil export tax, the extra value of Canadian oil in U.S. markets. Since both are hypothetical histories of Canadian oil policies, we cannot be sure which (if either!) is more realistic. We would note that certain political difficulties attend crude oil export taxes (i.e., Case 2), including the possibility of objections from the U.S. government (perhaps with appeals to GATT principles), and Canadian intergovernmental frictions that would arise as producing provinces (Alberta, in particular) saw the federal government capturing large revenues from provincial resources. As we shall see, the federal government was willing to take on these problems, beginning in 1973, but this was in the face of dramatic changes in the international crude oil market and rising concerns about the ability of Canadian oil to continue to meet Canadian domestic needs. In our judgment, Canadian governments in the 1960s would have been less likely to implement export taxes on crude, so we see Case 1 as the more realistic basis for evaluating the NOP.

Other scenarios for Canadian oil policy without the NOP are, of course, imaginable. Readers might like to consider a third, and obvious, possible case, which we have not considered in detail. Suppose Canada had adopted a policy to extend the market for Canadian-produced oil to Montreal, with those volumes that would otherwise have been shipped to the United States going to the Montreal market, and with Canadian oil producers then subsidized (relative to international oil prices) by as much as sales $WORV$ were subsidized under the NOP (i.e., to the price P_C in Figure 9.1). That is, prices $WORV$ and in Montreal were set at the higher NOP level (P_C in Figure 9.1.) From the viewpoint of the economic efficiency of Canadian oil markets, the NOP, relative to the Montreal pipeline extension, would contribute the same net social benefits to Canada as our Case 1, plus one additional gain. (That is, the NOP would be preferable to the Montreal market case.) Under the NOP, consumers in Montreal could buy at the lower international oil price, and the Canadian oil volumes freed could be sold to foreign (U.S.) refiners at the higher price, generating a net gain to Canada. Additionally the lower price to Quebec users under the NOP would generate higher consumption and a consumers' surplus gain.

Table 9.2: Economic Efficiency of the NOP: Two Cases (10⁶ current dollars)

	<i>Increased Export Values (EXV)</i>	<i>Consumers' Surplus Loss (CSL)</i>	<i>Increased Producer Costs (IPC)</i>	<i>Net Social Benefits (NSB) CASE 1</i>	<i>Net Social Benefits (NSB) CASE 2</i>
1961	93.7	10.1	9.4	74.2	-19.5
1962	118.9	9.8	10.3	98.8	-20.1
1963	112.0	9.5	9.6	92.9	-19.1
1964	197.7	19.9	20.6	157.2	-40.5
1965	250.6	27.0	28.0	195.6	-55.0
1966	255.8	25.4	27.1	203.3	-52.5
1967	315.1	28.6	32.7	253.8	-61.3
1968	147.5	8.1	9.6	129.8	-17.7
1969	375.6	28.6	36.3	310.7	-64.9
1970	522.7	36.1	49.3	437.3	-85.4
1971	496.0	28.5	42.0	425.5	-70.5
1972	515.5	22.1	38.0	455.4	-60.1
Sum	3,405.1	253.7	312.9	2838.5	-566.6
Annual Average	283.75	21.1	26.1	236.5	-47.2

Notes: Increased export value is area EHMJ in Figure 9.1.
 Consumer's surplus loss is area EFJ in Figure 9.1.
 Increased production cost is area GHM in Figure 9.1.
 CASE 1 NSB = EXV - CSL - IPC.
 CASE 2 NSB = -CSL - IPC.

Therefore, our Case 1 provides a lower bound estimate of the efficiency gain of the NOP relative to the Montreal market extension option that was so hotly debated at the Borden hearings.

Is there any way to estimate quantitatively the efficiency effects of the NOP in Cases 1 and 2? The dollar values of the various areas from Figure 9.1 clearly depend on how large the price and output impacts are. Table 9.1 provided estimates of the two most relevant prices (P_I and P_C). Oil export values have been taken from the *CAPP Statistical Handbook*. However, the size of the consumers' surplus and incremental production-cost effects (*EFJ* and *GHM* in Figure 9.1) also depend on the shapes of the demand and supply curves. Order of magnitude estimates of the efficiency effects may be obtained with the aid of some simplifying assumptions. In particular: (1) assume that the demand curve of Figure 9.1 is a straight line over the relevant range of prices (P_I to P_C) and that the (long-run) elasticity of demand is (-0.6) at the output and price actually observed (i.e., at point *J*); (2) similarly, assume a straight line supply curve with an elasticity of supply of 0.3 at point *M*. Then, as the note at the bottom of Table 9.2 shows, it is possible to estimate the size of areas *EFJ* and *GHM*. We would emphasize that these estimates are only roughly indicative of the efficiency effects of the NOP, since they involve a

number of rather arbitrary assumptions. In particular, the elasticity values are not based on careful empirical analysis of Canadian oil markets in the 1960s and fail to make any allowance for the short-run delays in adjusting oil production and consumption to price changes. (Short-run inelasticity would reduce the size of the consumers' surplus, production cost, and export revenue gain effects.)

Table 9.2 includes estimated net efficiency effects of the NOP for each year from 1961 through 1972 in each of Case 1 and Case 2. Case 1 sees a net gain each year to Canada, totalling over \$2.8 billion in undiscounted dollars over the twelve-year period, and an average of \$236 million per year. This would be the gain generated by the NOP if the outside policy regimes of the 1960s are taken as given, and a Canadian crude oil export tax is dismissed as a policy option. The NOP, from this perspective, allowed Canada to capitalize on the USOIQP by expanding sales to the United States at prices in excess of prevailing international prices. The Case 2 result shows net social losses to Canada each year as a result of the NOP, totalling over \$550 million from 1961 through 1972, with an average loss of \$47 million per year. This includes the consumer surplus losses and incremental production costs that occurred as a result of both Canada and the United States restricting international

The effects shown in Table 9.2 are estimated using:

- the Canadian and international prices of Table 9.1.
- actual export volumes as they occurred plus increased production and reduced consumption for hypothetical export volumes.
- estimates of reduced consumption WORV assume a demand elasticity of (-0.6) at the actually observed price and consumption along a straight line demand curve.
- estimates of increased production assume a supply elasticity of 0.3 at the actually observed price and quantity along a straight line supply curve.
- Canadian production, consumption and exports are taken from the CAPP *Statistical Handbook*.

Derivation of quantity changes along the demand curves utilize the following procedure. (The supply case is analogous.) The demand curve is a straight line, as illustrated in the figure below, with elasticity E at point 1. The curve can be given by:

$$Q = a + bP \tag{Eq. 1}$$

Then, a is the horizontal intercept of the curve (when $P = 0, Q = a$), and b is the reciprocal of the slope of the demand curve (when P changes by 1, the quantity changes by b).

By definition,

$$E = (\partial Q / \partial P)(P / Q) \tag{Eq. 2}$$

where ∂Q and ∂P are the instantaneous changes in quantity and price. Therefore $\partial Q / \partial P$ is the reciprocal of the slope of the demand curve, or b .

Substituting this in equation 2, we derive

$$b = \frac{(Q)(E)}{P} \tag{Eq. 3}$$

crude oil imports into North America. A similar efficiency cost can be ascribed to the NOP, even in the presence of the U.S. restrictions on imported offshore oil, if Canadian policy had involved no NOP but an export tax on sales to the United States.

In both cases, the estimates of net social benefit (cost) must be interpreted as rough approximations since they were not derived from complete models of the North American oil market, which would allow for lags in demand and supply response and incorporate the effects of royalty/tax provisions and market-demand prorating.

The \$3.4 billion dollar difference in the estimates (from +\$2.8 billion in Case 1 to -\$0.6 billion in Case 2) makes clear the importance of assumptions about what would occur in the absence of the NOP. Readers may form their own judgments in this regard. We

Since we know the values of P, Q , and E at point 1, we can calculate b .

From equation 1 we know that any change in quantity (Q) is related to a change in price (P) by

$$\partial Q = b(\partial P) \tag{Eq. 4}$$

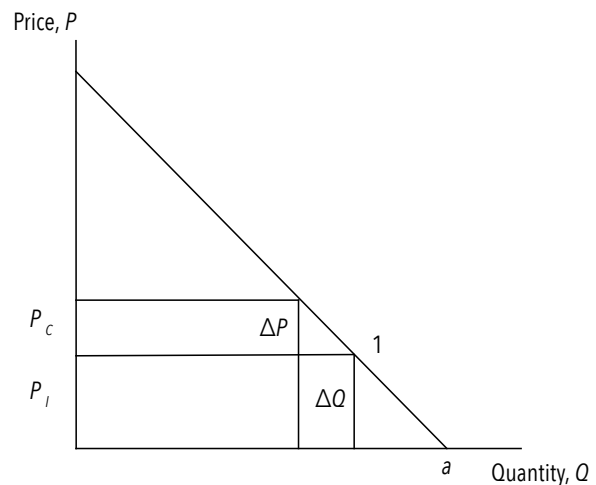
or, substituting in b from eq. 3,

$$\partial Q = \frac{(\partial P)QE}{P} \tag{Eq. 5}$$

Thus if we know P and Q (the observed market result), and assume a value for E , we can calculate the change in quantity (∂Q) associated with any given change in price (∂P).

With a straight line demand curve, the consumers' surplus loss (CSL) of a rise in price from P_i to P_c is:

$$CSL = 1/2 (\Delta P)(\Delta Q) \tag{Eq. 6}$$



would argue that efficiency losses were generated within North America by the decision to restrict access to cheaper foreign oil in the 1960s, but that the United States would have pursued this policy whether or not Canada did. It is harder to assess the status of Canada's exemption from the USOIQP. During a period of falling international oil prices, would the United States have continued to allow such an exemption if Canada had not moved to protect the market for its crude and to support prices well above the international level? And if the United States had allowed continued exemption under these circumstances, would the United States have tolerated a sizeable export tax to raise the Canadian sales price close to domestic U.S. levels? On balance, we would be inclined to emphasize the Case 1 result – North American import restrictions generated efficiency

losses in the 1960s, but, in the second-best world of the USOIQP, the National Oil Policy generated a net social benefit to Canada. It is ironic that Canada and the United States restricted the import of offshore crude oil when its prices were relatively low, only to adopt policies after 1970 that encouraged more use of offshore oil when international prices were relatively high. (For further discussion of these issues, see Watkins, 1987a and Bradley and Watkins, 1982.)

Moreover, many of the arguments about the NOP went beyond narrow assessment of changes in oil prices and output. We will now turn to several of these broader issues.

b. Other Effects of the NOP

(i) Equity (Distributional) Effects. Distributional effects of Canadian governments' oil policies are often considered at two different levels, which overlap only imperfectly. (1) The first is a 'functional' level that considers, mainly, oil consumers and oil-producing interests (especially shareholders and other private ownership interests, and the citizens who benefit from changes in government revenues from the oil industry). (2) The second is the 'geographic-political' level that considers various regional interests (especially net-oil-importing regions such as Ontario and net-oil-exporting areas such as Alberta). It must be recognized that the functional groups involve considerable overlap. A Canadian shareholder in Texaco is also an oil consumer and citizen. Citizens in an oil-producing region are also oil consumers. Moreover, it is impossible to trace the distributional effects of various oil policies with much precision. For example, neither the regional distribution of oil company shares, nor the impact on dividends and share prices of higher oil company profits and the attendant impacts on shareholders' incomes and tax payments, is well documented. Consider another example: increased government revenues from the oil industry may lead to reduced tax payments by other sectors of the economy (but, if so, exactly where?) and/or increased government expenditures (but, if so, on exactly which programs, to whose benefit?). Therefore, our consideration of distributive effects of the NOP must be general, and any conclusion tentative.

We have emphasized that the impact of the NOP must be considered in relationship to some alternative set of circumstances. We shall follow the Case 1 assumption discussed above in which the NOP is assumed to have generated a rise in the price of Canadian-produced oil above the international level. As a result, Canadian oil-producing interests (regionally, Alberta and Saskatchewan) benefited while

Canadian oil-consuming interests, WORV (regionally, Manitoba, Ontario, and British Columbia), and U.S. refiners using Canadian oil suffered. Remember that Case 1 assumes that Canada would not have imposed an oil export tax in the absence of the NOP, so U.S. refiners would have been able to buy Canadian oil at the lower international price. As noted above, we have not assessed the willingness of the United States to accept imports from Canada in this hypothetical case but have assumed that the flows into the U.S. market would have equalled the difference between western Canadian production and consumption. If this would not have been allowed under the USOIQP, the NOP in Case 1 also had the advantage of increasing Canadian exports to the United States.

Figure 9.1 and Tables 9.1 and 9.2 provide some basis for estimating the size of these distributional effects. The net gains to oil-producing interests can be approximated by multiplying total sales of Canadian oil by the price increase due to the NOP, less the incremental rise in production costs induced by the price rise (i.e., area P_1GMP_C in Figure 9.1); this amounts to \$5,109 million for the years 1961 through 1972. Canadian consumers WORV paid more on oil consumed and suffered a consumers' surplus loss (i.e., area P_1FJP_C in Figure 9.1); this adds up to \$2,272 million over the period. Finally, U.S. consumers paid an extra \$3,401 million from 1961 through 1972. In Figure 9.1 this is area $EJMH$.

At least three weaknesses in these rough estimates of the distributional effects of the NOP must be noted. First, we have used a partial equilibrium approach that considered the oil market in equilibrium, ignoring other impacts on the economy. Brief discussion from a more general equilibrium perspective follows in the discussion of macroeconomic effects of the NOP. Second, the impacts have not been separated regionally, or in terms of impacts on citizens through government revenue changes as compared to cost or profit changes.

Third, we have abstracted from the foreign ownership dimension of the problem. High levels of foreign investment in the Canadian petroleum industry imply that a significant part of the gain to oil producers would accrue to foreign shareholders either directly through higher dividend payments or indirectly through higher share prices in stock markets. Rough allowance for this can be made. Higher oil revenues would generate higher revenue to the government primarily through higher royalties; in 1972 the average Alberta crude oil royalty rate was about 16 per cent. The effective corporate income tax rate on oil industry profits was no more than 10 per cent in the 1960s

(Canadian Tax Foundation, *The National Finances*, 1972). Of the after-royalty and corporate tax profits, about 78 per cent could be allocated to foreign owners, using an average for non-resident ownership in the Canadian petroleum industry in the 1960s (EMR, 1973, vol. ii, p. 224). Some of this would have been subject to Canada's dividend withholding tax (15% in 1970). On the basis of these assumptions, \$3,014 million of the \$5,109 million gain in production profits estimated in the previous paragraphs would have gone to foreigners. \$2,095 million would have remained with Canadians, shareholders or governments. (This is something of an understatement to the extent that competitive bonus bids on newly issued mineral rights would have increased as well.)

It is of importance to note that the efficiency measures of the NOP, as estimated above, would be altered if the profits accruing to foreign shareholders are treated as a net loss to Canada. Case 1 net social benefit would fall from \$2.9 billion to minus \$175 million, and the Case 2 net social cost would rise from \$567 million to \$3,580 million, over the 1961 to 1972 period. Expressed in terms of 1961 present values, of course, the numbers would be considerably smaller. Moreover, profits to foreign shareholders should properly be considered in relation to the normal profit return on total foreign capital in the Canadian oil industry. However, if the capital would have earned normal profits at international oil prices, all the increased profits due to the NOP would be economic rent, except for the normal profits already included in the supply curve calculations for incremental production. One other aspect of this problem deserves brief comment. This is the question of whether profits accruing to foreign owners are a leakage from Canadian gains if, as was common in the petroleum industry, the foreign owners reinvest the economic rent in Canada. Proponents of foreign investment have generally seen such reinvestment as a benefit to Canada. Those critical of foreign investment have questioned whether this is a net contribution to investment (would Canadian sources have undertaken the same investment?); they also argue that such reinvestment simply serves to turn economic rent into foreign owned assets, and this asset value will not itself be taxed, so it will leave the country as depreciation payments to the foreign owner. The high foreign ownership share in the oil industry helps to explain the emphasis placed on government rent collection as oil prices began to rise in the 1970s; the government would clearly have also wished to tax high rents accruing solely to Canadian owners, but the issue received more urgency because of foreign ownership.

The NOP, as indicated, transferred spending power from consumers of oil in Canada WORV to producers, including governments in the oil-producing provinces, mainly Alberta. It is difficult to assess whether or not the transfer of funds was harmful to Canadian objectives of a 'fairer distribution of income.' In part this is because of uncertainty about exactly what our desires are in this regard. Individuals may well have quite varied opinions. Moreover, one of the primary means of expressing our social preferences is through general elections, but these are decided upon many concerns, so cannot serve as a referendum on a single issue such as equity.

A second problem arises from the fact that there is insufficient evidence to tally the full distributional effects of the NOP. Tentative judgments may be possible. Waverman (1975) argued, with respect to energy price rises in the early 1970s, that the oil price increases, considered across broad income classes, appear to be somewhat regressive. He looked at direct household expenditures on energy in the year 1969 plus estimated expenditures on public transportation and rental accommodation. Waverman found that for the average Canadian family 6.2 per cent of its spending was on energy. The poorest of his twelve classes (total expenditures of less than \$3,000 per year) put 8–9 per cent of spending into energy, while the highest expenditure group (over \$15,000 per year) allocated only 4.3 per cent of spending to energy. Regional patterns differed slightly. Thus, in Canada WORV, higher oil prices as a result of the NOP would fall somewhat more heavily on the poorer members of society.

As Waverman acknowledges, it is difficult to trace the indirect income distribution effects of energy price changes operating through the energy content of the goods and services that households purchase. He points out that energy input costs made up a relatively small proportion of the total value of shipments for most Canadian industries. In 1970, for example, for eleven main industries, energy costs varied from 1.0 to 5.4 per cent (paper and allied industries) of the value of shipments. For 1971, Powrie and Gainer (1976) report similar values (ranging from 0.31 per cent for clothing to 6.09 per cent for paper and allied products, averaging 1.99 per cent). Therefore, the indirect effect of higher oil prices on consumers due to the NOP would be small, regardless of how expenditures are spread over all the products of different industries.

Judgment about the income distribution effects of the NOP also hinge on the beneficiaries of increased payments, that is governments of producing provinces and shareholders of the oil companies. Opposite effects hold. Increased payments to the governments

would seem, at worst, to allow some tax relief thereby sharing in whatever progressivity the tax system exhibits; at best, the extra revenue would give the government more revenue to attain its objectives, including whatever is regarded as equitable. On the other hand, the stocks of corporations, including oil companies, are undoubtedly distributed in a regressive fashion with larger shares held by the relatively wealthy (and with a significant portion held by non-Canadians).

What can one conclude about the income distribution effects of the NOP? First, the size of the redistribution is not particularly large; the average estimated loss of consumer surplus and estimated higher payments by Canadian oil consumers amounted to only 0.2 per cent of Canadian GDP. Second, the regional distributional impacts were most evident with net-oil-importing regions (Ontario, in particular, but also Manitoba and B.C.) transferring funds to the net-oil-exporting regions (Alberta, especially, and Saskatchewan). Third, the underlying functional distributional effects were from oil consumers – in all regions west of the Ottawa River Valley – to oil-producing interests, including Canadian governments (especially the oil-producing provinces) and owners and shareholders of the oil companies (including non-Canadian shareholders). Most Canadians would probably feel that the net distributional effects were moderately unfavourable, especially insofar as gains accrued to non-residents and wealthy shareholders and consumer costs were borne more than proportionally by poorer income groups.

(ii) Macroeconomic Effects. Initial pressure for changes in Canadian oil policy in the late 1950s came primarily from the Alberta government and crude oil producers who feared declining oil industry activities. Market expansion was not obviously forthcoming and the large overhang of spare productive capacity limited the appeal of new exploration and development. The problem was viewed as critical for the Alberta economy. The oil industry is capital, rather than labour, intensive. Much of the employment that is generated directly by the industry, as well as the bulk of income-generating spending, does not occur during the operating phase of the crude oil industry but as a result of investment. Therefore, continued exploration and development were viewed as a key to continued economic growth in Alberta. (The role of the petroleum industry in the larger economy, and its tie to economic growth, will be discussed in more detail in Chapter Thirteen.)

Western and central Canada might experience quite different macroeconomic effects from increased sales of crude oil, at higher prices, as generated by the NOP. Expanded activity in Alberta involved some spill-over into, for example, Ontario, involving products like steel pipe. Despite such spill-over effects, it is expected that the overall effects would tend to be expansionary in the oil-exporting region and contractionary in the oil-importing region. However, recall that the price of Canadian-produced crude oil remained pretty well constant in nominal dollars throughout the 1960s, so that the NOP had the effect of slowing the decline in real prices to customers west of the Ottawa River Valley, rather than actually raising prices. Moreover, many of the customers who paid more than world prices for Alberta crude oil were in the United States (Americans in general paid more than the world price, thanks to the USOQP.) Thus, any net deflationary effects on central Canada were likely small.

One controversial further line of argument must be touched on. To the extent that conventional oil is a limited natural resource, it could be argued that policies that encourage more exploration and development are not so much generating entirely new industry activity, as simply advancing it in time. This would presumably be desirable to the extent that it encouraged development of a more permanently sustainable regional economy by accelerating the attainment of local economies of scale or agglomeration effects due to expanding population and market size. Such an exhaustible resource view might also see as desirable increased activity that levelled out cyclical fluctuations in the provincial economy. There is also the question of whether the extra production takes place in times of higher or lower prices; an ideal, and perfectly informed, social planner would prefer to concentrate production in the higher price periods, when the marginal value of the reserves are greater. In this regard, it is notable that the NOP inducement to higher exports came in a period in which, in retrospect, oil prices were relatively low. (And in the following period of high prices, as will be discussed in the next section of this chapter, exports were discouraged!) In fairness, however, it must be noted that few in the 1960s anticipated sharply rising oil prices.

We must again express scepticism about arguments that lay heavy emphasis upon the exhaustible nature of petroleum reserves (Adelman, 1990; Watkins, 1992). Depletion of oil deposits is primarily an economic phenomenon, reflecting a complex interplay of physical, technological, and economic factors,

with no clearly defined limit to the volumes of oil that may be produced. Increased industry activity in one period, then, cannot be seen as simply displacing similar activity in some later period.

(iii) National Security and Resource Depletion. For some, the NOP had national security implications. Oil is an essential input into the economy, particularly in the short run, and dependence in the 1960s upon supplies from developing countries, especially in the politically tense Middle East, raised security concerns in North America. However, the national security card is difficult to play. The issue has been more thoroughly debated in the United States than in Canada; see, for example, Bohi and Montgomery (1982) and Bohi and Toman (1996). We shall touch on the matter only briefly.

In the first place, the security implications of the NOP are rather difficult to specify. In part, this reflects the problem with defining an alternate scenario for the 1960s. In comparison to a continuation of the trends of the 1950s, it could be argued that the NOP increased national security by preserving markets WORV for Canadian crude and backing foreign oil products out of Ontario. But this might have happened anyway, although at falling international prices. However, compared to a Montreal pipeline extension, the NOP would be argued to provide less Canadian security of supply from disruptions in international oil flows since it left the Quebec market open to imported crude.

One must go beyond this to ask: what was the security of supply risk? Prior to 1960, there had been minor disruptions in oil supplies from the Middle East as a result of Arab–Israeli hostilities when Israel was founded in 1948 and during the 1956/7 Suez crisis when Israel, France, and the United Kingdom invaded Egypt. But the impact on oil shipments had been small, and Canada relied mainly on Venezuelan oil anyway. (In 1956 only a fifth of Canadian oil imports came from the Middle East, although the proportion was rising, up to just over 40% by 1960 [Simpson et al., 1963, p. 30].) Furthermore, even the theoretical nature of the security of supply risks is far from clearly defined. One might suppose that shortages of oil translate into reduced consumer satisfaction and reduced industrial output with associated losses of employment and profits, especially in the short-term when capital rigidities make it difficult to substitute away from oil into other energy forms. Ultimately, however, the security of supply problem is one of economic adjustment more than physical shortage. If

international oil supplies are disrupted, the primary effects come in the form of increased prices, which serve to ration available supplies. The price rises discourage the least-valued consumption and induce incremental oil production. In the 1950s and 1960s, when both Canada and the United States had considerable excess production capacity, the latter option proved to be of considerable importance. A country that relied on its own oil to a considerable extent might avoid the negative effects of sharp and temporary rises in crude oil prices due to an international supply crisis, but this would require the imposition of price controls, subsidization of any imports that did occur, and prohibitions of incremental exports attracted by high international prices. The hazards of such a pricing policy, adopted by Canada after 1972, will be discussed below.

Some observers have also suggested that there are trade-offs between short-term and long-term security of supply interests, since crude oil burned for its energy content is not a recyclable resource. (Less than 10% of oil has typically been used for non-energy purposes, such as lubricating motor oil, which may be partially recycled.) Given limited oil resources, increased utilization for security reasons in the current period means, it is argued, less potentially available for the future and therefore higher security risks at that date. There is some merit to this argument, though its strict application is blunted by the observation (which we have made before) that the limits to oil production are variable economic ones rather than strict physical constraints. In any event, depletability has suggested to some authors that security of supply concerns may justify other measures than increased domestic oil output. Stockpiles, for instance, may be accumulated (perhaps from the international market) and held in readiness for a possible crisis; there is, then, no need to constantly run down domestic supplies at a more rapid rate than current market conditions would warrant.

On balance, we find no strong national security arguments for modifying our discussion of the efficiency of the NOP.

C. Conclusion

Normative evaluations of economic policies must remain somewhat tentative, if only because not all observers stress the same objectives. We would argue that the combined decisions by Canada and the United States to protect the North American oil

industry generated net social costs to the continent in the 1960s. Higher oil prices than necessary meant consumer surplus losses and increased resource costs as higher-cost oil was produced.

However, if it is assumed that the USOIQP would have proceeded regardless of Canadian policy, evaluation of Canada's NOP must be somewhat tempered. At first glance, the most efficient policy would have been for Canada to follow declining prices in the international market while encouraging oil exports to the United States with an export tax to raise prices close to those of protected U.S. domestic crude. However, we suspect that U.S. government objections would have made this option impossible (Watkins, 1987a). From that point of view, the NOP can be seen as beneficial to Canada by encouraging greater use of sunk investments in oil-production capacity and allowing Canadian producers to capture some of the benefits of the high value of oil in the protected U.S. market.

Weighed against the gain are redistribution effects, with wealthier parties benefiting somewhat in comparison to poorer parties. Also, under royalty and tax regulations of the 1960s, a significant portion of the oil-producer gains accrued to foreign shareholders. The NOP appears to have had a stimulating impact on the Alberta economy. International security effects were minimal.

4. Strict Controls and the National Energy Program (NEP): 1973-85

A. The Policies

1. Background

The NOP had been established in 1961 against a background of falling international oil prices, a U.S. domestic crude oil protection policy (USOIQP), and high excess crude oil production capacity in Alberta. The universe had shifted by the early 1970s. International oil prices had begun to rise with the Teheran-Tripoli and Geneva Agreements, rising Canadian oil output had reduced spare production capacity, and Canadian crude oil reserves had begun to decline as production exceeded gross reserve additions.

The federal government's Department of Energy, Mines and Resources undertook a review of Canada's energy situation and in 1973 issued a comprehensive two-volume study. *An Energy Policy for Canada, Phase*

1, provided an overview of Canadian energy industries and a number of policy options open to the federal government. This had initially been envisioned as the first step in a process of participatory democracy spread over a number of years. The options presented in *An Energy Policy* would generate a public debate about energy policy, which would in turn allow the government to formulate new policies reflecting some consensus of public opinion. Whether such a process would have generated consensus, rather than anger and opposing entrenched positions, is unclear. In any event, the federal government felt it necessary to circumvent the process by introducing major changes in Canadian energy policies in 1973 just as discussion of *An Energy Policy* was beginning. (Debanné, 1974 looks at the Canadian oil industry in the years leading up to the direct control period. Many authors have described the policies in this period, including Anderson, 1976; Bradley and Watkins, 1982; Daniel and Goldberg, 1982; Dobson, 1981; Doern and Toner, 1985; Helliwell, 1979; Helliwell and Scott, 1981; Helliwell and McRae, 1981, 1982; Helliwell et al., 1989; McRae, 1982, 1985; Norrie, 1981; Plourde, 1986; Scarfe, 1980, 1984; Watkins, 1976, 1977a, 1981; 1987a, 1989; and Waverman 1980, 1984.)

2. Introduction of Strict Controls

In December 1972, the NEB issued a report on the Canadian crude oil situation that concluded that "production from all sources in Canada will not be able to supply the potential export and domestic market demand after 1973" and "the declining Western Province conventional maximum production rate ... will be unable to supply the domestic market by 1986" (NEB, 1972, pp. 18, 19). In February 1973, the NEB recommended the imposition of direct controls on crude oil exports, and, on February 15, the Government ordered the NEB to commence the licensing of crude oil exports under Part IV of the NEB Act (P.C. Order 1973 - 392). Licensing of crude and equivalent began March 1 and was extended to motor gasoline and middle distillates in June. On September 4, 1973, as part of its anti-inflation program, Ottawa imposed a five-month freeze (until the end of January 1974) on crude oil at the prevailing \$3.80/b price. (The regulated prices and those that follow, refer to 38° API gravity crude at pipeline terminals at Edmonton.)

Also in September, the NEB announced that it could not approve any further crude oil exports as the export price was too low. With frozen domestic prices, there was no obvious market remedy for this.

Therefore, on September 13, 1973, a federal export tax on crude, equal to \$0.40/b, was introduced to make up the difference between the Canadian price and the value of the oil in U.S. markets. Following the OPEC-generated price increases of mid-October, Ottawa raised the export tax to \$1.70/b (in December), to \$2.20 in January 1975, and then to \$6.40/b in February.

These three direct control measures – export volume limits, government-fixed prices and export taxes – continued through to June 1985 as a mainstay of Canadian energy policy, although the policies were effectively eroded over time. They fit together as the formal mechanisms to keep Canada an island of low crude oil prices in a sea of high international prices. Fixing domestic prices assures low costs to domestic users. However, the high value in the international market will attract domestic oil producers and traders. Hence, export controls and/or export taxes are also required. Volume controls limited the quantity of oil that could move to the United States, and the export tax was to ensure that Canada would receive the full world value for oil.

By October 1973, the NOP had been effectively abandoned. Formal internment came on December 3, 1973. In the House of Commons, Prime Minister Trudeau announced the new policy (Hansard, 1st Session, 29th Parliament, pp. 8478–80):

The new policy will abolish the “Ottawa Valley Line.” The Canadian market for oil will no longer be divided into two, one for domestically produced oil and another for imported oil. It will thus be a “one-Canada,” not a “two-Canada” oil policy. The western provinces will have a guaranteed outlet for increased production; and the eastern provinces will be guaranteed security of supply.

The creation of a national market for Canadian oil is one essential requirement of a new policy. Others are, first, a pricing mechanism which will provide sufficient incentives for the development of our oil resources; second, measures to ensure that any escalation in returns and revenues as a result of any higher prices will be used in a manner conducive to security and self-sufficiency; third, the establishment of a publicly-owned Canadian petroleum company principally to expedite exploration and development; fourth, the early completion of a pipeline of adequate capacity to serve Montreal and as required more eastern points; and fifth, intensification of research

on oil sands technology to permit their full and rapid development.

The prime minister went on to note that the frontier and non-conventional resources were high cost so that “we must in the long run allow the price of domestically produced crude oil to rise toward a level high enough to ensure development of the Alberta oil sands and other Canadian resources but not one bit higher.” Prices need not rise at once, however. Discussions would be undertaken with the oil companies and the Government of Alberta. Any oil price changes must reflect the national interest. In particular,

We will not be prepared to acquiesce in any situation in which windfall profits accrue to private corporations simply because of unusual and unpredictable circumstances of shortage created by major world oil producers for political and economic reasons of their own. Nor do we feel that it would be fair or just to have any windfall financial benefits accrue only to the producing provinces, leaving all the rest of the people of Canada with nothing but the burdens.

Prime Minister Trudeau also announced, with respect to oil, that “the federal government will continue to levy a tax, or, after February 1, a charge equal to the difference between our domestic price and the export price as determined by the National Energy Board.” Ottawa expressed a willingness to share the export tax revenue equally with the oil-producing provinces, but this did not occur. In addition, the one-price for Canada policy required the implementation of an Oil Import Compensation Program to compensate refiners that purchased imported crude oil for the difference between the world price and the Canadian price.

Ottawa’s move to control oil prices and exports drew predictably hostile reactions from the oil industry and the Alberta Government. It also set the tone for a twelve-year intergovernmental imbroglio. Alberta provided the main opposition, with both practical and general objections. At the practical level, export limitations and low domestic prices would, all else being equal, reduce the revenue flowing to the oil industry, thereby impacting negatively on industry activity, the incomes of Alberta residents, and provincial government revenues. At the more general level, Alberta questioned the constitutional validity of federal acts that affected the value and production levels of a particular commodity, especially one produced

mainly from provincial Crown land, and which was specified in the 1930 amendment to the *BNA Act* as being under provincial control.

3. Strict Controls before the NEP: 1973–80

a. Price Controls

The September 1973 price freeze at \$3.80/bbl had been a unilateral federal act. The freeze was to last for five months, through January 1974, to allow the assessment of Canadian oil policies. Canadian oil prices had been slated to go to the world level at the end of the freeze, but this was forgotten with the quadrupling of international prices between September and December of 1973.

Table 6.3 provides crude oil prices at year end for the strict control period. Our concern here is with the regulatory background. January 1974 saw a First Ministers Conference, followed by informal talks in March at which the prime minister and ten provincial premiers agreed to increase the price for Canadian-produced oil from \$3.80 to \$6.50/b for the period from April 1, 1974 through January 30, 1975. Regulation had moved from direct control by Ottawa into the forum of intergovernmental negotiation within the Canadian confederation. Why had this happened?

The eruption of OPEC as an effective cartel brought energy policy to the forefront of economic and political decision-making everywhere in the world. Amongst the industrialized nations, Canada was in an exceptionally favourable situation with crude oil exports of 1,107,000 b/d in 1973 compared to imports of 927,000 b/d. The United States had the world's largest crude oil output rate in 1973 but was still a net importer in the amount of 3,404,000 b/d. Mexico was still producing mainly for local use and the North Sea was just beginning to reveal its oil potential, so Norway and the United Kingdom did not become net exporters until 1975 and 1980, respectively. (Data are from OECD *Oil Statistics Supply and Disposal* reports.)

Within Canada, virtually everyone was affected by the revolution in oil prices. Consumers were hurt by oil price increases, especially in the short run when a very low elasticity of demand implied that expenditures on oil would rise sharply. Consumers were also an unorganized group – all citizens were affected but had no effective spokesman. Their interests would presumably be voiced by their elected representatives, federal MPs and provincial MLAs. Governments, however, had broader concerns, since they also represented citizens in their shareholder, taxpaying, and

consumer-of-public-services roles. Oil producers – companies, employees, and shareholders – benefited from oil price rises. There were well-established producer interest groups, like the Canadian Petroleum Association (CPA), and producers would also expect that *their* elected representatives would give weight to their interests.

With oil in the public policy arena, the federal and provincial governments became the key players, and, amongst them all, Ottawa and Edmonton dominated. B.C. and Saskatchewan shared a petroleum producer stand with Alberta, to some extent, but Alberta was by far the dominant producing province. Ottawa presumably represented the concerns of all Canadians. As many observers have pointed out, the Liberal party was in power federally throughout most of this period – nine months in 1979 and the period after September 1984 are the exceptions. There was minimal Liberal representation for electoral districts (e.g., in Alberta) with strong oil-producer interests.

As economists, we are loath to enter into any lengthy analysis of underlying political processes. We are, however, unable to resist offering several comments (following on those of the Introduction to Part Three of this book). Governments themselves are prone to explain their behaviour from a 'public interest' point of view, in which case Ottawa would, of course, pay heed to the concerns of oil producers as well as any other interests of Canadian citizens. From this point of view, Ottawa reflects all Canadians while the Alberta provincial government represents the much smaller provincial constituency.

There are political economists who have suggested that there are more 'realistic' views of the political decision-making powers than the public interest model. Some have suggested an 'interest group' approach in which governments are still seen as reacting to perceptions of the interests of citizens, but those perceptions are formed by the input from special interest groups in society. In this case, public policy tends to be dominated by the desires of relatively small groups, which are affected in a major way by policy changes while large groups of individuals who are affected only in a minor way tend to remain unorganized and unheard. From this point of view, the oil-producer group should have had a disproportionate impact on government policies.

An alternative 'realistic' theory views government decision-makers as self-interested. Elected representatives therefore are motivated to increase the 'perks,' power and prestige of their position. Or they tend to focus on maximization of the likelihood of re-election.

The latter motivation suggests that a government would be reluctant to write off the interests of any significant part of the electorate unless it means clear gains in support elsewhere. This approach suggests that governments are strongly motivated to put the best face on their actions, and that what matters is less the reality of policies than their appearance; unless one supposes a well-informed electorate, appearance and reality may differ, especially on complex policy issues.

The reader may wish to speculate on which, if any – or all – of these views of government best fits the period of direct control over the Canadian oil industry. Books that emphasize the personalities and politics of Canadian petroleum policies in the direct-control era include Doern (1992), Foster (1982), and Simpson (1984).

As might be expected, a variety of points of view were expressed at intergovernmental conferences dealing with oil policy issues. Policy positions tended to reflect the most immediate interests of the province, but these were often somewhat complex and were generally filtered through an ideological prism. Thus, some insight can be gained by separating provinces into net oil exporters (Alberta and Saskatchewan) and net oil importers (the other eight). At the same time, several of the importing provinces had reasons to support petroleum-producer interests to some degree. British Columbia, for instance, was a net-natural-gas exporter, and possible offshore oil or gas potential became increasingly important to Newfoundland and Nova Scotia. Other provinces (e.g., Quebec) were particularly sensitive to federal government initiatives that might infringe on the powers of provincial governments. The economies of the three most western provinces (and Manitoba to a more limited extent) were very much affected by the activities of the crude petroleum industry. However, B.C., Saskatchewan, and Manitoba also had NDP governments over at least a part of this period, which were more inclined to active government intervention than was the Alberta Progressive Conservative government.

Some flavour of the input into the federal-provincial oil price negotiations can be gleaned from the policy statements issued at the April 9–10, 1975, Conference of First Ministers.

Newfoundland (F.D. Moores)

Concerned about rapid rises in oil prices. Saw provincial ownership of resources as a key factor. Eventually Canadian prices should go to the world price level.

P.E.I. (A.D. Campbell)

Reluctantly agreed that Canadian petroleum prices should rise over time to the continental (i.e., U.S.) level.

Nova Scotia (G. Regan)

No further increase in oil prices warranted. Oil companies do not need the revenue the OPEC price implies in order to undertake more activity. High foreign ownership of petroleum companies is a concern. “I am unable to see why the Government of Alberta needs this extra revenue.”

New Brunswick (R.B. Hatfield)

Cannot support a further price rise. Price rises could be justified only if closely tied to a policy of domestic energy self-sufficiency.

Quebec (R. Bourassa)

Stable prices would help fight inflation, but increased prices would induce reduced consumption and more production. Advocates a gradual rise to the U.S. price level.

Ontario (W.G. Davis)

Oil prices have not generated additional supply and have negative macroeconomic consequences. Keep prices constant, at least until inflation and unemployment rates are lower.

Manitoba (E. Schreyer)

(Did not refer to oil pricing.)

Saskatchewan (A. Blakeney)

‘Old’ oil price increases be held to the inflation rate. ‘New’ oil would get a higher price. Extra revenue goes to the provincial and federal governments for an Energy Security Fund.

Alberta (P. Lougheed)

World prices set the appropriate price level.

B.C. (D. Barrett)

No oil price increase if the rise goes to the multinational petroleum companies. Some increase with extra revenue going to an energy fund would be acceptable.

Ottawa

To encourage conservation and new suppliers the oil price must rise toward the world level, but not necessarily all the way up.

The First Ministers Conferences included all eleven governments. Our discussion will emphasize only two positions, those of the federal government ('Ottawa') and the Alberta provincial government ('Alberta'). In addition to those concerns that we have already discussed, two other issues of particular financial import for Ottawa should be noted. The first relates to the one-price oil policy for Canada. This involved subsidizing users of imported oil (in practice, oil refiners) for the difference between the higher world price and the lower regulated Canadian price. So long as Canadian oil imports and exports were approximately equal, this policy had no significant net financial impact for the federal government, since revenue from the oil export tax would match required subsidies. This would not be entirely true if Ottawa shared export tax revenues with producing provinces, but sharing was not the case in the 1970s. Of course, a decision to subsidize oil imports meant that the revenue involved could not be used in any other way. However, as oil exports to the United States were cut, this balance between oil export tax revenue and oil import subsidies would become more and more unbalanced, and the net financial outflow to Ottawa higher and higher. The lower the Canadian price was held, the greater the net cost to the federal treasury of the Oil Import Compensation Program.

Ottawa was also concerned about the impact of changing oil prices on the federal-provincial equalization grant program. These grants were designed to equalize the ability of the provinces to provide services to their citizens and involved grants by Ottawa to the less-well-off provinces. The details were complex and were subject to periodic change; they have generated a large literature. (See, for example, Economic Council of Canada, 1982, and the discussion by various authors in the summer/autumn 1982 issue of *Canadian Public Policy*. The Appendix to Courchene, 2005, provides a summary of the equalization provisions related to natural resources from 1867 to 1982; Courchene notes that natural resource revenues have almost never entered fully into the Canadian equalization formulae.) Higher petroleum prices generated higher bonus bid and royalty revenue for the petroleum-producing provinces and hence generated a higher equalization grant obligation on Ottawa. The effect was pronounced because the main beneficiary from higher oil and natural gas prices was Alberta, which was a high-income 'have' province. The effects would have been different had Alberta been a 'have-not' province, since higher petroleum revenues would have reduced its claims for equalization grants. Newfoundland

and Nova Scotia have been very much concerned about the possible loss of such grants attendant on development of their offshore petroleum resources, a point of negotiation with Ottawa until an agreement was finally reached in early 2005. British Columbia, with a lot of natural gas production, was also a 'have' province, and Saskatchewan has been in some years. One way to minimize the equalization grant effects of petroleum price changes would be to amend the grant formula, but the recipient provinces would not welcome such a change. In January 1974, the agreement had been amended to exclude about one-third of provincial natural resource revenues from equalization obligations on the ground that this amount was being diverted into capital funds, like the Alberta Heritage Trust Fund, rather than being used to fund current provincial government activities. In 1982, the equalization formula was further modified, in the calculation of the relevant tax base, from a 'national average standard' to a 'five province standard,' which excluded Alberta and its petroleum revenues from inclusion in the equalization formula. Revenues were to be calculated on the basis of government receipts in five provinces, Quebec, Ontario, Manitoba, Saskatchewan, and British Columbia, although average tax rates across all ten provinces were still utilized (Courchene, 1981, 1984). We shall not delve further into the connections between petroleum revenues and the equalization fund, but readers should be aware that Ottawa was acutely aware of these ties. Courchene (2005, 2006) provides a fascinating discussion of the equalization program, with particular emphasis on the treatment of petroleum resources revenues including the differing positions of different petroleum-producing provinces and possible strains in the system posed by the rise in oil and gas prices starting in 2003. See also Usher (2007).

To recapitulate, Canadian oil policy had moved into a stage of direct control. This involved inter-governmental negotiation, with Ottawa and Alberta playing the leading roles. Alberta had a well-identified interest in higher petroleum prices and looked on OPEC's world prices as the appropriate level. Ottawa's interests were more divided. Lower oil prices were attractive to Canadian citizens as oil users, reduced the call on the federal treasury for equalization grants, and were presumed to give lower inflation rates and to lower unemployment, at least east of Saskatchewan. On the other hand, higher oil prices would encourage reduced oil use and higher production, therefore encouraging more Canadian energy self-sufficiency. Higher prices also reduced the drain on the federal

treasury for crude oil import subsidization. Moreover, some of the shareholders in oil companies were also citizens, and taxpayers would benefit from the higher government revenue from increased economic rent on oil. As the previous discussion indicated, Ottawa's general approach was to allow for gradual increases in domestic oil prices towards the world level. The second revolution in world oil prices, 1979–81, intervened before price equality was reached, so Canadian prices remained under government control.

The January–March 1974 First Ministers negotiations had led to a crude oil price rise from \$3.80/b up to \$6.50. The April 1975 First Ministers Conference failed to reach agreement on a change in the crude oil price. In the June 23, 1975 budget, Ottawa, with Edmonton's agreement, raised the crude price by \$1.50/b to \$8.00, for one year.

In spring 1976, intergovernmental negotiations failed to reach unanimity. Once again, Ottawa and Alberta were able to agree. The federal Energy minister announced a \$1.00/b price rise (to \$9.00) on July 1, 1976, followed by \$0.75 on January 1, 1977 (to \$9.75/b). Again in the spring of 1977, consensus was not attained, with Manitoba, Nova Scotia, and Ontario dissenting from the other eight governments (*Oil-week*, May 16, 1977, p. 5). On June 27, federal Energy minister Gillespie announced a two-year agreement with \$1.00/b price rises every six months. This would raise the crude price to \$13.75/b by January 1, 1979, so long as the Canadian price did not exceed the price of Middle East oil or the average price of crude delivered to Chicago. (The U.S. Congress was, at this time, debating a proposal by President Carter to remove U.S. crude oil price control regulations.)

The expectation in June 1977 had been that the gap between the world oil price and the price of Canadian-produced crude would become smaller and perhaps disappear. This fit the federal government's 1976 *Energy Strategy for Canada: Policies for Self-Reliance* (Energy, Mines and Resources, 1976, p. 127), which argued:

We must continue the process that began in April of 1974, of phasing the price of domestic oil toward international levels. Canada does not necessarily have to go to international prices. Because we have domestic resources to develop, we have a degree of independence from the oil-exporting cartel that many countries do not enjoy and that is to our advantage. But if we do not raise our prices to levels at which those resources can be found,

developed and delivered, we will find ourselves in the same position as those countries that do not have domestic resources....

It is the federal government's objective to see domestic oil prices increase to a level sufficient to bring on new Canadian supplies. To the degree that this level is lower than international oil prices, it is a differential for the benefit of Canadian consumers and Canadian producers, industrial and agricultural. Should it be the case that a price sufficient to bring on Canadian supplies were to exceed international prices, it would be necessary to make a further decision, as we did in 1961, as to whether it is in our best interest to continue to develop our own resources or to import supplies from other countries. Such a decision would depend on the extent to which the appropriate Canadian price exceeds international prices, relative to the risks we would face as a nation if we removed our dependence on imported oil.

However, as shown in Chapter Three, after the revolution in Iran, in late 1978, international oil prices increased rapidly and dramatically, leaving Canadian oil prices far behind.

Alberta agreed to a six-month postponement of the January 1, 1979 price increase, with an extension of the agreement with Ottawa to the end of June 1980, including another \$1.00/b rise on January 1, 1980. Accordingly the crude price rose to \$13.75/b (July 1979), then \$14.75 (January 1980). A tentative longer-term pricing agreement reached in the fall of 1979 was aborted by the fall of the minority Conservative government in December. Negotiations between Edmonton and the new Liberal government in Ottawa covered the whole range of petroleum pricing and economic rent sharing issues. The two sides could not reach agreement. On August 1, 1980, Alberta, for the first and only time, unilaterally increased the crude oil price, by \$2.00/b to \$16.75. Ottawa, which had offered a \$2.00 price rise, did not utilize the *Petroleum Administration Act* (see below) to override Alberta.

However, it was clear that the sudden jump in international crude oil prices starting late in 1978, and the prospect of further increases, had destroyed the Ottawa–Edmonton consensual approach to petroleum policy.

Oil sands production proved to be an exception to the oil pricing formulae. As part of the protracted negotiations over the Syncrude project in late 1972 and 1975, it was agreed that Syncrude oil would receive

world prices (see Helliwell and May, 1976; Pratt, 1976; and Helliwell et al., 1989, pp. 170–72). Output began from Syncrude in 1978, and, in August, Ottawa introduced a tax on oil refiners on all oil they processed (the “Syncrude levy”) to provide the revenue in excess of that earned by Canadian crude prices for the oil sands output. In April 1979, as part of an agreement with Suncor to expand its oil sands plant, the world price was also granted to all of the output from this plant.

Relations between Ottawa and Edmonton exhibited what a psychologist might call ‘approach–avoidance’ behaviour. The governments met and, from 1974 to 1979, agreed upon a level of price for Canadian-produced crude oil. At the same time, each was concerned with setting out an institutional infrastructure that allowed it to meet its objectives in the face of opposition from the other.

Ottawa, for example, introduced the *Petroleum Administration Act*, which was passed on June 19, 1975. Sections 6 through 9 established an oil export tax, with a level based on recommendations from the NEB. Section 22 allowed the federal government and producing provinces to agree on “mutually acceptable prices” for crude oil in Canada, but, in the absence of agreement, under Section 3 “the Governor in Council may, by regulation, establish maximum prices for the various qualities and kinds of crude oil.” (Sections 49 and 52 did the same for natural gas.) Section 38 allowed Ottawa to order the NEB to take control of flows of oil once they crossed a provincial border.

To help assert provincial rights over petroleum, Alberta passed the *Petroleum Marketing Act*, which was given assent on December 14, 1973. Section 2 of the act set up the Alberta Petroleum Marketing Commission (APMC) as an agent of the government (Tyerman, 1976). Section 13 gave the APMC the power to acquire petroleum as a broker (i.e., intermediary between producers or buyers). At the provincial government’s request, the APMC would act as the sales agent for the province’s share of output (i.e., royalty oil and any of the province’s tar sands equity production; Section 15) and the lessee’s share of conventional crude (Section 21). That is, virtually all the provincial government’s crude oil would be marketed by the APMC. The APMC was given power to set prices, including quality differentials, and to determine which parties would be eligible as buyers of Alberta crude (Helliwell et al., 1989, pp. 42–43). In April 1981, the APMC took direct control of the marketing of crude oil; the refiner paid the APMC at the refinery gate and the APMC paid the shipment costs to the refinery.

b. Export Controls

By the end of 1973, the export price on Canadian crude was made up of three components: (1) the government fixed wellhead price, (2) transmission costs, and (3) the export tax. The level of the export tax was set so as to make up the difference between the lower Canadian price and the higher international (OPEC) price, which established the value of Canadian oil in U.S. markets. As was discussed in Chapter Six, with the passage of time the NEB found it necessary to distinguish more grades of crude oil, all at different tax levels (Table 6.4). We noted in Chapter Six that a government regulatory scheme which was simple in concept – capture for Canada the difference between international and domestic prices – proved to be increasingly complex and costly to administer in practice. Rising international oil prices, coupled with smaller increases in the domestic oil price, led to an export tax on light and medium crude of \$26.00/b by 1980.

The volume of crude oil exports had been subject to NEB licensing since Ottawa’s March 1973 announcement. Chapter Six documented the level of crude oil exports over this period (Table 6.4). The NEB set out the general criteria in an October 1974 report on oil exports, following public hearings on the topic. The board found that “a deficiency of supply to meet Canadian demand for feedstocks from indigenous oil is possible in the early 1980s” (NEB, 1974, p. 1-3). However, “if exports were immediately discontinued the Board believes that reserve addition rates would be no more than one-half of those that would be forthcoming if new reserves were to have immediate market access” (p. 4-4). Accordingly, the board proposed a formula for allowable exports which looked forward for ten years and restricted exports the more pressing were anticipated Canadian needs. The export formula was (p. 4-8):

$$E = [P - (D + C)] (t/10)$$

where:

- E* is annual average volume available for export in a particular year;
- P* is forecast annual average oil producibility for that year;
- D* is forecast annual average “demand” for oil in western Canada for that year;
- C* is forecast incremental annual average demand which would have occurred had new conservation measures not been effective;

t is the number of years from that year in which western Canadian “demand” rises to be equal to western Canadian supply (maximum of 10 years).

Each year, allowable exports were to be estimated by this formula. The NEB would then permit up to this volume of exports under month-long licences. The formula was designed to allow a phased adjustment to reduced exports and was set up so as not to discourage Canadian oil conservation measures. The ten-year horizon in the formula was substantially less restrictive than the longer-term one in the board’s gas export surplus tests. (See Chapter Twelve, Section 3.) Completion of the Montreal extension of Interprovincial Pipe Line would add some 200,000 b/d to the western Canadian market. By 1976, oil exports were less than half the 1973 volume. The Sarnia to Montreal pipeline began operation in June 1976. For technical reasons, it was held at 50 per cent of capacity at first, then 65 per cent, reaching 100 per cent in May 1978.

In its September 1975 report on the Canadian oil industry (NEB, 1975b), the NEB reviewed the surplus formula, then turned attention to complaints from heavy oil producers that Canadian refiners could not accept their crude oil and that the export licensing producers were unfairly restricting their market. “From information currently available, the Board does not see the need, at this time, to license heavy crude separately as a protection procedure for Canadian refineries.” However, in November 1976, the board changed its opinion and began the separate licensing of heavy crude oil. This procedure continued through to the deregulation date of June 1985. As Table 6.4 shows, exports of light and medium crude oil were cut to zero by 1980, rising gradually after that to 33,000 m³/d by the first half of 1985. Heavy oil exports exceeded light in every year from 1979 through the first half of 1985.

4. The NEP: 1980–85

The rapid rise in international prices after the revolution in Iran in late 1978 left the Canadian policy of a gradual transition to world oil prices farther than ever from realization. By early fall 1980, delivered prices of international crude oil were about \$40/b in Montreal. A Canadian price of \$17/b necessitated an export tax of \$26/b. The minority Progressive Conservative government in Ottawa had fallen in December 1979 before a new oil price agreement could

be realized with Alberta. The newly elected Liberals had included in their platform a “made-in-Canada oil price.” This meant a single price (apart from transportation costs) for all Canadians, whether they used domestic or imported oil, and a price that would not necessarily be based on the “artificial” OPEC ones. It was consistent with the underlying premise of the direct control period as set out by Prime Minister Trudeau back in December 1973. Alberta and the oil companies found it no more appealing in 1980 than they had seven years earlier. Meetings between government officials from Ottawa and Edmonton continued during 1980 but were not considered to be productive. Nemeth (2006) offers a detailed review of the introduction of the NEP; she argues that internal federal government documents show that the federal government had no serious intent of reaching an agreement with Alberta, and that meetings were few and far from productive.

a. The NEP. On October 28, 1980, Finance Minister Allan MacEachan introduced a federal government budget. The budget consisted primarily of a “National Energy Program,” crafted at the Department of Energy, Mines and Resources under Minister Marc Lalonde. What we shall refer to as the NEP is actually a series of eight sets of documents issued from October 1980 to April 1984. The NEP began with the 1980 budget speech but was modified in light of subsequent federal–provincial negotiations and changing circumstances in the oil market. (Scarfe, 1980, and Walker, 1981, amongst others, provide an overview of the NEP.)

Our concern here is with the oil-pricing provisions of the NEP, but an overview of the program is required to set the stage. Minister Lalonde’s introduction was headed “An Energy Program for the People of Canada,” and announced “a set of national decisions by the Government of Canada” (EMR, 1980, p. 1) based on “three precepts of federal action” (p. 2):

- It must establish the basis for Canadians to seize control of their own energy future through security of supply and ultimate independence from the world oil market.
- It must offer to Canadians, all Canadians, the real opportunity to participate in the energy industry in general and the petroleum industry in particular, and to share in the benefits of industry expansion.
- It must establish a petroleum pricing and revenue-sharing regime that recognizes the requirement

of fairness to all Canadians no matter where they live.

Issues of revenue-sharing, which turned out to be the most contentious part of the NEP, will be discussed in Chapter Eleven (on taxation and the division of economic rent). We shall touch only briefly on matters of Canadianization insofar as they impact upon Alberta. For the most part, these measures deal with the stimulation of Canadian-owned companies (especially Petro-Canada, the national oil company) and applied with particular force to “Federal lands,” the potential petroleum basins in Canadian frontiers outside Alberta. Crane (1982) provides a complete case for the view that there is excessive foreign investment in the Canadian petroleum industry and how the NEP was designed to address this. The brief discussion in Chapter Six points out the contentious nature of these arguments. Halpern et al. (1988) provide a very useful assessment of Petro-Canada’s first decade. The Canadian government began to privatize Petro-Canada in the early 1990s, selling off its last equity holding, of just under 20 per cent, in 2004. The *Petro-Canada Public Participation Act* specifies that no single shareholder can own more than 20 per cent of Petro-Canada’s common shares, and that its headquarters must remain in Calgary. The share limitation condition would continue to be met under the merger between Petro-Canada and Suncor announced in March 2009 and effected at the start of August 2010.

Reasons for a continuation of crude oil price controls were scattered through the report and included:

- i. the existence of OPEC, so that “the oil market is not a free market” (p. 3);
- ii. because of the OPEC price increases “the economics of the industrialized world – including Canada’s – have been stretched to the point where the growth momentum of the pre-1975 decade has been halted, and in some cases reversed” (p. 5);
- iii. because “the Government of Canada has the responsibility to help the national economy adjust to OPEC’s shocks, and to see that the benefits and burdens are fairly distributed” (p. 11);
- iv. because it would be “a mistake” if Canadian prices reflected “the uncertainty and erratic movements in world oil prices, [so that] Canadian economic performance would be made even more vulnerable to the economic repercussions of the world oil situation” (p. 23);

- v. because “there is no need to punish consumers with large unexpected price changes” (p. 24);
- vi. because “prices for oil and gas will be a major determinant of the distribution of income between consumers and governments. The determination of such basic national policy simply cannot be left to the actions of a foreign cartel” (p. 24);
- vii. because “a price mechanism reflecting Canadian costs, not international oil prices, and which offer high and predictable returns for higher-cost oil industry sources, is a better way to provide the necessary incentive” (p. 24); and
- viii. “oil pricing policy should translate Canada’s relative strength in oil and other energy into a competitive advantage for Canadian industries, through prices that are below those prevailing in other industrial countries” (p. 25).

The NEP “would establish a new schedule of prices for domestic oil production, and a new price system to blend the costs of different sources of oil into one weighted average price to consumers” (p. 25). It is necessary to consider separately prices on Canadian oil production (which varied by category of oil), prices paid by Canadian consumers (which were “blended”) and prices paid by those importing Canadian oil (which included the oil export tax). We have already discussed the latter, where the NEB set the export tax at the level necessary to raise the Canadian producer price up to the world level.

The October 1980 NEP set up three categories of Canadian-produced oil (pp. 27–29).

1. **Oil Sands**, including all the Syncrude output, and the incremental output from the Suncor expansion in the late 1970s. An “oil sands reference price” was established at \$38.00/b effective January 1, 1981. (This was the approximate world price netted back to Alberta at the time of the October 1980 budget.) Henceforth the oil sands reference price would be the lesser of the world price or a schedule of prices given by \$38.00 escalated each January by the Consumer Price Index. (A table [p. 26] showed the oil sands reference price rising to \$79.65/b by January 1990, implying an initial inflation rate of 10 per cent, falling to 8 per cent by 1986.)
2. **Tertiary Oil** would receive a “tertiary oil reference price” on any approved tertiary recovery projects (i.e., EOR projects other than secondary

[waterflood] recovery). This price would be \$30.00/b on January 1, 1981 (about 79% of the oil sands price) and would change annually “in a manner similar to the method of changing the oil sands reference price.”

3. **Conventional Oil** was the remainder of Canadian output. The price of 38° reference crude oil would be the lesser of the (quality adjusted) oil sands reference price or a scheduled price. The scheduled price involved a \$1/b increase every six months (starting with a \$1 rise to \$17.75/b on January 1, 1981) up to July 1983, and a \$2.25/b increase each six months for two years, and \$3.50 each six months thereafter. “If by 1990 the conventional oil price” (\$66.75/b on the schedule) “is still below that for reference price oil, consideration should be given to a more rapid rate of escalation.” (p. 27)

It was unremarked, but anomalous, that the scheduled price for conventional oil exceeded that for tertiary oil by July 1989. It was noted that different reference prices for other oils – e.g., frontier – “may be established when more is known about the costs” (p. 29).

We shall comment briefly on the October 1980 NEP oil production prices. First, the CPI escalation factors applied to oil sands and tertiary oil implied constant real prices over time. Second, there was no schedule of estimated world prices, but by showing rising Canadian prices over time it was implied that world real prices were expected to remain constant or rise. Third, if inflation were lower than expected, real conventional oil prices (with a fixed dollar increment) would rise more rapidly than the scheduled prices implied, and hit the oil sands price ceiling more quickly. Fourth, should real world prices fall, they would begin to determine Canadian prices (via the oil sands reference price and the tertiary price tied to it, and eventually the conventional oil price); that is, the “made in Canada” pricing policy held for rising world prices, but not for falling prices.

The “blending” process complicated the link to world prices. Canadian crude oil refiners would pay a “blended” price for the crude they took in through a combination of crude oil costs, levies, and subsidies. The starting point for a refiner would be the price for conventional Canadian crude oil or the price of imported oil, depending on which the refiner bought. Each refinery would be assessed a levy (“Petroleum Compensation Charge” or PCC), which included: (i) the old Syncrude Levy of \$1.78/b (which would, presumably, also cover the excess of tertiary oil prices

above conventional crude prices); and (ii) a new charge designed to cover the excess cost of imported crude. The latter was to commence at \$0.80/b and rise by \$2.00/b each January 1 from 1981 through 1983. The PCC would be \$10.05/b by January 1, 1983. All refiners would pay the PCC. Refiners using imported oil would be paid a subsidy equal to the difference in price between conventional Canadian oil and the world price. Hence, all refiners would, in the end, be paying a “blended” price for oil. The price would be the same for all refiners (apart from transmission costs). (Quality differentials posed problems for such an oil import subsidy program. The NEP originally ignored these price differentials, but by 1982 had to begin to recognize them. See Helliwell et al., 1989, p. 37.) The government also announced, in the NEP, its intent to introduce an additional charge on all oil used in Canada to help cover the costs to the Government of Canada of its Canadianization program (NEP, p. 51). While the oil-pricing provisions of the NEP continued the general policy established back in 1973, they involve several refinements. Canadian prices had been held below world prices since 1973, but the NEP clearly set the price for Canadian oil consumers at the volume-weighted average of the prices paid to various oil producers, plus the Canadianization charge. Refiners would buy domestic oil at the conventional oil price and imported oil at the world price, with importers of imported oil compensated for the difference, and all refiners would pay the same charge to cover the PCC and Canadianization charges.

The NEP stipulated that the “blended price will never exceed 85% of the international price or the average price of oil in the United States, whichever is lower” (p. 30). Obviously Canadian prices would be maintained below international prices. There were curiosities in this blended price ceiling, although they were not commented on in the NEP. In particular, consider the suggestion that “if by 1990 the conventional oil price is still below that for reference price oil, consideration should be given to a more rapid rate of escalation” (p. 27). How does this relate to the “85% of world price” ceiling for a blended oil price? (We shall abstract from tertiary oil with a price between oil sands and conventional oil, and the possibility of U.S. prices below world levels.) Clearly the price of conventional crude must be less than 85 per cent of the world price, if the blended price is to be at 85 per cent or less. (The lower conventional price must compensate for oil imports at the world price.) The greater the proportion of imports, the lower is the ceiling price for conventional oil.

Simple algebra can be used to demonstrate these connections. Assume there are only conventional oil and oil imports, and that f_c is the fraction of refiner oil that is met by Canadian production. Clearly $(1-f_c)$ is the import share. Let P_w be the world price. Then the 85 per cent limit on blended price implies that the maximum price for conventional oil (p_c^m) would be determined in the following equation:

$$(.85)p_w = f_c (p_c^m) + (1-f_c) p_w \quad (\text{Eq. 1})$$

Solving for p_c^m gives:

$$p_c^m = (f_c p_w - .15 p_w) / f_c \quad (\text{Eq. 2})$$

For example, if Canada were self-sufficient ($f_c = 1$), then the maximum conventional oil price (p_c^m) would be 85 per cent of the world level. But if imports meet 50 per cent of Canadian demand, then the maximum conventional price would be 70 per cent of the world level. That is, the more dependent Canada is on imported oil, the lower the ceiling price on domestic conventional oil! This is a perverse result. We can only assume that it reflected the strong belief of the framers of the NEP that the real world oil price would continue to rise, so that the schedule of conventional prices was unlikely to hit the maximum price allowable. Consider, for example, the scheduled prices for July 1990 (NEP, p. 26) of \$79.65/b for the oil sands reference price and \$66.75/b for conventional oil. The conventional oil price is almost 84 per cent of the reference price. If the world real price had stayed constant (using the CPI inflation factors), then conventional oil could receive the scheduled \$66.75/b only if imports provided 7 1/2 per cent or less of Canadian consumption. (In equation 1 above, substitute $P_w = \$79.65$ and $p_c^m = \$66.75$, and solve for f_c .) The suggestion that the conventional price might accelerate to the oil sands reference price would depend on even higher world oil prices. For example, if the conventional price were to rise all the way to the oil sands reference price, and Canadian production met 80 per cent of refinery demand, the world price would have to be at least \$98.03/b. If Canadian production were 60 per cent of consumption, the world price would have to be \$106.20/b before conventional oil could be priced at the oil sands reference price.

If the nominal world oil price remained at the late 1980 level of about \$38.00/b, and the import share stayed at about one-third, the ceiling price for conventional oil would be \$29.50/b, a level attained under the NEP schedule in January 1985. If the CPI increases

implied by the oil sands reference price series were to prove accurate, they would imply a real price of conventional oil in January 1985 of about \$20.75/b (in 1980 dollars), a rise of 23 per cent above the August 1980 price. Thus, it is not at all clear that the NEP price schedule, considered in real terms, would provide "strong encouragement for industry's efforts" (p. 27). Only if inflation rates slowed appreciably would real conventional oil prices rise significantly.

The terms of the NEP (especially the tax components discussed in Chapter Eleven) and its unilateral nature brought an immediate retaliatory response from Alberta. Premier Lougheed made a province-wide TV appearance on October 30, 1980, just two days after the federal budget presentation, dramatically opening it with the statement that "the Ottawa government has, without negotiation, without agreement, simply walked into our home and occupied the living room." He announced that Alberta oil output would be cut back by 15 per cent (180,000 b/d) in three equal steps commencing March 1, 1981, with three month lags between steps. In addition, any pending synthetic crude projects would be put on hold. (In the event of a disruption in international supplies to Canada, Alberta would rescind the cutbacks.) The federal government responded by announcing that the Petroleum Compensation Charge would be increased to cover the cost of any additional crude imports, as happened on March 1 and June 1, 1981.

Serious negotiations between Edmonton and Ottawa began in early spring 1981, with agreement reached late in the summer. (James, 1990, considers the interactions between Ottawa and Alberta in the context of game theory.)

b. 1981 Memorandum of Agreement. The September 1, 1981, agreement was to last for five years. It maintained the blended oil price concept but modified the October 1980 NEP oil price schedules and introduced an additional category of Canadian oil production. This was "new oil," and it was given a "New Oil Reference Price" (NORP). NORP applied to most synthetic oil (including Suncor oil), oil from Canada Lands (the frontiers with Crown land owned by the federal government) and "new" Alberta conventional oil (p. 3). New oil included oil in pools discovered in 1981 and later, bitumen from experimental and new projects begun in 1981 or later and additional petroleum due to EOR schemes (other than waterflood) beginning in 1981 or later (p. 3). Syncrude oil would, essentially, receive the international price. A five-year

schedule of NORP prices in Montreal implied a well-head price rising from \$45.92/b January 1, 1982 in six month increments to \$77.48/b in July 1986 (p. 4). (The January 1982 price was almost 10% above the oil sands reference price given in October 1980, and the July 1986 price was 32% higher.) However, the world oil price set a ceiling for NORP (p. 5).

The remainder of Alberta crude was labelled “conventional old oil.” Its price rose by \$2.00/b October 1, 1981, by \$2.20/b on January 1 and July 1, 1982, and by \$1.00/b every six months thereafter (p. 2). This meant a price of \$23.50/b on January 1, 1982, compared to \$19.75 under the October 1980 schedule; by July 1986 the price of \$57.75/b was \$19.00 higher than that in the October 1980 schedule. Thus the late 1980 conventional price was, ostensibly, almost 50 per cent higher under the September 1981 *Memorandum* than the October 1980 budget. However, the difference presumed rising world oil prices. Under the September *Memorandum of Agreement*, the old oil price was not to exceed 75 per cent of the world price (p. 2). So long as Canadian production served at least 60 per cent of the Canadian market, the price ceiling under the *Memorandum of Agreement* exceeded the October 1980 maximum. The *Memorandum* noted (p. 1, in the Summary) that the July 1986 price was 75 per cent of a “moderate world oil price forecast.” It was also provided that if “the conventional old oil price has already exceeded the 75% limit, there will be no roll-back or retroactive adjustment” (p. 64). Shortly after September 1981, the NORP was extended to almost all experimental oil projects and to pentanes plus.

As under the original NEP, the refiner purchase price would reflect the conventional old oil price plus the Petroleum Compensation Charge (PCC). “Subject to the fiscal undertakings contained in this Agreement, it is the intention of the government of Canada to set the level of the PCC so as to leave no revenue in excess of the amount required to finance oil import compensation and oil qualifying for the New Oil Reference Price, for the period 1981–1986” (pp. 8–9).

c. June 1982 Update. International oil prices failed to rise as the 1980 and 1981 NEP documents had anticipated, so the 100 per cent of world price provision immediately supplanted the NORP schedule. In June 1982, Ottawa issued a *NEP Update 1982* (EMR, 1982), which reaffirmed the goals of the NEP (“security,” “opportunity,” and “fairness”) and expressed “pleasure with progress made to date” (p. iv). The *Update* noted “a current price softness, and a perception that this

may signal a more moderate price outlook” (p. 10) but went on to argue that “there seems to be a preponderance of factors leading to higher, rather than lower, prices” (p. 10). On balance, “the outlook, however, is not necessarily for either low or high prices, but for uncertain prices” (p. 11). Despite this, for “planning purposes,” the *Update* assumed rising nominal prices, with the real price rising at 2 per cent per year after 1983.

In an effort to offer further support to Canadian production, the *Update* extended the NORP, as of January 1, 1983, to all tertiary recovery projects, all experimental projects and output from wells that had been suspended for at least three years (subject to qualifications related to provincial royalties) (pp. 74–75). More significantly, a new category of oil was created, and allowed, as of July 1, 1983, 75 per cent of the world price. This was a SOOP (Special Old Oil Price) applicable to oil from pools discovered after 1973 but before the NORP date of January 1, 1981.

d. 1983–85. The weakness in world oil prices continued, with OPEC reducing its price in March 1983 from \$34.00/b to \$29.00/b (U.S. dollars for 34° Saudi Arabia oil in the Persian Gulf). Conventional old oil (at \$29.75/b) now exceeded the 75 per cent of world price ceiling, so was frozen at that level. In June 1983 a revision of the NEP extended the NORP to oil from infill wells and moved the SOOP to NORP. NORP, of course, was at the international price, well below the prices set out in the September 1981 schedules.

Thus the original NEP price increases, set under schedules that basically assumed Canadian oil prices would always be independent of and below world oil prices (the “made-in-Canada” pricing regime), were superseded by schedules expressing oil prices as a direct function of world oil prices. By the summer of 1984, essentially two types of oil were identified. “New” oil was syncrude, conventional oil discovered after 1973 and tertiary recovery; it received world prices. The remainder of production was “old” oil, accounting for about 60 per cent of total Canadian production; it received 75 per cent of the world price (or more, if the prevailing price of \$29.75/bbl was greater than 75 per cent of the world price). Within this basic distinction was a proliferation of categories of oil (ten in Alberta) on which new or old status was conferred. And it is remarkable how much old oil became new at the stroke of a pen! By mid-1984 the NORP, anticipated in the September 1981 *Memorandum* to be \$63/b by June 1984, was in fact \$39/b.

The convolutions in the various categories of oil produced and the complexities of oil import compensation created myriad administrative headaches, especially with regard to appropriate quality differentials and the lags involved in tying domestic prices to world prices. The complications led eventually to instances where some Canadian crude oils were priced above world levels. (For example, this would happen if world prices were weak while NORP prices were tied either to lagged world prices or to official OPEC prices which did not reflect current market discounts.) Under these circumstances, Canadian buyers would be under an incentive to purchase foreign crude even though Canadian oil was available, as some Montreal refiners were doing by 1984. Differential import compensation for crude oil and products also led to anomalies whereby it was cheaper to import foreign products into Canada, receive compensation, and shut in Canadian crude oil. Occasionally, the combination of import compensation and export taxes resulted in a situation where a product could be imported into one area of the country, with compensation paid by the federal government, then exported from another province and the export tax paid, with the original importer making a profit on the transaction. (Helliwell et al., 1989, pp. 46–47, provide somewhat more detail on import valuation and product differentials.)

By the time the new Progressive Conservative federal government was elected in September 1984, it had become clear that most elements of the NEP were insufficiently sensitive to the vagaries of the oil market. The steadily increasing world price, which had formed the backdrop to the NEP, had not materialized. The market for oil, with a heterogeneous product, complex refineries, and a world market becoming increasingly ‘commoditized,’ proved difficult to regulate by direct control. Regulations became increasingly elaborate and costly to administer.

Change was at hand. (See Section 5, below.)

B. Evaluation of the Direct Control Period

1. Effects of Direct Controls

As discussed in our analysis of the National Oil Policy, the effects of a government program must be set out in contrast to a hypothetical situation, namely the world as it would have been without the program. Definition of this hypothetical world calls on the judgment of the economic analyst, and economists may well disagree. Our presumption is that rising

world oil prices would have brought the NOP to an end in any event and that the alternative to direct controls would have been a largely unregulated crude oil market. (Presumably Alberta conservation regulations, designed to ensure good production practices in oil reservoirs, would have continued.) The United States would have dismantled the Oil Import Quota Program, as it did in actuality. With the disappearance of spare production capacity in the United States, crude oil imports become the marginal source of crude oil supply. World oil prices would determine the price for Canadian-produced crude oil, as Canadian oil commanded the world price in U.S. markets, and met barrel-to-barrel with imported crude in the Niagara Peninsula. The U.S., eager to reduce reliance on crude from OPEC, and the unstable Middle East in particular, would welcome flows of oil from Canada. Potentially this could involve the diversion of western Canadian crude from the populated regions of southern Ontario into markets in the United States closer to Alberta (the Midwest, including Chicago). We assume that the existence of an established pipeline link (Interprovincial Pipe Line) to Port Credit, plus likely opposition from Ottawa and the Ontario provincial government would mean that Canadian crude oil continued to serve the Toronto area. However, the Montreal extension would not have been built. If anything, pressure might have existed to build a west-flowing line from Montreal to allow imports into the Toronto/Sarnia market.

The impact of the direct control period was to limit the volume of exports to the United States and to hold Canadian prices below the international level. The general effects on the crude oil market are illustrated in Figure 9.2. (Comparative static analyses like this have been used by many economists analyzing post-1973 Canadian oil policies. See Watkins, 1977a, 1981; Waverman, 1975; Thirsk and Wright, 1977; and Powrie and Gainer, 1977. Waverman and Watkins, 1985, focus on the impacts on the downstream oil industry.) This is a simplified ‘generic’ policy that holds the price to both Canadian producers and consumers (p_c) below the world price (p_w). As we shall discuss below, the actual Canadian regulations varied over time and did not always exactly fit this simple analytical model. In Figure 9.2, Panel (a) shows the “western Canadian” market (WORV), while Panel (b) shows “eastern Canada” (EORV), following the established consumption regions as established under the NOP. In Panel (a), D^{WC} is the western Canadian demand curve, and S_c the supply curve. In Panel (b), D^{EC} is the eastern Canadian demand curve.

In western Canada, the effect of direct controls on price was to hold the Canadian price below world levels ($P_c < P_w$) to encourage additional consumption ($Q_4 > Q_1$) and to discourage production ($Q_2 < Q_5$). Exports fell from $(Q_5 - Q_1)$ to $(Q_2 - Q_4)$. Oil consumers benefit from reduced prices on the oil they would consume at the higher price; they pay an amount less indicated by area $P_c A J P_w$. In addition, there is a consumers' surplus gain of ABJ on the incremental output. The Canadian government gains export tax revenue equal to $BDHI$. Oil-producing interests (shareholders in oil companies and governments that receive payments from the industry's economic rent) lose because of the lower prices and reduced consumption. Total dollar losses of $P_c E F P_w$ plus $Q_2 Q_5 E D$ are partly matched by reduced production costs of $Q_2 D F Q_5$.

If there are additional limitations on the volume of exports, as was true, particularly for light and medium crude over the 1973 to 1985 period, then export volumes could be further reduced to $(Q_3 - Q_4)$ with a loss of revenue to producers of $Q_3 Q_2 D C$, a saving to producers of costs $(Q_3 K D Q_2)$ and a loss of export tax revenue to the government $(C D H G)$.

In eastern Canada (Panel [b] of Figure 9.2), the decision to impose a made-in-Canada price (P_c) lower than the world price (P_w) generates increased consumption ($Q_1 Q_2$). Consumers benefit from reduced payments on what would be bought at the higher price plus a consumer's surplus gain $(P_c B D P_w)$. Taxpayers finance oil imports in the amount of $P_c B C P_w$. It can be seen that the export tax revenue will partly or entirely balance import subsidies, depending on whether or not exports are less than, equal to, or greater than imports.

Figure 9.2 illustrates, in general, the effects on Canadian oil markets of the direct government controls from 1973 to 1985. The precise impacts are more complex. For example, beginning with Syncrude in 1977, and with increasing complexity thereafter, some Canadian production was allowed prices higher than the rest of output, with the price to consumers lying between the world price and the lowest producer prices. Another example relates to the oil export volume limitations and taxes, which varied depending upon the grade of the crude oil, with tighter volume limits and higher taxes on lighter crudes. Estimation of the impact of the oil price and export controls over the 1973 to 1985 period is, therefore, difficult.

Moreover, as was noted above, the impacts of policies can be assessed only in relation to that never-seen universe that would have occurred had the policies

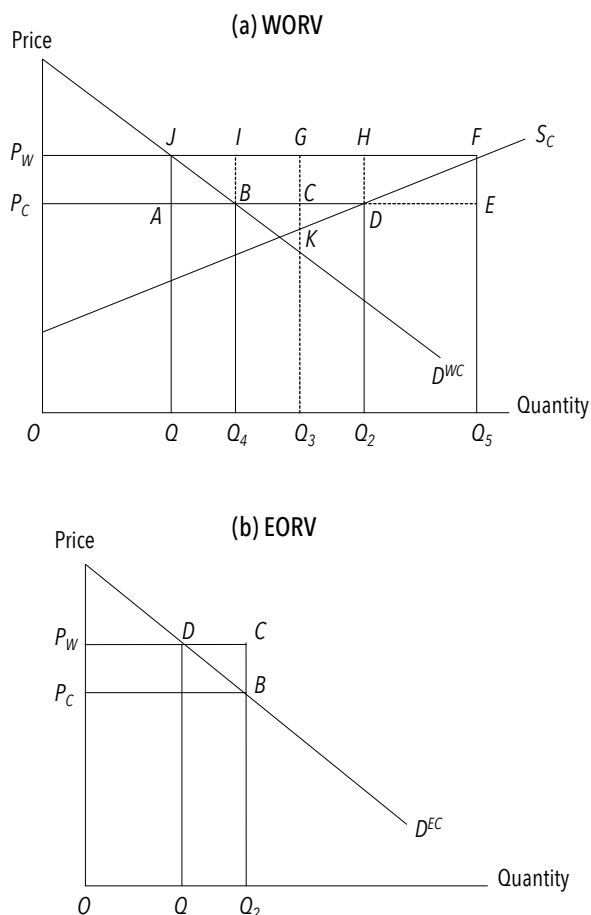


Figure 9.2 Canadian Oil under the NEP

not been imposed. We shall assume that Canadian prices would have been at the world level and that the U.S. market, in its desire to reduce dependence on OPEC oil, would have been willing to absorb whatever exports Canadian producers would have been willing to make. Since Canada is a small producer at the global level, we assume that an absence of Canadian price controls would have had no effect on the price of international crude. Hence the crude oil price controls meant lower prices to Canadian consumers and producers than would otherwise have occurred. The impact on the federal government is more complicated, since it would not have received oil export tax revenue (or such receipts as the Syncrude Levy) but would also not have had to subsidize oil imports. Further, as Chapter Eleven discusses, the revenue received by the federal government from the oil industry is determined in part by the crude oil price; after 1980, it was affected as well by special levies introduced

under the NEP, and no one can know what the tax (or rent collection) provisions might have been had the government not proceeded with the price control provisions of the NEP.

Export levels are also subject to great uncertainty. We assume ready willingness of the United States to accept Canadian oil and presume there were amounts available that would be excess to consumption levels (at the world price) in established Canadian markets for Canadian crude (i.e., WORV). Restrictions under the USOIQP had disappeared. However, amounts available would depend in part on the Alberta market-demand prorating regulations and in part on the balance over time between reservoir depletion and reserves additions at international price levels. One might assume that high exports in the mid-1970s would have absorbed excess capacity and run down domestic oil producibility more rapidly – this, after all, was the concern that led to export limits on crude in the first place. But, as we have noted, crude availability is less a physical phenomenon than an economic one, and the greater demand for oil and higher prices would offer a stronger inducement to add reserves thereby supporting or even increasing export capabilities.

Helliwell et al. (1989) undertook detailed economic analysis of the Canadian petroleum industry, including estimation of equations to describe aggregate production and consumption decisions. Those equations can then be utilized to provide estimates of how the industry might have behaved had conditions been different. Thus, their Chapter 10 looks at the actual course of events in the overt control period, 1973–85, and compares them with four other sets of circumstances that might possibly have occurred. One of the scenarios assumes that Canadian oil and natural gas prices had been free to move to market-clearing levels throughout the 1973 to 1985 period, and that export volumes were also largely uncontrolled. (Since industry expenditures depend on oil and gas prices, it is necessary that some assumption be made about gas market regulations as well as those for crude oil. We would note that the assumptions about crude are relatively uncontroversial – Canadian domestic and export prices follow world levels, and any feasible production in excess of domestic requirements is exported. The appropriate assumptions for natural gas are harder, for reasons set out in Chapter Twelve. Helliwell et al. basically assume a fixed ratio of gas to oil prices, and that gas export volumes equal historical levels after 1979 when the United States exhibited signs of gas surplus.) Helliwell et al. find that in the

deregulated case oil export volumes are much higher than were observed historically, being “relatively constant over most of the simulation period, averaging about 260 million barrels per year (113,000 m³/d) during the 1974–85 period and then falling gradually” (p. 200). Table 6.1 shows that actual oil exports from Alberta did increase substantially with deregulation rising to about 104,000 m³/d by 1993 from some 43,000 m³/d in 1984. This was still below 1973 exports of almost 160,000 m³/d. However, it suggests that the Helliwell et al. estimate of Canadian exports of 113,000 m³/d without regulations from 1974 to 1985 is quite reasonable. In the absence of the overt controls, the Sarnia–Montreal pipeline extension would not have been built. So at least a part of the increased exports would be met, not by increased production, but by increased imports into Quebec. (Deliveries of Alberta oil to the Montreal market hit a peak of 42,000 m³/d in 1980.)

The price effects of the overt control period are somewhat difficult to establish exactly. Table 6.3 provides a record of year-end prices for the main categories of oil, but prices changed at various points of time during the year, and it must be remembered that different prices applied to different categories of crude. Table 9.3 provides a summary of pricing in the 1973–85 period on the assumption that there are three categories of oil: imported crude, domestic “old” crude, and (for 1982–85) domestic “new” crude. It is assumed that synthetic crude from the tar sands received the world price, which was true for most of the period, and held for all new projects. We have not shown the “Special Old Oil Price” (SOOP), which applied to oil discovered from 1974 to 1980 and received a price between the old and new oil prices; this category existed for only one year, from mid-1982 to mid-1983, whereupon it was “NORPED” into the new oil category. Table 9.3 does not make complete allowance for quality differentiation problems, but the price differences shown are representative of those that existed in the overt price control years. Prices for “old” oil were less than \$1.00/bbl below world prices when crude prices were frozen in late 1973 and were generally held \$2.50 to \$4.00 lower through to the sharp increase in OPEC prices, which began in late 1978. The differential then grew rapidly, to over \$22.00/bbl by 1981, subsequently falling as Canadian prices rose and international prices began to weaken.

By early 1985, immediately prior to deregulation of Canadian crude prices, the price of old oil was about \$8.00/b below the international level. (Recall that “old” oil, in essence, was production from any reserves

Table 9.3: Average Annual Prices of Oil in the Overt Control Period (\$/b)

	World Price (P_W)	Canadian Producer Prices		Consumer Levies	Consumer Price (P_C)	Price Differentials		
		'Old' Oil (P_O)	'New' Oil (P_N)			$P_W - P_O$	$P_W - P_N$	$P_W - P_C$
1973*	4.57	3.80	3.80	0	3.80	0.77	0.77	0.77
1974	9.74	5.825	5.825	0	5.825	3.915	3.915	3.915
1975	11.20	7.25	7.25	0	7.25	3.95	3.95	3.95
1976	11.46	8.525	8.525	0	8.525	2.935	2.935	2.935
1977	13.58	10.25	10.25	0	10.25	3.330	3.330	3.330
1978	14.76	12.25	12.25	0.05	12.30	2.51	2.51	2.46
1979	21.09	13.25	13.25	0.45	13.65	7.84	7.84	7.39
1980	35.75	15.583	15.583	1.47	17.023	20.167	20.167	18.697
1981	41.38	18.875	18.875	8.14	27.015	22.505	22.505	14.365
1982	39.99	24.625	39.99	7.45	31.075	15.365	0	8.915
1983	35.23	29.75	35.23	4.91	34.66	5.48	0	0.57
1984	36.99	29.75	36.99	5.30	35.05	7.24	0	1.94
1985*	37.79	29.75	37.79	7.69	37.44	8.04	0	0.35

Notes:

* = last four months of 1973 and first five months of 1985.

World price is the average cost of oil imports at Montreal as reported in the CAPP *Statistical Handbook* less \$1.31/b for Edmonton–Montreal pipeline transmission. (This was the June 1985 pipeline tariff as reported in the 1986 *Canadian Petroleum Monitoring Survey* of the Petroleum Monitoring Agency.)

Canadian prices are those set by regulation as Edmonton prices of 'par crude.' Prices are time-weighted averages. Until the 1981 *Memorandum of Agreement* only synthetic crude oil, and starting with the October 1980 NEP, a small amount of tertiary crude, received a higher price than old oil. Accordingly, a different new oil price is not recorded until 1982. It is assumed that new oil received the world price beginning in January 1982.

Consumer levies are the petroleum compensation charge (PCC), special compensation charge (SCC), and Canadianization of oil special charge (COSPP), as reported in the 1986 *Canadian Petroleum Industry Monitoring Survey* of the Petroleum Monitoring Agency. The levies are time-weighted averages for the year.

Consumer price is the old oil price plus the consumer levies. This is defined at the Alberta border. For consumers in other markets, the differential with world prices would be smaller than this suggests because of the added transmission component.

proved up prior to the start of 1980, except that reserve additions associated with new discoveries from the start of 1974 through 1980 were allowed higher prices beginning in 1982, first as SOOP, then NORP. Oil from enhanced recovery projects beyond waterflooding was also largely shifted to these categories.) "New" oil prices were identical to old until the September 1981 *Memorandum of Agreement*, then, starting January 1, 1982, were given the NORP values (which turned out to be the international level) from 1982 on. More difficult to assess accurately is the netback on lifted oil or reserves additions, which depend not just on oil prices but also on taxes and costs; such netbacks play an important role in the oil supply models discussed in Chapter Eight. Scarfe (1984), amongst others, provides some netback estimates for the NEP years.

Prices to energy users throughout Canada were the old oil price plus a variety of "consumer levies,"

designed to generate the overt control policy's "made-in-Canada" blended price. (Consumers also paid actual or hypothetical transmission costs from Alberta to their market.) The levies include: the "Syn crude" charge introduced in 1978, the Canadianization charges introduced in 1981, and the charges designed to cover the costs in excess of old oil prices for imports and new oil introduced with the NEP. Until 1978, the differential between the world price and the lower price paid by consumers was the same as the price differential for producers. After that, the differential was smaller for consumers than producers of old oil; the peak consumer price subsidy of over \$18/b was hit in 1980, but it fell sharply after that to under \$2.00 by 1983–85. The consumer subsidy was, in fact, much less than anticipated in the NEP or the 1981 *Memorandum*, but this was because international prices did not rise as rapidly as those agreements expected.

2. Normative Analysis of Strict (Overt) Controls

As with our discussion of the NOP, we shall begin with an analysis of the efficiency of the policies focussing on the oil market in isolation, after which we shall briefly consider other possible reasons for the government regulations.

a. Efficiency of Strict Controls

In comparison to an unregulated market with Canadian oil prices set by world crude oil prices, the period of overt controls, culminating in the NEP, served to keep prices to Canadian oil producers and consumers lower than they would otherwise have been. In addition, a crude oil pipeline extension to Montreal took place, which would otherwise not likely have occurred, and crude oil exports – mainly of light oil – were restricted. The restriction was likely of a greater volume than implied by the diversion of Canadian oil from the export market to Montreal. Viewed through a political lens, the main effect was to benefit crude-oil-consuming interests across the country at the expense of crude-oil-producing interests (centred largely in Alberta). Such effects are, however, largely transfers from one group of Canadians to another and therefore cancel without net efficiency effects. Economic efficiency looks quite different from a narrower Alberta perspective, where there is a significant outflow from the Alberta government, Alberta oil producers, and others in the province to other parts of Canada. (See Mansell and Percy, 1990, Appendix A, for an assessment of this at the government level). As Figure 9.2 illustrated, from a Canadian perspective, the low price policy does have two types of efficiency cost (or deadweight loss). First, it engendered incremental oil consumption with values to consumers less than the world oil price (which represents the opportunity cost to the country of the oil consumed); that is, the gain in consumers' surplus from using the oil was less than the cost of the oil. Second, the low price discouraged the addition of supplies even though the cost of the incremental oil was below its value in international markets; that is, there was a loss of economic rent to the country. In addition, there were the costs of building and operating the Sarnia–Montreal leg of the Interprovincial Pipe Line.

Table 9.4 provides approximate estimates of the size of these efficiency losses. (Analysis begins with 1974, since the price freeze began only in September 1973, and prices were held only slightly below international levels for the rest of that year.) The method utilized is identical to that applied in analyzing the

efficiency of the NOP. In particular, straight line supply and demand curves were assumed with elasticities of 0.3 and -0.6 , respectively, at the observed production and consumption points. (Thirsk and Wright, 1977, amongst others, apply this approach using a variety of elasticity assumptions.) Our elasticities are taken to be representative of the long run. The approach is, therefore, static, even though the underlying processes are dynamic. For example, short-run rigidities in adjustment are not taken into account, and there is no formal allowance for the ongoing effects of reserves additions. Moreover, unlike the NOP years, when Canadian oil prices were relatively fixed, the overt control period saw significant changes in prices. This implies some inconsistency between two key assumptions. For example, a straight line demand curve will have different elasticities at every price (with a higher elasticity at higher prices). (Unless the supply curve passes through the origin, it, too, will have different elasticities at every price.) Yet we have assumed a constant elasticity in each year at whatever price was observed, and prices tended to rise significantly over the period, implying hyperbolic demand and supply functions. Clearly our calculations must be taken as indicative of efficiency effects, not precise estimates.

We have ignored the operating costs of the Montreal pipeline but include the capital cost and an assumed 10 per cent required rate of return on un-depreciated capital; the line was assumed to be depreciated on a straight line bases over twenty-five years (i.e., 4%/year). The economic rent inefficiency was assumed to apply to conventional oil only, since incremental tar sands projects were allowed the world price throughout the period.

The inefficiencies of the price and trade control regulations were large, as Table 9.4 shows, with an average annual value of over \$1.2 billion. In the peak year (1980), they amounted to \$6.3 billion, which was 2 per cent of Canadian GDP. The costs tended to become lower from 1974 to 1978 as Canadian oil prices approached world prices but ballooned in the next two years as world oil prices exploded. They fell sharply thereafter for several reasons. When world oil prices levelled off, and then began to soften, the gap between Canadian and world prices narrowed once again. Recall that this was fortuitous, rather than a matter of policy, as the October 1980 NEP and September 1981 *Memorandum* were wrong in their forecasts of rising OPEC prices. A second factor was the major change initiated in the 1981 *Memorandum* to allow higher (as it happened, world) prices for a potentially large volume of new oil. Table 9.4 assumes

Table 9.4: Efficiency Costs of Overt Controls (10⁶ Canadian dollars)

	<i>Consumption Losses</i>	<i>Economic Rent Foregone</i>	<i>Montreal Pipeline Costs</i>	<i>Total</i>
1974	498.83	259.08	0	757.91
1975	398.20	181.08	185.00	764.28
1976	191.86	77.28	18.50	287.64
1977	214.85	83.25	17.76	315.86
1978	95.00	38.76	17.02	150.78
1979	847.93	386.63	16.28	1,250.84
1980	4,230.48	2,013.01	15.54	6,259.03
1981	1,451.16	1,871.57	14.80	3,337.53
1982	417.16	0	14.06	431.22
1983	1.43	0	13.32	14.75
1984	16.86	0	12.58	29.44
1985	0.48	0	11.84	12.32
Total	8,364.24	4,910.66	336.70	13,611.60
Yearly Average	760.39	446.42	30.60	1,237.42

Notes:

The yearly average is for 1974 through 1984.

The analysis assumes straight-line demand and supply curves over the relevant price ranges. An elasticity of demand of -0.6 and an elasticity of supply of 0.3 are assumed. For the mechanics of the calculation of efficiency losses, see the discussion in Table 9.2.

Consumption losses: Assumes that the demand curve passes through the point given by the consumer price of Table 9.3 and an estimate of Canadian crude oil utilization as derived from *Annual Reports* of the NEB. This estimate is derived by adding crude oil imports to production and subtracting exports. (It therefore abstracts from stock changes and net product imports.) The consumer price subsidy is given by the difference between world price and consumer price reported in Table 9.3.

Economic rent foregone: Assume the supply curve passes through a point given by the new oil price of Table 9.3 and a production level equal to Canadian production as reported in the NEB *Annual Reports* less Syncrude production as reported in the ERCB *Annual Statistic Summary*. The price differential due to the policy is given by the world price–new oil price differential of Table 9.3.

Montreal pipeline: The 1975 *Annual Report* of the NEB noted the issuance of a public certificate on May 21, 1975 (#OC-30) for construction of the 520-mile 30" diameter line. Estimated capital cost was \$185 million. It was assumed that this sum was spent in 1975. Operating costs other than return on capital were assumed to be insignificant. Capital is assumed to be depreciated over 25 years on a straight-line basis, and a 10% return on undepreciated capital included as a cost of the line.

that all potential incremental oil supplies received the world price after 1981, so that no further economic rent losses occurred. In fact, this underestimates rent losses, since the incorporation of different supply sources in the new oil category took place more gradually than that implies. For example, the full world price for extension drilling new additions in pools discovered between 1974 and 1980 was not granted until mid-1983. Further, some potential incremental oil production never received the world price. Consider the abandonment decision. Prices lower than the world level for oil from wells in pools discovered prior to 1974 would generate an earlier shutdown time. However, since these pools have relatively low output rates and high operating costs, the rent foregone would be relatively small. (This is, however, a rather perverse result in a policy that took energy self-sufficiency as an important objective). The *Annual*

Reports of the APMC record payments to Alberta oil producers for the crude handled by the APMC, including the payments above the old oil price for SOOP and NORP. They suggest that the proportion of Alberta oil production classified as “new” rose from 4 per cent in 1982 to 38 per cent by 1985.

Overall, the overt control period generated large inefficiencies in the Canadian crude oil market. By the end of the period, the inefficiencies had been reduced significantly. However, this was in part accidental as world oil prices weakened and came only with a complex administrative structure with more and more different categories of crude, some ten by 1984.

b. Other Aspects of Strict Controls

Other reasons for the pricing and trade policies adopted in the overt control period include macroeconomic stabilization, national security,

conservation, and rent-sharing. Similar arguments were discussed when we reviewed the NOP, though the direction of connection ran the opposite way in the overt control period, since prices were held below world levels, rather than above as during the NOP. We shall comment only briefly on three of the arguments and will save most of our discussion of rent-sharing issues for Chapter Eleven.

Macroeconomic Stabilization. Rising international oil prices have been implicated in the ‘stagflation’ (concurrent recession, or slow growth, and inflation) that began to characterize many economies in the 1970s. In brief, it was argued that rising oil prices (which tended to pull up the prices of other energy products) provided a ‘cost-push’ effect on price levels. Since prices of many goods tend to be rigid in a downward direction, a rise in the price of a key input such as energy can generate a rise in the average price level, and if other inputs – e.g., labour – operate to increase their prices as general price levels rise, additional upward price pressure is created. At the same time, the higher payments for energy – especially payments to OPEC – meant that consumers had less to spend on other goods and services so the demand for them fell, generating recessionary pressures and higher unemployment rates. OPEC members were, in the aggregate, net savers in the years immediately following an oil-price increase, so their spending did not rise by enough to offset spending declines by oil consumers. Nor, of course, did OPEC members necessarily distribute extra spending geographically in the same proportions as their extra earnings. OPEC’s utilization of funds was commonly referred to as a ‘recycling’ problem. (These macroeconomic arguments about the effect of changes in oil prices have been controversial. A review and sceptical view is Barsky and Kilian, 2004.)

Evidence on this issue is discussed by Helliwell et al. (1989, chap. 11) for Canada. They note that the direct recessionary effects of an energy price rise on a net energy importing nation is generally supplemented by indirect recessionary impulses as other countries suffering from recessions reduce their imports of goods and services from this country. Qualifications to the analysis may be required for a country like Canada, which was a net energy exporter in 1973, since higher energy prices mean increased international earnings and a stimulus to investment in energy industries. Helliwell et al. use a large macroeconomic model, with a well-structured energy sector – the MACE (Macro and Energy) model – to

simulate the operation of the Canadian economy under a variety of scenarios.

What would have happened had Canadian policies been the same in the overt control period except that petroleum prices were allowed to go to world levels? They find that Canadian real GNP would have been lower in every year by amounts ranging from one half of one per cent to 2.5 per cent; price levels would have been higher (pp. 212–14). However, the implication that higher oil prices tend to be stagflationary for Canada requires further consideration. In particular, a second simulation looks at both world pricing for petroleum and a policy of unregulated exports (especially for oil). In this case, price levels are still higher than was actually observed in the overt control period (except in 1984 and 1985), but real GNP is slightly lower only in 1974 and higher in other years, by as much as 3.5 per cent in 1983 (pp. 213–14). The domestic price controls and export limitations together, then, seem to have reduced inflation slightly but generated reduced real output.

Of course, both simulations involve comparison to a world history in which OPEC raised crude oil prices dramatically. What were the combined effects of the OPEC price shocks and the Canadian policies? Helliwell et al. address this by a hypothetical simulation in which world oil prices rise smoothly over time as the general price level of expenditures in the United States did over this period. They find (pp. 223–25) stagflationary effects in what actually occurred relative to this hypothetical scenario without the sharp OPEC oil price changes; that is, the oil price increases tended to reduce real GDP and increase inflation. However, the extra inflation and reduced GDP are both smaller as actually observed than they would have been had Canada pursued a deregulated petroleum pricing policy. “Overall, the results suggest that domestic policies – especially domestic pricing policies – were successful in moderating to some extent the impact of the OPEC price shocks in the 1970s.... The results also indicate, however, that domestic policies had far less impact on the economy than the price shocks themselves” (p. 225). Helliwell et al. do not report a gradual price rise scenario where both price deregulation and no oil export restrictions are considered; the earlier results suggest that this might exhibit a less pronounced recessionary effect than was actually observed.

Overall, the evidence in Helliwell et al. suggests that the policy of holding Canadian petroleum prices below world levels taken by itself did have the effect of

moderating the recessionary and inflationary effects of higher world oil prices in the 1974–85 period. Such gains must of course be set against the other effects of the policies, including the administrative costs of the programs and the efficiency losses. It is also fair to ask whether alternative macroeconomic stabilization policies might not have better attained the macro objectives. Moreover, it must be noted that macroeconomic stabilization seems unlikely to have been a prime rationale for the program since other policies of overt control period appear to have worked against relatively higher real growth. As was discussed above, the oil export limitations tended to reduce Canadian GNP, and so, according to Helliwell et al.'s simulations, did the various petroleum tax changes introduced by provincial and federal governments as petroleum prices rose.

Security of Supply. Amongst the measures of the direct control period were those limiting oil exports and extending the Interprovincial Pipe Line (IPL) to Montreal. After 1976, Montreal refineries began using western Canadian oil. Construction of the pipeline had the direct backing of the federal government; tariffs for the extension were subsidized until 1980, and after that the costs were spread over all the costs of the IPL system (i.e., 'rolled in,' so that Montreal refiners did not have to pay the full incremental cost of the extension). The eastward flow of Alberta oil as far as Montreal clearly required a regulatory directive. Even under the NEP, oil imports to Montreal started to rise in 1983 as regulated prices lagged behind weakening international prices. With deregulation in 1985, exports of western Canadian crude oil to the United States increased, and exports to Montreal fell. By 1990, the Sarnia–Montreal extension was mothballed, and Canada once again relied on imports for Montreal refineries. In fact, by the mid-1990s, many were speculating on whether the line should be reversed to allow imported crude into the Ontario market, as finally occurred in 1999.

The key question is whether this policy generated a national security benefit, and, if it did, whether it was commensurate with the costs of the policy. We shall not analyze this issue with any rigour but must express our scepticism about the national security argument. It is true that international crude oil movements have been prone to disruption, especially those originating in the Middle East. However, analyses of the 1967, 1973/74, 1979/80, and 1990/91 crises show that the actual net losses of crude oil were very small

relative to world consumption and that perceived shortages have been shared relatively equitably across the world. Further, Canada joined other members of the International Energy Agency (IEA) in 1975 to formalize a shared shortage plan. More fundamentally, perhaps, several analyses suggest that the main 'shortages' in previous crises were as much due to government regulations (e.g., "gasless Sundays") as to the supply disruptions.

The increased willingness of countries to rely upon market mechanisms during supply crises – as evidenced by actions in the 1990 Gulf War – also affects the national security argument. Here, higher prices provide the conservation incentives needed to cope with the supply disruption and no 'shortages' appear because the market clears at the higher prices. Market reliance also casts doubt on the IEA emergency sharing agreement since rising prices will spread the adjustments throughout the world without the necessity for formal government allocation measures. A number of analysts have suggested that there is still a role for the utilization of strategic stockpiles to help blunt any crisis-induced price panics that might result from less than fully rational, destabilizing, changes in expectations.

Much is often unformulated in the national security argument. Which uses of oil are critical to national security? And why wouldn't these needs be among those that continue to be met during a crisis? To our mind, the more critical security of supply issues relate to the stability of market mechanisms during a crisis and the equity effects of a crisis (e.g., the impact upon the very poor of a large, sudden rise in the price of fuel oil used for heating). The first problem requires joint international monitoring in the market, whereas the brunt of the second most logically falls on social support programs. Neither is well addressed by the decision to hold domestic oil prices below world levels and to limit exports.

Conservation. Energy policies have often been justified on 'conservation' grounds, generally in terms of decreasing current use in order to increase supplies available in later periods. While such a claim might be made for the oil export regulations discussed in Section 3, it is harder to do so for the overt price controls. As a package, oil and gas price levels were held lower than would have been expected on the basis of world prices, therefore encouraging more current consumption. While the high price of gas exports in the early 1980s did discourage foreign use of Canadian

gas, this seems to have been an unintended consequence of the uniform border pricing policy and the emphasis on the substitution (replacement) value of the gas. By 1983, the government had introduced a volume discount plan to encourage higher exports. (Natural gas policies are discussed in more detail in Chapter Twelve.)

Rent Sharing. As was noted in our discussion of Figure 9.2, a main effect of holding Canadian oil prices below the world level is to transfer revenue from oil producers to oil consumers. There is an added regional dimension to this since crude oil production is so concentrated in one part of the country. In such circumstances, concern with the distribution of rent between producing and consuming interests is likely to be felt by the central government. A regional government in the producing area, such as Alberta, is most likely to be concerned jointly with maximizing the size of the economic rent going to producing interests and with increasing the share of this rent, which goes to the government instead of companies. As we saw in our discussion of the NOP, the direct impact of lower oil prices tends to be moderately progressive across consuming groups, and the wealthier tend to benefit most from higher dividend payments from, or share prices for, oil companies. These equity concerns seem to have been a major impetus behind the federal government's policies in the overt control period. This conclusion is reinforced by the observation that the package of measures introduced with the October 1980 NEP also included new taxes designed to capture more rent for the federal government.

Since the equity objectives of the overt control policies are so tied up with the issue of rent-sharing, we defer further discussion to Chapter Eleven, apart from one observation. One might justify the efficiency costs of the oil pricing policy on the grounds of equity gains, but this argument is valid only if there were no way to attain the equity objectives while allowing Canadian oil prices to rise to world levels. Are governments unable to capture and redistribute a large share of rent as oil prices rise? And can the two levels of government not agree to share this rent? Our general view is that the inefficiencies of the overt control period were a largely undesirable and unnecessary cost of governments' search for an effective economic rent-sharing policy. However, Nemeth (2006) argues that the problem was not simply the difficulty in agreeing on how to share the economic rent from petroleum, but that the Lougheed government in Edmonton and the Trudeau government in Ottawa

had completely different views on the contribution of petroleum to the economy; in her view, Lougheed saw the resource as Alberta's and essential to an active provincial economic diversification policy, while Trudeau believed in a strong central government utilizing the oil profits to fund federal programs of benefit to all Canadians.

5. Deregulation and the Free Trade Era: 1985-

The deregulation of Canadian crude oil, based on the Western Accord, began on June 1, 1985. We argued in Chapter Six that the adjustment to the new environment took place quickly and easily. (This contrasts with natural gas, as will be discussed in Chapter Twelve.) However, there was one new type of government action that could affect the Alberta petroleum industry – free trade agreements. The *Canada–U.S. Free Trade Agreement* (FTA) became effective January 1, 1989; most of the provisions of this agreement were rolled into the *North American Free Trade Agreement* (NAFTA), which admitted Mexico and became effective on January 1, 1994. Our discussion draws primarily upon Schwartz et al. (1985), Watkins (1991b, 1993, 1994), McDougall (1991), Plourde (1988, 1991, 1993, 2005), Plourde and Waverman (1989), Watkins and Waverman (1993), Bradley and Watkins (2003), Doern and Gattinger (2003), Brownlie (2005) and Angevine (2010a).

A. Provisions of the Agreements

Since energy trade between Canada and Mexico is minimal, and the key provisions of NAFTA regarding energy trade between Canada and the United States replicate the provisions of the FTA, we shall outline the key clauses of the FTA.

Chapter 9 of the FTA (Chapter 6 of the NAFTA) deals with energy and is in part based on the General Agreement on Tariffs and Trade (GATT): “subject to the further rights and obligations of this Agreement (FTA) the parties affirm their respective rights and obligations under the General Agreement on Tariffs and Trade (GATT) with respect to prohibitions or restrictions on bilateral trade in energy goods” (#902 of the FTA, p. 145). Concomitantly, the United States agreed to partially lift its ban on exports of Alaskan crude oil and allow Canada to import up to 50,000 barrels per day.

Basically, the existing GATT provisions (Article XX(l) and (j), “the ensuring of domestic supplies”; XX(g) “conservation”; and XI(2a) “emergencies”) are codified and strengthened. Governments cannot set minimum price requirements for exports or imports (#901, Section 603 in the NAFTA) nor are export taxes allowed (#903, Section 604 in the NAFTA). “Neither Party shall maintain or introduce any tax, duty, or charge on the export of any energy good to the other Party, unless such tax, duty, or charge is also maintained or introduced on such energy good when destined for domestic consumption” (FTA, p. 146). Article 905 of the FTA (Article 608 of the NAFTA) allows direct “high level” consultation if regulatory processes other than price factors are considered odious (FTA, p. 147):

If either Party considers that energy regulatory actions by the other Party would directly result in discrimination against its energy goods or its persons inconsistent with the principles of this Agreement, that Party may initiate direct consultations with the other Party. For purposes of this Article, “an energy regulatory action” shall include any action, in the case of Canada, by the National Energy Board, or its successor, and in the case of the United States of America, by either the Federal Energy Regulatory Commission or the Economic Regulatory Administration or their successors. Consultations with respect to the actions of these agencies shall include, in the case of Canada, the Department of Energy, Mines and Resources and, in the case of the United States of America, the Department of Energy. With respect to a regulatory action of another agency, at any level of government, the Parties shall determine which agencies shall participate in the consultations.

The Annex to Article 905 (Article 608 in the NAFTA) concerning oil and gas reads (FTA, p. 150):

1. Of the tests set under subparagraph 6(2)(z) of the National Energy Board Part VI Regulations on the export of energy goods to the United States of America, Canada shall eliminate the “least cost alternative test,” described in subparagraph 6(2)(z)(iii).
4. It is understood that the implementation of this Chapter includes the administration of any “surplus tests” on the export of any energy good to

the other Party in a manner consistent with the provisions of Articles 902, 903 and 904 (Articles 608 of the NAFTA).

Article 906 (Government Incentives for Energy Resource Development) (Article 608 in the NAFTA) allows for “existing or future incentives for oil and gas exploration, development and related activities in order to maintain the reserve base for these energy resources” (FTA, p. 147).

Article 907 (Article 607 of the NAFTA) allows for restriction of imports and exports of an energy good only in the event of National Security.

Article 907 (Annex 608 in the NAFTA) states that if there is inconsistency between the “Agreement on an International Energy Program” (IEP) and Chapter 9 of the FTA, the provisions of the IEP shall prevail. Thus, for example, as a member of the International Energy Agency, Canada’s obligations to share oil in the event of a severe disruption in oil supplies would override the “proportionality” provisions of the FTA.

The FTA does allow for the export surplus test that governed Canadian gas exports from 1959 to 1986, but it would be subject to the proportionality requirement (Section 904 of the FTA; Section 605 of the NAFTA). That section is the most contentious of the energy sections of the Agreement. It reads as follows (FTA, p. 146):

Either Party may maintain or introduce a restriction otherwise justified under the provisions of Articles XI:2(a) and XX(g), (i) and (j) of the GATT with respect to the export of an energy good of the Party to the territory of the other Party, only if:

- (a) the restriction does not reduce the proportion of the total export shipments of a specific energy good made available to the other Party relative to the total supply of that good of the Party maintaining the restriction as compared to the proportion prevailing in the most recent 36-month period for which data are available prior to the imposition of the measure, or in such other representative period on which the Parties may agree;
- (b) the Party does not impose a higher price for exports of an energy good to the other Party than the price charged for such energy good when consumed domestically, by means of any measure such as licences, fees, taxation and minimum price requirements. The foregoing provision does not apply to a

- higher price which may result from a measure taken pursuant to subparagraph (a) that only restricts the volume of exports; and
- (c) the restriction does not require the disruption of normal channels of supply to the other Party or normal proportions among specific energy goods supplied to the other Party such as, for example, between crude oil and refined products and among different categories of crude oil and of refined products.

Total supply is defined in the FTA as “shipments to domestic users and foreign users from: (a) domestic production, (b) domestic inventory, and (c) other imports (as appropriate)” (FTA, p. 148).

The “as appropriate” determination of imports rests on location. For example, the Canadian maritime provinces rely solely on imported oil. An increase in demand in these provinces would increase imports and thus the potential exports of Canadian oil to the United States – this increase would not be “appropriate.” The ambiguous phrase “as appropriate” will spawn different interpretations.

The NAFTA is notable for its special treatment of Mexican energy industries, but it essentially carries forward the FTA provisions regarding trade in petroleum between Canada and the United States, but with a few modifications. For example, the “proportionality” requirements do not apply to Mexico and clause 603 prohibits maximum as well as minimum export and import prices. Article 609 of the NAFTA extends the definition of “energy regulatory measures” covered by the agreement to include those of “sub-federal entities,” including, for example, Alberta’s Energy Resources Conservation Board (ERCB). Plourde (1993, pp. 62–64) notes that the agreement, negotiated by the federal government, is not legally binding on provincial agencies; however, if the federal government cannot persuade a provincial body to eliminate any violation of a NAFTA provision, the federal government may have to provide compensation for the violation. Article 603 of the NAFTA also goes beyond the FTA in allowing export and import licensing schemes for energy products, so long as other provisions of the agreement are not violated. Such licences were not explicitly recognized by the FTA, although the NEB has utilized them for over three decades.

The FTA and NAFTA include, as well, (in section 11 of NAFTA) provisions respecting investment that require each party to the agreement to accord equal status in investment possibilities to other parties as

are given to domestic investors. This is most clearly set out in Article 1102 on ‘National Treatment’ (article 1602 in the FTA), which states:

1. Each Party shall accord to investors of another Party treatment no less favorable than that it accords, in like circumstances, to its own investors with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale or other disposition of investments.
2. Each Party shall accord to investments of investors of another Party treatment no less favorable than that it accords, in like circumstances, to investments of its own investors with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale or other disposition of investments.
3. The treatment accorded by a Party under paragraphs 1 and 2 means, with respect to a state or province, treatment no less favorable than the most favorable treatment accorded, in like circumstances, by that state or province to investors, and to investments of investors, of the Party of which it forms a part.
4. For greater certainty, no Party may:
 - (a) impose on an investor of another Party a requirement that a minimum level of equity in an enterprise in the territory of the Party be held by its nationals, other than nominal qualifying shares for directors or incorporators of corporations; or
 - (b) require an investor of another Party, by reason of its nationality, to sell or otherwise dispose of an investment in the territory of the Party.

There are some constraints on the applicability of the clause with respect to investment, including the exemption of Mexican energy industries (Annex 3 in NAFTA) and Article 1114 setting out the government’s right to maintain environmental, health, and social policies.

The FTA also included dispute resolution mechanisms, extended in a slightly stronger form in NAFTA, which provide more formal avenues of recourse to Canada and Mexico in dealing with their larger trading partner.

Up to 2012, no action has triggered NAFTA’s energy-dispute mechanisms or official interpretations

of any of the more controversial clauses with respect to oil and gas trade.

B. Implications of the Provisions

In the deregulated oil environment, the free trade agreements have had minimal impact. Their main effect is in the constraints they impose upon government actions that would involve a move back to regulations typical of the pre-1985 period. It makes the manipulation of markets by price controls more difficult, and it discourages any sort of policy discrimination. For example, oil export taxes are precluded. Plourde (1991) argues that government-enforced price discrimination to favour domestic over foreign consumers, as in the overt control period, would be prohibited. However, prices or subsidies could still be set by government fiat, for example, differentiating between sources of production, so long as the discrimination is not between foreign and domestic users. The provisions with respect to foreign investment close the door on policies that would favour Canadian companies over those from the United States. Roth (2009) argues, with respect to the oil sands royalty changes under discussion, and finally introduced, in 2007–2009, that the NAFTA foreign investment provisions may offer protection against government royalty changes to U.S. companies in Canada that are not available to domestic Canadian producers and would require compensation be paid to the foreign companies; however, as of 2012, no U.S. investors had sought compensation under NAFTA rules.

The “proportionality” clause has proved to be the most controversial feature of the free trade agreements, particularly for crude oil where both countries rely to a significant extent on unstable imports from off the continent. As noted above, this clause provided that if energy supplies were restricted to one of the countries for reasons of conservation, supply shortage, or price stabilization, then the share of available supplies for export purchase could not fall below the average export share over the previous three-year period. Critics have argued that this provision unduly constrains Canadian policy by limiting the country’s ability to protect its own citizens in the event of another international oil crisis or by inhibiting a policy change that attempted to retain Canadian petroleum for Canadian users in light of fears about the depletion of low-cost domestic deposits. (Laxer and Dillon, 2008, provide a strong statement of this position.)

Watkins and Waverman (1993) find that Canadian exports of oil and gas to the United States would likely have been substantially higher after the 1973 oil price shocks had the FTA been in effect. They also argue that such higher export volumes would have been beneficial, providing Canada with higher export revenues and increased petroleum industry activity and, perhaps, inhibiting to some extent OPEC price rises. It should be noted that the free trade agreements do not necessarily prohibit all schemes that might direct supplies from the export market to domestic users, but the regulations would have to be much more labyrinthine than the more obvious ones used in the overt control period, and the policies could not be obviously discriminatory. This is another way of saying, again, that the agreements have the effect of pushing the governments towards energy policies with relatively low levels of regulation.

It should be noted that the proportionality clause does not guarantee a country the same average volume of imports, or even the same share of the other country’s supply, as held in the previous thirty-six months; as noted before, the clause is invokable only under a specified set of circumstances. Moreover, it refers to “availability” or “access,” but the entire amount would not necessarily be purchased. If, for example, Canada relies upon higher prices to clear the oil market during a supply crisis, U.S. customers might well reduce their share of imports below the average of the previous three years. Where the proportionality clause would apply seems to relate to cases in which Canada undertakes measures that interfere with normal market decisions and which thereby restricted U.S. consumers’ ability to take delivery of Canadian energy for which they are willing to pay the going price. Laxer and Dillon (2008) give three examples in which Canadian government policies might trigger the proportionality clause: restricting production in Canada for conservation reasons; shipping oil further east for security reasons, and diverting natural gas to petrochemical feedstock use. From this perspective, the clause is less about guaranteeing fixed access by U.S. consumers to Canadian oil than it is a commitment on the part of the Canadian government not to introduce policies (such the Direct Control period price controls) that effectively set lower prices for Canadian consumers than those in the United States. Up to the spring of 2013, there has been no occasion for testing how the proportionality clause would operate. The agreements provide for consultation in the event of disputes between the countries.

The FTA and the NAFTA provide an important landmark in North American economic relationships. With respect to Canadian crude oil, there is still substantial room for specific federal or Canadian policies on a variety of issues, including regulations aimed at exploration and development, taxation, environmental policies, and the like. What is constrained is the ability to use export taxes, tariffs, or blatantly discriminatory ways of differentiating between Canadian and U.S. consumers. This is entirely consistent with the moves to deregulation taken in 1985.

6. Conclusion

We join most economists in being sceptical about the desirability of policies that interfere in the operation of competitive markets in determining the price of a commodity. Oil is an international good, and Canada is a small enough producer that we operate essentially as a price-taker for crude. That is, the world price sets the 'opportunity cost' of Canada's oil: it is the amount that we must pay for imported oil, and the amount we give up if we divert oil from export to domestic users.

If we hold the domestic price above the world price, as we did west of the Ottawa River Valley under the National Oil Policy from 1960 through 1972, we encourage under-consumption and overproduction. Should domestic prices be held below world prices, as from 1973 to 1985 including the National Energy Program, we generate over-consumption and under-production. Some have seen a reciprocal symmetry in these two periods, of equal length and with opposite effects: a period where oil consumers (the 'East') subsidized oil producers (the 'West') followed by a balancing period the other way around. However, our analysis suggests that the level of transfers were much higher in the second period, thereby offsetting the apparent symmetry. More fundamentally, there are ways to transfer funds between regions or individuals, if this is what is desired, that do not involve the inefficient allocation of a particular commodity.

Our view is that the NEP can best be understood in terms of what economists call 'rent-seeking.' Governments respond to the interests of certain subgroups of society by introducing programs that benefit them, albeit to the cost of other groups in society and with overall efficiency losses. Pressure for such policies

is often strongest when conditions are undergoing change – and significant adjustments in the world oil price are a major point of change for the petroleum industry. Moreover, it seems common in human nature that cries for action are loudest when the change generates losses. (People are happy to garner gains quietly. Moreover, losses seem to have more psychological impact than gains of equal size, a phenomenon often called 'loss aversion.' See Kahneman and Tversky, 1982, and Thaler, 1995.) Hence many North American oil-producing interests called out in the late 1950s when world oil prices fell, and consuming interests were more vocal in the early 1970s as OPEC prices rose.

There is one other undercurrent of thought that we find largely unconvincing. This is that conventional market mechanisms, including free trade, are inappropriate for a commodity such as oil. The arguments are rarely well formulated, and, in fact, often mix two somewhat different concerns. One is that of national security, tied to oil's crucial role in a modern industrial economy. However, we interpret energy security as an international issue and would argue that the market mechanism itself generated useful reallocation during the past four major international oil supply crises. The second argument is that market mechanisms fail to allocate depletable natural resources optimally. For example, this argument might say that it was inappropriate for Canada to export low-cost oil in the 1950s and 1960s at low prices, when it might have met Canadian needs (or earned higher export revenues) in the environment of high prices in the 1970s and 1980s. Our view is that oil companies do in fact operate in a forward-looking manner in order to maximize their profits (especially if certain common property problems are overcome; see Chapter Ten). Moreover, we see little evidence that governments are more prescient or effective than the private sector. For example, Ottawa and Alberta encouraged oil exports in the low price 1960s; during the high price years of the NEP, Ottawa discouraged exports; by the mid-1990s, when oil prices were much lower, policy was again in support of greater exports. The NEP avowed a goal of self-sufficiency but invoked price controls that encouraged more oil use and discouraged production.

From this point of view, the move to deregulation in 1985 and the commitment to free markets implied by the FTA and NAFTA were eminently sensible policies.

Government Controls on the Petroleum Industry: Oil Prorating

Readers' Guide: This chapter deals with a set of regulations used in Alberta and many other North American jurisdictions to offset harmful effects of the 'rule of capture,' a legal provision that says that the petroleum from a reservoir where access is shared by several producers is not owned until it is brought to the surface. Producers therefore have an incentive to lift the oil rapidly to capture it before their competitors do. As a result, the pool is not drained efficiently, and total recovery may be greatly reduced. The Government of Alberta adopted a variety of measures to control this problem, including minimum well-spacing regulations (to limit the number of wells drilled), 'unitization' incentives to encourage companies to join together and produce from the pool as a single unit, and market-demand prorating. The latter was a controversial approach through which the government estimated the consumption of oil from the province, and restricted total production to this volume, allocating ('prorating') it to individual producers. However, such regulations interfered with the normal operation of the oil market, and the specific manner in which output was prorated across oil companies could generate significant inefficiencies. This chapter focuses on market-demand prorating, with particular emphasis on the extent to which the regulations encouraged higher cost production methods within a reservoir than were necessary. Readers not interested in the fine details of the regulations may wish to read only sections 1 and 6.

1. Introduction

In the petroleum industry the word 'conservation' is used in two distinct ways. It may refer to the consumption side of the oil market, where it normally refers to accomplishing the same tasks with reduced use of petroleum. From an economic perspective, higher oil prices are an effective way to encourage such conservation. In this chapter, we discuss a major feature of 'conservation' on the production side of the petroleum market. Here the term has referred to a variety of regulations designed to improve the physical recovery of petroleum from underground reservoirs. Most of these relate to perceived 'externalities' in the market, where petroleum producers, in the absence of regulation, are not motivated to consider the entire impact that their activities have on others. Governments have imposed a variety of regulations designed to address such concerns. Many of these are not discussed in detail in this book, including such examples as requirements to re-inject natural gas into the reservoir (rather than flaring it); regulations on the use of water, and the disposal of water produced in conjunction with petroleum; rules to reduce the risks and safety hazards of well blowouts and spills including well abandonment procedures, etc. In the North American petroleum industry, common property rights within oil reservoirs (the rule of capture) have induced government authorities to regulate production by setting quotas for individual producers. This is called 'prorating,' and is a typical part of regulatory systems intended to promote conservation in the

sense of maximizing oil recovery and especially in the sense of protecting leaseholder's property rights.

Chapter Four of this book included a brief theoretical analysis of the rule of capture and crude oil prorationing regulations. It will be recalled that the rule of capture is a provision of the legal system, often inherited through British common law tradition. (Daintith, 2010, provides a detailed review, from a legal perspective of the acceptance of the rule of capture in the United States, and the various regulatory responses to it. Low, 2009, reviews the legal basis of the rule of capture in Canada.) The rule of capture credits ownership of a fugacious resource to the party that captures it, therefore implying that crude oil within a shared reservoir is unowned, that is common property to those producers with access to the reservoir. The implications of the rule of capture are particularly large for light and medium crude oil pools with good permeability since such crude may migrate quite readily from one part of the reservoir to another.

The nature of the land tenure system is important. In North America, the size of surface area plots leased or owned by oil producers tends to be small in relation to the areal extent of individual oil pools. Some analysts have associated this with what Daintith (2010) calls an 'accession' system, where mineral rights are held by surface rights owners and sold or leased by them, as was true for much of the prospective petroleum area of the continental United States; because of small surface holdings, or larger surface acreages being separated into smaller parcels of mineral rights, petroleum leases were typically much smaller than the oil pool. Daintith, however, notes that the same problem may arise with a 'domanial and regalian' legal system in which mineral rights are held in ownership by the monarch or state, if the state issues small acreage petroleum rights to private producers. Of course, the issue of protecting the property rights of the individual surface rights land owner, which played a major role in the United States, is not of concern under the domanial system since all the oil drained from the pool comes from the state-owned oil rights. (Alberta exhibits both legal systems, as the province holds ownership of mineral rights over most of the land area of the province, but some early private surface right land grants included mineral rights as well.) Within Alberta, as in the United States, most reservoirs have been shared. Companies therefore have been under strong pressure from the rule of capture to lift oil quickly, before the neighbours do likewise. The results, at pool and industry levels, are vastly different than might be expected if reservoirs were developed under

unitized conditions. Unitization occurs when producers sharing an oil pool cooperate to introduce a single petroleum authority for the pool, sharing jointly in costs and revenues. Individual producers are therefore unable to capture oil for themselves at the expense of other companies.

At the individual pool level, the rule of capture induces high levels of development investment, high initial output rates, and rapid production decline, often with reduced ultimate recovery from the pool. Such loss of reserves was the 'physical waste' that attracted early proposals for 'conservation' regulations in the crude oil industry. In addition, there was a desire to protect correlative property rights, in the sense of the mineral rights owners' reasonable claims to lift the petroleum to which they have access. (Daintith, 2010, chap. 7, provides discussion of the experience in the United States.)

At the industry level, the rule of capture tends to generate price instability. Rapid output increases from a new oil play, resulting from intensive development, drive the price down, especially with a very inelastic short-run demand for oil. A little later output will tend to fall as a result of high production decline in the pools in this play, and the decreased supply will push prices higher. Market prices will tend to fluctuate markedly as new oil plays succeed one another. This market price instability also led to calls for government regulation. (Daintith, 2010, chap. 9, provides an extended and valuable discussion of the regulatory response in the United States, from a legal point of view.)

Many observers of the crude oil industry called for compulsory unitization as a way to eliminate both the pool-specific and industry-wide effects of the rule of capture. While economists have generally been strongly inclined to favour unitization, it has been demonstrated that unitization may fail to be optimal from an economic point of view if reservoirs contain both oil and natural gas, with separate rights for the two products, and depending on how the agreements handle the inevitable uncertainties about reservoir characteristics and market developments (Libecap and Smith, 2002). Still, unitization has usually been favoured as a way to allow more efficient development of petroleum reservoirs. It may be asked why voluntary unitization was not common, since it would reduce, if not entirely eliminate, the inefficiencies suffered at the pool level by operators. This would be an illustration of the application of the famous Coase theorem (Coase, 1960). Coase argued that, in the absence of 'transactions costs,' private decision-makers

would be driven to negotiate agreements that maximize the net value of assets. The rationale for Coase's proposition is simple. Suppose that agreements have no costs of implementation, monitoring, or enforcement. Then a rearrangement of the use of an asset which generates aggregate additional benefits to participants greater than aggregate additional costs would allow all participants to move to a preferred position (i.e., experience a net gain); rational decision-makers would exploit all such opportunities.

How does the Coase theorem apply to the oil industry and to the rule of capture? Under the rule of capture, the present value lifetime profits from an oil reservoir are not maximized. Producers tend to ignore the user costs of depletion in their current output decisions. That is, they focus on immediate costs and revenues and do not give much weight to the future profit implications of today's production decision. Why leave crude oil in the ground for future profits if your neighbour is likely to capture the oil before you plan to produce it? However the economic waste of the rule of capture – the reduced net present value of the oil pool – could be avoided by an agreement amongst all producers to operate the pool as unit in the maximum profit manner, and all producers could be made better off.

This brings us back to the question: why were voluntary unitization agreements uncommon? Several explanations spring to mind. Some economists have suggested that decision-makers are not as rational as conventional thinking suggests and may tend to value changes in position quite differently depending whether they are 'framed' as 'gains' or 'losses' (e.g., Thaler, 1995). In particular, 'loss aversion' (also called the 'status quo' effect) is common, in which, even apart from risk aversion, decision-makers tend to put more weight on what is viewed as a loss than they do on an equal-sized gain. This could serve as a disincentive to sign a unitization agreement if the agreement is seen as a loss of current profits in return for a gain of future profits. Second, there are very significant transaction costs in negotiating a unit operation in an oil pool, especially if all producers and all landowners must voluntarily agree to sign. This was particularly significant in the United States, where there were typically many freehold land holders with a stake in the pool. Third, the presence of uncertainty – about the size of a pool and the dynamics of reservoir depletion – greatly complicates the agreement process (Libecap and Wiggins, 1984, 1985; Wiggins and Libecap, 1985). The essence of a unitization agreement is the shares in operation granted to

the various companies, and in the presence of uncertainty there may be genuine disagreement about what these shares should be. Further, reasonable estimates of reservoir size, pressure mechanisms and flow rates are not known until a number of years after the initial discovery. Will negotiation of a unitization agreement be delayed until this information is gathered? If so, are the companies who first drill into the pool to be denied production until this date, and, if not, what production rates will they be allowed? Fourth, since different companies enter the pool at different times, especially if it is a large deposit, the early entrants (and the landowners from whom they have purchased oil rights) have a strong interest to drill rapidly before other companies enter and before an agreement can be negotiated, and hence may believe that they will profit more under the rule of capture than through unitization. Also, some leaseholders tend to hold out for additional rewards to sign an agreement, which can bedevil negotiations. Finally, some parties have expressed fear that agreements might fall foul of combines (anti-monopoly) regulations.

As a result, in the United States voluntary unitization agreements tended to be restricted to pools that had few operators; the rule of capture held sway in most cases. Many observers called for compulsory unitization agreements, which were adopted in Saskatchewan. As Daintith (2010) discusses, the U.S. federal government can require unitization if operations are likely to damage reservoir recovery mechanisms in reservoirs on federal lands such as in offshore areas of the United States. A number of other North American jurisdictions, including Alberta, have similar regulations. However, the main government response to the rule of capture was to introduce market-demand prorationing.

Within North America, the first instance of proration of oil production by a public regulatory agency was in Oklahoma in 1915, but the most significant factor was probably its adoption by Texas in 1932 (Lovejoy and Homan, 1967; McDonald, 1971; Breen, 1993; Daintith, 2010). Proration of oil production by government regulation was introduced in Alberta in 1938, for the Turner Valley Pool, and remained in effect until the late 1980s.

Economists have frequently alleged that proration is inefficient, especially as practised in the United States (Adelman, 1964). The impact of proration on the economic efficiency of oil production in Alberta is analyzed in what follows (derived from Watkins 1971, 1977c). The empirical analysis is restricted to measurement at the 'intensive' margin, that is, within

oil reservoirs. Insufficient data exist to allow reliable estimation of the efficiency of prorationing at the 'extensive' margin, that is, in the allocation of provincial output among different oil pools.

An oil reservoir investment model is used to define theoretical optimum reservoir well spacing, subject to the regulation of production by proration in Alberta. Well spacing determines the number of wells in a reservoir, which constitutes the main cost of reservoir development.

Inter alia, the following issues are addressed. Have the proration schemes imposed in Alberta induced inefficient development and production? If so, is such inefficiency widespread or concentrated in relatively few reservoirs? If the latter, is there a dominant reservoir variable? Have operators been activated by profit maximization, within the constraints imposed by proration? Has the efficiency of proration been significantly affected by the types of proration plans adopted? Would full unitization have produced significant economies? And are the other regulatory paraphernalia, especially well spacing regulations, an important adjunct to proration? While not discussed in this study, the location of wells, in addition to the number of wells allowed in a pool (i.e., well spacing) is also important; in particular, provisions that specify a minimum distance for wells from the lease boundary reduce the impact of the rule of capture. In addition, Alberta has compulsory 'pooling' regulations that require producers with acreage holdings smaller than the minimum well spacing to be added to larger parcels, rather than drilling wells themselves (Low, 2008, p. 821). This reduces capture while assuring that the small producer obtains its share of oil production.

In what follows, the background to proration in Alberta is traced in Section 2. In particular, the three main schemes of proration employed are outlined: the 1950, 1957, and 1964 plans. The latter plan essentially governed production until the demise of market-demand proration in the late 1980s. For reasons that concern their nature, subsequent analytical attention is primarily directed towards the 1950 and 1957 plans, rather than the 1964 version.

Sections 3 and 4 parallel each other. The first parts of each section concern the theoretical framework. Then optimum patterns of reservoir development under the 1950 and 1957 proration plans are estimated. The optima measure incentives under proration itself by excluding the effect of external factors such as the land tenure system and well spacing regulation.

Estimates of diseconomies resulting from proration for the reservoirs analyzed in Sections 3 and 4

are made in Section 5. Analysis is undertaken both in relation to the actual well spacing patterns, which reflect many factors, including proration, and in relation to the theoretical optimum spacing values which exclude external influences. The significance of the results in relation to the 1964 plan is also discussed.

The main conclusions of the analysis are summarized in Section 6. Appendix 10.1 gives details on the oil reservoir development model employed.

2. Prorationing in Alberta

As outlined earlier, sustained growth of the Alberta oil industry commenced with the discovery of the Leduc field in 1947. Continuing substantial discoveries resulted in growing surplus capacity. By 1950, excess capacity in one large field alone, Redwater, amounted to some 84 per cent of total Alberta oil production. Of importance in the development of excess productive capacity were changes in provincial land regulations in July 1947, which discouraged concentration of reservoir ownership and stimulated intensive development well drilling, given the rule of capture.

In September 1950, the industry requested Alberta's Oil and Gas Conservation Board (OGCB) to administer a scheme of market-demand proration. Breen (1993) provides a detailed history of the OGCB from its beginnings in Turner Valley in 1932 through to 1962. The 1932 *Oil and Gas Conservation Act*, creating a Turner Valley Gas Conservation Board, was challenged in court by a small natural-gas-producing company and found unconstitutional. The 1938 *Oil and Gas Conservation Act* created a Petroleum and Natural Gas Conservation Board (PNGCB), an independent regulatory board with legislatively defined powers to regulate oil and gas production and to administer other provincial regulations on the industry. (See Breen, 1993, chaps. 2 and 3.) Section 8 of the act (S.A., 1938, chap. 15) gave the Board responsibility for:

- (a) preventing the exhaustion from a petroleum providing area of the energy necessary to produce petroleum by methods shown to be uneconomic ... to the end that the maximum alternate recovery of petroleum can be attained;
- (b) prorationing the production of petroleum or natural gas from the wells in any area to the economic markets available in such manner that an uneconomic reduction of price is not brought

about and in such a manner that an equitable share of the available market for petroleum or natural gas is available to each producing well.

Note that these guiding directions explicitly require conservation of “maximum ultimate recovery,” “economic markets” and the “uneconomic reduction of price” and an “equitable share” of markets. These principles remained in the board’s mandate, even as it evolved into the Oil and Gas Conservation Board (OGCB, 1957), the Energy Resources Conservation Board (ERCB, 1971), and the Energy and Utilities Board (EUB, 1995), before being transformed back to the ERCB in 2007. Amongst the board’s first orders in 1938 were prorationing regulations for both oil and gas in the Turner Valley field.

The board introduced a province-wide proration plan on December 1, 1950. Major changes to the plan were made in 1957 and 1964. The nature of the original plan (the 1950 plan) and the major changes to it are described below. Subsequently, the virtual elimination of excess production capacity in the 1980s made market-demand prorationing – but not other regulations – redundant. The Conservation Board has maintained a variety of other conservation regulations to govern oil and gas production practices. Minimum well spacing will be discussed further below. We also take as given the Maximum Permissive Rate (MPR) restrictions, which set a ceiling on well output rates based on technological factors and are designed to prevent undue damage to reservoir natural drive. Regulations restricting the flaring of associated gas and governing practices such as disposal of waste water, handling blowouts, abandoning and sealing wells, etc. are socially important but will not be discussed.

A. The 1950 Plan

The plan (Petroleum and Natural Gas Conservation Board, 1951; Breen 1993, pp. 289–317) assigned a fixed-variable production quota to each eligible well. The fixed portion, called an “economic” allowance, was graduated with well depth and was intended to compensate for the major costs of drilling and operating wells. The variable portion was calculated by allocating the remaining market demand (after satisfaction of all the economic allowances) in proportion to well productive capacity. The latter was represented mainly by the maximum permissive rate (MPR).

Symbolically, the production quota under the 1950 plan assigned to a well in reservoir j at time t was

$f_{t,j} = e_{a,j} + m_j AF_t$, where $f_{t,j}$ = well production quota, reservoir j , time t ; $e_{a,j}$ is the economic allowance for this well; m_j = well capacity (defined by well MPR), reservoir j ; AF_t = allocation factor. The numerator of the allocation factor was the market demand (V_t) less the provincial sum of economic allowances; the denominator was the total provincial well capacity at time t . Thus, $AF_t = (V_t - \sum e_a) / \sum m$.

By virtue of the economic allowance, the 1950 plan guaranteed the long-term and short-term profitability of any well capable of economic operation. This had important implications for reservoir development, as shown later.

B. The 1957 Plan

The first major change to the 1950 plan was announced by the OGCB on August 30, 1957 (Oil and Gas Conservation Board, 1957; see also Breen, 1993, chap. 7). Two main aspects of the 1950 plan were altered. The changes were made over a transition period, with full implementation by January 1, 1960.

First, the single economic allowance schedule was replaced by a two-tier system, involving an initial economic allowance for a seven-year period after initial pool development, subsequently replaced by a lower operating economic allowance. Both allowances remained graduated with well depth. The purpose of the two-tier system was to prevent indefinite continuance of an economic allowance that would allow multiple recovery of some investments, especially drilling costs. Second, the allocation factor (see above) was applied to the well’s MPR less its economic allowance, rather than to the MPR alone, as in the 1950 plan. This was called the residual MPR method.

Symbolically, the 1957 plan is represented as:

$$f_{t,j}(1,7) = e_i + (m_j - e_j)AF_t, f_{t,j}(8,n) = e_o + (m_j - e_o)AF_t$$

where e_i = initial economic allowance; e_o = operating economic allowance; and the other variables are as defined above, although the denominator of the allocation factor (AF_t) becomes total provincial capacity less total economic allowance ($\sum m - \sum e_a$). The brackets (1,7) and (8,n) following $f_{t,j}$ indicate the period in years after development of the pool that the formula applied; n is the reservoir life.

While the changes defining the 1957 plan are significant, nevertheless essentially they represent refinements to the 1950 plan. In contrast, the 1964 plan involved significant structural alternations.

C. The 1964 Plan

Extensive hearings were held by the OGCB in 1963 on virtually all aspects of the proration plan, and in mid-1964 the board outlined a new plan, for full implementation by 1969 (Oil and Gas Conservation Board, 1964b).

The two-tier economic allowance was abolished and replaced by a single and substantially reduced minimum allowance, which compensated only for operating costs and certain other recurring expenditures; it continued to be graduated with well depth. And it applied strictly as a 'floor,' not as an initial entitlement, as in the 1950 and 1957 plans.

Demand was to be allocated among reservoirs in proportion to reserves without reference to well capacity or the number of wells in a reservoir. Within reservoirs, demand was to be distributed in proportion to the acreage assigned to a well (well spacing), subject to minimum allowance.

Symbolically, the 1964 plan was: $f_{i,j} = [(a_w/A_{i,j})(u_{i,j} - c_{i,j})/2]AF_t$, or m_{aj} , whichever will be greater, where a_w = well spacing; $A_{i,j}$ = area of reservoir j , time t ; $u_{i,j}$ = ultimate reserves, reservoir j , time t ; $c_{i,j}$ = cumulative production, reservoir j , time t ; m_{aj} = well minimum allowance reservoir j . Ultimate reserves are remaining reserves plus cumulative production. The numerator of the allocation factor was simply the market demand V_t ; the denominator was the sum of the provincial ultimate reserves, u , less one-half total cumulative production, c (i.e., $\Sigma u - [\Sigma c/2]$).

Thus, the 1964 plan removed the guarantee of long-run well profitability inherent in the 1950 and 1957 plans but continued to assure short-run profitability.

The main concern of the analysis below is with the relation between proration and the development of individual reservoirs. The strong positive relationship between the number of wells drilled in a reservoir and reservoir quotas under the 1950 and 1957 plans is therefore of special importance. But under the 1964 plan well quotas were essentially independent of the number of wells in the reservoir. Consequently, in terms of impact on the intensity of reservoir investment, attention is concentrated on the 1950 and 1957 plans.

The analysis employs a reservoir investment model, which is outlined and discussed in Appendix 10.1. The main variable governing planned reservoir development is the number of wells. The model assumes the reservoir operator will maximize expected present value profits. The profit-maximizing criterion translates into one of maximizing present

value profit per acre, given uniform well spacing within each reservoir. The value of well spacing that maximizes present value profit per acre is designated s_j^* , the optimum spacing value for reservoir j .

D. The End of Prorationing

The expansion of markets for Alberta oil, falling reserves additions generating declining remaining reserves, and the ongoing depletion of pools discovered in the 1940s, 1950s, and 1960s gradually removed the need for stringent prorationing regulations. Increased knowledge about reservoir dynamics also led more companies to voluntary adoption of unitization agreements, a practice that may have been spurred by the Conservation Board's powers to force such agreements if necessary to increase the recovery of oil.

In the 1980s an increasing number of pools were put on "good production practise" (GPP) status and were exempt from market-demand proration and maximum rate limitations. Often these pools had been in production for many years so that output rates had naturally fallen below the MPR regulated level, and companies had little incentive to install new equipment. (The board could re-establish MPR limits if the pool's natural energy was unnecessarily damaged.) By 1990, some 75 per cent of Alberta oil reservoirs were GPP pools (ERCB, 1990).

With deregulation in 1985, light sweet oil exports to the United States became significant again. Output rose, spare production capacity dwindled, and the reserves to production ratio was low. Effective on June 1, 1987, the ERCB announced a six-month experiment to rescind market-demand-prorationing regulations and allow a market-oriented system to operate in which producers and buyers were free to negotiate agreements. The new system would be monitored, presumably to ensure that smaller producers were not frozen out of the market and that oil reservoirs were not damaged. Problems were, evidently, minimal as the new arrangement was made permanent in November 1987. By 1989, market-demand prorationing in Alberta was at an end, after thirty-seven years.

3. Optimum Well Spacing: The 1950 Alberta Proration Plan

This section briefly discusses incorporation of the formulas defining well production quotas under

the 1950 plan in the reservoir investment model (Watkins, 1971, 1977c). The model is then applied to the actual reservoirs developed under the 1950 plan to calculate optimum well spacing, given the regulatory constraints imposed by proration. The results are compared with the actual well spacing recorded for each reservoir.

A. Well Quota and Profit Functions

As shown above, the well quota for the 1950 plan was a function of a fixed “economic” allowance, well capacity (the MPR), and the allocation factor. Further specification of the quota function requires attribution of a functional form to the latter two elements.

An examination of values for the MPR and well spacing disclosed a linear relationship, but with different linear coefficients by reservoir. The choice of a functional form for the allocation factor was made on the basis of recorded expectations. A parabolic fit gave a close approximation. Moreover, a U-shaped curve was more consistent with then expected trends. Industry opinion in the mid-1950s generally anticipated an initial rate of growth in capacity exceeding that in demand; hence the allocation factor would fall. The relationship was expected to reverse as Alberta became more fully explored and opportunities for oil exports to the United States increased.

Insertion of the MPR and allocation factor relationships in the quota function permits specification of well production rates as well spacing (s) varies, subject to the constraint that cumulative well production not exceed its reserves. Inherent here are the assumptions that the well has the physical capability to produce the assigned level of production, that reservoirs are homogeneous, and that well spacing is independent of the allocation factor. The latter assumption is consistent with the reservoir investment model. Nevertheless, for a reservoir of exceptional areal extent (such as Pembina), dense spacing would result in the reservoir economic allowance being sufficient to significantly affect the allocation factor. However, other analysis suggested that AF_i was a relatively unimportant determinant of optimum spacing, s^* , and thus the assumption that AF_i is exogenous is not distortive. Reservoir profit functions are then derived by substituting the relevant reservoir quota function in the general present value profit per acre function given by Eq. (7) in the Appendix.

More specifically, the present value profit (PVP) per acre is evaluated for a feasible range of well spacing for any reservoir by iterative substitution in the

investment model (see Eq. (7) of Appendix). The well spacing value corresponding to the maximum value of PVP per acre then is ascertained. The reservoir life corresponding to the estimated s^* will indicate whether it is a reasonable solution in terms of industry time horizons.

The main features of the data employed are: the pools all had a developed area greater than 160 acres (smaller pools would tend to be developed by the reservoir delineation process itself); well and ancillary facility costs by pool were derived from cost-depth correlations based on industry data; an average royalty rate of 10 per cent was adopted, based on average royalties paid, 1950–56; an allowance for dry development wells was made by inflating estimated productive well costs by 8 per cent; and an 8 per cent discount factor based on recorded long-term bond yields, the typical petroleum industry financial structure (debt-equity ratios), and an allowance for risk.

B. Optimum Well Spacing, 1950 Plan

This section summarizes the results of calculations of optimum well spacing for seventy-five oil reservoirs that commenced production over the period 1950 to 1956.

It is emphasized that the optima are constrained and should not be confused with the optima that would apply in the absence of institutional and other restrictions. The main constraint, of course, is that production is set by the 1950 Proration Plan; other constraints are the assumptions underlying the reservoir model used. Moreover, the results are theoretical and do not necessarily represent a realistic choice for an operator. In practice, such a choice was limited by lease ownership divisions in a reservoir and other regulatory restrictions (as discussed below). The importance of the results lies in the broad indication they give of incentives inherent in the 1950 Proration Plan.

The crude mean optimum reservoir spacing value (s^*) was 147 acres, with a standard deviation of 212 acres and a range of 3 to 1,400 acres. With the exception of only one pool, all indicated reservoir lives were less than twenty-five years. The distribution of optimum spacing by reservoir was skewed towards the lower well spacing values.

The calculation of the crude mean gives each reservoir equal weight, regardless of size. If optimum well spacing values (s^*) were weighted by implied optimum number of wells (q^*), the resultant weighted mean optimum spacing fell to 101 acres, mainly reflecting

the increased weight of five pools with exceptionally small values of s^* ($q^* = \text{reservoir area } (A_j)/\text{optimum well spacing } (s_j^*)$).

A frequent criticism of the 1950 and 1957 Alberta proration plans was the encouragement they provided for close well spacing (defined as 80 acres or less). The range of optimum spacing computed clearly shows that under the 1950 plan for many pools this is not the case; the extent to which such encouragement existed depends on the properties of each individual reservoir.

More detailed analysis of the results by particular reservoir characteristics – such as shallow and deep, low and high reserve density – reveals that the dominant variable determining optimum well spacing under the 1950 plan was the reserve density (reserve per acre) of the reservoir. A high reserve density exerted a strong incentive towards very close spacing; conversely, for low reserve density, maximization of present value profits would be achieved by the adoption of relatively wide spacing. These relationships appeared to hold irrespective of the values for other determinants, for instance prices and depth. Recall that depth sets capital and operating costs and partly determines the rate of production (since the economic allowance was graduated with depth).

Tests of several of the assumptions underlying the analysis, including royalties, well productivity decline, and the discount rate, indicated that the main approximating assumptions underlying the analysis were satisfactory (Watkins 1971, p. 27).

C. Comparison of Theoretical and Actual Well Spacing, 1950 Plan

The main purpose here is to show the degree to which the theoretical well spacing was consistent with actual well spacing. In turn, this will indicate whether the theoretical analysis is reasonable.

As mentioned, the theoretical results assume complete freedom of choice of well spacing, while in reality an operator's choice was circumscribed in several ways. For example, minimum spacing levels and standard spacing patterns are set up by Alberta's Oil and Gas Conservation Board (OGCB). From 1950 to 1956, minimum spacing was 40 acres per well. Alternate spacing patterns were confined mainly to 80, 160, or 320 acres per well, with generally only one pattern prevailing in a reservoir. Alberta government land regulations provided an opportunity through surrender provisions, and subsequent resale of the petroleum rights, for competing operators to acquire acreage in a

new reservoir. The varied ownership interests within a reservoir tended to induce adoption of a spacing pattern that reflected the smallest area under lease. Also, well spacing choice might be constrained by the physical nature of the reservoir (for example, narrow irregularly contoured reservoirs or small reservoirs discourage wide spacing). The adoption of a forty-acre minimum well spacing standard by the OGCB seemed wide in relation to historical well spacing levels in the United States, where much of the Canadian petroleum industry experience, both regulatory and private, was garnered. This probably induced a tendency to adhere to the minimum permissible standard, rather than to venture to wider levels; such levels at one time were believed to inhibit efficient drainage of a pool. Thus the force of tradition should not be underestimated as a factor restraining an operator's choice of well spacing. Moreover, its impact would be accentuated by the division of lease ownership within a reservoir.

This background proves useful in comparing the estimated optimum well spacing levels under proration (s^*) with the corresponding actual well spacing recorded (s_a) for the seventy-five pools examined. Overall, the comparisons between theoretical and actual spacing showed that differences could be attributable to: the factors alluded to above, especially minimum spacing regulations and the division of lease ownership within reservoirs; variations between estimated and actual drilling costs; and inherent restraints placed on wider spacing by reservoirs small in area (Watkins, 1971, pp. 257–64). This result provides confidence in the theoretical method of analysis adopted to measure well spacing incentives under the 1950 plan. It is inferred that operators were motivated by profit maximization, within the constraints set by regulations and proration.

4. Optimum Well Spacing: The 1957 Alberta Proration Plan

This section essentially parallels Section 3 but deals with the 1957 plan. Assumptions and symbols in that section that apply equally here are not repeated.

A. Well Quota and Profit Functions

Similarly to the development of the 1950 plan well production formula, further analysis of the 1957 plan well quota function (see earlier) requires assignment

of a specific function form to the MPR and the allocation factor.

No changes were made to the MPR function itself under the 1957 plan, so, as before, the MPR is treated as a linear function of spacing. The selection of a suitable functional form for the allocation factor was predicated on both industry and government expectations of future trends as revealed by contemporary projections. The projections were found to be well represented by a linear function of time (in contrast with the earlier U-shaped curves).

The quota function may now be expanded to incorporate the assumed form of the MPR and allocation factor functions. As before, profit functions are developed for appropriate ranges of well spacing by inserting the quota function in the reservoir investment model (Appendix, Eq. (7)), after inclusion of the cumulative production-reserves constraint. The details are burdensome. The reader is referred to Watkins (1971). The earlier summary of the main aspects of the reservoir data applies equally to the 108 pools examined here. Based on 1957 to 1964 evidence, the values set for the three parameters common to all reservoirs were: average royalty rate, 10 per cent; dry development well allowance, 10 per cent; annual discount rate, 10 per cent.

B. Optimum Well Spacing, 1957 Plan

Optimum well spacing (s^*) was estimated for 108 reservoirs that commenced production over the period 1957 to 1964. The theoretical optima are those that obtain given the constraints on production set by the 1957 plan. The same caveats listed for the 1950 plan results apply here. The crude mean optimum spacing value was 240 acres per well, with a standard deviation of 294 acres and a wide range of 9 to 1,500 acres. If the optimum spacing values were weighted by the implied number of wells for each reservoir, the resultant weighted mean is 88 acres, considerably less than the unweighted value.

The range of theoretical optimum spacing indicates that criticism of the 1957 plan (Oil and Gas Conservation Board, 1964b) on the grounds that it encouraged the drilling of “unnecessary development wells” (i.e., relatively dense spacing) is not universally valid. For many pools, no incentive existed for dense spacing. Thus, as for the 1950 plan, the extent to which dense spacing was encouraged by the 1957 plan is clearly dependent on the particular physical and economic characteristics of an individual reservoir.

The more detailed analysis of the results by reservoir categories suggested that, in common with the 1950–56 group of pools, the key variable determining optimum well spacing was the reserve density of a pool.

C. Comparison of Theoretical and Actual Well Spacing, 1957 Plan

The results in Section 4.B assume an operator would not be subject to external constraints in exercising his choice of well spacing. In reality, the operator’s freedom was restricted, as discussed in Section 3.C. These restrictions apply equally to the 1957–64 period. But in 1957, minimum well spacing in roughly the eastern half of the province was increased to 80 acres (in the western half, 40 acres was retained). In 1962, a minimum well spacing of 160 acres was adopted for the entire province (for new oil reservoirs).

The analysis of actual (s_a) and optimum spacing (s^*) follows the same lines as for the 1950 plan. The conclusions were also the same. That is: spacing regulations, fragmentary ownership, data variations, and other factors accounted for significant variations between s_a and s^* , which in turn suggests the theoretical analysis is sound.

5. Efficiency of Production under Prorating in Alberta: Intensive Diseconomies

Our purpose here is to estimate by how much production costs under proration in Alberta exceeded those under a more efficient system. As mentioned earlier, the analysis is confined to the efficiency of the distribution of production within reservoirs (intensive diseconomies), rather than efficiency of the distribution of output among reservoirs (extensive diseconomies). Definitive measurement of the latter would require model simulation of the Alberta oil industry in the absence of proration. That daunting task is not attempted.

In what follows, first, intensive diseconomies are defined and discussed. Second, estimates are made of apparent actual diseconomies for the group of reservoirs examined in Sections 3 and 4. Next, diseconomies that would have been incurred had the reservoirs been developed on the hypothetical optimum spacing calculated in Sections 3 and 4 (hypothetical

diseconomies) are estimated. The implications of the hypothetical and actual results are also discussed.

A. Intensive Diseconomies

Intensive diseconomies are measured by comparing the production costs of output allocated by proration with the costs of producing the same volume of oil using the minimum number of wells necessary. The latter condition generally is achieved when reservoir lease ownership is not effectively divided and complete flexibility of production within a reservoir prevails, such as would hold under full unitization. Thus, the diseconomies estimated in the following sections approximate those resulting from proration compared with production under full unitization, assuming the distribution of production between reservoirs were fixed. (As discussed above, higher costs than would have been incurred had output been allocated differently between reservoirs is an 'extensive' diseconomy of prorating.)

Section 2 identified three proration plans: the 1950, 1957, and 1964 plans. The regulation of production within a reservoir under the 1964 plan tended to result in effective conditions within the reservoir, closely comparable to those under full unitization (Watkins, 1971). Under the 1964 plan, no incentive existed to install or maintain capacity in excess of allocated quotas, although inefficiencies might still result through the land tenure system itself, or through poor reservoir delineation. These latter factors are external to proration per se. It follows that the 1964 plan did not involve intensive diseconomies as defined beforehand: they are relevant only to pools developed under the 1950 and 1957 proration plans. It also follows that any estimated diseconomies may be interpreted as differences between reservoir output costs under the 1950 and 1957 plans and under the 1964 plan, since the suggestion is that any estimated inefficiency could have been largely eliminated had the provisions for the distribution of production within a pool under the 1964 plan been in force.

To estimate intensive diseconomies incurred under the 1950 and 1957 plans, a distinction is made between actual and hypothetical diseconomies. Actual diseconomies are estimated on the basis of the actual well production and capacity data available for the reservoirs examined. Hypothetical diseconomies are those that would have resulted from development of reservoirs under the theoretical optimum spacing

patterns dictated by the proration formula discussed in Sections 3 and 4.

The distinction is useful since it will indicate the degree to which actual diseconomies, which reflect the influence of proration and external constraints such as the land tenure system, are correlated with diseconomies that would result from development on theoretical optimum spacing under proration, from which external restrictions are excluded.

B. Actual Intensive Diseconomies

To estimate actual diseconomies, the same method was applied to both groups of reservoirs used in the analysis of the 1950 and 1957 plans, the 1950 to 1956 group and the 1957 to 1964 group.

In essence, actual intensive diseconomies were estimated by the difference between actual reservoir installed capacity and peak actual production (Watkins, 1971). Any such surplus capacity was translated into an implied number of surplus wells by division by average well capacity. In turn, the surplus wells were converted to estimated surplus capital and capitalized operating costs (assuming a thirty-six-year reservoir life).

On this basis, total surplus capital costs and capitalized operating costs for the 183 reservoirs examined were \$271 million. The significance of this number is indicated by translating the surplus investment it represents to an equivalent number of exploratory wells. About 2,500 extra exploratory wells could have been drilled (assuming \$100,000 per well, costs in dollars of the day): this is an increase of close to 40 per cent over the number actually drilled in Alberta over the 1950-64 period.

The majority of the estimated diseconomies are concentrated in a relatively small number of pools. For the 1950-56 group, total surplus capital costs in fifteen pools accounted for 85 per cent of the corresponding total for all seventy-five pools. The average ratio of required wells to actual wells was 84 per cent. However, this is heavily influenced by the high ratio of 98 per cent for the large Pembina reservoir, which accounts for approximately half of the required and actual wells; if Pembina were excluded, the average ratio becomes 71 per cent. The apparent efficient development of Pembina under proration, in an intensive sense, is significant. (Recall here our concern is with efficiency given a fixed distribution of output amongst reservoirs. If such output were allowed to

vary, to reduce extensive diseconomies, it would not necessarily follow that the degree and timing of the development of Pembina was efficient.)

For the 1957–64 group, eleven pools accounted for 84 per cent of total surplus well capital costs for all 108 pools. The average ratio of required to actual wells was 77 per cent.

For the combined period 1950 to 1964, the average ratio of required to actual wells was 82 per cent. Thus, on an average, about one development well in five drilled in the oil reservoirs discovered in Alberta over the period 1950 to 1964 was surplus, under the prevailing distribution of production among reservoirs.

In Section 5.A, reference was made to production within a reservoir under the 1964 plan being closely comparable to production under full unitization. Hence the results in this section indicate the potential savings available had the 1964 plan provisions been in effect during the period considered. The efficiency of proration, then, is significantly affected by the form of proration imposed.

C. Hypothetical Intensive Diseconomies

In Section 3, theoretical optimum well spacing given the constraints of the 1950 Proration Plan was estimated. An important question is the extent to which reservoir development under theoretical, optimum well spacing would have resulted in the installation of spare capacity. That is, to what extent would pursuit of maximum present value profit be consistent with the deliberate installation of excess capacity, given the proration formula in operation?

Such diseconomies are measured by first determining the peak level of output, called f_{max}^* , reached by a reservoir assuming it were developed under its computed optimum spacing, s^* . Efficient production requires wells to be produced at capacity. The latter is defined as the authorized capacity, the MPR. (While the MPR was a regulatory formula, it nevertheless is a reasonable representation of actual capacity.) If f_{max}^* were constrained by the MPR, no intensive diseconomies would be incurred by the choice of s^* as well spacing since the theoretical capacity of the wells drilled on optimum spacing would be utilized at some point in the reservoir's assumed life. However, if there were redundant capacity, theoretical diseconomies would occur.

For such reservoirs (that is, where the theoretical capacity, defined as the product of the number of

wells drilled on optimum spacing and the well MPR, exceeded f_{max}^*), the implication is that f_{max}^* would have been produced more efficiently by increasing well spacing and producing the resulting reduced number of wells at their MPR. If this wider spacing were designated s_{max} , a cost saving by developing a reservoir on the spacing s_{max} can be imputed. This is composed of two elements: capital and operating costs. The expression for capital costs is: $C_s = wA [(1/s^*) - (1/s_{max})]$, where C_s = capital cost saving, w = cost of well; s^* = theoretical optimum spacing under proration; s_{max} = efficient spacing; A = reservoir area. The capitalized operating cost saving, Y_s , between reservoir development on spacing s_{max} and s^* is: $Y_s = Ay [a_i n^*/s^* - (a_i n_m/s_{max})]$, where y = annual operating costs per well; i = discount rate; n^* = reservoir life under spacing s_{max} ; n_m = reservoir life under spacing s_{max} and a_i is the annuity factor, discount rate i . For detailed development of these formulae see Watkins (1971, pp. 325–30, 338–40).

As mentioned above, hypothetical surplus costs would only be incurred for those reservoirs where the well MPR exceeded the calculated maximum well output (i.e., $m > f_{max}$). Of the total of seventy-five reservoirs in the 1950–56 group, thirty-four fell in this category. Hypothetical diseconomies for these pools totalled \$464 million; similarly to the actual diseconomies, most were concentrated in a few pools: six pools accounted for 88 per cent. Hypothetical surplus costs were only relevant to twenty of the 108 reservoirs in the 1957–64 group; total hypothetical diseconomies amount to some \$179 million and were concentrated in a few reservoirs: four accounted for 83 per cent of estimated surplus well capital costs. The mix of pools in the 1957–64 group is of course different from the earlier group, which prevents proper comparison between the hypothetical results. Nevertheless, the lower figure for total diseconomies (\$179 million) compared with the 1950–56 group (\$464 million) is expected, having regard for the smaller total acreage of the 1957–64 group and the lower average reserves per acre.

The much higher total diseconomies under theoretical spacing compared with the estimated actual diseconomies mainly reflects the elimination of minimum spacing regulations in the theoretical analysis. This suggests that the minimum spacing levels imposed by the OGCB were important in negating incentives to install additional excess productive capacity in certain reservoirs. In the absence of such regulations, the economics of reservoir development under

the 1950 and 1957 proration plan formulae would have encouraged very close spacing in high reserve density reservoirs and substantial investment in redundant capacity.

6. Summary and Conclusions

A. Analysis of Prorationing in Alberta

The importance of the rule of capture in precipitating proration in 1950 is confirmed. The most significant aspect of the 1950 and 1957 Alberta proration plans was the attempt to guarantee long-run well profitability by the “economic” allowance. In contrast, the 1964 plan eliminated the former guarantee, although short-run well profitability was assured. Under the 1950 and 1957 plans, there was a close correspondence between the number of wells in a reservoir and the volume of production allocated to it. The 1964 plan severed this relationship. This is important because the number of wells is the most significant determinant of reservoir production costs.

Reservoir development incentives given proration have been appraised by constructing a simplified reservoir investment model. Theoretical optimum well spacing is defined as the value of well spacing that maximizes present value profit per acre. The theoretical values so determined measure the inherent influence of the proration formulae, since other constraints on the choice of well spacing, for instance regulatory restrictions, are excluded.

The calculation of optimum well spacing, given the control of production by proration, for the 183 largest reservoirs developed under the 1950 and 1957 plans shows that, while the distribution of optimum spacing by reservoir is skewed towards lower levels, the range is very wide. Thus the general proposition that the 1950 and 1957 plans of themselves encouraged inefficient well spacing is rejected. Instead, such inefficiency was found to depend on the characteristics of the individual reservoirs.

The analysis discloses that the dominant variable determining optimum well spacing for a given reservoir is its reserve density (reserves per acre). Both the 1950 and 1957 plans produced strong incentives towards very close spacing in reservoirs with high reserve densities.

A comparison of the theoretical results with actual well spacing values by reservoir showed broad consistency, after consideration of institutional limitations

on actual spacing and possible biases in the data used for the theoretical calculations. This suggests the theoretical analysis employed is sound and that operators were motivated by profit maximization within the constraints imposed by proration.

The extent of extensive diseconomies among different reservoirs has not been assessed but must have been significant. Production capacity was well above actual production throughout the 1950s and 1960s, with as much as half of capacity lying unused. Therefore, there was spare capacity in the more productive lower-cost pools while production took place in the higher-cost ones. However, without a very detailed and complex intertemporal aggregate oil supply model of the Alberta industry, incorporating stochastic elements in a reasonable manner, it is not possible to simulate how the exploration and development in the province might have proceeded under unitized conditions, so a reliable estimate of extensive diseconomies is not available.

For the same reason, it is not possible to tell with any precision the impact of prorationing on Alberta crude oil prices. In terms of direction of effect, the appearance of significant excess capacity beginning in the late 1940s suggests that prices were held higher than would otherwise have been the case – certainly higher than the rule of capture would have generated. The comparison with unitized conditions is less clear, although the rush of new discoveries after Leduc in 1947 would have put significant downward pressure on prices, likely pushing prices even lower than actually occurred in order to increase sales in markets reached by pipeline extensions and to attract even more distant markets. Lower prices, however, would tend to inhibit exploration and development, so that the timing and sequencing of discoveries and reservoir development would have been quite different under unitization from what was observed. It becomes problematic, therefore, to speculate on how different oil prices might have been in the 1960s.

The relative stability of crude prices under market-demand prorationing is also notable, with occasional changes in the 1947 through 1962 period, and a constant (nominal) price from then through to 1970. (See Table 6.2.) Market-demand prorationing tends to induce such price stability by transferring to the prorationing authorities the power to adjust production to meet demand at prevailing prices. Moreover, the rigidity of crude oil prices contrasts sharply with the day-to-day price volatility that has characterized Alberta crude oil markets since deregulation in 1985.

However, two main points of caution must attend any comparison of the historical level and stability of Alberta crude oil prices with a never-observed (counterfactual) history of prices under unitization. The first relates to market structure. In Chapter Six, we characterized the industry as one of oligopoly-oligopsony and such markets are frequently characterized by rigid prices. The uncertainty is whether prorationing simply sanctioned a pattern of rigid prices, which the industry would have attained anyway, or whether the existence of prorationing was what allowed the companies to behave in this way. Our inclination is to the latter hypothesis. This is consistent with the extreme instability in crude oil prices in the United States under the rule of capture in the years 1860 through 1930, prior to the introduction of market-demand prorationing, and the rigidity of prices after 1930 when market-demand prorationing by state governments become common. It is useful to consider two separate issues here, price stability and the extent to which the market was managed. It is clear that market-demand prorationing was successful in avoiding the extreme price instability that characterizes the rule of capture. Prorationing also seems to have limited output expansion by allowing the majors, in their role as purchasers of crude oil, to impose limits on the volumes of crude produced. Remember that refiners nominated volumes of oil they would buy, and the Conservation Board allocated this amount over potential producers. The interesting question is whether market expansion might have occurred more rapidly under unitization (without proration).

The second caution relates to conditions in the United States, which served as a major competitive interface for Alberta crude from 1947 on. Here oil prices were also affected by government regulations, particularly market-demand prorationing in the main oil-producing states and (after 1959) the oil import quota scheme. The relative stability of U.S. oil prices would have reflected back to Alberta even in the absence of market-demand prorationing in the province. Moreover, lower prices for Alberta oil would probably not have generated significantly higher sales in the United States, given U.S. concern about the level of oil imports.

As was argued in Chapter Four, Alberta is a relatively small player in the international petroleum industry and produces significantly less oil than the United States; hence the oil price effects of prorationing in Alberta were probably relatively minor, linked to minor adjustments in the competitive interface for Alberta oil. However, the price effects in

North America, and in the international market prior to the mid-1950s, of market-demand prorationing in all North American jurisdictions combined, were significant.

B. Efficiency of Prorationing in Alberta

Assessment of the economic efficiency of a government regulatory program such as market-demand prorationing requires that the activities under the program be compared to what would have occurred in its absence. In the case of prorationing, there is some ambiguity as two quite different states of the world suggest themselves as alternatives: one in which the rule of capture operated freely and a second in which reservoirs were unitized. Prorationing in combination with other regulations (in particular minimum well spacing) clearly reduced the overinvestment and price instability associated with the rule of capture. However, economists have long argued that prorationing fails to internalize the real externality associated with the rule of capture, that is, the lack of clearly defined property rights over the oil in the ground (Adelman, 1964; Lovejoy and Homan, 1967). One criterion of economic efficiency that we have utilized in our comparison of market-demand prorationing to unitized conditions is that of cost minimization: clearly economic efficiency requires that oil be produced in a least-cost manner.

Our formal quantitative analysis concentrated on efficiency in relation to a fixed distribution of output between reservoirs (intensive efficiency). This is an important restriction because it excludes the measurement of efficiency for varying output configurations, such as might arise if minimization of the cost of a given level of total provincial production was sought (extensive efficiency). Thus, the numerical estimate of total diseconomies represents a minimum level.

1. Extensive Diseconomies

As mentioned beforehand, we have no basis for estimating how much higher total inefficiencies were, once extensive diseconomies are included. Diseconomies are the incremental costs of producing crude under prorationing, as opposed to effective unitization. Extensive diseconomies would occur as a result of developing and operating higher-cost projects (e.g., small pools, deep pools, low-productivity pools, high-cost EOR schemes) when low-cost projects (e.g., large, high-productivity, high-permeability pools)

are restricted by prorationing. Whereas the intensive diseconomies involve incremental costs of developing specific pools, the extensive diseconomies involve different costs among pools.

There is reason to suppose that the extensive diseconomies were significant. In particular, as has been noted elsewhere in this chapter, many of the large, productive pools operated at a small portion of installed capacity during the 1950s and 1960s. At the same time, many small less-productive pools were guaranteed output by prorationing. Discovery allowances, and high allowances to cover investment costs under the 1950 and 1957 schemes, made exploration for and development of such small reservoirs economically attractive. It would have been more efficient to draw more heavily upon the lower-cost pools before undertaking expenditures on higher-cost pools, though uncertainty in exploration makes a strict scheduling of pools in ascending order of cost impossible to achieve.

As discussed above, there are insufficient data to allow a reasonable estimate of the size of these external diseconomies. Detailed pool-by-pool cost estimates are not readily available. More seriously, it would be necessary to simulate the history of the Alberta crude oil industry under unitization, including the evolution of market prices and the sequence of discoveries, in order to compare the costs of this hypothetical history with what actually occurred. This implies a large-scale optimization model of the industry, and such a model does not exist.

2. Intensive Diseconomies

Realized intensive diseconomies were measured by comparing production costs for peak reservoir output under proration with the estimated minimum costs of producing the same output. The comparison indicates that, for the 183 reservoirs examined, on average, about one in five of the actual development wells drilled was superfluous. Total actual intensive diseconomies incurred under the 1950 and 1957 proration plans were estimated as \$271 million (without adjustment); the majority was located in relatively few pools. These diseconomies reflect, not only proration itself, but all other institutional factors affecting reservoir development and production, for example, minimum well spacing regulations and the land tenure system. They approximate the savings realizable if a regime of compulsory unitization had been imposed.

No inherent incentive for installation of surplus productive capacity within reservoirs existed under

the 1964 plan, and hence the estimates of diseconomies also indicate the potential for savings had the provisions of this plan for the distribution of production with reservoirs been in effect from 1950 onward. A further conclusion is that the efficiency of proration is fundamentally affected by the form it takes.

If the same 183 reservoirs had been developed on the calculated optimum well spacing under the 1950 and 1957 proration plans, total intensive diseconomies would have been some \$643 million, considerably higher than the estimate of actual diseconomies. The difference between the hypothetical results, which assume no restriction on choice of spacing, and the actual diseconomies suggests that the imposition of minimum well spacing regulations played an important role in preventing inefficiency, especially in reservoirs of high reserve density. It illustrates the way in which one set of rules may need bolstering by another: regulations breed.

Since full implementation of the 1964 proration plan in 1969, the kinds of inefficiencies cited above largely disappeared. Some changes were made to the plan in the 1970s, but they were not structural. Thus in large measure the provisions of the 1964 plan remained in effect until the absorption of spare oil production capacity made prorationing redundant in the late 1980s.

3. Market Equilibrium

Under prorationing, Alberta crude oil prices were relatively stable, exhibiting none of the wasteful price instability expected under the rule of capture. In fact, it can be argued that prices were too stable under prorationing, thereby interfering with the efficient market signals expected under unitization without government production limits. As suggested above, one would have anticipated somewhat greater price movement in response to underlying changes in demand and supply than was in fact observed in the 1950s and 1960s. The flurry of discoveries following Leduc would normally have pushed prices even lower than was seen in the 1950s, the lower prices serving both to encourage greater consumption in the markets for Alberta oil and to discourage further supply increases until prices had risen again. This suggests a different timing of industry expenditures, with some of the exploration and development expenses occurring later than actually occurred. Society would benefit because the present value of expenses in the crude oil industry would be less (due both to delay and any cost-saving technological advances).

Three counterarguments, not necessarily independent of one another, can be raised against these criticisms of market-demand prorationing's impact upon the price of oil.

The first counterargument questions the desirability of a reliance on free markets for crude oil, even if oil pools were unitized. If individual producers fail to anticipate future market conditions in a rational manner, then a unitized oil market might still tend to generate unnecessarily large cycles of price and output; these would be similar to, though not necessarily as extreme as, those under the rule of capture. If regulatory authorities are better able to foresee future market conditions, they might utilize a regulatory device such as market-demand prorationing to reduce price variability. Of course, one would have to balance the administrative costs and inefficiencies of prorationing against the benefits of greater price stability.

Many economists are unconvinced by the basic premises of this argument. They are sceptical that governments can read the future of markets better than participants in the industry and that current investment and production decisions are based on irrational forecasts of the future. The idea of 'rational expectations' in economics does not say that forecasts are correct, since there is inescapable uncertainty about what is going to happen. It says that rational forecasts make full use of available information so that any deviation between what actually occurs and what was expected is random error. The status of rational expectations in complex macroeconomic systems is very controversial; it is more readily accepted by economists in the somewhat simpler microeconomic environment of markets for individual products.

The key issue is the effectiveness of profit maximization by producers. Somewhat more formally, utilizing the conceptual apparatus of Chapter Four, the question is whether producers make due allowance for the 'user costs' of oil production. Thus, for example, economic theory suggests, not only that lower prices today inhibit investment and production today, but that the anticipation of these lower prices in earlier periods will have inhibited investment in those earlier periods. We find it hard to believe that most of the industry's investors, certainly the successful ones, are persistently myopic, and so much so that government controls on production levels would be justified. Despite this scepticism, three issues deserve further empirical analysis.

One is the suggestion that industry investment is driven more by the desire to generate immediate or early cash flow than by profit maximization. For

example, even though present value profits might be greater if the company sat on its mineral rights for several years before investing, the desire for faster, earlier returns might stimulate immediate investment. This suggests a bias by the industry towards overinvestment and rapid depletion of oil pools, even under unitized conditions. We are, as noted, sceptical about the significance of this argument, but know little empirical work that addresses it.

A related issue that has received little quantitative analysis is the extent to which various government regulations may push companies to invest earlier than they might wish to do so if they were unconstrained in their pursuit of maximum profits. For example, Crown mineral rights must often be drilled on within several years or automatically transferred back to the government.

Another dimension relates to the efficiency of corporate decision-making tools. Most companies do rely heavily upon investment criteria that emphasize profit maximization. This would include both the net present value and the internal rate of return (discounted cash flow rate or 'hurdle' rate) criterion. (See, for example, Van Meurs, 1970, or McCray, 1975.) However, it is not clear that the application of these criteria adequately allow for uncertainty about the future. It is common to handle such uncertainty using a single value for uncertain variables. Sometimes the decision-maker may simply say "we don't know what the future will bring, so let's use today's value." In this case, decision-making will tend to be myopic in the sense that it lags behind any persistent trends. This view has a long history amongst oil analysts. For example, Frank (1966) suggested that the oil industry is inherently unstable in part because of cycles of over- and underinvestment, which have ongoing price effects. Many economists found Adelman's (1972) counterarguments convincing, that the industry tends to be inherently stable (if the rule of capture is offset) because, in part, of the forward-looking nature of the investment decision. In this case, decision-makers do not automatically utilize today's value. The value selected may be a different expected value (for example, a probability weighted average of future values that are seen as possible). However, the net present value calculated using the single certainty equivalent number will be an inaccurate measure of expected profit unless net present value (profit) is a linear function of various values of the uncertain variable (MacFadyen, 1988). It has also been argued that there are a number of cognitive biases that are common in processing information about uncertain

situations (Kahneman et al., 1982). More recently, it has been suggested that conventional net present value techniques tend to be biased in favour of current investment over delay. At its most basic level, this would reflect a tendency to assess a current investment project on a “yes or no” basis, without explicitly comparing it to a delay option. At a more complex level, it has been argued (Dixit and Pindyck, 1994) that current investment involves a cost in the form of a foregone ‘option value,’ which net present value techniques typically ignore. For example, if one is uncertain whether next period’s price will be high or low, delay of investment gives one the option of investing or not depending on the price level actually observed; investing today means that this option is foregone.

On balance, in the absence of any strong empirical evidence, we remain unconvinced that an effectively competitive unitized oil industry would involve severely biased investment and production decisions. Even if it were demonstrated, we would need to be persuaded that the government could do better, and even then, market-demand prorationing does not suggest itself as an appropriate regulatory program.

A second argument in support of market-demand prorationing relies on ‘second-best’ considerations. In particular, it notes that Alberta in 1950 was facing a petroleum market where U.S. oil provided the main competition and also potential markets. However, market-demand prorationing, with all its inefficiencies, was in place in a number of the main producing states, and it was becoming increasingly clear during the 1950s that there were limits on the willingness of the U.S. government to tolerate higher oil imports. Moreover, we have noted the oligopoly/oligopsony nature of Canadian oil markets. Alberta oil, therefore, was not entering an effectively competitive free market. The theory of second-best implies that a program which would be inefficient in a ‘first-best’ (i.e., perfectly competitive) world may not be so in a ‘second-best’ world. A plausible line of argument would note that Alberta oil prices would necessarily be tied to prices in watershed markets and that reliance on an unregulated private sector to sell under these conditions was undesirable because the oligopolistic major oil companies would have favoured their crude-oil-producing affiliates over the independents. Prorationing did ensure that all producers were allowed to produce. However, it has not been demonstrated, so far as we know, that it was optimal to extend the market for Alberta oil to Toronto and no further. Moreover, this line of argument provides no

support for the intensive and extensive diseconomies generated by prorationing.

A third line of argument may, however, supplement the second. It is a close cousin of the ‘optimal tariff’ argument, which suggests that a country selling an export good may gain (in the absence of retaliation) by imposing a tariff, effectively exercising market power to raise the price of the good and gain more revenue. The price-increasing effects of market-demand prorationing may, therefore, have been inefficient from a global or even total Canadian perspective, but they may have been beneficial to Alberta, particularly to the extent that the provincial government gained through higher royalty and bonus bid revenues. (However, higher production costs, endemic to prorationing, would tend to reduce bonus bids.) Once again, however, this argument offers no justification for the specific regulations under the 1950 and 1957 plans, which generated large intensive diseconomies. And a price support – output allocation program like market-demand prorationing seems destined to involve external diseconomies by failing to ensure that only the lowest-cost oil is produced.

C. Conclusion

The rule of capture induces rapid, and inefficient, exploitation of a region’s crude oil resource base. The Alberta Government and oil industry were well aware of this. With the rush of new discoveries after the 1947 Leduc find, the government moved (in 1950) to adopt the regulatory response most common in the United States – market-demand prorationing. (Daintith, 2010, chap. 13, provides a valuable review of the rule of capture and assorted responses to it.) Alberta’s regulations were in place until 1989. The effects were major.

One effect of market-demand prorationing in North America was to eliminate the market price instability that had been so pronounced under the rule of capture. The Alberta scheme fitted into a North American oil market in which crude prices were already much stabilized by prorationing in the major U.S. producing states. The Alberta regulations did, however, significantly reduce the flexibility with which Alberta oil interacted with the rest of the continental crude oil market. The details of these interactions have been discussed in Chapters Six and Nine of this book.

Proponents of market-demand prorationing would argue that it allowed an orderly expansion of Alberta crude into more distant markets and ensured

that all producers, even the smallest independent, was ensured a portion of that market (i.e., it did act to protect correlative property rights), and satisfied notions of equity that embraced the opportunity to produce from any reservoir. Critics of the scheme might accept the argument, in part but would go on to argue that market-demand prorationing had major disadvantages relative to compulsory unitization as a way of controlling the excess of the rule of capture. In particular, it may have blunted the forces of market adjustment, thereby restricting the ability of both buyers and sellers to respond to changing circumstances. In particular, it inhibited the full price decline and market expansion that the discoveries of the 1940s and 1950s warranted. Perhaps more significantly, the somewhat higher prices and, especially, the guaranteed-production, served as an incentive to continued exploration and development when the Alberta industry was operating at less than 50 per cent of productive capacity.

Expressed in other terms, as a result of market-demand prorationing, the industry incurred significantly higher costs than were necessary. This channelled resources into the crude oil industry that society might have utilized beneficially elsewhere. The higher costs involved both external diseconomies (use of oil from higher-cost pools when lower-cost

pools had unproduced oil available) and internal diseconomies (higher incremental and operating costs within pools than was necessary). The size of the external economies has not been estimated. The internal diseconomies relate to specific regulations in the 1950 and 1957 prorationing schemes that encouraged excess development in oil pools. The 1964 regulations removed these incentives. The external/internal diseconomies were large.

Therefore we conclude that prorationing was beneficial in offsetting the worst effects of the rule of capture but that there were significant inefficiencies attendant to the Alberta market-demand prorationing regulations compared to the option of compulsory unitization. The inefficiencies potential in the prorationing regulations, compared to unitization, were offset in part, but only in part, by well-spacing regulations. Since the rule of capture is in effect in Alberta, the end of market-demand prorationing in 1989 left control of the negative effects of the rule to voluntary unitization and to other regulations, such as minimum well-spacing, well location regulations, pooling regulations and the authority of the ERCB to order maximum output levels ('rateable take') if one party can demonstrate reduced recovery due to the rule of capture (Low, 2009, Section 5, D).

Appendix 10.1: A Reservoir Investment Model under Proration in Alberta

Reservoir development and production costs are primarily a function of wells drilled (well density): in Alberta, a representative figure for development drilling costs would be about two-thirds of reservoir development expenditures. Hence well spacing is of fundamental importance. Fuller treatment of the following model to estimate the effects of prorationing can be found in Watkins (1971).

It is assumed that:

- (i) each reservoir is sufficiently small in relation to the industry that its development plan would not affect factor prices;
- (ii) the reservoir produces no gas,
- (iii) the reservoir is under unified ownership,
- (iv) the purpose of the reservoir owner(s) is to maximize present value pre-tax profit from the mineral rights it holds in the reservoir.

It is only for exceptionally large reservoirs in terms of area (e.g., Pembina) that the first assumption would not hold. The second assumption is not stringent: gas production could be easily accommodated in the reservoir model. The third assumption is necessary to measure well spacing incentives under proration independently of the effect of the land tenure system. The pre-tax specification in assumption (iv) acknowledges the complexities of petroleum taxation and is justified also for consistent treatment of reservoirs owned by different companies.

Given these assumptions, the reservoir operator will attempt to ascertain a schedule of production that would maximize present value profits:

$$MaxP_j = \max \int_0^{n_j} (R_{t,j} - C_{t,j}) D_t dt \quad (1)$$

where:

- P_j = present value profits, reservoir j ,
- $R_{t,j}$ = expected revenue function at time t , reservoir j ,
- $C_{t,j}$ = expected cost function at time t , reservoir j ,
- n_j = expected production life function, reservoir j ,
- D_t = expected discount function, time t .

Each function is discussed below.

The Revenue Function

Expected revenue at time t is the product of expected price, net of royalties, and the rate of production. Oil royalties in Alberta were, up to a certain level of production, rate-of-production sensitive. However, for simplicity, royalties were expressed as a fixed proportion of unit price, and the sensitivity of results to this assumption was tested. Historically, beyond 1952, no general price trends were apparent in Alberta. Hence the expected price of Alberta crude oil for each reservoir was treated as a constant, although such prices varied by reservoir. Also, the extant price structure was assumed to accommodate fluctuations in production from a reservoir. In short, the producer is presumed to be a price taker. Given proration, this assumption is entirely reasonable.

Under proration, well production was prescribed by the proration formulas outlined in Section 2, subject to maximum rate limitations mainly defined by the maximum permissive rate (MPR), designated for a well in reservoir j as m_j .

If a single well spacing pattern prevailed in the reservoir, and if the number of productive wells were q_j at time t , the level of reservoir output, $f_{t,j}$, would be defined as:

$$f_{t,j} = q_{t,j}f(t) \quad (2)$$

where $f(t)$, the rate of well production, is the lesser of the prorated quota or the MPR. (The presumption that spacing is uniform in a reservoir is compatible with controls exercised by the OGC. Few reservoirs were developed on more than one spacing pattern.)

Equation (2) assumes the maximum rate of production and the well production quota would be sufficient to specify the level of well production. However, oil reservoirs are generally characterized by declining

well productivity as the reservoir is depleted, given constant technology. It is unlikely the omission of decline rates will result in significant error when production is prorated because the impact of productivity decline is experienced primarily when the reservoir is produced at capacity while proration fundamentally assumes the existence of excess capacity. Productivity decline does not affect well production rates until productivity falls below production quotas: these conditions tend to be confined to the later stages of a reservoir's life. (For confirmation of these points, see Muskat, 1949. Nevertheless, the sensitivity of the results to the incorporation of productivity declines was tested.)

In summary, the revenue function for reservoir j is

$$R_{t,j} = p_j f_{t,j} \quad (3)$$

where p_j is net of royalty and $f_{t,j}$ is given by Eq. (2).

The Cost Function

The cost function comprises productive development well costs, dry development well costs, ancillary facilities, and operating costs. A simplifying assumption is made that all investment expenditures are incurred in the first year of reservoir development (year zero). This is reasonable for small reservoirs but questionable for reservoirs large in area. However, in terms of present value profits, the effect of concentrating development in period zero is to some extent offset by the corresponding assumption that full production commences in period one. Productive development well costs are the product of the number of productive wells (q_j) and the average costs of drilling and completing a well. Dry development wells are impossible to anticipate precisely, but their historical frequency in relation to productive wells is known. A dry development well costs less than a productive well. Hence, dry hole costs are represented by the product of the cost of productive development wells, the ratio of dry development wells to productive wells, and the ratio of the costs of a dry development well to productive well.

Detailed data that would permit proper analysis of expenditures on ancillary (above-ground) reservoir facilities were not available. The variable to which ancillary investments is most obviously related is the number of productive wells (q_j); it remains the best variable with which to approximate ancillary facilities, and thus these costs are the product of the number of wells and ancillary costs per well. Ancillary facilities

are a minor proportion of typical reservoir costs, which limits the significance of any specification error.

Well operating costs tend to be insensitive to the rate of production and are incurred over the life time of the well. No Alberta data for examining trends in operating costs over time were readily available, but data were available linking operating costs to reservoir depth. Hence, operating costs at time t were the product of the number wells (q_j) and average annual costs per well.

In summary, the costs function is:

$$\begin{aligned} C_{tj} &= q_j(w_j(1 + b_1b_2) + a_w) t = 0, \\ &= q_jy_j t = 1, 2, \dots, n, \end{aligned} \quad (4)$$

where:

- w_j = drilling and completion costs of productive well, reservoir j ,
- b_1 = ratio of dry developments wells to productive wells,
- b_2 = ratio of cost of dry development well to productive well,
- a_w = ancillary costs per well,
- y_j = annual well operating costs, reservoir j .

Reservoir Life and Discount Rate Functions

The reserves of oil in a reservoir (r_j) are assumed to be distributed uniformly over its area, an assumption made by many engineering analyses. Since it is presumed that maximum production rate regulations apply, recoverable reserves are not affected by the rate of production and therefore r_j is constant for each reservoir.

Thus, the reservoir life function, n_j , may be determined from the expression:

$$r_j = \int_0^{n_j} f_{tj} dt \quad (5)$$

In practice, some limitation on industry's time horizons is normal: twenty-five years is frequently used.

The discount rate, i , is assumed to be fixed over time for any one reservoir. This acknowledges

difficulties in forecasting discount rates and reflects general industry practice in Alberta.

An additional assumption, mainly for mathematical convenience, is that discount rates are continuous. Thus the discount function is:

$$D_t = e^{-it}. \quad (6)$$

Optimization under Proration

Equations (3) to (6) now may be inserted in Eq. (1) to give:

$$P_j = \int_0^{n_j} (p_j f_{tj} - q_j y_j) e^{-it} dt - q_j (w_j (1 + b_1 b_2) + a_w). \quad (7)$$

This, then, is the function the operator should seek to maximize in planning reservoir development. Expression (7) is simplified. The general problem of optimum reservoir development is very complex. For example, see Goodnight et al. (1970), and Miller and Dyes (1959).

The main variable on which choice is exercised in planning reservoir development is the number of wells. With uniform well spacing prevailing in any one reservoir, this choice may be translated into one of well spacing. Thus, given constant reserves per acre, optimum profitability will be achieved by the well spacing value that will maximize present value profit per acre. Thus, the value of spacing, s_j , which will maximize P_j/A_j for reservoir j is sought, where:

$$\begin{aligned} P_j &= \text{present value profit, reservoir } j, \\ A_j &= \text{acreage, reservoir } j, \end{aligned}$$

and the required reservoir parameters for the calculation of P_j are given. This value of s_j is designated s_j^* , the optimum spacing value for reservoir j . Although given a sufficient production life, a reservoir could be drained by only a few wells (Craze and Granville, 1955), minimum market requirements, and facility capacities, for instance, pipeline throughputs, and normal time horizons impose a practical limitation on well spacing width.

CHAPTER ELEVEN

Economic Rent and Fiscal Regimes

Readers' Guide: Nowhere are the petropolitical dimensions of the petroleum industry more pronounced than in the area of rent sharing. Because of depletable and the heterogeneity in the quality of petroleum deposits, plus periods of high international prices due to the exercise of oligopoly power, many oil and gas reservoirs earn revenues far in excess of necessary production costs. Governments have a number of reasons to feel they have a special claim on the resultant profits (economic rent), most frequently because the natural resource is regarded as the property of the populace in the region, and also for ability to pay reasons since the economic rent is a surplus in excess of what private parties require in order to produce the petroleum. However, it difficult to devise a method of sharing the economic rent that yields a high share to the government but has minimal effects on the activity of the petroleum industry. This chapter reviews the mechanisms used to transfer economic rent from the Alberta crude oil industry to Canadian governments, with special emphasis on the problems arising in a federal state where two levels of government may feel that they each have a claim on the economic rent.

1. Introduction

This chapter deals with fiscal measures affecting the Alberta petroleum industry, covering all types of payments by the industry to government, including taxes, rentals, royalties and bonus bids. Emphasis is

on conventional crude oil, although, as will be seen, many of the measures affected other aspects of the petroleum industry. (Chapter Seven looked at aspects particular to the oil sands, and Chapter Twelve does the same for natural gas.) The issue is complex. In part this reflects the constitutional realities that played such an important part in our discussion of pricing: both provincial and federal governments have legitimate taxation powers. Within this framework, taxes may be imposed by governments for many reasons. Broadly, a tax may aim to change industry behaviour, or it may try to generate revenue with as little impact on behaviour as possible. In this chapter we shall assume that the latter purpose ('neutrality') predominates. Petroleum taxation is important because the industry is expected to generate significant profits beyond normal levels. In natural resource industries, such profits are frequently called 'economic rents'. A significant proportion of the fiscal burden on the petroleum industry reflects the claims that government may make on these economic rents as the primary resource owner. However, monies paid to governments in their role of resource owner differ from those paid as general taxes by all businesses.

Three main sections follow. The first is conceptual, on the taxation interests of government (especially the province), the meaning of the term 'economic rent' and some of the different forms of 'rent collection' (taxation or 'fiscal take'). The second presents an historical review of the main rent-collection measures of the Alberta provincial government, while the third looks at federal government tax policies. Our attention is on provincial Crown land, rather than the relatively small areas of freehold mineral rights and federal

Crown land in Alberta, which have rent-collection regulations of their own. In addition, income tax provisions will be discussed under the federal measures, although this tax has in fact been shared between the two levels of government.

2. Conceptual Matters

A. Governments and Economic Rent

A potential producer of petroleum must obtain the legal right to necessary inputs, including both surface rights to land under which petroleum lies and underground rights ('mineral rights') to claim any products found beneath the surface. Governments are directly involved for two reasons. First, they set up the institutional framework within which private parties can exchange goods and services. Provisions of law hold here, including those registration and arbitration procedures under which oil companies pay compensation for the use of surface land in surveys, drilling, production, and transmission. Second, and of special interest in the context of petroleum, since the *BNA Act* of 1930, most of the mineral rights in the province of Alberta have been the property of the provincial government ('the Crown'), and as owner of the petroleum rights the government has an abiding interest in the conditions under which companies engage in petroleum exploration and production.

It is useful, analytically, to separate the provincial government's role as owner from its role as rule-maker for economic exchange. This is important since the government predominates but does not have complete initial ownership over Alberta underground mineral rights and must, therefore, set up rules for exchange for private resource owner to oil company transfers and for government resource owner (Crown land) to oil company transfers. Viewed in this light, it is commonly argued that the prime goal of the government as resource owner is to obtain the maximum present value revenue from its mineral rights. The government represents the public as the owner of Crown mineral rights. Presumably it could set up discriminatory rules that favour the owners of mineral rights over producers or consumers or surface land owners. It has not obviously done so. However, it has been willing to use its powers to discriminate between itself and private mineral rights owners. For example, in 1972–73, it forced the owners of Crown leases to accept much higher royalties (or a new tax). Private mineral rights owners who had negotiated leases with fixed royalty

arrangements did not benefit from this provincial government policy and had no power to force such changes on leaseholders.

The argument is not that the Alberta government is interested only in petroleum revenue. Goals such as environmental protection and conservation, including the assurance of adequate supplies for future generations of Albertans or Canadians and the economic development of the province may be relevant. However, these goals apply to both Crown oil and oil from non-Crown land, and so require regulations governing all Alberta oil production. Within whatever regulatory climate is established for the industry as a whole, we assume that the provincial government can be seen as wishing to maximize the present value of the revenue it receives from Crown land. Several possible exceptions to this assumption can be raised.

For example, the increase in petroleum revenues of the Alberta government after 1973 were undoubtedly resented by many citizens and government authorities elsewhere in Canada and induced increased federal taxes. Higher Alberta petroleum revenues, all else being equal, had financial implications for the federal–provincial taxation equalization agreements, with even Ontario shifting toward the 'have not' category (Courchene, 1976, 1981, 2005). In such circumstances, there could be some advantage to the government of Alberta in spreading oil and gas revenues out over more time, even if the present value of total revenue is somewhat reduced as a result.

A second argument also suggests that the government might issue mineral rights with an eye more to the timing of receipt of revenue than to maximization of the present value of receipts. In practice, it may not be possible to separate the receipt of revenue by the government from the uses to which the funds are put. For example, the greater the current revenue of the government, the stronger the pressures to utilize funds now even on relatively trivial projects. Given the electoral process, it has been argued that governments may undertake expenditures with an eye more to short-term political payoff than to long-term gains. Governments might then either try to generate revenue earlier so to have access to such politically useful funds or to delay receipt of funds so as to reduce the temptations to spend rashly. This line of thinking may be even more realistic – though more analytically complicated – if it is argued that political parties represent particular special interests. These arguments will not be considered in this book, although we would suggest that their surface plausibility should not exempt them from reasoned empirical consideration. After all, they presume a general lack of awareness

by the electorate of what does constitute long-term economic gain and the ability of well-primed public 'bribes' to secure political rewards.

There are also more indirect ways in which the gains derived from public petroleum revenues are not independent of the timing in which the revenue is generated or used. For example, if oil monies significantly increase net provincial income per capita in Alberta relative to the rest of Canada, then in-migration can be expected. Such an effect reflects the way in which the government utilizes the funds. Migration to Alberta would likely be lower if the government spent its oil revenues on direct money grants to already-established residents or on long-term loans to people outside the province, than if the funds were used to reduce sales and income taxes. Regardless of the specific use to which the revenue is put, potential migrants may be affected by reports of the size of current government earnings. However, the government may wish to spread its earnings out more evenly over time, attracting fewer in-migrants, to the greater benefit of current residents. Alternatively, the government might be attracted by higher immigration, more rapid growth, and the hope for a larger economy.

Given the difficulties in sorting through these options, we shall simply assume that the government is interested in maximizing revenue from its own (Crown) land.

The idea of the maximization of net economic returns from petroleum is a slippery one. (The literature on natural resource rents and rent-collection is huge. Interested readers might refer to Cairns, 1985; Crommelin, 1975; Crommelin and Thompson, 1977; Gaffney, 1967; Kemp, 1987; McDonald, 1963, 1970; Scott, 1976; Van Meurs, 1971; and Watkins and Scarfe, 1985.) Interest centres on what might be called 'ex post economic rent': The excess of revenue from the sale of petroleum above the actual labour, capital, material, and other input costs (including a 'normal' profit to the entrepreneurs) of finding, developing, and lifting the petroleum. To suggest that the government wishes to maximize its revenue as landowner is to suggest that it wishes to capture all of this economic rent. As a basis for mineral rights policy, this concept of available revenue must be interpreted carefully in at least three major regards.

1. Quasi-Rents

Economic rent should not be confused with 'quasi-rent,' or short-term rents, where an input has already been put in place (e.g., a piece of capital equipment like well-pipe, or a service like the drilling cost of an

exploratory well) and hence is 'sunk' or 'fixed.' Prior to commencing activities, a company has no fixed costs; all are variable. But, after a reservoir is in production, exploration and some development costs will be sunk. A government might be tempted to look solely at the costs specific to productive oil and gas pools (the successful exploratory well, all the development wells, flow lines, etc.) and try to take as tax revenue any excess of producer receipts over these costs (including a suitable return to compensate for normal profits). After all, pretty well any informed observer of the Alberta industry could pick out a number of the most profitable individual pools and say that these generate a great excess of revenue over costs. To tax individual oil pools on such a basis, however, would also tax the quasi-rents for exploration and therefore tend to drive the industry out of business. Dry holes are common, and inevitable, in the conventional oil and gas industry and therefore must be allowed for as a cost. Unfortunately, the size of necessary exploration costs is difficult to estimate and may necessarily be ambiguous or arbitrary due to the joint product nature of exploration. It will be recalled that a joint product process is one in which a single activity (like exploration) yields more than one valuable output (e.g., oil and gas pools and information which is valuable over many years in selecting sites at which to drill exploratory wells). Since expenditures on the activity generate all the outcomes, there is no valid way to allocate the expenditures to separate outcomes (e.g., oil pools), although a variety of methods are often applied to simplify analysis.

It could be argued that a decision to tax quasi-rents would be rational, once the industry has discovered pretty well all the low-cost petroleum expected in the region, since further exploration is not likely anyway. Apart from the difficulty in determining when this condition is met, there are obvious political and ethical problems since it amounts to expropriation (of exploration assets) without compensation. If the industry is largely foreign-owned, however, this may be appealing to some people, who argue that much of the exploration expenditures of the major foreign-owned firms have come from 'excessive' after-tax profits (earned in the past).

2. Ex Ante and Ex Post Profits

In a world of perfect certainty, the profits accruing from a venture would be known before the venture began (and, of course, there would be no dry holes). But we live in a world of uncertainty. This is evident for the petroleum industry, dependent as it is upon

a natural resource invisibly stored thousands of feet below the surface with profits tied to the vagaries of international and domestic politics. The industry's actions are based upon its expectations (that is, upon expected or *ex ante* rents). If the landowner (e.g., the government) were to impose fees higher than the *ex ante* (expected) rent of a project, then the company would not normally undertake the activity. From this point of view, the Alberta government is interested in expected profits as well as the actual economic rent earned. (This distinction is discussed in Watkins, 1975.)

How do the actual (*ex post*) profits relate to the expected (*ex ante*) profits? The two differ because: (1) 'unexpected,' that is unforeseen, events may occur, and (2) of all the possibilities that were foreseen, only one actually takes place. One might generate a fine academic debate about whether these are really two separate issues: Are any occurrences ever completely unforeseen, or are they foreseen but assigned a very low probability? The essential point is that actual occurrences are specific so that the *ex post* rent is single-valued, while the *ex ante* rent incorporates a wide variety of possible specific futures. That the actual rents earned (*ex post* economic rents) are most visible must not cloud the fact that it is the *ex ante* expectations of the producer (after expected payments to the landowner and government) that determine behaviour. Expressed in other terms, the rent-collection measures of the government are both a revenue-sharing and a risk-sharing device: The government collects a share of the expected revenues from the venture and also derives some share of any deviation in actual revenues from what was expected.

3. Allocative Role of Economic Rents

There has always been some haziness in the theoretical analysis of profits. It is recognized that financial capital must earn a normal return on investment, equivalent to the risk-adjusted return such funds might earn elsewhere in the economy. Beyond this, it is often argued both (1) that any profits above this normal level are excess and therefore can be taken away and (2) that expectations of above normal profits are the essential signal to attract new resources to those industries in which net investment is desired (because input prices have fallen or technological changes have lowered costs or demand increases have occurred). Obviously the two arguments conflict: If all profits above the normal level were taxed away, then excess profits could not serve their allocative role. One response is

that in a well-functioning competitive marketplace long-run excess profits will not occur. However, through well-designed corporate profit taxes, a share – but not all – of any short-run profits above normal profit can be captured by the government. Hence the incentive function is maintained. But how are long- and short-run profits to be differentiated? And what share of short-run profits is required to induce more, and faster, investment?

The prospect of earning a supernormal profit may also serve as an incentive to hold costs down, therefore maximizing the size of before-tax excess profits. From the opposite point of view, in the extreme, if a company were able to reduce taxes on a one-for-one basis as other costs rise, it would have a strong incentive to inflate costs. This would allow companies to capture profits by disguising them as costs, providing 'gold-plated' services at much higher costs than are necessary with attendant benefits to management. Or the producer may simply be able to operate inefficiently, exhibiting what some economists call *X*-inefficiency (Leibenstein, 1976).

A further incentive dilemma exists with respect to the economic rent from a natural resource such as petroleum. If the Alberta crude petroleum industry were effectively competitive, long-run monopoly profits are not anticipated. However, the limited and depletable natural resource base, and cost and location differences, mean that economic rents will exist. That is, revenues from the sale of petroleum (especially from the most productive deposits) will exceed costs of production even after allowance is made for normal profits and all the essential dry-well exploratory effort (i.e., quasi-rents). In other terms, reservoirs with costs lower than those for the marginal deposit necessary to clear the market will generate a 'differential' rent due to their relatively lower cost. Effective competition does not compete away such profits, particularly since the number of high-quality petroleum fields is limited, and new entrants cannot expect to find such pools. (We abstract here from the 'open access' problem, which will be discussed below.) In addition, what we have called economic rent in the oil industry includes a 'pure scarcity' value (often called the 'user cost,' as in Chapter Four), and as such it can be argued to serve an important allocative role. A barrel of oil is scarce and can be used only once. To which time period should the producer allocate it – should it be produced this year or left in the ground for the future? Obviously, from the producer's point of view, it should go to the period that generates the largest (present-value) profit for the oil pool (subject to contractual

arrangements and other factors). It is important that the government (as mineral rights owner) devise a scheme for the capture of economic rents that does not interfere unduly with this time-allocative role.

In summary, the government as mineral rights owner might be argued to have as its objective the maximization of the present value of the revenue it receives from the issue of such rights. This can be interpreted as meaning that the government wishes to capture the *ex post* economic rent from crude petroleum production. At the same time, it should not take quasi-rents (e.g., revenue required for exploratory efforts such as general geophysical work and inevitable dry holes); it must remember that industry behaviour is governed by *ex ante* (expected) rents; it must ensure that returns to producers continue to serve an allocative function, in determining the best time period in which the oil should be produced; and it is desirable to maintain a strong incentive to efficient operations and new investment, when conditions warrant additional production.

B. Policy Instruments

Obviously if the government is to capture economic rent from the petroleum industry, some financial mechanism is essential. Many can be imagined; we shall discuss two that have been rejected in Alberta and then briefly review theoretical aspects of several that have been adopted.

1. Two Methods Not Adopted

Public Monopoly. Seemingly, all economic rent from provincial Crown lands would be captured by the Alberta government if Crown lands were entirely exploited by a government oil company (National Oil Company or NOC). This approach has not been followed in Alberta, in part for 'philosophical' reasons. Provincial governments, whether Social Credit or Progressive Conservative, have professed faith in free enterprise. Advocates of this viewpoint advance many arguments against a public monopoly petroleum company. Such a company concentrates too much power in a single entity, would be too subject to political influence, would stifle the diversity of viewpoints essential in an industry with so much uncertainty, would tend to have inefficient management (since the managers would probably have no financial share in successful ventures), and would hence dissipate most rents in high costs. A number of these arguments are

amenable to empirical analysis, but the debate functions much more on an emotional-political level. At that level, the socialist answer has been a non-starter in Alberta. Crommelin (1975) argued that a Crown corporation should be established to undertake preliminary exploratory drilling, but in competition with private companies, not as a monopoly. He also suggested that the Crown company participate in private-sector leases, in place of Crown royalties, as a way for the government to share in economic rent. The Alberta government never established such a Crown corporation.

Public Utility-Type Regulation. A public board might be established to monitor individual company's operations and to take any excess of revenues over allowed costs. The public utility regulatory approach has normally been recommended for industries that are 'natural monopolies,' that is, where the average cost of production declines as output expands. Hence, efficient production dictates a single producer. But this creates a monopoly that is likely to be able to generate supernormal profits by exercising market power. In this case, it might be judged desirable to regulate prices so that revenues are just high enough to cover costs. However, the crude petroleum industry is an increasing cost industry, capable of supporting many firms. As noted above, economic rent is generated due to the scarcity value of oil as a non-renewable resource, and because of the varying quality of petroleum deposits, so will exist even in the absence of monopoly or oligopoly forces. Hence, the natural monopoly argument for regulation is not valid.

Many economists are sceptical of a public utility-type approach. It would be a complex, and costly, administrative task, given the large number of companies active in Alberta. Beyond this, however, many economists have doubts about the efficiency of the regulatory procedure. It is usually advocated only in those cases in which the structure of the market is such that effective competition seems impossible. For one thing, there are difficulties in determining the exact level of the 'normal profit' component of cost. Given the disincentive effect of too low a rate of return, there may be a tendency to set the return too high, in which case companies have a 'residual' profit motive to expand their capital structure. At its worst, this can lead to significant 'gold-plating.' The larger the capital expenditures, the greater the allowable return to the company. In this way, costs may expand significantly, dissipating economic rent, with companies using too highly capital-intensive production

practices. If the revenue requirements to cover costs are established correctly, the allocative role of profits has been banished along with the economic rent. Therefore, the utility-type regulation to capture rents for the government would have to be supplemented by output allocation and cost control regulations for each individual company. In essence, then, this regulatory approach comes to resemble the public monopoly approach, but with a higher administrative cost.

2. Financial Instruments Actually Used

No attempt will be made to discuss all possible ways in which a landowner might obtain revenue from the crude petroleum industry. Rather, the measures used by the Alberta government will be noted, along with a brief review of the major advantages and disadvantages of each. We shall give attention to three issues: The extent to which the approach makes allowance for all necessary costs, the impact on *ex ante* (expected) rents (including risk-sharing aspects), and effects upon the allocative function of rents.

The measures will be discussed in verbal terms. In addition, graphical analysis, like that introduced in Chapter Four, will be used. The impacts of rent-collection measures will differ according to the specifics of the device and the project. It is not possible to show, graphically, all possibilities, since many factors affect the expected and actual sizes of economic rents earned. At this time, we shall examine a single oil project in a single year, using a medium-run perspective. One limitation of this approach is that it does not explicitly consider the effect of various rent-collection measures on the exploration decision, or on the inter-temporal allocation of production. With respect to exploration, the producer would have to consider the impact of the rent-collection regulations on each of the possibilities foreseen (i.e., a dry hole, a small oil discovery, a large oil discovery, a small gas discovery, a large gas discovery, etc.). By looking at a discovered pool, much of this information has been gathered (though the exact size and characteristics of the pool are not well known until some development occurs). Exploration costs are sunk costs, although they may be relevant for tax purposes.

For a discovered pool, the pre-tax economic rent available will be a function of the cost of producing the oil and the price of oil. Since these graphs take exploration costs as sunk, what is labelled economic rent will include the 'quasi-rent' necessary to cover these exploration costs. In the following graphs, we show high- and low-rent pools by varying only the

second of these two factors, the price of oil. Available economic rent (defined as the product of output and the difference between price and average production costs) is shown as the shaded areas in Figure 11.1. In subsequent graphs, the shaded area is the rent captured by the government. In the graphs, the curves MPC_1 and APC_1 represent, respectively, the marginal and average private before tax production costs of oil. For simplicity, the average and marginal cost curves are drawn as upward-sloping straight lines. Since oil production from the limited resources of the pool is subject to diminishing returns, the cost curves must eventually have a positive slope. Expressed in other terms, incremental production implies rising costs, as new wells must be placed in less-favourable locations, or because additional wells interfere with flow rates in existing wells, or because expensive enhanced oil-recovery techniques must be used. In the subsequent graphs, MPC_2 and APC_2 represent costs to the producer including the relevant payment to government.

Figure 11.1 includes an additional curve, labelled MC^* . Its intersection with the price line (demand curve) shows the desired output level of a perfectly competitive profit-maximizing firm. That is, production occurs at Q^* where price equals marginal cost. MC^* includes the 'marginal user cost' of the oil produced. As discussed in Chapter Four, this is the present value of the reduction in future profits that results from producing this barrel now. The user cost is actually a part of the economic rent (on the last barrel produced the economic rent and marginal user cost are identical); it explains the time-allocative function of prices. Since the graphs become excessively complicated if the MC^* curves are shown, we have included it only in Figure 11.1. Subsequent figures show the expected level of output (Q) under the financial scheme, relative to Q^* , thereby illustrating the allocative effect of the scheme.

As noted, Figure 11.1 has two parts that differ in the assumed price level: Part B shows a higher real oil price. To the extent that producers are uncertain about the future level of oil prices, the *ex ante* (expected) economic rent for an oil project can be imagined as a probability weighted average of the two price cases. It is also possible that the higher price is entirely unexpected.

It is not easy in these single-year graphs to show the time-allocation problem and the effect of a tax measure on lifetime revenues of the company and government. For example, some of the government revenue from a price rise may consist of revenue that would have been received anyway but is obtained

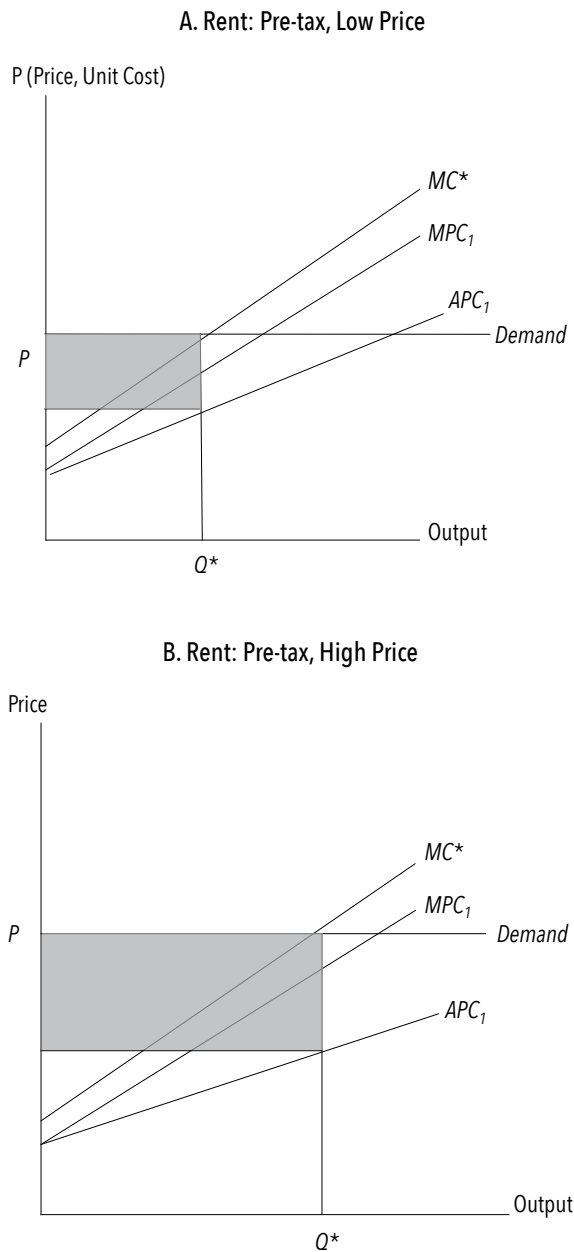


Figure 11.1 Petroleum Rent

now rather than later because the price rise induces the company to shift output toward the present. (A real price rise can also be expected to increase ultimate recovery, as more oil can be recovered profitably from high-cost pools.) Figure 11.1 Part B suggests that a price rise will generate more output in the current period; it has been drawn with the same MC^* curve as Part A. In fact, a rise in the current price will often increase expected future prices and therefore shift the

MC^* curve up (the user cost, based on the expected profit from future production, rises). In most circumstances, then, output in the current year will rise as the price rises, but not by as much as Part B suggests. Of course, introduction of a tax will also affect producers' expectations about future profits, and therefore shift the MC^* curve. As mentioned above, new MC curves, showing production costs, user costs, and taxes, have not been shown in the figures but would intersect the price line vertically above the output levels (Q) chosen.

Complexities are rampant, but it is hoped that the verbal and graphical discussions that follow will convey the key information. Five financial schemes will be discussed, each separately, although the Alberta government has actually used them concurrently. The first four have been provincial regulations: (i) competitive bonus bid; (ii) land rental; (iii) sliding-scale *ad valorem* royalty based on production; and (iv) sliding-scale *ad valorem* royalty based on price. The fifth is the corporate income tax, which has functioned, with only minor qualification, as the province's share of a federal tax, so will be discussed in detail when Ottawa's tax schemes are evaluated (in Section 3). Moreover, the government of Alberta has not applied such a tax as a part of its Crown land mineral leasing policy but assesses it on all petroleum companies in the province, just as on all other private corporations. By and large, the corporate income tax has not aimed specifically at resource rents but at corporate profits generally.

a. Competitive Bonus Bid

The competitive bonus bid (the shaded areas in Figure 11.2) is the only financial payment that is clearly *ex ante*. In this figure, the curve labelled ATC includes the average cost of the bonus bid. Since it is a fixed sum, the average bonus bid per unit of output (the difference between the ATC and APC_1 curves) becomes smaller and smaller as output rises. Also, since it is a sunk cost, it does not affect the marginal cost curves, or the output level (Q^*). The size of the bonus (the shaded area) is the same in Parts A and B since it is a sum that was paid in the past. In Part A, it is assumed that at a low price for oil, economic rents are insufficient to recover the past bonus bid, so at the optimal output level the average total cost is higher than price, but the average production cost (apart from the bonus bid) is lower than price.

Petroleum rights are issued to the company that offers the highest dollar bid, and that sum is paid whether or not the land is subsequently drilled, and, if

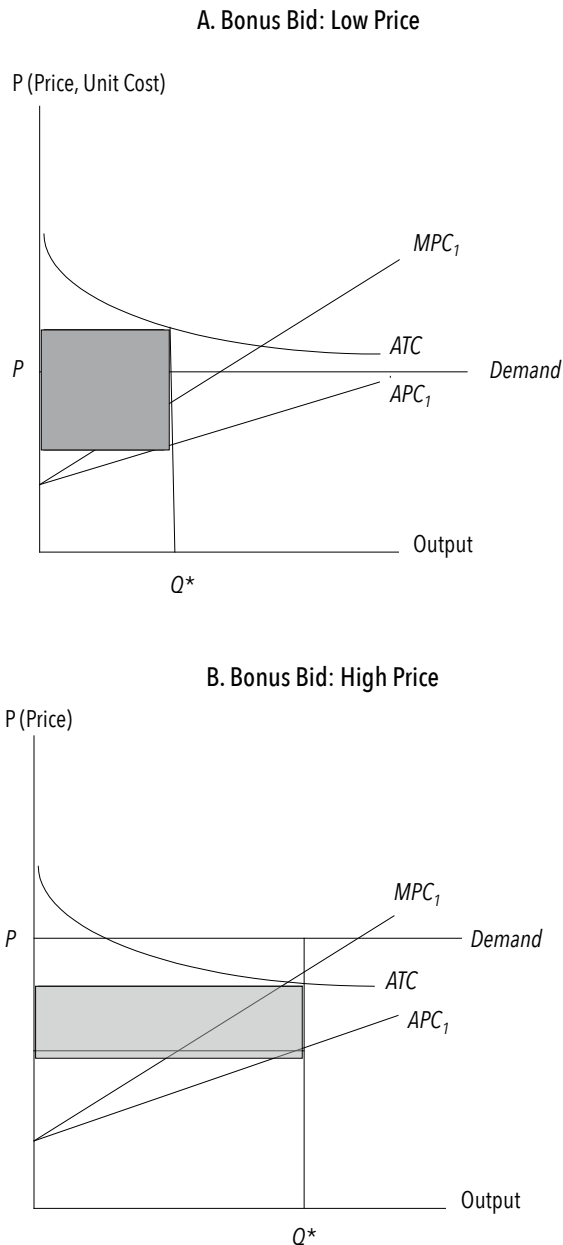


Figure 11.2 Bonus Bid

drilled, whether dry or with a small or large discovery. It is a 'voluntary' payment (whose magnitude is determined by the company bidding) and will never exceed *ex ante* (anticipated) rent. Being *ex ante*, it is a sunk cost when any production occurs, so should not affect the rate of production. In a very competitive bidding situation, companies will be willing to bid close to their estimated *ex ante* rents; therefore, such a scheme will leave the company some of the *ex post* rent from

unusually (unexpectedly) low-cost fields and take more than the *ex post* rent of dry wells and high-cost pools. In other words, the fact that some pools turn out to be very productive and profitable is not, by itself, sufficient reason to suppose that a scheme of competitive bonus bids is inefficient. Finally, because of its *ex ante* nature, a competitive bonus bid will not give the government a share of rent changes due to 'unexpected' events. ('Unexpected' in this context means both those outcomes that were not foreseen at all, and cases in which the actual result differs from the average expected result.) So long as companies engage in active competition in bonus bidding, and the average result that actually occurs corresponds closely to the expected average result, a competitive bonus bid is an attractive way for the landowner to capture *ex ante* rents.

Obviously risk falls upon the company making the winning bid. This may lead to regret and second thoughts on the part of the landowner selling mineral rights, if *ex post* rents turn out to be unexpectedly large. (Comparing Parts A and B, none of the extra rent due to an unexpected price rise goes to the government, and if prices remain low, the company may generate a loss on this reservoir.) On the other hand, a landowner in virgin territory with a high probability of no oil may prefer a positive bonus bid to the absence of royalty revenue in the event of a dry hole.

Bonus bids may fall short of the government's assessment of the value of the mineral rights. This may happen if the bidding process were oligopsonistic (with few bidders), or if bidders collude, or if the government is more optimistic about the property than companies are. However, it would also occur if companies are more risk-averse than the government or if company discount rates exceed the government's 'social rate of discount.' In this event, the government might prefer to rely less on bonus bids and more on payments that accrue as oil revenues are earned. The timing of land sales is also critical since any excess of the government's valuation over the private sector's will increase with rises in the time between the land sale date and the expected start of oil production.

There may be an offsetting phenomenon, which generates bonus bid revenue to the government in excess of *ex ante* rents. This is known as the 'Winner's Curse,' and refers to the tendency for winning bids to go to the bidder that is most optimistically inaccurate in assessing the value of the property. (Kahneman et al., 1991, and Kagel and Levin, 2002, provide overviews.) It is not clear how important the Winner's Curse is in petroleum rights bidding by oil companies.

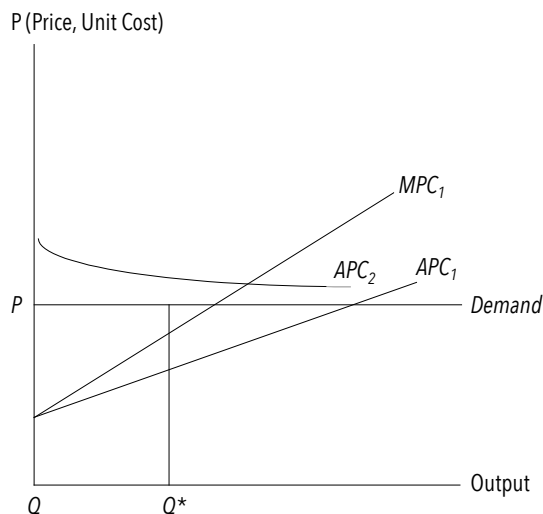
Recommended bidding strategies are designed to make some allowance for it, and studies of bidding for mineral rights in the United States suggest that bids approximate *ex ante* land values. (See, for example, Gilley et al., 1986, and Mead, 1984, 1994). We provide some evidence on the Alberta experience below.

b. Land Rental

A rental payment is an annual charge for each acre held. As shown in Figure 11.3, it has the effect of raising the operator's costs. It has been assumed that higher output does not involve greater acreage, so no incremental land rental is incurred by producing more. The rental payment is therefore a marginal cost associated with the decision to produce the first unit of output and raises the average cost curve throughout. The high marginal production cost for the first unit of output is not shown. As with the bonus bid, the unit rental becomes smaller and smaller as more is produced, so the APC_2 curve approaches the APC_1 curve. A land rental does have an effect upon the production decision since it will induce the operator to abandon land more quickly thereby saving the rental cost. This is illustrated in Part A, in which the producer in the low-price case is shown to cease production. (That is, actual production (Q) is zero, since price is less than average production cost at the output level where price equals marginal cost.) There would also be an output effect through the marginal user cost component, with earlier production seeming more attractive since it saves later rental payments. This is not shown in the figure. Obviously a rental payment high enough to approximate *ex post* rent on the most profitable outcomes would dissuade all other ventures. It would also induce early abandonment of a profitable venture, as production decline occurs. Finally, it would reduce the anticipated (*ex ante*) rent on ventures and discourage exploratory, and some development, effort. Since payments cease when mineral rights are abandoned, some of the industry's risk is shared with the government. Overall fixed rental payments are not suitable as the major rent-collection measure.

There are two main reasons that land rentals might be used. First, they generate revenue for the government from acreage that is non-productive, and hence capture some of the *ex ante* rent when actual (*ex post*) rent is zero. The second reason does not relate to the capture of economic rent. The use of land for petroleum purposes may involve giving up the value from some other land use (e.g., forestry or wilderness) or may necessitate expenditures by the government (e.g., road construction and maintenance). If such social

A. Land Rental: Low Price



B. Land Rental: High Price

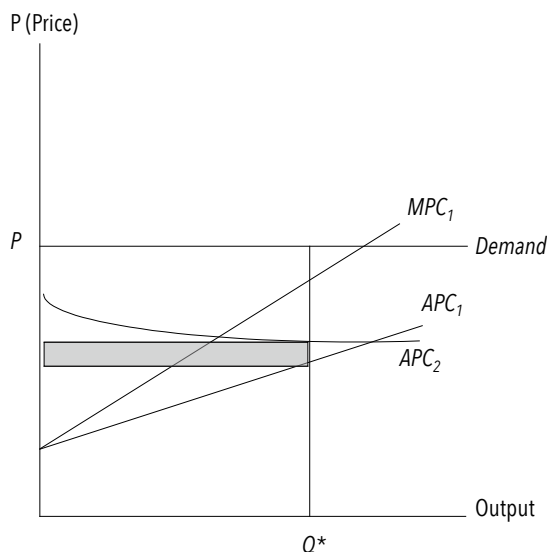


Figure 11.3 Land Rental

costs exist, the government may assess land rents to cover them. Rentals may also be imposed to cover the general administrative costs the government occurs in regulating the industry.

c. Ad Valorem Royalty, Sliding-scale Based on Output

An *ad valorem* royalty is a gross royalty based on revenue (i.e., it is some proportion of revenue). In a strict

sense, the royalty might be based on volume of output, as has been the case in Alberta, but once output is sold at the prevailing price, the royalty is equivalent to percentage of revenue. A sliding-scale royalty has variable proportions: in this case, a higher royalty rate is assessed against higher output levels. Therefore, a higher price and/or a higher production level imply a higher dollar payment per cubic metre. Because it raises the cost of output, it encourages lower production and earlier abandonment, and, by affecting expected profitability, inhibits investment in reserves additions. A sliding-scale royalty based on production may induce the operator to spread production more evenly over the life of the pool, and, perhaps, operate the pool for a greater number of years, than would a flat-rate royalty or, even, no royalty (although cumulative output will normally be reduced). This is because reducing production in the earlier years means a lower royalty rate. With this royalty, more profitable outcomes tend to be assessed a higher per unit charge: a higher price raises the royalty and higher output wells tend to have a lower average operating cost. (A higher output level will mean that costs that are fixed for the well are spread over a larger volume so per unit cost is less.) However, some high-output wells may still have high costs and therefore not be able to support a high royalty rate. This could be true of very deep wells, those in unfavourable geographical locations, those based upon an enhanced recovery scheme, etc. This type of royalty will also gather more revenue when the actual average result involves either more output or a higher price than the average result expected. (If average profits are higher because per unit costs are lower, the royalty does not generate more revenue since it is based on gross revenues.) Clearly the royalty involves the government bearing a share of risk. For another example, dry wells make no payment to government since the tax is entire *ex post* and based on production. An *ad valorem* sliding-scale royalty, then, cannot collect all the potential economic rent (either *ex ante* or *ex post*) since it reduces oil exploration and production. At the same time, its flexibility makes it preferable to rental payments as a measure to collect economic rent.

Figure 11.4 assumes that as the pool output rate rises, the average output per well becomes smaller and smaller (due, for example, to well interference). A sliding-scale royalty based on the well's output rate (as has been the case in Alberta) means that the marginal cost of the royalty becomes smaller as the pool production rate increases, so the distance between the marginal cost curve excluding the royalty (MPC_1) and

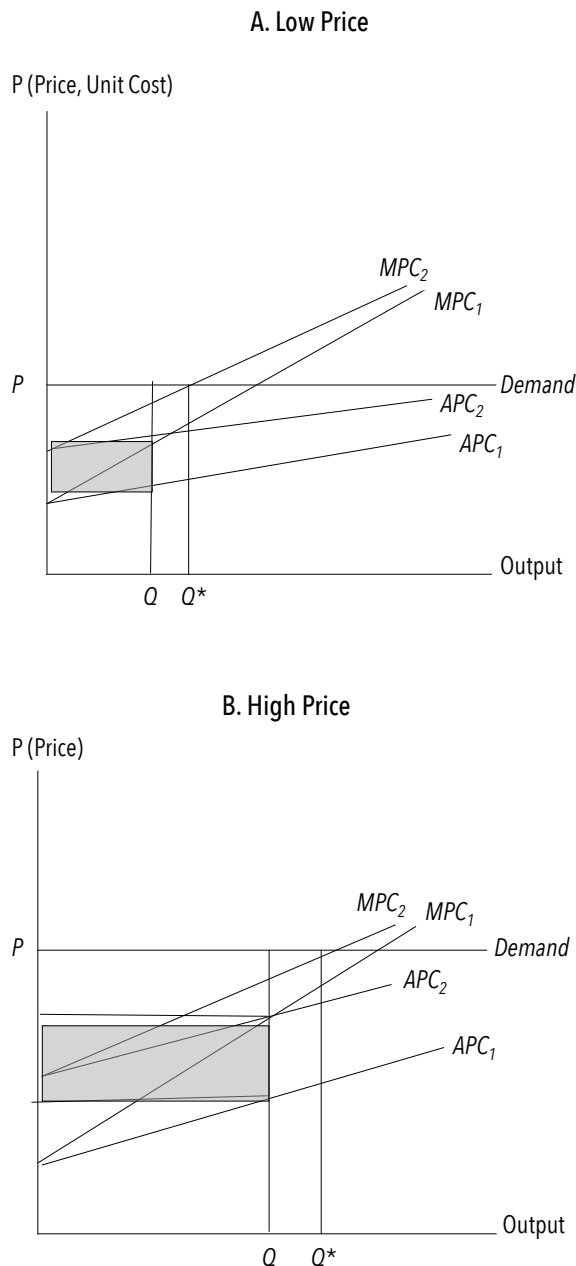


Figure 11.4 *Ad Valorem* Sliding-Scale Royalty (Output)

the marginal cost curve with royalty (MPC_2) becomes smaller as output rises. Since the royalty hinges on the value of the oil, the unit royalty payment for any given output rate is somewhat higher in the high-price case (Part B). Higher costs due to the royalty are shown as reducing the output rate. Once again, the shaded area shows the revenue flow to the government.

d. Ad Valorem Royalty, Sliding-scale Based on Price

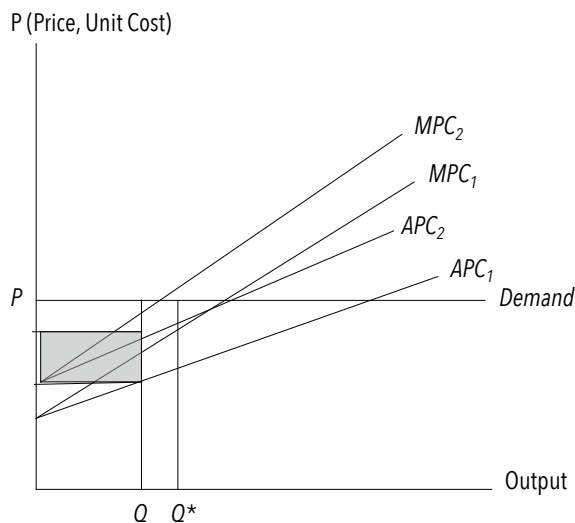
Figure 11.5 shows a flat-rate *ad valorem* royalty for each unit of output, but with a higher rate the higher is price. Accordingly a price increase raises the per unit royalty payment both because the same percentage of price would now mean a higher charge and because the percentage rate rises. (For instance, a 20% royalty would generate \$2/b at a price of \$10/b and \$4/b at a price of \$20/b. If, in addition, the royalty rate rose to 30% as the price rose, an extra \$2 would be generated for a total royalty of \$6/b at the \$20 price.)

A sliding-scale based on price obviously brings in a larger proportion of the economic rent from production at higher prices than would a flat-rate royalty, but it also eliminates more production of higher cost oil. By making such oil less profitable, it also reduces the *ex ante* (expected) rent of new exploratory prospects and so will reduce the total number of mineral rights purchased, and the level of exploration. It does, however, ensure that if the price of petroleum exceeds the average expected price (so that *ex post* rents exceed *ex ante* rents) the government derives a significant share of the unanticipated ('windfall') gain. As with other types of royalties, risk is shared between the companies and the government, although companies bear a relatively greater share of the negative market outcomes than the positive. (For example, if the price fell by a dollar, the royalty might decline by 20 cents, whereas if price rose by a dollar, the royalty might rise by 30 cents. The company bears 80% of the price decline, but enjoys 70% of the increase.)

e. Corporate Income Tax

Analysis of the corporate income tax is complicated by the fact that governments already assess such a tax on the corporate sector generally, whereas our interest is in a special tax on income to capture economic rent. As noted earlier, Alberta has not applied such an income tax on Crown mineral leases (Saskatchewan has), but it is a frequently recommended option. Essentially such a tax is some percentage of revenue less allowable costs: normally all exploratory costs are deductible on some basis. The general results are depicted in Figures 11.6. The tax is shown to increase the firm's costs, and hence to lower output (from Q^* to Q). It also reduces *ex ante* rent, thereby serving as a disincentive to exploration. The increase in costs is not an inevitable part of a tax on net income but commonly occurs for two separate reasons. Firstly, capital expenditures can normally be deducted from revenue as a cost but must usually be amortized over a period of years so that the present value of the capital cost

A. Low Price



B. High Price

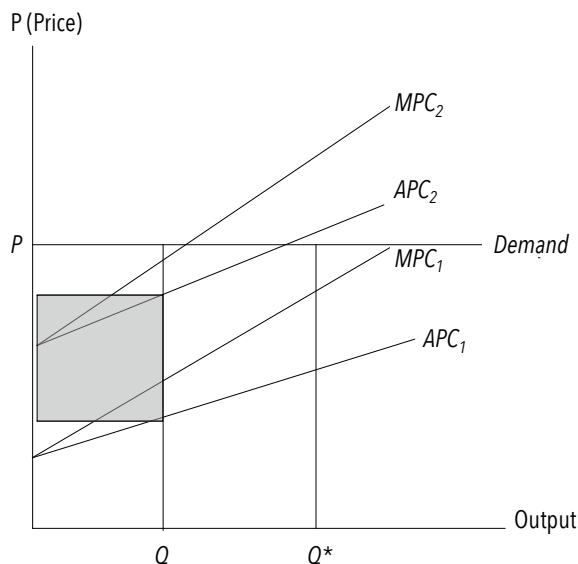


Figure 11.5 *Ad Valorem* Sliding-Scale Royalty (Price)

deduction for tax purposes is less than the expenditure itself; hence the tax falls upon a part of capital costs, the effect being greater the greater the proportion of costs that must be expensed over time. Secondly, an income tax usually makes incomplete allowance for normal profits as a cost; that is, the required return on equity capital is not treated as a cost. Hence this part of cost is taxed, the effect being greater the greater

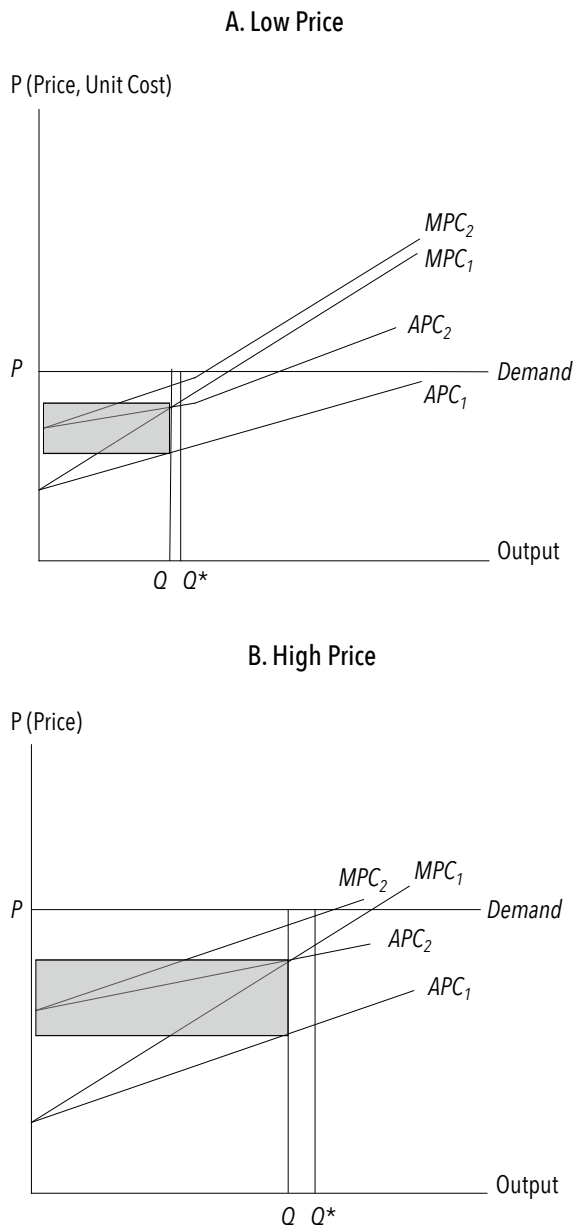


Figure 11.6 Corporate Income Tax

the proportion of activities financed by equity capital and the higher the necessary risk premium for such capital. Usually interest payments on debt capital are deductible as an expense so the corporate income tax does not fall on this cost of financing. An income tax, then, unless very carefully drawn up, does have a disincentive effect upon investment (*ex ante* rent expected by the company is reduced and may become negative) and may induce output reductions and

earlier abandonment. Unless the tax rate is very high, however, such effects will probably be minimal except for the projects at the very margin of acceptability.

There is also the problem that income taxes have usually been applied on a corporate basis, whereas the problem at hand relates to profits on specific projects. This raises the additional difficulty of assuring that the tax regulations allow for recovery of all necessary costs, including dry-hole exploratory expenditures. (As was discussed in Chapter Seven, Alberta did introduce a profit tax on oil sands projects. Since the resource base is well mapped out, such projects do not have an exploration cost component; therefore, it is not difficult to 'ring-fence' each project and define the relevant costs for purposes of the tax.) It may also be politically difficult for the government if expenditures exceed revenues for many years, so the producer appears to be paying zero tax (since tax payments will be forthcoming only in the future when revenues rise above costs).

A variant on the income tax has been suggested for mineral resources, in the form of a 'net royalty' or "resource rent royalty," which would amount to some percentage of each year's net cash flow; the government could actually make payments to a company in years in which expenditures exceed revenue, but it is more common to suggest that negative cash flows be carried forward along with an appropriate rate of return. (For an example of this tax, see Garnaut and Clunies-Ross, 1977.) Watkins and Bradley (1987) note that there are difficulties in establishing such a tax, particularly on a project-by-project basis where determination of an appropriate level of cost for pre-project expenses is difficult and necessarily somewhat arbitrary. Also, it is not clear that all investors, or all types of projects, will have the same risk-adjusted measured rate of return ('hurdle rate') to apply to losses carried forward.

f. Conclusion

The theoretical discussion seems to point to the attractiveness of competitive bonus bids (so long as the bidding process is effectively competitive); companies should be willing to bid close to the full *ex ante* economic rent, but such payments would have no effect upon the industry's activities. Other payment schemes tend to induce earlier abandonment of pools and discourage exploration, though such disincentives are less for payments closely tied to the profitability of the venture. Competitive bonus bids do have disadvantages, however. Bonus bids, since they are based upon expected (*ex ante*) profits, are not responsive at

all to events that generate actual (*ex post*) profits on the average project above the expected level; in theory, this works in both negative and positive directions, but it is the latter, as typified by the OPEC prices rises, starting in the 1970s, that attracts most interest. Hence governments may wish to supplement the competitive bonus bid with measures that are responsive to changing circumstances, although such rent-collection devices will, of course, reduce the size of bonus bids. The inevitable disincentive effect of such measures must be recognized as well, unless the measure applies only to outcomes the industry discounts entirely. It is apparent that the key issue here is risk. Since the government bears none of the outcome-risk with a bonus bid, the probability of after-the-fact regret is significant. Behavioural economic research suggests that the regret at 'losing' the high value from very profitable projects is likely to be much more keenly felt than the gratification from receiving bonus bids on ventures (e.g., dry holes) that turn out to be unprofitable.

Risk is significant in another sense. Private industry is commonly supposed to exhibit risk-aversion; this is often posited for smaller companies and for larger companies on very expensive projects. It has been suggested that risk-aversion may have less influence than commonly supposed, given the possibilities for risk-spreading in financial markets, the risk-sharing characteristics of the income tax laws and the risk-pooling possibilities in the petroleum industry (see Stiglitz, 1975). Theoretical discussion of the impact of risk and risk preferences on financial terms of mineral lease contracts can be found in Hyde (1978) and Leland (1978). Risk-aversion reduces the size of bonus bids that companies offer and may also lessen the competitiveness of the bidding process. Moreover, it may accentuate the effect of any imperfections in capital markets. Detailed evaluation of these arguments is not possible here, but they can be easily summarized. Risk-aversion implies that companies will calculate a maximum bid that is smaller than the present value of the expected economic rent; unless the government is equally or more risk-averse, it is smaller than the value of the property as viewed by the government (given identical expectations about the property). Moreover, if smaller companies are more risk-averse, or if capital markets demand higher returns from them due to risk, then the bidding procedure, and certainly winning bids, will be dominated by a smaller number of generally larger companies.

Hence, the government may be reluctant to rely solely upon competitive bonus bids for its revenue, and may supplement them with a variety of

other rent-collection measures. (Cairns, 1985, similarly argues for use of a variety of rent-collection measures.)

Thus far, we have been concerned with those clauses in the Crown land mineral rights agreements that generate revenue for the provincial government. Brief comment should be made on financial subsidies, which are intended in large part to offset the disincentive effects on exploration of the various tax measures just discussed. (The disincentives are even greater when allowance is made for various federal tax levies on the industry.) Included in such provincial subsidies are geological and geophysical incentive plans or exploratory drilling incentive plans that allow some part of these costs to earn cash rebates or to be credited against royalties, rentals, and bonuses owing. Royalty reductions or holidays on successful exploratory wells in new plays or new fields are another common incentive. Also common have been rules that give the government the power to reduce royalties by administrative order, if it is judged desirable (e.g., if abandonment of the well might otherwise occur). As suggested, such measures are best viewed, in the context of mineral rights policy, as a method of offsetting the disincentive effects of non-neutral financial terms. In this light, the efficiency of the subsidy can be measured by two criteria: (1) the extent to which the desired activity is encouraged, and (2) the extent to which loss of government revenue from ventures that would have taken place without the subsidy is minimal.

3. Non-Financial Conditions Attached to Mineral Rights Issue

a. Acreage

From an economic point of view, it is desirable that the area of the mineral right correspond to the economically efficient size of operation; thus the purchaser of the right can undertake activities at the lowest per unit cost and not waste economic rent in unnecessary expenses. Areas larger than this could be granted, but that runs some risk of reducing the number of firms in the industry and therefore the amount of competition.

But what is the efficient size of a mineral rights issue? For productive acreage, given the various unitization and conservation schemes in existence, an area small enough to support a typical well or production platform in a wide-spacing pattern would be sufficient. This would probably be smaller in onshore oil pools than offshore; in Alberta, it might be as small

as 1,280 acres (2 sections), although this is, in part, a function of reservoir production characteristics.

It is rare, however, that a parcel of land is sold as a productive entity; generally there is a significant chance of a dry well. For exploratory ventures, the prime output is knowledge, and exploratory knowledge normally has implications for more than the immediate location. For how large an area? This is in large part a function of how extensively that region has been explored up until the moment; the greater past exploratory effort the smaller can be efficient-sized mineral leases.

Major problems arise in relatively unexplored areas, however. Knowledge from a single well may have value over a wide area. Unless the company has mineral rights over the entire area, a 'free-rider' problem arises: the company will underexplore, and undervalue the mineral right since it is unable to capture the full benefit of the information itself. It would rather wait and let someone else generate the information. This free-rider problem can be somewhat mitigated if the company is allowed to keep private any information gained, but that conveys a type of monopoly power to the company and is likely to induce others to duplicate its efforts, which is wasteful of society's scarce resources.

This seems to argue for the issuance of large areas in mineral rights, if very little exploration has been undertaken. Against this must be balanced two counterarguments of particular weight if the government relies upon competitive bonus bidding as a method of rent collection. (1) The competitive implications are unattractive since there is potential for a very high degree of concentration of resulting reserves. Furthermore, if bonus bidding is used to capture economic rent, the larger the area the higher the bid desired, but the more difficult this front-end load makes it for smaller companies. (2) In the presence of risk-aversion, unexplored areas have greater risk and therefore a more severe negative effect upon bonus bids. Since all areas will, at one point, be unexplored, a large proportion of productive leases will have initially been generated by large-area mineral rights issues on which bonus bids would be low due to risk-aversion. Also, the risk-sharing characteristics of bonus bids mean that the government exposes itself to considerable after-the-fact regret.

For these reasons, governments may wish to use quite different mechanisms for acreage in well-explored and unexplored regions. In the former, small-area leases can be issued, although there is a potential open access problem in exploitation if leases cross

pool boundaries. (This is the rule of capture problem discussed in Chapter Ten.) For virgin territory, two approaches are commonly suggested. One is for the government to undertake an exploratory well-drilling program itself, thereby generating knowledge about the broad geological details and reducing the risk for operators; since subsequent wells will tend to convey information that is site-specific, issues of mineral rights to relatively small areas will be efficient. Of course, the government is bearing all the risk at this stage, and critics of government involvement would point to the danger that excessive drilling and other inefficiencies would generate high costs. However, a careful government drilling program would reduce risk for others and save companies the costs of such general knowledge gathering, therefore enabling them to select well sites more carefully. For both reasons, the competitive bonus bids on mineral rights issued should be higher than they would otherwise be, unless the government drilling program demonstrates that prospects over the entire area are much worse than was previously expected.

The second approach is for the government to issue a mineral right that is for exploration only, but allows selective, but not complete, conversion to a production lease; part of the land must be returned to the government for subsequent resale. The company stands to derive a major benefit from knowledge it gains in exploration, but the government retains a share of mineral rights for resale when general geologic risk is reduced. In this case, the competitive bid for exploration rights should be larger than if the company had access to only a small area, insufficient to realize all the economies of exploration. At the same time, the government has reduced the magnitude of the revenue losses to itself due to a lack of competition or the presence of risk-aversion.

As this discussion makes clear, the optimal area to be covered in a single issue of Crown mineral rights is not obvious.

b. Work Commitments

Often mineral rights include a provision that, unless a certain amount of exploratory expenditure occurs, the right must be returned ('relinquished') to the Crown. Such measures are often justified on the grounds that the more exploration the better: after all, isn't knowledge always valuable, and aren't we better off the more oil we have? From an economic point of view, the answer to both questions is "Yes," so long as the knowledge and oil are costless. Otherwise, the cost must be balanced against the benefit. From the

viewpoint of a land owner attempting to maximize his revenue, work commitments are questionable, if the oil market, including the process of issuing rights, is effectively competitive. In this case, work commitments are unnecessary since the company, in attempting to maximize its own profits, would be willing to undertake some level of exploration expenditure in any event. If required work commitments exceed this expenditure, the prime effect is to reduce the amount of economic rent the company expects and therefore the size of the bonus bids. If the required work commitment is less than the company plans on spending, the requirements have no effect. (Occasionally the expenditure under the work commitment is made deductible from the rental and bonus owing; the main effect of such a scheme is to increase the size of the maximum bonus a company is willing to pay. Suppose a company places the net value on a piece of land at \$1 million. If an exploratory well will cost \$500,000 and the bonus paid can now be reduced by that amount, how much will the company be willing to bid before claiming the credit? The answer is \$1.5 million!)

The main theoretical rationales for work commitments relate to imperfect competition, imperfect knowledge, and industry risk. Work commitments obviously increase the cost of holding land and therefore inhibit larger companies from moving to monopolize petroleum land by acquiring large acreages and holding them idle. Even in a competitive industry, work commitments will inhibit the tendency of firms to acquire land early, long before they might wish to drill on it; in the presence of risk-aversion, such early acquisition is liable to reduce the present value of economic rent gained by the government. (Since more information is available later, risk is less.) In light of these considerations, provision for moderate work requirements may be judged advantageous, although the dangers of excessive drilling and attendant rent loss must be borne in mind. In addition, one of the main purposes of exploration is to generate the knowledge that reduces uncertainty about underground geology and the location of oil and gas plays. Work commitments help to bring new knowledge to light sooner, and, to the extent that the knowledge becomes generally available, allow industry and government to reap the benefits.

c. Duration

In an effectively competitive industry, without risk-aversion, mineral rights issues could be issued for perpetuity. Since firms could not hold oil deposits off the market for monopoly gain, they would time

their activity to maximize their profits; with the lease operated to generate maximum economic rent, competition should generate a maximum competitive bonus bid. On productive mineral acreage, leases of indefinite term (i.e., until production ceases) are necessary if the operator is to schedule output in the early years consistent with the maximum lifetime net present value of the deposit. Leases of limited term (like an expectation of nationalization) tend to encourage excessive and wasteful current production. Hence leases should be renewable so long as production is likely.

However, on non-productive mineral right holdings, the government might desire to impose a time limit for the reasons discussed in the previous paragraph – it reduces the likelihood of monopolization of mineral rights and helps avoid low competitive bids by risk-averse firms attempting to acquire mineral rights long before they wish to drill. At the same time, those companies that do acquire rights early may now drill earlier, even if the economic rent is reduced by doing so. (For example, it might be economically desirable to await the geological information from a well the same firm is drilling on a site three miles away, but with the time limit on leases the firm may not be able to wait.) Remember that drilling is a cost to society and the less we can get away with, for any given amount of oil, the better off we are.

d. Timing of Sales

How quickly should the government issue its mineral rights? Once again, in an externality-free world of perfect competition, risk neutrality, and perfect capital markets, this issue would be irrelevant. The government could issue all the rights by competitive bonus bid on 'Day One,' and each parcel would sell for an amount equal to the present value of the maximum economic rent expected from the land. Companies would wait to explore and produce from the land until the expected profit was at a maximum.

In the real world, however, the imperfections discussed above suggest that the government spread out sales over time. Imperfections in capital markets and risk-aversion mean that it is desirable not to place too heavy a financial commitment for bonus bids on the industry at one time. The desire to encourage more small companies (for more competition) argues the same way. The effect of risk-aversion on bonus bids and the willingness of the government to bear some of the general geological risk by awaiting information suggest the advantage of delaying sale of much of the land in a region until some exploratory results

are in. It was noted above that the government might have strong reasons for including work commitment provisions and limited terms in the lease provisions but that such clauses run the danger of encouraging excessively high-cost exploration (i.e., overdrilling): this danger can be mitigated by spreading the sale of mineral rights over time. Finally, if mineral right sales are spread over time, the 'open access' problems of the exploration process may be reduced.

e. Open Access and Petroleum Exploration

Discussion of 'open access' arose in the previous sections. At risk of repetition, some elaboration of this concept is desirable. The term 'open access' is used to describe the often undesirable situation in which property rights to an asset are initially unowned but can be captured by the first party to claim them. If capturing and holding the asset (e.g., mineral production rights on a piece of land) were costless, then companies would be motivated to snap up the property right as quickly as possible, so long as any possibility of profit exists. The asset would then be withdrawn from production until the date at which it generated maximum profit. If holding the asset does involve costs, then companies will be inclined to try to capture the land so long as the expected cost is less than the expected profit. Suppose that the real resource cost is higher the longer the asset is held or that the probability of obtaining the asset is greater the more that is spent: then there is a powerful incentive for parties to spend all the expected profit in order to obtain the legal right to the asset. Open access in this case means that all the expected profit is dissipated in higher costs; there will seem to be no economic rent!

With perfect competition, no risk aversion, etc., the government could issue the rights through competitive bonus bids and capture all the rent, but in the real world the government has valid reasons for preferring to spread sales over time. Open access explains why companies would be eager to take any land that is offered, as soon as it is offered, so long as the expectation of any profit exists. Therefore open access also helps explain why a policy of spreading mineral rights issues over time is desirable. It may also help explain why the government reserves the right to refuse the sale of mineral rights if the highest bid is felt to be too low. If rights are costless, companies wish to own the mineral right simply to prevent a competitor from gaining it, even if there is an extremely low expectation of the land actually containing oil. In the absence of a floor price – reservation price – by the government, companies would submit very low bids on just

about any parcel, even if they had not analyzed it to estimate its expected economic rent. Especially early in the life of the industry in a region, before any major discoveries, it is likely that all land would have low expected values, and open access would induce firms to acquire mineral rights over the entire area with very low bids.

The problem of open access within a single reservoir was discussed in the previous chapter. To what extent is undiscovered oil also 'fugacious'? If no one knows where it is for sure, until drilling takes place, the deposits might be labelled fugitive, and, as argued above, companies will acquire mineral rights as soon as possible. However, so long as the government issues such mineral rights by competitive bonus bidding, the company should be willing to bid away all anticipated economic rent. So long as the mineral right gives exclusive rights to any oil beneath the surface (as ensured, for example, by prorationing or unitization regulations), there should be no overbearing incentive to dissipate possible rents in excessive exploration. (Presumably some incentive exists to overspend at the pre-acquisition stage.) The only exception to this would be where firms are completely unable to distinguish the relative attractiveness of potential drilling sites prior to exploratory drilling. But then all acreage would command the same per acre bonus bid, which clearly is not true. However, if the rights have clauses limiting the term of the rights or work commitments, then wasteful exploration (too much drilling, too early) may occur, and a schedule of phased-in leasing would be desirable. Finally, in a world with less-than-perfect competition, risk-aversion, and great geological, engineering, economic and political uncertainty, the government would likely be able to generate more economic rent by spreading the issuance of mineral rights judiciously over time, rather than issuing them as soon as any interested companies express an interest.

C. Conclusions

The government of Alberta has responsibility to establish regulations over the entire petroleum industry to ensure maximum benefit to the province. It happens that a large majority of the prospective petroleum-bearing land has provincially owned (Crown) mineral rights. It is commonly suggested that as the landowner the provincial government might be viewed as trying to maximize the present value of payments it receives from these mineral rights. However, for a number of

reasons set out above – the importance of maintaining incentives for efficient operation, the existence of uncertainty, and the inevitable inefficiencies in various rent-collection instruments – we would argue that this is an unattainable ideal. Watkins (1987b, p. 328; 2002a), for instance, suggests that the government should aim at “obtaining a preponderance of, rather than all, the apparent and uncertain long-run economic rent,” perhaps “two thirds to three quarters.” In Alberta, since the provincial government adopted explicit objectives for various departments and agencies in the 1990s, the aim has been to obtain a certain percentage of the petroleum industry’s “net operating revenues,” defined as industry sales revenues less operating costs, administration expenses, and taxes. The *Annual Report* of the Department of Energy sets the target at 20 to 25 per cent, a target that was largely met by the province until the international oil price rises in the mid-2000s. No indication is offered of the percentage this would yield of economic rent, but it is apparent why the province would adopt the standard it does. Net operating revenue can be clearly defined each year, whereas economic rent is based on lifetime profits and can only be known with certainty at the end of a project’s life. Therefore, the government desires to establish a method of issuing mineral rights on Crown land to private companies which (1) pays a high proportion of profits to the government, (2) does not unduly deter exploration and development, and (3) does not induce premature abandonment of pools or excessively costly exploration, development, and production techniques. Governments also have an interest in maintaining relatively steady and predictable revenue streams. This makes planning and financing of expenditures easier and minimizes self-control problems that might encourage the government to increase spending unduly in years with unusually high revenues. However, stability in resource revenue may be very difficult to attain. Government revenue is, of course, only partly a function of the rent-collection instruments utilized; variation in the levels of production of oil and gas and, especially, sale prices will also affect revenue, and these are not under government control. Governments may, then, try to increase predictability and stability in two ways. The first is to ensure that at least some of the rent-collection measures are ones that provide relative revenue stability. For example, since the volume of land held has often been more stable than prices, land rentals provide a more predictable revenue flow. However, as was noted above, since rentals are not directly tied to profitability, they are not very efficient as a way to capture rent.

The alternate approach is to accept that government resource revenues will be unstable, because the flow of economic rent is unstable, and to attack the problem of predictability at the opposite end, the utilization of resource revenues. This involves revenue stabilization funds, which build up in years of higher government revenues and are run down in years of lower revenue. Chapter Thirteen briefly reviews Alberta’s experience with such funds.

Simple economic analysis suggests that competitive bonus bids have much to recommend them, so long as the bidding process is open and competitive, since such schemes should not affect marginal exploration or production activities. However, this requires payment before a venture commences; such a heavy front-end load may discourage smaller companies, especially if ready access to financial capital is difficult for them. In addition, almost all the risk is borne by the private companies rather than the government. If companies are risk-averse, this will reduce the size of bonus bids they are willing to make. Moreover, with a scheme of competitive bonus bids, the government will not benefit from unusually or unexpectedly beneficial conditions affecting the industry as a whole.

Hence, there are strong reasons for the government to supplement the *ex ante* financial process of competitive bonus bidding with a flexible *ex post* tax scheme, such as sliding-scale royalties or an income (profits) tax.

Given the weaknesses of the competitive bonus bidding procedure, governments have reason to consider the imposition of other-than-financial obligations to the mineral rights issues including work commitments, clauses for partial relinquishment of the area to the government, and limits on the duration of the lease. Also, careful attention must be given to the timing of issue of mineral leases, with staggered sales conferring likely benefits to the government. Partly this is because it allows more time to determine the really valuable plots of land, as successful exploration occurs, and partly it helps in attaining greater stability in revenue flows, by spreading bonus bids and other payments over more years. It is difficult to say with any degree of authority exactly what these lease provisions should be. While a considerable literature discusses characteristics of an optimal taxation regime for capturing the economic rent from petroleum, we are unaware of any convincing research setting out the optimal pattern of non-financial lease terms. Crommelin (1975) and Crommelin et al. (1976) discuss the problem for Alberta, noting its importance, but the complexities of possible provisions and the

complications of the common access dimension make definite conclusions difficult.

3. Alberta Government Policy

A. Introduction

The intent of this section is to review the main details of the Alberta government policy on Crown mineral rights. Ballem (1973) provides a discussion of oil and natural gas leases in the Canadian context, for freehold leases. And Thompson (1965) contrasts petroleum land policies in Canada and the United States. We draw on the *Annual Reports* of the government departments responsible for mineral rights and on Crommelin (1975), Somerville (1977), and the 2002 review from the Department of Energy. Breen (1993), chap. 1, provides a more detailed review of the federal regulations in the years up to 1930. He notes that they included most of the main features that appeared in subsequent provincial regulations. The actual regulations have been multifarious and subject to periodic change; to summarize, all these details would be both tedious and irrelevant. Rather, the major characteristics of the regulations and the most important changes will be noted. We will follow this review of the regulations with some general evaluative comments based on the theoretical discussion above, supplemented, where possible, by relevant statistics. Finally, several case studies of the effectiveness of rent-collection in Alberta will be reviewed.

B. Alberta Regulations

1. Pre-1930

Until the *BNA Act* of 1930 (*British North America Act, 1930, 20-21 Geo. V, c. 26 (U.K.)*), Crown land rights in the prairies were held by the federal government. Ottawa had transferred some of the mineral rights in Alberta to private hands through three main mechanisms.

- (i) When Canada acquired the lands of the Northwest Territories from the Hudson's Bay Company in 1869, the HBC was given title to 5 per cent of the land in the south-central belt of the prairie provinces – a total of 2.4 million acres in Alberta.

- (ii) Ottawa's support for the C.P.R. in building the transcontinental railway included land grants with attached mineral rights. Other smaller land grants to railways were made, for a total of 13 million acres.
- (iii) Initial grants of land to homesteaders, under the *Dominion Lands Act* of 1872, included the mineral rights; only with Privy Council Order No. 1070 of October 31, 1887, were mineral rights beneath such land reserved for the Crown. Hence, mineral rights are in private hands on land that was homesteaded before 1887. Such areas are relatively small in Alberta (larger in Saskatchewan and still larger in Manitoba, given the earlier date of settlement as one moves to the east).

The mineral rights held in private hands make up a relatively small part of Alberta's sedimentary basin and are concentrated in the south and central parts. Here oil producers have been able to lease privately owned mineral rights, as well as Crown. Often the financial terms on privately issued leases were more favourable to companies than on Crown leases: private landowners could not arrange the same open competitive bidding process as the Crown and lacked the various tools of the Crown to encourage renegotiation of leases in the face of changing market conditions such as those after 1973.

The presence of adjacent Crown and private mineral leases explains the inclusion of "offset drilling" provisions in Crown leases, as is common in freehold leases: if a productive well on a neighbouring lease is productive, this provision allows the Crown to order the leaseholder to drill a well to prevent drainage from under the Crown land, with a resultant loss of royalty revenue to the government.

Effective in 1931, most of the Crown acreage was transferred to the province: this included both unleased mineral rights and the outstanding mineral leases issued by Ottawa prior to the transfer. Holdings of mineral rights were as follows (in thousands of acres) (Alberta, Department of Mines and Minerals, 1972, p. 1):

Federal:	Dominion parks	13,434	(8.2%)
	Indian reserves	1,328	(0.8%)
Provincial government		132,620	(81.2%)
Freehold:	Railways	13,032	(8.0%)
	H.B.C.	2,404	(1.5%)
	Other	564	(0.3%)

The first explicit federal regulations allowing issuance of petroleum rights on Crown land were promulgated in 1890s; through 1930, a number of further regulations were introduced (Klassen, 1999, pp. 183–85). Initially petroleum rights could be obtained on application, for relatively small areas, subject to a \$1/acre rental and a 2½ per cent gross royalty, both on successful ventures. Various modifications subsequent to 1898 foreshadowed elements that were common in later regulations. Rental fees were made payable whether or not discovery occurred (1910); on areas in forest reserves, one half the area taken in lease was set aside as Crown Reserve for possible subsequent sale by competitive bid (1920/21); royalties were charged in various ways – for example, a royalty holiday was utilized (1910/1919 leases, good on oil until 1930) and royalties were left to the discretion of the Governor-in-Council subject to a range with a minimum of 2½ per cent in the first five years of production, 5 per cent in the next five years, and 10 per cent after (1920). Generally, the maximum size of an individual lease was 1,920 acres, and leases were obtained by simple application. There were annual work commitments but leases could be consolidated by a company in this regard. Leases had a life of twenty-one years and were renewable for another twenty-one. In the second through fifth years, expenditures on unsuccessful leases could be used as a credit against the lease rental.

2. 1930–47

On October 31, 1930, a total of 18,868 leases covering 2,460,962 acres were transferred to the province (an average size per lease of 130 acres), generally with provision for a 5 per cent royalty. In the first full fiscal year of provincial operation (April 1, 1931 to March 31, 1932), the provincial government received \$10,883 in royalties and \$87,456 in lease rentals. Alberta's first provincial regulations governing issuance of Crown oil and gas rights appeared as O.C. 669-31 in June 1931 (under the provisions of the *Provincial Lands Act*) and allowed the lieutenant governor-in-council to establish royalty rates and set up leasing regulations similar to those for Dominion (federal) leases. We shall not detail the Alberta provisions but will summarize the major aspects.

a. Royalties

The royalty rates on crude oil were gross *ad valorem* royalties (that is, a percentage of the gross sales value) as follows:

Table 11.1: Alberta Government Revenue from Petroleum, Fiscal years 1930/31 to 1947/48 (10³ dollars)

	<i>Royalties</i>	<i>Rentals</i>	<i>Bonuses</i>
1930 ^a	110.8	87.5	0
1931	106.1	57.7	0
1932	73.2	42.2	0
1933	73.5	81.5	0
1934	61.3	92.8	11.4
1935	117.5	116.2	0.8
1936	108.3	361.0	76.4
1937	273.5	320.2	11.2
1938	522.8	409.8	3.4
1939	523.3	373.4	4.4
1940	523.3	262.4	3.7
1941	658.9	213.5	1.0
1942	630.2	287.8	3.6
1943	550.4	249.2	7.2
1944	708.2	606.9	54.1
1945	588.9	541.0	34.5
1946	610.2	287.5	0.3
1947	875.2	733.2	26.4

Sources and Notes:

a 6 months from October 1930 to March 1931.

The highest petroleum revenue source each year is indicated in bold. Data are from *Annual Reports* of the Department of Lands and Mines.

January 1931 to December 1934	5%
January 1935 to December 1939	10%
January 1940 to June 1941	12½%
June 1941 to May 1951	5 to 15% sliding scale based on output per well (with an option to select a 12.5% flat rate)

Table 11.1 shows annual royalties received in fiscal years ending in 1931 through 1948. The major increase in revenue following 1936 reflects the share of Crown land in the Turner Valley (Rundle Formation) oil pool discovered in that year, as well as some increases in oil prices over the period.

b. Issuance of Rights

(i) **Leases.** Initially Alberta followed the federal practice of issuing mainly leases, over relatively small acreages. As noted, there were 18,868 federal leases when Alberta took over the Crown reserves. By 1934,

the number had fallen to 3,888; it increased after the Turner Valley oil discovery (to a pre-1950 peak of 6,518 in 1939) then fell back to 2,315, covering 843,000 acres at the start of 1948. Generally, the maximum lease area was 1,920 acres (3 sections); there was a rental of \$1/acre (often 50 cents/acre in the first year, prior to 1941, which could be reduced by undertaking expenditures).

Annual Reports of the provincial Department of Lands and Mines in the 1930s indicate that rentals foregone as a result of exploration were about equal to rentals received. Over the entire 1930–47 period rentals contributed 72 per cent as much revenue to the province as did royalties. The combination of generally poor drilling results, work requirements, and a continuing annual rental kept the turnover of leases relatively high. The small lease area meant that small companies and individual investors could easily acquire leases, but a charge of \$1,280/year on a 2-section lease was a significant investment. Even for a large company, to hold such a lease for five years would involve a present value cost of \$5,290.00, which is significant for a small area lease with, in most circumstances, a relatively small chance of an oil reservoir. F. K. Beach (1954) reports that, of 567 wells drilled in Alberta to 1946, only 27 or 4.8 per cent found oil. Suppose that there was, generally, a 5 per cent change of success, and that twenty leases were therefore required to yield a likely find: the present value cost of twenty such leases, if held an average five years, would be \$105,000 – a high cost given the average size of a find expected in Alberta at that time, and the prices of the 1930s. An average exploratory well in 1946 probably cost about \$90,000. Of course, some of this cost might be credited against lease rentals.

(ii) Exploratory Permits. Under federal regulations, companies could also obtain ‘prospecting permits’ that allowed conversion to lease; these covered relatively small areas and relatively few were issued. Commencing in 1936, the province began to introduce more liberal regulations for exploratory permits, which have, since then, been variously called “permits,” “reservations,” “drilling reservations,” and “licences,” each with its own peculiar set of conditions. These covered much larger areas than the leases and earlier permits and normally provided for partial conversion to lease, with the remainder returned to the Crown. They were for a relatively short term (often less than a year) and had a work requirement. At the start of fiscal 1936/37, there were fifty-four such mineral right issues covering 240,436 acres (for an average

of 4,450 acres each); by 1940/41 there were twenty-two with an acreage of 443,431 (average 20,150) and by 1947/48 there were seventy-two, with an acreage of 7,438,105 (average 103,300). The rental per acre was much lower than on a lease, 5 cents/acre. By the later years such exploratory permits were of short duration and conveyed no right to lift oil; conversion to lease was necessary for that.

(iii) Crown Reserves. In 1937, regulations were established setting up areas of “Crown Reserve” – a separate category of provincial Crown land. Included were: fourteen large areas of “provincial Reserves”; in unsurveyed land, an area adjoining to and equal in size to any lease issued; all land in forest reserves; all Crown rights in odd number sections of townships north of T52 (i.e., Edmonton), and certain other smaller acreages. The government could issue leases or exploratory rights from Crown Reserves, using competitive bonus bids if it wished. The Crown Reserves ensured a continued strong land interest by the province in areas in which exploration was demonstrated to be productive.

(iv) Bonus Bids. Bonus bids were used, but not extensively, in years prior to 1948. Table 11.1 includes the total of bid revenue for fiscal years beginning in 1930 through 1947: it provided only 2 per cent of total Alberta government petroleum revenue. With the 1947 Leduc discovery, bonus bid revenue rose considerably. Breen (1993, pp. 280–81) outlines Alberta’s five-month experiment with royalty bidding. Some saw this as a way to encourage participation of smaller companies (since up-front costs are reduced and exploratory risk shared with the government). The larger companies objected, and the Conservation Board pointed out that higher royalty rates encouraged early abandonment. The government abandoned the approach.

c. Conclusion

Years prior to 1947 yielded few exploratory successes in Alberta. The provincial government held mineral rights to over 80 per cent of the area of the province, but outstanding leases in any year never amounted to more than 1.3 per cent of this total area, and even cumulative exploratory permits issued over the period covered acreage smaller than 18 per cent of the provincial Crown-rights area. (Some such exploratory rights issues may have overlapped, of course.) At the start of 1947, leases outstanding amounted to 0.8 per cent of the area of Crown land and exploratory rights to 5.6 per cent. Economic and technological conditions

meant that most of the drilling that had taken place was relatively shallow.

At the same time, a mineral rights policy had evolved, which:

- (1) distinguished between large-area exploratory rights and much smaller acreages that allowed production as well;
- (2) kept a share for the government of unleased acreage in Crown Reserves adjoint to acreage that was leased, especially in the western, the central, and the north-central parts of the province;
- (3) exacted an *ex post* payment (i.e., conditional on discovery) in the form of royalties;
- (4) ensured continuing revenue through land rentals and also discouraged companies from holding areas idle unless they had real expectations of success; and
- (5) opened the door to the use of competitive bonus bids.

Into this environment exploded the news of the Leduc discovery by Imperial Oil in early 1947. The find was large; it was also in a deep and heretofore unexplored formation. The industry began to move into exploratory high gear, and the province took a long hard look at its mineral leasing policy.

3. 1948-73

This period covers the years from the discovery of Leduc through the main Alberta oil plays to the revolution in oil prices brought about by OPEC, spanning the development of the Alberta oil industry to maturity. While a number of regulatory changes were made over the period, there was a relatively consistent framework for Crown mineral rights. Production of oil or gas required a lease; while leases could be consolidated for certain purposes, individual leases were generally restricted to a maximum size of nine sections (5,760 acres) and required a rental payment per acre and an *ad valorem* royalty on production. Exploratory rights could be rented and covered larger areas. They did not convey a right to production but could be partially converted into leases, with the above-described rental and royalty provisions. The land not converted to lease was relinquished back to the government; these surrender provisions were new and ensured that the government retained land in the areas of ongoing exploration. Rights to new leases (i.e., those not converted from exploratory rights)

were sold by competitive bonus bid. Exploratory rights were for a relatively short term, while leases lasted longer, indefinitely if production occurred. The underlying rationale for these general conditions can easily be perceived from the theoretical discussion above. The government offered some incentive for knowledge-gathering (exploration) and installed a mechanism to capture a high proportion of anticipated rent. At the same time, through royalties and the relinquishment provisions in exploration rights, the government bore a share of risk, including that associated with entirely unexpected developments and with low-probability events that became reality. What follows covers some of these general provisions in greater detail. The 1947 Leduc find, and the subsequent surge in industry interest, brought changes in all parts of the Alberta provincial mineral rights legislation, commencing with the introduction of an entirely new *Mines and Minerals Act* in 1949. Subsequent changes in regulations regarding Crown mineral rights were generally consistent with the spirit of this major piece of legislation.

a. Royalties

The *Mines and Minerals Act* of 1949 gave the lieutenant general-in-council the authority to change royalty rates, subject to the limitation of a maximum rate of 16 $\frac{2}{3}$ per cent (one-sixth) during the first twenty-one-year term of the lease. Effective June 1, 1951 (O.C. 808/51), a new sliding-scale schedule was set up with rates from 5 per cent up to 16 $\frac{2}{3}$ per cent. This was realized by a rising marginal royalty rate: the marginal royalty was 5 per cent for the first 600 barrels per month of a well, rising to 20 per cent for monthly output between 1,800 and 4,500 barrels from the well. (Appendix 11.1A shows the detailed royalty schedules for years from 1951 on.)

The general revision of petroleum regulations in 1962 involved new royalty rates. The 16 $\frac{2}{3}$ per cent ceiling rate was maintained; this was the ceiling for twenty-one-year leases under the 1949 rules and for the new ten-year leases the government began to issue in 1962. The new royalties involved only three marginal rates: a well paid 8 per cent on the first 750 barrels per month, 20 per cent on each of the next 1,950 barrels, and 16 $\frac{2}{3}$ per cent on anything above that. For all wells, except those producing more than 4,050 barrels per month, the new royalty schedule involved a higher rate.

The next royalty change on oil was introduced in 1972 (under the *Mineral Taxation Act*), effective at the start of 1973 (Government of Alberta, April 1972). It

was designed to provide the province with a larger share of the revenue from the price rises that had begun in 1970. (Under the 1962 schedule, the government obtained an average royalty, in 1970, of 15.1 per cent, so would get 15.1 cents of each \$1 per barrel price rise on oil from Crown leases.) The new act provided for: (1) a new, higher, royalty schedule on newly issued leases or those old leases being extended beyond the primary term of ten or twenty-one years; (2) the application of this schedule to old leases still in the primary term which voluntarily submitted to the new schedule; and (3) a new reserves tax on freehold production and output from old Crown leases which did not voluntarily adopt the new royalty schedule. Since the government was soon to abrogate unilaterally the royalty ceiling on outstanding leases, and since the reserves tax was to be made equivalent in revenue terms to the new royalty scheme, only the royalty scheme will be discussed here. The new royalty schedule began with a marginal rate of 5 per cent, rising to 25 per cent on any output in excess of 1,200 barrels per month for the well; the average royalty also began at 5 per cent and rose asymptotically to 25 per cent. Wells with an output per month less than 180 barrels paid a lower marginal royalty under the new regulations; wells with an output of less than 360 barrels per month paid a smaller average royalty under the new regulations. Wells with output in excess of these values paid higher royalties.

It should be noted that the Alberta royalty regulations also included a provision that allowed an operator to ask for royalty relief, if the well would otherwise be abandoned.

Table 11.2 shows the rapid rise in royalty payments after the 1947 Leduc find.

b. Issuance of Rights

(i) **Production Rights.** Leases were required for production. The revised regulations of 1949 under the new *Mines and Minerals Act* established procedures for petroleum leases:

- (1) they were to be twenty-one-year leases, renewable for a further twenty-one years of while production lasted;
- (2) a lease could be a maximum of nine sections (5,760 acres) in a regular square or rectangular (maximum eight sections) pattern with the length no more than twice the width;
- (3) a rental of \$1/acre/year was charged;
- (4) royalties would be set by order-in-council with a ceiling of 16 2/3 per cent during the first term;

- (5) the minister could order drilling on a lease and customarily did after the tenth year if none had been undertaken.

Leases could be acquired in two ways: by selection from land to which the company had exploration rights (e.g., reservations; see below) or by purchase as a lease from Crown Reserves (see below) by competitive bonus bidding. The regulations gave the government considerable leeway to dispose of mineral rights "as the Minister sees fit": virtually all rights since the late 1940s have been disposed of by competitive bonus bids, either in leases or in exploration rights convertible to lease. In the early years, some petroleum and natural gas reservations on unexplored land were an exception. In 1962, the leasing regulations were changed, under the new *Mines and Minerals Act*, to restrict the initial term to ten years, renewable for a further term or as long as production continued; the minister could – but, as a matter of practice, did not – order drilling after the fifth year.

(ii) **Exploration Rights.** Exploratory rights under the 1949 act consisted, initially, of petroleum and natural gas (P&NG) reservations:

- (1) a reservation covered a relatively large area (maximum 100,000 acres);
- (2) it had a rental per acre starting at 10 cents/acre in the first term and rising to about 25 cents/acre in the third year;
- (3) they were for an initial term of four months, but could be extended for up to two years;
- (4) there were drilling requirements (50 per cent of which could be applied as a credit against the first year's rent on any leases taken out);
- (5) up to 50 per cent of the area could be taken in leases but in a checkerboard fashion including only 50 per cent of any single township, and subject to the restrictions on lease size noted above. (The remainder of the land entered Crown Reserves and could be reissued by the government in leases or exploration rights.)

Between 1951 and 1962, several new types of exploratory rights were introduced, with characteristics similar to the P&NG Reservations. Crown Reserve Drilling Reservations, first issued in 1954, were sold by competitive bonus bid on land in Crown Reserves with a rental of 25 cents/acre each six months; they had a maximum term of three years and were partially (usually 25 per cent) convertible to leases in the same

Table 11.2: Payments to the Alberta Government, Fiscal years 1947/8 to 2011/12 (10⁶ Dollars)

Part A: 1947/48 to 1971/72

	<i>Crude Oil and Natural Gas Royalty</i>	<i>Oil and Natural Gas Rentals</i>	<i>Bonus Bids</i>	<i>Oil Sands Royalty and Rentals</i>
1947	0.9	0.7	0.0	0
1948	1.8	2.3	8.9	0
1949	3.6	5.9	23.5	0
1950	5.2	9.4	29.4	0
1951	11.0	14.6	25.0	0
1952	13.5	17.5	25.9	0.1
1953	18.6	19.7	58.1	0.1
1954	20.2	18.3	42.4	0
1955	28.8	20.3	77.1	0.2
1956	37.3	35.3	71.0	0.1
1957	32.8	28.8	60.9	0.5
1958	25.4	28.3	55.7	0.4
1959	27.3	30.3	83.5	0.5
1960	27.7	29.2	45.8	0.7
1961	39.2	30.0	54.0	0.8
1962	51.0	36.9	32.3	0.7
1963	56.7	36.6	54.9	0.6
1964	62.1	44.6	94.4	0.8
1965	68.6	54.5	129.8	0.7
1966	80.2	49.9	114.2	0.9
1967	94.1	51.4	79.1	1.0
1968	105.1	52.7	128.9	2.3
1969	121.1	58.8	77.5	3.1
1970	143.7	56.2	35.3	2.4
1971	174.6	58.4	34.0	3.0

Part B: 1972/73 to 1984/85

	<i>Crude Oil Royalty</i>	<i>Natural Gas and NGL Royalty</i>	<i>Oil and Natural Gas Rentals</i>	<i>Bonus Bids</i>	<i>Freehold Mineral Tax</i>	<i>Oil Sands Royalty</i>	<i>Oil Sands Rental</i>	<i>Incentive Credits</i>
1972	172.3	70.0	51.4	81.7	69.1	3.8	1.5	(10.1)
1973	302.1	70.0	51.4	81.7	69.1	8.2	1.5	(10.1)
1974	956.4	231.5	52.4	80.9	45.4	13.9	2.2	(15.3)
1975	975.4	519.1	52.7	141.0	54.1	15.4	4.5	(33.4)
1976	1,049.3	721.7	57.8	207.8	76.3	19.1	4.8	(49.2)
1977	1,323.2	980.8	64.8	736.1	76.5	23.8	5.1	(75.1)
1978*	1,617.9	1,196.2	69.0	677.5	96.5	27.8	5.2	(71.4)
	(1,775.7)	(1,300.9)	(75.0)	(707.5)	(96.8)	(30.6)	(5.7)	((104.0))
1979	1,899.9	1,509.9	64.3	1,057.7	99.9	46.2	5.0	(98.7)
1980	1,970.1	1,903.0	84.2	758.8	145.8	224.9	4.4	(148.5)
1981	2,179.8	1,956.3	91.0	556.9	134.8	299.7	4.8	(157.9)
1982	2,339.8	1,873.4	85.4	336.5	155.9	362.3	9.5	(121.3)
1983	2,883.1	1,694.1	79.5	487.0	160.0	303.8	6.5	(73.9)
1984	2,867.6	1,942.4	83.4**	662.1	185.5	185.5	na	(128.0)

Table 11.2/continued

Part C: 1985/86 to 2011/12

	<i>Crude Oil Royalty</i>	<i>Natural Gas and NGL Royalty</i>	<i>Oil, Oil Sands and Natural Gas Rentals</i>	<i>Bonus Bids</i>	<i>Freehold Mineral Tax</i>	<i>Oil Sands Royalty</i>	<i>Incentive Credits</i>
1985	2,735	1,806	85	724	189	25	(44)
1986	1,005	1,097	77	292	96	11	(169)
1987	1,359	1,011	74	761	92	23	(197)
1988	957	989	74	409	71	19	(580)
1989	1,126	961	72	389	69	28	(375)
1990	1,325	1,080	94	416	76	39	(500)
1991	1,038	839	105	261	75	31	na
1992	1,009	1,069	102	167	73	65	na
1993	787	1,410	106	717	84	66	na
1994	1,095	1,257	116	978	102	209	na
1995	1,057	1,003	116	319	102	312	na
1996	1,386	1,299	131	525	117	512	na
1997	914	1,660	148	1,071	131	192	na
1998	450	1,467	142	464	112	59	(249)
1999	1,103	2,441	141	743	134	426	(188)
2000	1,500	7,200	147	1,159	256	712	(144)
2001	987	4,030	148	970	319	185	(109)
2002	1,177	5,126	153	566	202	183	(84)
2003	981	5,450	154	967	288	197	(82)
2004	1,273	6,439	153	1,262	306	718	(102)
2005	1,463	8,388	156	3,490	334	950	(111)
2006	1,400	5,988	159	2,463	317	2,411	(174)
2007	1,655	5,199	159	1,128	247	2,913	(44)
2008	1,800	5,834	160	1,112	261	2,973	0
2009	1,848	1,525	158	1,165	124	3,160	(1,119)
2010	2,236	1,416	161	2,635	127	3,723	(1,774)
2011	2,284	1,304	169	3,312	127	4,513	(25)

Sources and Notes:

* In this year the department changed its revenue reporting from a receipts basis to an accrual basis (including accounts receivable and accrued interest). The first of the reported values is on the receipts basis, so comparable to earlier years; the second set of values is on an accrual basis, so comparable to later years.

** Includes oil sands rentals.

The largest revenue source each year is highlighted in bold.

Parentheses indicate a payment to the industry by the government.

From 1998 on the all incentive credits are royalty tax credits.

Data are from *Annual Reports* of the Alberta government department overseeing the petroleum industry, variously the Department of Mines and Minerals, Department of Energy and Natural Resources, and Department of Energy.

manner as P&NG Reservations; they covered a smaller area (twenty sections) and had to be drilled to a particular formation. Beginning in 1951, Crown Reserve Natural Gas Licences (and in 1952 Natural Gas Leases) were introduced: they allowed exploration for natural gas if a particular formation in that area had already proved to contain natural gas and were specific to that

formation; they had a life of three years with a rental of 5 cents/acre each month; they were convertible to natural gas leases in part or total depending upon the amount of exploration undertaken.

In 1962, a major change was made when an area of the province named "Block A" was created. It was an area considered very well explored, and hence not

viewed as likely to hold any major undiscovered oil plays. Block A covered the central, southern and eastern parts of the province (townships 1 to 64, i.e., south of a line through Cold Lake), east of the fifth meridian, and here the exploratory rights were to consist of permits. Permits had a higher rental than the various licences or reservations, equal to 50 cents/acre, but were entirely (100%) convertible to lease.

Rental payments formed an important part of total government petroleum revenue in this period, as can be seen in Table 11.2. Over this period, rental payments usually contributed 20 to 30 per cent of government petroleum revenue, although the share had fallen to 10 per cent by 1973.

(iii) **Crown Reserves.** This consisted of mineral rights in those areas specifically set aside by the government as well as land relinquished from reservations or licences. It was available for subsequent sale by the government in the form of leases (if close to a successful venture) or exploratory rights.

(iv) **Bonus Bids.** Competitive bonus bids were required on most mineral rights issued after 1947. Obviously this is one mechanism of allocating a scarce resource among competing producers. Further, it is an allocation procedure that tends to favour those producers who are most efficient, since lower costs tend to mean higher expected profits, and therefore higher bonus bids. As discussed above, under competitive conditions, the government can capture a high proportion of the expected (*ex ante*) economic rent from the land.

Bonuses formed a major part of government petroleum revenue after 1947 but were also more variable than either royalties or rentals (see Table 11.2). Royalties and rental payments for productive leases are ongoing payments that are spread over the entire life of a petroleum deposit; hence the effect of a change in conditions in the oil market is felt on the stream of such payments. A bonus bid, however, reflects the entire expected capitalized net value of the asset, and the full impact of a change in the expected profits of a project is reflected in that single bid. Bonus bids, therefore, tend to reflect changes in geological and economic conditions much more immediately and markedly than do royalties or rentals. The variability in bonuses can be related to geological factors (payments rose following the first major Devonian finds in 1947, the Pembina find in 1953, the Keg River find in 1964) and to changed economic conditions

(payment rose significantly with oil price rises in the early 1970s).

c. Conclusion

The years from 1947 through 1973 saw the maturation of the conventional Alberta oil industry in a market environment that was relatively stable. Beginning with the Leduc find in 1947, a major rise in petroleum exploration quickly took place with drilling through the 1950s and 1960s testing new areas both geographically (with increasing numbers of wells going into the northern and foothills areas) and geologically (with more wells testing horizons down to Pre-Cambrian basement rock). By the start of 1973, a total of 10,985 exploratory wells (excluding outpost wells) had been drilled in Alberta. This amounted to about 0.05 of a well per square mile of sedimentary basin area in Alberta; of course, this is an average, with many parts of the basin less intensively explored, and many wells not passing through all potentially petroliferous geological horizons. The intensity of exploration by 1973 was still significantly less than the average for the onshore lower-48 states in the United States but was much higher than that for any other petroleum-producing nation. There were changes in the prices of oil and natural gas over this period, but the year-to-year changes were minor as compared to the OPEC-induced price changes after 1972.

Given that the provincial government was reluctant to undertake a government-run exploratory drilling program, the regulatory environment was successful in achieving two main objectives: (1) ensuring that exploration proceeded at a level high enough to generate continuing geological knowledge about promising areas of the province that were relatively lightly explored; and (2) ensuring that a significant portion of economic rents were captured by the province. Large area exploratory reservations and permits helped to encourage exploratory activity, while the relinquishment provisions ensured that the province would bear some of the risk of exploration and maintain an interest in those locations newly discovered to hold profitable oil and gas deposits. It should be noted that the checkerboard leasing pattern that resulted contributed to the rule of capture problem discussed in detail in Chapter Ten. Large amounts of money were raised by rentals, bonuses, and royalties; in addition, Alberta derived some revenue from its share of the corporate income tax.

The reliance on rentals and gross royalties might be judged inefficient since both are production-based

taxes that make no explicit allowance for costs; hence they may tend to encourage earlier abandonment of producing wells and discourage some exploration and development. In contrast, the competitive bonus bid is effective in distinguishing between projects of higher and lower expected profitability. However, both political and theoretical factors argue against sole reliance upon competitive bonus bids. In political terms, governments find it important to demonstrate that resource industries are paying taxes to the government while production occurs. Beyond this, in a world of uncertainty, competitive bonus bidding procedures have risk-sharing characteristics that transfer all risk to the companies. Usually, governments will wish to assume some of this risk, particularly if risk-aversion leads companies to offer low competitive bids or if the lack of knowledge means that the bidding process on some mineral rights is not effectively competitive.

Critics might argue that rentals and royalties were not a suitable form by which to generate revenue additional to competitive bonus bids. A preferable alternative would be a corporate income tax designed explicitly to fall on the economic rent from petroleum production. Recall, from above, that such a tax would differ from the usual corporate income tax by allowing for the deduction as a cost of an allowance for return to equity capital. There are, of course, administrative problems in designing such a tax, but it has much to recommend it since it should be relatively neutral (i.e., have few disincentive effects). However, there are disadvantages.

In practical terms, a net profits tax might have involved jurisdictional problems in the Canadian federal system. In the period before 1974, it was accepted by Ottawa that rental payments, royalty payments, and (after 1962) competitive bonus bids paid to provincial governments could be deducted as a cost of business for the corporate income tax; the province could not be sure that the same treatment would be accorded to a net profit tax. Beyond this, there are disadvantages to a net profits tax in an industry in which the open access problem may be severe: increased exploratory expenditures could serve to drive the net profit and government revenue towards zero. Rental and gross royalty payments, since they are an inescapable cost, do not have this characteristic; competitive bonus bids may act as the major cost category that absorbs the incremental expenditure induced by open access, especially if the government limits the number of mineral rights issued each period.

However, the non-neutrality (inefficiency) of the rental/royalty payment schemes must be admitted.

Clearly, the adoption of a sliding scale based on production was designed to minimize the bias, on the presumption that higher-cost oil would tend to come from lower-output wells. Many of the basic operating costs of the well would be written off over a smaller amount of output, and declines in petroleum output in wells as depletion progresses are often accompanied by greater water production and higher disposal costs. The movement from a 5 per cent minimum royalty rate to an 8 per cent rate in 1962 may have increased the inefficiency of the royalty, but the minimum rate was reduced to 5 per cent again in 1973. However, it is not only low-output wells that have high per unit costs, so a gross royalty may have significant disincentive effects of other types. Two examples follow. First, there are relatively small reserve pools that have high initial production rates per well (but a small number of wells); all else being equal, the exploration cost per barrel will tend to be relatively high for a small reserve pool of this type and a significant royalty burden could inhibit exploration. Second, one might suppose that many wells producing under conditions of enhanced recovery (EOR) will have relatively high production rates, and therefore high marginal and average royalty rates; but the EOR expenditures may also be large, and the royalties might make the venture unattractive. No quantitative studies have assessed the magnitude of these disincentive effects, but it is clear that, by the end of the 1947–73 period, the technological options for EOR recovery were significantly greater, and the average oil discovery size was becoming smaller, so that the disincentive effects of rentals and royalties may have become more significant. Against this, however, the government could balance the rising real prices of oil in North American markets.

By the early 1970s, the most dissatisfying feature of the mineral rights arrangements for Crown land, from the viewpoint of the government, was probably the risk-sharing aspect. None of competitive bonus bids, rentals, and royalties (with a maximum rate of 16½%) were very responsive to unexpected changes in economic rent, particularly rises due to increased oil prices in world markets. One could argue that the government of Alberta became more willing to bear risk as the 1950s and 1960s passed and the province became wealthier. Alternatively, one might argue that the risk-sharing preferences of the government were essentially unchanged, but by the early 1970s the government was suffering after-the-fact regrets, when the higher-than-expected value of oil became apparent. In these circumstances, the concerns were somewhat different for newly issued, as opposed to

previously issued, Crown mineral rights. On the mineral rights still to be issued, the competitive bonus bid could be expected to capture at least a portion of the higher anticipated value due to rising oil prices. Even on these rights, however, the competitive bonus bid did not allow the government to bear a share of the increasing market risk. In the early 1970s, it was clear that OPEC was beginning to show international economic muscle; moreover, the heavy reliance of the world upon OPEC oil, and the short- and medium-term inelasticity of international petroleum demand and supply (outside OPEC), meant that large rises in oil prices would be beneficial to OPEC. But no one knew exactly how high prices could go before OPEC began to suffer from significantly reduced sales, nor how likely it was that individual OPEC members could cooperate to the extent necessary.

The government of Alberta responded by imposing higher taxes to capture some share of increased industry profits. These changes, in 1973, eventually involved higher royalty rates on all except the lowest output wells. The government maintained the appearance of abiding by the clauses of the previously issued petroleum leases by making the increased royalty voluntary for leases still under their initial ten-year term (for leases issued after 1962) or twenty-one-year leases (for leases issued before 1962). Companies that did not agree to the higher royalty were, however, assessed a new mineral reserves tax. While the industry cannot have found these higher taxes surprising, they regarded them with trepidation. In part, this reflected the non-neutrality of a gross royalty with its investment and production disincentives. Beyond this, however, it was now apparent that the provincial government was quite willing to change tax arrangements if it felt that its share of the actual rent earned was 'too low.' It was less clear what would happen if events turned out to be particularly unfavourable and the government's share of the rent was 'too high.' As a result the political risk perceived by the industry was clearly increased, and companies would now be justified in expecting a smaller share of the economic rent from the more positive market situations seen as possible. Thus, while rising real market prices for oil and natural gas in the early 1970s should have had the effect of attracting more investment to the industry, the market stimulus to invest was offset to some extent by the higher royalties and by a perceived increased probability of higher taxes.

This problem might have been minimized if the government had moved to a net profits tax of some kind in the early 1970s. Such a tax is closer to neutral

in effect than a gross royalty and has very clear risk-sharing characteristics. However, the change from the prevailing royalty system is marked, as it is very difficult, if not impossible, to express a profits tax as a percentage of the volume of output, as had been the case thus far with the royalty. It was suggested above that the province may have seen three problems with a profits tax – its implications under the Canadian federal system of government, its relationship to the open access characteristics of petroleum exploration, and the difficulties in allocating costs, given the joint product nature of petroleum activities. However, given the federal–provincial jurisdictional disputes over petroleum taxation, which were to erupt with full-force in the mid-1970s, we can argue with benefit of hindsight that some federal–provincial agreement on rent and risk sharing in the early 1970s would have been most desirable. Also, the overall exploration of the province had advanced considerably by the early 1970s, so that the open access problems were probably much reduced.

In any event, the failure to find a satisfactory solution to the rent-collection and risk-sharing problems led to a turbulent decade after 1973 when international oil prices skyrocketed. One might ask whether the rent-collection scheme in Alberta was efficient in collecting *ex ante* (expected) rents. The question has not been answered in a satisfactory manner, although the amount of revenue paid by the industry clearly was large. Several studies of land sales associated with specific exploratory plays in the 1960s and early 1970s found that most of the anticipated economic rent on the leases sold was captured by the government (Watkins, 1975, and Watkins and Kirby, 1981). Watkins also noted that the government did not capture unanticipated rents. Industry spokesmen might point to the aggregate revenue and expenditure data that showed industry expenditures exceeding revenue in Alberta for all years before 1961 and with cumulative revenues from 1947 falling short of cumulative expenditures at the end of the year 1973. Clearly, any gap between revenues and expenditures on equipment and materials was more than absorbed by payments to governments. But such annual cash flow data are an inappropriate indicator of the efficiency of the rent-collection process for three major reasons. First, petroleum deposits are capital assets with long lives and the major expenditures tend to be very heavily front-end-loaded. As a result, the total division of economic rent cannot be determined from annual data over a part of the industry's life. Secondly, actual payment and receipt data are not necessarily a valid

indicator of the division of anticipated rents. Thirdly, the efficient collection of economic rent also implies that industry activity proceeds in an optimal manner so that rents are not dissipated for open access reasons. Hence, one is concerned not so much with actual revenues and expenditures from petroleum sales as with the ideal flows: this is a very complex problem and has not been carefully examined for Alberta.

4. 1974-2012

Canadian oil prices had begun to rise in 1970, following U.S. oil prices and the increasing taxes imposed by OPEC commencing with the Teheran-Tripoli agreements. Industry spokesmen in the late 1960s had spoken of the need for higher oil prices, often justifying the requirement with reference to the depletable nature of petroleum deposits, and the inherent need to progress to less-productive deposits. One can see that the industry would wish to see higher prices for its product, and the discovery rate for large volume low-cost petroleum reserves had fallen off, within North America at least. In the international context, however, it is less clear that oil price increases were inevitable. From the perspective of the late 1960s, real international prices had actually been falling since 1959, with increasing competition, and the reserves to production ratio for OPEC as a whole exceeded thirty in the late 1960s, indicating large available reserves; moreover, by North American standards, most OPEC nations were very lightly explored. It is hard to know whether companies in Alberta in the late 1960s were actually assessing projects under the expectation of price rises for oil. In any event, the quadrupling of the international posted price for OPEC oil between October 1, 1973, and January 1, 1974, raised international oil prices by an amount that far exceeded anyone's expectations. The value of energy throughout the world increased since any additional production tended to displace high-priced OPEC oil.

From the viewpoint of oil-producing companies in Alberta, the international oil price rises were welcome; much higher profits could be earned on all oil discovered before January 1974, and the full range of potential new projects was more attractive. Other Canadian groups viewed the price rises with less favour. Consumers were alarmed by the increased price of energy and, as discussed in Chapter Nine, their concerns found an outlet in government's energy pricing regulations. The governments that shared in the economic rent from petroleum were also

concerned about the increasing value of Canadian petroleum, particularly since neither federal nor provincial petroleum taxes were designed to capture a high share of the rent from unexpected price increases. The competing rent-collection objectives of Ottawa and Edmonton gave rise to the jurisdictional disputes, which dominated the Canadian energy scene from 1974 through 1985. Hyndman and Bucovetsky (1974) provide a perspective from the start of this period while Helliwell et al. (1989), Plourde (1989), and Watkins and Scarfe (1985) are among the many authors who discuss Alberta and Ottawa rent-collection measures in this period.

Table 11.2 shows petroleum industry payments to the Alberta government over this period.

a. Royalties

The rising value of oil immediately made the 1973 royalty schedule (and *Mineral Resource Tax*) seem inappropriate to the Alberta government. Effective April 1, 1974, a "supplemental" oil royalty was introduced in addition to the "basic" royalty assessed under the January 1973 schedule. (See Appendix 11.A for more details.) The purpose of the supplemental royalty was to capture for the government a fraction of the increased revenue to the industry from price rises above the 1973 level. The prevailing price was established as a 'Par' price, and the supplemental royalty was assessed on its excess above a 'Select' price, which was initially set at \$4.11/b, representative of the 1973 price. The government argued that most oil found before 1974 was expected to be profitable at prices that prevailed before that date and hence could bear a relatively high supplemental royalty. However, many projects that might be undertaken after 1973 would appear attractive at the new higher oil prices but would not have been undertaken at earlier prices. These projects obviously would generate less economic rent and hence were assessed a lower supplemental royalty. The supplemental royalty therefore distinguished between "old" oil (that from reserves as of April 1974) and "new" oil. The supplemental royalty was tied to the basic royalty, which, it will be recalled, was a sliding-scale royalty with lower rates for low-output wells. (In July 1979, a significant adjustment was made for low-output wells, with the minimum basic royalty rate tending towards zero as output fell to zero.) On higher-production wells, the supplemental royalty was essentially designed to capture 65 per cent of any price rise above the early 1974 level on old oil, and 35 per cent on new oil. (Appendix 11.1 A shows the actual formula.)

The unilateral move to higher federal taxation of the petroleum industry in 1974 (higher corporate income taxes, achieved in part by the disallowance of royalties paid to provincial governments as a cost of doing business) led to several modifications of the Alberta regulations. The base price (revenue above which was subject to the supplemental royalty) was raised by 60 cents per barrel on January 1, 1975, and the maximum supplemental royalty on old oil was reduced from 65 per cent to 50 per cent of the revenue increase, effective July 1, 1975, then further reduced to 45 per cent in April 1982.

Other significant modifications were made in 1982, once again in large part in response to the federal tax initiatives under the 1980 *National Energy Program* (NEP) and September 1981 *Memorandum of Agreement* between Ottawa and Edmonton, and to the NEP *Update* announced by Ottawa in 1982. In part, the changes involved recognizing two new classes of oil created by the NEP and the Memorandum. Royalty regulations had to be specified for NORP oil; essentially this was oil found after December 31, 1980, which would receive the New Oil Reference Price (international price subject to some qualifications). In addition, oil found between 1973 and 1981 was also to get a higher price than conventional old (pre-1974) oil, but less than the NORP; the royalty regulations had to recognize the higher price of such oil. Both categories of oil were recognized as “new oil” under the Alberta regulations and hence assessed a maximum supplemental royalty rate of 35 per cent. By April of 1981, the average royalty rate on old oil was 43 per cent; for new oil it was 25 per cent. Approximately 75 per cent of provincial output was old oil (Canadian Tax Foundation, *Provincial and Municipal Finances*, 1981).

In April 1982, Alberta announced two measures that reduced provincial royalty rates. The ‘Select’ price against which the price rise for the supplemental royalty was to be calculated was raised to \$40.90/m³ (\$6.50/b). Secondly, the supplemental royalty on old oil was now designed to take 45 per cent of the increased revenue rise rather than 50 per cent. In June 1985, the royalty formulae were further modified to take 40 per cent of the revenue increase on old oil and 30 per cent on new. (This was initially a two-year program but was extended indefinitely in October 1986; in addition, the new oil percentage of increased revenue was cut to 27 per cent so long as the oil price was below \$30/b.)

Starting on January 1, 1993, the royalty formula (presumably the Select price) was subject to annual revision to reflect changes in the GDP price deflator,

and a separate Par price was established for heavy oil. Oil discovered after September 1, 1992 was labelled ‘third-tier’ and would be assessed royalties 1/3 lower than in the formula for new oil. In addition, third-tier wells producing less than 20 m³/month are exempt from royalties. Also, the maximum royalty rates were reduced with a ceiling rate of 35 per cent. There were thus, for royalty purposes, four different categories of conventional crude oil in the province: old oil, new oil, third-tier oil, and heavy oil. The royalty schedules exhibited common characteristics across all categories of oil – higher royalty rates as production rises and at higher prices of oil – but the specific factors (and average royalty rates) differ, with old oil paying the highest royalties. Alberta Energy (2003) provided a detailed summary of tax and royalty regulations for the four western Canadian provinces, including Alberta. In 2005, 26 per cent of Alberta conventional light and medium oil output was classed as ‘old,’ 56 per cent as ‘new’ and 18 per cent as ‘third tier’ (Alberta Royalty Review Panel, 2007, p. 57).

The sharp rise in crude oil prices after 2003 sparked renewed interest in the petroleum royalty formula. For example, the Pembina Institute undertook comparisons of government petroleum revenues in Canadian jurisdictions with those in Norway and Alaska, finding, over the years from 1995 to 2002, that the latter jurisdictions gathered over 90 per cent of available economic rent, while Alberta captured just under 70 per cent. Pembina argued that the Alberta royalty take was unacceptably low (Pembina Institute, 2004). While several earlier critiques of the Alberta rent-collection system had compared shares of gross revenues, the Pembina study took into account estimated costs of production, therefore allowing the authors to speak of shares in ‘economic rent.’ Pembina considered ‘average’ petroleum operations, in the sense that they used total regional revenues and costs, which, they recognized, failed to distinguish amongst individual ventures of varying cost; expressed differently, their analysis could not address the important question of the impact of taxes and royalties on the marginal investment project. The differences between the Alberta oil industry and those of other areas are significant. For example, Alberta had far more oil wells than producing regions such as Alaska and the North Sea, with an average commercial oil pool size of about 300,000 barrels in Alberta as compared to a world average of just over 100,000,000 barrels (Alberta Royalty Review Panel, 2007, p. 50). The large number of wells in Alberta partly reflects pool characteristics; it also results from more intensive use

of reservoirs than in some parts of the world (e.g., OPEC), and the well-drilling incentives of prorating discussed in Chapter Ten. It should also be noted that the Pembina analysis approached the tricky joint product problem by transforming natural gas into oil on an energy-equivalent basis, rather than treating the oil and gas royalties separately. Unfortunately, in the Pembina study, production costs are measured by combining annual investment costs per barrel of oil reserves added (i.e., oil-in-the-ground) with operating costs per barrel of oil lifted (Pembina, 2004, p. 6). As discussed in Chapter Eight, this would tend to understate unit costs by failing to allow for the delay in transforming reserves into lifted oil and implicitly assumes that the costs of establishing reserves now are a reasonable measure of the costs of oil lifted now for which investment occurred in the past. The authors of the study admit that it is difficult to accept their precise numbers as entirely accurate; however, since the same method was applied to all jurisdictions, they suggest that their results do demonstrate that Alberta's petroleum rent-collection regime is less effective than those of a number of the other areas. In 2010, the Parkland Institute published a review of revenue and rent shares in the conventional petroleum industry in Alberta, which also argued that the government was leaving substantial rents in the hands of the private sector and failing to meet its own objectives for shares of rent and revenue captured. However, from an economic point of view, there are problems with their estimation procedures as they do not undertake life-cycle estimation of projects to estimate economic rents, and their methodology seems to ignore the required return to undepreciated capital after the year of investment (Parkland Institute, 2010).

The Pembina and Parkland conclusions contradict an early study frequently cited by the industry and referred to in the 2007 *Report of Alberta Royalty Review Panel* (p. 24); this was a 1997 study by Van Meurs of a large number of oil and gas royalty systems in the world. Van Meurs found that Alberta stood in the middle in terms of the share of rent captured.

However, particularly with the rising oil and gas prices after 2003, there was widespread speculation in the province that the government's share of economic rent was no longer satisfactory. In early 2007, the government appointed a panel to investigate the province's petroleum rent-collection regulations. The *Report* of the panel began by noting that "Albertans do not receive their fair share from energy development" (Alberta Royalty Review Panel, 2007, p. 7). This conclusion stemmed to a significant degree from an updated study by Van Meurs (cited on p. 23 of the

Panel Report) and simulations undertaken for the panel by the Department of Energy (Appendix to the *Alberta Royalty Review Panel Report*, 2007), which suggested Alberta received relatively low shares of economic rent in comparison to a number of other jurisdictions in North America and the world, as simulated for a variety of 'typical' projects at assorted price levels. Since the similar 1997 Van Meurs analysis had found that Alberta stood in the middle in terms of rent collection, the main reasons for the low ranking were the rise in oil prices, the relative insensitivity of Alberta royalties to oil price, reductions in the Canadian corporate income tax rate, and the failure, unlike many other governments, to modify regulations in light of the large price increases after 2003. The *Report* and the background material provided by the Alberta Department of Energy (2007a, b) provide a valuable overview of Alberta regulations and their strengths and weaknesses, although they did not provide much discussion of the risk-sharing aspects of rent-collection schemes, and paid little attention to the interactions between bonus bids and royalties.

In essence, the Royalty Review Panel recommended that the existing system be simplified by eliminating the vintage distinctions (old, new, and third-tier) and dropping the various royalty reduction incentive schemes. Average oil royalty revenue would be increased through a new royalty structure, which would involve two separate sliding-scale royalties, one volume-dependent, and the other price-dependent. The new schedules would reduce the royalty rate for low-output wells but significantly increase the highest rate (to 50% from 35%) at higher output and price levels (Alberta Royalty Review Panel, 2007, pp. 71-73). Based on simulations across a number of output rates and oil prices, the panel estimated that the rent share of conventional oil accruing to the provincial government would rise from 44 per cent to 49 per cent (p. 7), ignoring any impacts through bonus bids.

Later that year (October 2007), the Alberta government issued its response to the recommendations of the panel (Alberta Department of Energy, 2007c). The government announced new conventional oil royalties to become effective at the beginning of 2009. Given the very high prices in effect in 2007, one might question why there was a delay in implementing the new royalty formula, but the revision did address the panel's concern that the previous formula was insufficiently responsive to high international oil prices. The panel's recommendations to eliminate the distinction between 'old' and 'new' oil was accepted, and some of the incentive programs for conventional oil were to be eliminated as the panel had recommended. (Two

enhanced oil recovery programs were to be retained.) A new two-part royalty formula was announced, which sounded very much like what the panel had recommended: separate sliding scales for output level and prices, with the maximum royalty rate increasing from 35 per cent to 50 per cent. At low-output rates and low prices, the royalty rate would be 0 per cent, for example, at prices as high as \$85/b, so long as output was 10 m³/month or less, and at output rates as high as 145 m³/month, so long as the price was \$20/b or less. For very low production of 5 m³/month or less, the royalty would hit a maximum rate of 9 per cent so long as the oil price was at least \$125/b. At prices of \$20/b or less, the maximum royalty would be 26 per cent at output rates of 749 m³/month or more. The highest rate of 50 per cent would not apply unless price was at least \$70/b, and the output rate high enough (e.g., at least 677 m³/month at the \$70/b price). Compared to the royalty formula it replaced, the new regulations generated lower royalties than the old formula at lower prices (below about \$65/b, depending on the well output rate), and higher rates above that, and also garnered lower royalties on low-output wells. The new royalty schedule was to become effective January 1, 2009. Given the high prices of international oil, commencing as early as 1999, many critics thought that the government had unduly delayed revisions to the royalty rates; by the start of 2009, prices had fallen considerably below the peak of early summer 2008.

The new regulations drew forth criticism from the industry, especially as oil prices fell dramatically after mid-2008. In November 2008, the government announced a transition period for the new royalty regime, under which companies commencing drilling wells between a depth of 1,000 m and 3,500 m after 2009 could select a transitional royalty schedule that would delay the new rates until January 1, 2014. The government also appointed a Competitiveness Review Committee, which pointed out that Alberta's share in western Canadian industry activity had fallen after 2007 and that Alberta's royalties were generally higher than those in Saskatchewan and B.C., especially in the earlier years for more productive wells (Sierra Systems, 2010; Alberta, 2010). In May 2010, a modification was made to the royalty schedules, reducing the maximum royalty rate from 50 per cent to 40 per cent, effective January 1, 2011. (The revised schedule also reduced royalty rates slightly for some wells at prices around \$100/b. The formulae for the two part royalty are shown in Appendix 11.1.)

As can be seen in Table 11.2, royalty payments to the Alberta government rose tremendously after 1973,

reflecting both energy price rises and the increased royalty rates. The revenue flows from royalties far exceeded either rental or bonus payments. The table includes gas and natural gas liquids (NGL) royalties as well as oil royalties, and it can be seen that, by the 1990s, natural gas royalty revenue became larger than conventional oil royalty revenue, reflecting both higher relative gas prices and proportionately higher gas output. By 2000, natural gas royalties were far in excess of oil royalties. However, declining gas output and, particularly, prices meant that in 2009/10 and 2010/11, for the first time in over a decade, conventional oil royalties exceeded natural gas royalties. Beginning in 2009/10, the largest royalty contribution to the provincial government came from the oil sands. (Chapter Twelve deals with natural gas royalties and Chapter Seven with oil sands royalties.)

Several more technical aspects of the oil royalty in the 1974 through 2012 period deserve brief comment. The precise definition of "new" oil was obviously of concern to producers since the supplemental royalty is so much lower for such oil. Oil in pools discovered after March 31, 1974, could clearly be considered new oil. More difficult to handle was oil from pools found earlier but which may have been thought unproducible under the lower prices that existed before 1974. The definition of new oil was therefore expanded to include oil discovered before April 1, 1974, but: (1) outside delineated pool boundaries as of April 1, 1974; (2) in enhanced recovery schemes that commenced after January 1, 1974; and (3) from pools that had not produced any oil for at least three years.

Another set of problems existed with respect to the wide variation in producing rates from Alberta wells. The incremental royalty was geared to recover a percentage of the price rise for oil above the 1974 level but was implemented by a formula that tied the supplemental royalty to a production-based sliding-scale royalty. Therefore, the incremental royalty could take exactly the desired percentage of the revenue increase only at one specific output rate. Both the basic and supplemental royalties would be higher for wells with a higher output rate than this, and both would be lower for wells with a lower output rate. Prior to 1979, the components of the supplemental royalty were devised to capture the desired amount of revenue from a well with the average output rate in the province. However, as a result of production decline, the average output rate was falling over time; as a result the rising price of oil in the late 1970s generated progressively higher incremental royalty rates on revenue increases for high-output wells. In 1979, the province decided to modify the incremental royalty

in the future on the basis of a well producing 120 b/d (572.1 m³/month) even though the average production from an Alberta oil well continued to fall.

b. Issuance of Rights

The basic principles of mineral leasing, as established in the 1947–73 period, remained in force, while numerous changes in detail were made. (Alberta Energy, 2002, provides detailed review of land tenure policies.) Exploration rights are issued by competitive bonus bids and are convertible in whole or part to lease.

Lease areas are also issued by competitive bonus bid, generally on smaller areas. Effective July 1, 1976, leases were issued with a five-year term reduced from the ten-years under the 1962 regulations. The rental rate is currently \$2.50 per year per hectare. The lease will revert to the Crown unless drilling commences within the five-year initial term, although the Crown may allow an extension of up to three years. Holders of leases issued before 1976 were also required to drill on their leases or relinquish them. There were provisions that allowed leases to be grouped in respect of drilling requirements. The government has moved to separate leasing to some extent by depth and occasionally by product (e.g., a natural gas lease). Starting in 1976, companies that did not drill into deeper formations for which they held petroleum rights, while producing from shallower formations, were required to relinquish the deeper mineral rights back to the province, which could then be resold. In 2008, the government announced that it would require relinquishment of rights as well to shallower formations above producing pools.

Effective June 30, 1978, the issuance of “reservations” ceased, although exploratory permits continued to be issued in the form of “licences,” which had been introduced two years previously. Licences had a rental fee of \$2.50 per hectare, a term that varied from two to five years depending on the location in the province, a maximum area varying from twenty-nine to thirty-six sections, depending on location, and were convertible in part or in whole into leases, depending upon the depth of the well drilled.

The province was divided into three areas – Plains, Northern, and Foothills – with increasing maximum size and licence term in this order. Presumably, the Plains area is more fully explored and less costly to drill than the Northern, while the Foothills is still less explored and more costly. In a sense, the 1976 regulations turned the entire province into an area like “Block A” under the 1962 regulations, in recognition of the maturity of exploratory effort. Large area exploration rights with partial relinquishment to the

Crown were no longer viewed as necessary to ensure adequate bonus bids. (Reservations under the 1957 regulations would cover up to 100,000 acres, or over 150 sections.) As noted above, provisions were also introduced in 1976 and extended in 1985 for the rights to deeper areas to revert to the Crown if companies produced from or drilled to shallow depths. From 1976 to 1998, companies could earn a waiver on the rental on licences, if they engaged in early drilling. In July 1990, the rental rate was set at \$3.50 per hectare for all petroleum rights.

In 1995, the government set up an Industry Advisory Committee to assess the petroleum land tenure system (Alberta Energy, 2002). No clear consensus emerged, but the government continued to consult with industry and introduced revised legislation and regulations in 1998 and 2000. The provisions follow the spirit of the previous regulations. There are now two types of mineral rights, licences and leases, which may cover all geological formations or only those above or below a certain geological zone. Companies may request that mineral rights be offered for sale, but allocation is by sealed bonus bid. Maximum and minimum areas and duration are defined, varying in the Plains, Foothills, and Northern parts of the province. Licences have drilling requirements, although these may be combined across neighbouring licences; drilling extends the term of the licence, and such licences are treated as a lease and therefore allow production of oil and gas. Lease provisions continued as set out in 1976.

As Table 11.2 shows, bonus bids continued to provide significant revenue to the province, with the revenue rising as oil prices also increased. Of course, the bonus payments related to mineral rights where discoveries would pay the “new” oil and gas royalties. Bonuses tended, as before, to be more variable than rentals or royalties. Once again, the magnitude of bonus payments can be related to geological factors (e.g., the land boom in the West Pembina area in 1977), political factors (the industry reaction to the NEP in 1981), and economic factors (oil price changes, as, for example, the surge in 1997 and fall in 1998).

c. Incentive Schemes

The period after 1973 was characterized by a new development in provincial regulation: a wide variety of incentive schemes were introduced in order to encourage industry activity. It might be thought that such schemes would be unnecessary in a period when oil and gas prices were increasing significantly, but two other factors are important. First, one might expect that as the industry matures the remaining

undiscovered prospects look less attractive (of course, technological change and new knowledge may offset this). If the government wishes to maintain continuing activity in the petroleum sector, incentives of some sort may be necessary. Second, and related to the first, is the tax burden factor. As has been evident, the provincial government does not rely primarily on profits taxes, and therefore the industry will be dissuaded from some types of activities due to the royalty-tax burden. (Ottawa, until the 1980 NEP, relied upon the corporate income tax, but this is not a completely neutral tax and is certainly not so when companies may not deduct royalty payments as a cost.)

Since 1974, the provincial government has utilized many different types of 'incentive' programs, and the specific regulations governing them have been changed frequently. EnviroEconomics (2010) provides a review of Canadian royalty and tax provisions, including various incentive programs, within the context of various 'subsidies' granted to the oil industry. They suggest that 'subsidies' to the petroleum industry in Alberta in the years 2004–2009 amounted to 5.7 per cent of the value of production. Their definition of 'subsidy' is quite broad; for example, it treats the incentive programs as subsidies, rather than as policies, for example, designed to offset inefficiencies in an *ad valorem* royalty.

We shall not set out all the details, but, in terms of broad classes, the major incentive schemes included the following:

Exploratory Drilling Incentive Program. This was first introduced in 1972 and involved a five-year royalty holiday on successful wildcat oil wells (finding oil in a previously unproductive structure); in addition, each foot of wildcat well earned a credit that could be claimed by the company against royalties owed. The scheme was maintained in various forms from 1972 to 2009 and was expanded to include a two-year royalty holiday for wildcat gas discoveries, higher credits for deeper footage and more remote parts of the province, credits made applicable to bonuses as well as royalties, and the deep footage of deep-pool exploratory tests eligible for a credit.

Geophysical Incentive Program. This was introduced in 1975 and continued through 1982, although with greatly reduced incentives after 1979. In mid-1983, it was reintroduced and continued to 2008. It allowed a portion of the cost of seismic surveys to serve as payment or credit against other provincial tax revenue owed by the company so long as the survey met certain criteria and the results were offered for sale

to others after three years. The province was divided into three regions, with higher credits in the more remote areas.

Royalty Credit. Effective in 1975, all companies in the province could claim a \$1 million credit against royalties owed to the province. Most significant producers paid well over \$1 million per year in royalties. (An average royalty rate of 35 per cent on an oil price of \$10.00 per barrel would require about 286,000 barrels per year, or 783 barrels per day, to yield \$1 million.) Therefore, for most companies, the royalty credit would increase total corporate after-tax profit but not affect the marginal royalty rate on corporate output. However, for small producers, owing less than \$1 million in royalties, the marginal and average royalty rates on incremental output became zero. In October 1981, the royalty credit amount was increased to \$2 million, and then to \$4 million in April 1982. It was subsequently lowered again, and changed to a to-be-specified percentage (%) of the first \$X of royalty paid. Both '%' and 'X' were changed periodically in relationship to the price of oil, with a lower royalty credit as the oil price was appreciably higher. Also, in January 1975, the provincial government announced that royalties paid would be deductible as a cost of business for the provincial part of the corporate income tax. Other royalty credit regulations have been introduced, including one for 'third-tier' exploratory wells drilled after September 1992 (a twelve-month royalty holiday, up to \$1 million in value), and, from the same date, a royalty holiday on the first eight thousand cubic metres produced from a previously inactive well. Also effective after September 1992, wells that had been producing at low-output rates were accorded a maximum royalty rate of 5 per cent on the next sixteen thousand cubic metres of production. The royalty credit program was dropped in 2006.

Petroleum Incentive Payments (PIP). The National Energy Program introduced a scheme of subsidy payments for exploratory and development activities. Such payments were to be higher for companies with greater Canadian ownership, for exploratory expenditures and on frontier lands. In the September 1981 *Agreement* with Ottawa, the Government of Alberta agreed to take over payment of the PIP grants for oil industry activities in Alberta.

The conditions governing PIP payments in Alberta were as follows: The scheme was to last until 1986. The amount of the PIP payment was deducted from the cost of the capital expenditures for the purposes of capital consumption allowances in the corporate

income tax. In effect, the PIP payment was taxable, although the tax payment might be deferred to the future, depending on the taxable position of the company and the capital consumption allowance provision for the activity concerned. The PIP payments were phased in gradually (as the 'earned depletion allowance,' see below, was phased out). By 1984, on provincial Crown lands in Alberta, the PIP grants covered 15 per cent of exploration costs for companies with 50–75 per cent Canadian ownership and 35 per cent of exploration costs if the ownership rate exceeded 75 per cent. Development costs were covered to the extent of 10 per cent and 20 per cent respectively. Companies with less than 50 per cent Canadian ownership did not receive PIP grants. In the 1981–82 fiscal year, Alberta paid about \$1.7 billion under the PIP program. PIP grants ended with the demise of the NEP under the *Western Accord* in June 1985.

Well-Servicing Grants Program. In April 1981, the government announced a program for 1981 and 1982 whereby 50 per cent of the cost of maintenance, repair, and service of a well would be paid for by the province, to a maximum of \$75,000 per well, for wells on provincial Crown land. The program was extended to cover injection, water disposal, and observation wells in August 1981, and for about 25 per cent of the drilling cost of development wells (varying with depth and location in the province). The province allocated a total of \$250 million to the program.

Enhanced Recovery Incentives. In 1976, authority was given to the lieutenant-general-in-council to reduce the royalty rate to 5 per cent on approved experimental projects. Effective in 1977, any new 'tertiary' enhanced recovery project (beyond the waterflood stage) could apply to have the royalty assessed on revenue less the incremental costs of the scheme, thereby reducing the effective royalty rate (moving closer to a profits tax); total royalties paid must still be as high as they would have been with primary and waterflood ('secondary') recovery. In 2002, additional royalty reductions were introduced for EOR schemes that utilized CO₂.

Horizontal Well Incentives. After July 1991, reduced royalties were granted to horizontal wells, based on the number of vertical wells made unnecessary. Presumably the intent was to encourage this new technology and to allow for the disincentive under an output-based sliding-scale royalty for higher output wells. In 1993, horizontal extensions to existing vertical wells

were also granted reduced royalties. The program was eliminated at the end of 2008 in line with the recommendations of the Royalty Review Panel.

Deep Exploratory Well Royalty Credit. This program, announced in 2008, allowed relief from up to \$1 million in first year production royalties for exploratory well deeper than 2,000 metres.

Royalty Drilling Credit. Effective for 2009–11, this granted a credit against royalties for wells drilled in an amount up to \$200/m drilled.

New Well Royalty Reduction. Wells drilled between 2009 and 2011 were granted a one-year royalty rate of 5 per cent. The 2011/12 budget announced that the provision would be made permanent.

d. Conclusion

Two major weaknesses of the Alberta rent-collection policy haunted the 1970s and came to the fore again after the turn of the century. First, the reliance upon competitive bonus bids as a way to distinguish between high- and low-profit ventures left the province without a significant share of the unexpected rent increase associated with rapidly increasing world oil prices after 1970. The resultant move to raise royalty rates, in combination with the rent-sharing disputes with Ottawa, could not help but raise the political risk perceived by the industry.

The second problem relates to the weaknesses of the *ad valorem* royalty as a rent-collection device. Since it is based upon gross revenue rather than net revenue (profits), it can easily become a high burden on particular projects, thereby discouraging investment or causing earlier abandonment of oil pools. If the royalty is set low to avoid these effects, it is ineffective as a rent-collection device. Therefore, it normally becomes necessary both to introduce complex royalty provisions that differentiate between broad classes of pools and also to introduce a variety of supplemental measures that offer incentives to those activities that have been discouraged through inefficiencies in the royalty. There are at least four main problems with this approach: it is administratively complex and costly; it seems likely to increase the political risk to companies; it is difficult to know the exact costs of the various programs and the overall incentive effect; and it is virtually impossible to fine-tune (with gross royalties and incentives) so that the unique rent-generating characteristics of each project is recognized.

Watkins and Scarfe (1985) review the output and price-sensitive royalty scheme of 1974 and assess its effectiveness as a rent-collection device in the following terms (pp. 28–29):

In terms of efficiency of rent collection, we assume that the elasticity of royalties with respect to well production and price at any point in time should exceed unity, implying that the marginal royalty rate would exceed the average. However, the marginal rate should not be punitive; rather it should be comfortably below unity.

... We find that the elasticity of royalties with respect to the rate of production starts at 2 for low production levels and eventually approaches unity at high production levels. While the elasticity exceeds unity, the royalty formula is not well calibrated with resource quality because the changes in royalties become less onerous at higher levels of well production.

How do royalties vary with prices ...?

The elasticity of the volume of royalties with respect to price is a rather curious creature, asymptotically approaching zero as price increases become very large. The elasticity is less than unity for the values currently inserted in the royalty formula for both new and old oil. However, if we look at royalty revenues, the picture becomes rather different. The elasticity of royalty revenues with respect to price exceeds unity, implying that marginal royalty revenues exceed the average as prices increase. But the elasticity falls as price rises. Again, we conclude that the royalty structure is not well calibrated to capture economic rents arising from unanticipated rises in oil prices.

With respect to bonus bids, Watkins and Scarfe argue (pp. 29–30):

Alberta's other main device for obtaining economic rent is bonus bidding. If foresight and competition were perfect and sealed bids were submitted on all petroleum properties, the bidding process would mop up any remaining foreseeable economic rent. The term remaining rent here refers to the residual after deduction of taxes, rentals, and royalties, which are treated as costs in bid determination. However, competition is not perfect because bidders

seldom have equivalent information for a lease; competition may not be sufficiently intense; deficient foresight will ensure discrepancies between ex post and ex ante rents; and, most importantly, because of the lease retention provisions described earlier, not all production leases are subject to bids. Nevertheless, the evidence suggests competition among bidders in Alberta is sufficiently strong to allow the government to capture a large portion of ex ante rents on leases that are put up for bid.

Thus bonus bidding will tend to pick up remaining rents arising from quality differentials but not from unanticipated price increases. Neither will it pick up rents not absorbed by royalties on properties for which bids do not have to be made. In this way, the Alberta land system provides strong incentives for successful exploration – an additional reward for risk takers – as long as the rewards are not negated by other measures – such as the federal tax and pricing regime.

There is no detailed empirical analysis of the disincentive effects of the Alberta Crown mineral rights revenue terms. (Appendix 11.1 B provides further discussion of possible disincentive effects of a gross royalty, and shows, for four different well output rates, how royalties on crude oil differed across the various Alberta regulations from 1951 on.) In practice, it was, of course, almost impossible to separate the effect of the provincial royalty rate increases from the new federal tax initiatives of the 1970s. Four effects might be noted. Firstly, projects that are only marginally acceptable without such a royalty will become unacceptable with the royalty. Unless the royalty can be argued to cover a social cost that the project sponsors have failed to consider, this is an undesirable result. Secondly, a gross royalty will encourage premature abandonment of operating wells since a royalty is viewed by the producers as a variable operating cost. This is particularly important for wells that have high operating costs apart from the royalty since such wells will be running at high-output levels and therefore facing high marginal royalty rates even as they approach the economic date of abandonment. In Alberta, this problem has been offset at least to some extent by the provision that producers can ask for royalty relief to forestall abandonment. Thirdly, the disincentive effect of a gross royalty will be particularly heavy on those projects that have a relatively high ratio of costs to revenues and those that have a lower probability

of failure. Finally, a royalty schedule may also induce output shifts over time, in addition to the incentive to abandon earlier. In Alberta, until the late 1980s, the ability to change the intertemporal depletion of the reservoir as a result of royalty regulations was inhibited by market-demand prorationing regulations.

The Alberta royalty schedule will offer a general (but not invariant) incentive to reduce the current output from a well and to shift this output into a future period. This was true for two reasons. First, the present value of any fixed percentage royalty based on a fixed price will be less the further in the future the royalty is. Second, with a sliding-scale royalty based upon output, it is possible to reduce the marginal and average royalty rates by shifting output from high-volume periods to lower-volume periods. Since oil pools, and most oil wells, tend to exhibit production decline, this means shifting some output from the earlier to the later years. On the other hand, since the royalty is assessed on a per-well basis, it may encourage more rapid depletion through more infill drilling, which raises the pool output rate and depletes reserves faster but leads to a lower output per well and may therefore reduce the royalty rate.

At first glance, it may appear somewhat contradictory that the Government of Alberta in the 1970s should have both unilaterally raised royalties on Crown lands and introduced a variety of royalty credit or incentive payment schemes applicable to industry activities on Crown lands. But the reliance on gross royalties as the main rent-collection device explains their somewhat contradictory actions: royalties are relatively poor as a risk-sharing device, so changing market conditions call for a revamping of the regulations; but higher royalties to capture a share of the *ex post* rent tend to have disincentive effects, which must then be addressed by new measures. Hence, by the early 2000s, the Alberta conventional oil royalty scheme had evolved into a complex web of regulations: variations in rates for several classes of oil, by type and vintage; variations in rates for different output rates; variations in rates for different prices; and a number of lowered royalty rates for specific types of oil production. (See Alberta Department of Energy, 2007, for a summary.)

Table 11.2 includes data for years since 1973 on Government of Alberta revenue from the petroleum industry. Also shown, where available, are the costs of various incentive schemes, although it is difficult to know whether all costs are directly included here, since some of the royalty credit and holiday provisions will be reflected in a smaller total for royalties, rather

than recorded as a cost. This is an example of a 'tax expenditure.' (The years are not all strictly comparable since the reporting system for revenue was changed in 1979 to an accrual basis. Two sets of figures are included for the fiscal year 1978–79, one set on the old basis and the second on the new accrual basis.) The significant rise over the decade in both petroleum revenue and the exploration drilling incentives is apparent. The revenue effects of the royalty holiday mechanism are not apparent.

A tremendous increase in the sales revenue from Crown leases is apparent after 1973, suggesting that this is still an effective means of capturing *ex ante* rent and that expected profits of new ventures did increase, despite the various new taxes the industry faced. The fall in Crown rights sales revenues after 1980 may reflect the influence of the NEP, although it is hard to be sure of this since bonus payments are unstable over time. Table 11.2 also shows revenues from gas royalties, the tar sands, and the freehold mineral reserves tax. (Prior to 1975, the latter includes some revenue from Crown lands under the mineral reserves tax.)

After international oil prices rose to new highs (in nominal terms), the 2007 Alberta Royalty Review Panel recommended simplification of this system by eliminating the vintage distinctions and the incentive programs; it also suggested new schedules of price- and output-based rates that would reduce royalty rates for less productive wells and raise them for more productive wells, especially at higher price levels. In October 2007, the government announced changes to be effective at the start of 2009 that were largely consistent with the recommendations of the review panel. These changes would preserve the long-established structure of the Alberta oil rent-collection system (i.e., reliance on bonus bids, rentals, *ad valorem* royalties, and the corporate income tax) while increasing total payments to the Alberta government, especially in an environment of high oil prices. Under this royalty regime, Mintz and Chen (2010) looked at the 'effective marginal tax and royalty rate' for an 80 b/d well in Alberta and found it was appreciably higher than in other Canadian provinces or in Texas. While this meant more rent would be collected on such a well, it also suggested a greater inhibition of marginal investments.

Then, in 2010, the government announced reductions in the royalty rates effective January 1, 2011, which moved them much closer to those prevailing prior to 2007, with a maximum rate of 40 per cent (as compared to 35 per cent in 2007); the government retained lower rates at lower prices and for lower

output wells. There is something of a paradox in these changes. The motivation was concern that the old royalty regulations generated insufficient revenue in what many assumed to be a new higher-priced environment. However, given continuing production decline in operating reservoirs and declining discoveries and discovery size due to the maturity of the conventional industry, the final impact of the new regulations (with lower rates at the low-output end) may well be reduced conventional oil royalty receipts. A sense of *déjà vu* may have been enhanced by the government decision to introduce a number of new incentive programs as well.

In essence, the same problems we have noted before still held true: the government elected to rely upon royalties as the main rent-collection device, which allowed risk-sharing with industry, but a gross *ad valorem* royalty necessarily has disincentive effects. Perhaps the royalty review of 2007–2010 represents a missed opportunity to move towards a net royalty system. A first step would have been to recognize operating costs as a deduction before royalties are applied; incremental development costs could also have been recognized as an allowable expense. To go further, given the successful adoption of a net-profits tax on oil sands projects, perhaps the time would have been ripe to adopt a similar tax on conventional crude oil and natural gas. There are, as discussed above, some thorny issues involved here, particularly with respect to definition of allowable costs, including the difficulty in incorporating dry hole exploration costs. It would be necessary for companies to maintain an agreed-upon cost accounting for conventional oil and gas activities in Alberta, so obvious questions would arise, particularly for companies active in more than conventional activities and outside the province as well as within. Mintz and Chen (2010) suggested that the time might be suitable to move from a gross royalty to a cash flow tax. If allowance is made to carry forward negative balances with an appropriate interest charge, this approximates a net profit (or resource rent) tax. However, problems might arise since the cash flow tax is normally applied on a company basis, whereas Alberta Crown royalties are a part of the mineral rights provisions on specific properties. In any event, in 2010, the province decided to stay with much the same system as in the past, but with a somewhat larger maximum royalty rate if prices move to high levels.

In conclusion, one could argue, in retrospect at least, that it would have been preferable for the Alberta government to have shifted from reliance

upon gross royalties to reliance upon some type of net profit tax or net royalty, even as early as the 1970s. (In a different approach, Crommelin, 1976, suggested that the province consider a shift from competitive bonus bids to competitive royalty bidding; compared to competitive bonus bids, this would be expected to give the province a greater share of rising rents due to price increases, but poses a problem with earlier abandonment, assuming the royalty rate bid is high.) As was discussed in Chapter Seven, the 'generic' oil sands royalty introduced in the mid-1990s was a net royalty, with a gross royalty floor. A profit tax or net royalty is very responsive to changing economic rent, including unexpected variations; that is, it has very desirable risk-sharing properties, and, if designed carefully, small disincentive effects. One major disadvantage of a net profits tax relates to open access problems, but if it is used in conjunction with bonus bids, and if mineral rights sales in any region tend to be spread over time, open access problems should not be severe, particularly when the main geological features of the region are quite well mapped. However, given that reliance upon royalties continued, it is easy to understand why the royalty regulations involved sliding scales (based on production level, vintage, and price), and why the government was drawn to a variety of incentive schemes. We will not address the legal problems that may have inhibited the province in replacement of the conventional gross royalty with a net royalty or profit tax, given that the leasing arrangements with companies specified a gross royalty obligation and the status of petroleum-industry-specific profit taxes are not clear under the federal corporate income tax.

4. Federal Regulations

A. Pre-1973

Prior to the transfer of most Crown mineral holdings to the provincial government in 1930, Ottawa had the responsibility to set rent and royalty provisions on Crown land in Alberta. We shall not review the details (see Breen, 1993, chap. 1) but would note that by 1930 they included a number of provisions that were later adopted in the provincial regulations described above, including: fixed lease acreages, drilling requirements, per-acre lease rentals, a relatively low *ad valorem* royalty, relinquishment provisions and the possibility for issuance of some rights by bonus bids. After 1930, the federal government no longer had a significant role

in Alberta in setting out the petroleum rights tenure regulations, except on the remaining areas of federal Crown land.

Before 1973, the main federal provision affecting the distribution of economic rents from provincial Crown lands was the federal corporate income tax. (We abstract from payments on oil production by unincorporated producers.) Under the *BNA Act*, both federal and provincial governments were allowed to impose income taxes (“direct taxes”), so responsibility here has been shared. Summaries of corporate income tax provisions can be found in various ongoing publications of the Canadian Tax Foundation. These also provide a very good summary of the various tax rental and sharing arguments, which have, in essence, let Ottawa set the provisions of the tax while provincial governments have been free to set a provincial tax rate. It should also be noted that our examination of revenues associated with the corporate income tax on petroleum production abstracts from any reductions in personal income tax payments as a result of the partial integration of the corporate and personal income taxes. (This refers to provisions such as the non- or lower taxation of capital gains and the dividend tax credit in the personal income tax code. We view these as ways of reducing the double taxation of corporate profits, although it is notable that these personal income tax advantages were not reduced as the corporate income tax rate was reduced in the 1990s and 2000s.) Amongst various summaries of federal income tax regulations for crude oil production, we have drawn particularly on Helliwell et al. (1989, chap. 5 and Appendix 5.1) as well as various issues of *The National Finances*, issued annually by the Canadian Tax Foundation. We review the main features of the tax system but do not present many of the smaller adjustments or document the changes in tax rates.

Simply put, the corporate income tax is a tax on the “taxable profits” of corporations. Procedurally, as far as Alberta is concerned, the federal government sets the tax regulations and a tax rate (e.g., 46%); it then specifies an “abatement” (e.g., 12 percentage points, reducing the federal tax rate to 34%) that allows each provincial government to impose its own corporate tax rate (e.g., if Alberta imposes a rate of 11%, the total corporate income tax rate would be 45%). Governments might on occasion impose temporary surcharges or reductions on top of the basic tax rate.

Taxable profits are corporate revenues less allowable deductions. The complexity of the tax code lies largely in the variety of ways in which these deductions may be calculated. With reference to the crude

oil industry, it is useful to note eight classes of deductions. Specific provisions for each of these classes have been subject to change, but the general nature of provisions up to 1973 will be indicated in the following list. (The provisions are those for corporations whose “principal business” was petroleum production.)

- (1) **Operating costs:** These were deducted as incurred.
- (2) **(Intangible) Exploration expenses:** These are generally viewed by economists as capital expenditures, since they are undertaken with the intent of generating assets (petroleum deposits) of long life. They were expensible (100% deductible) as incurred.
- (3) **(Intangible) Development Capital:** Was also expensible as incurred.
- (4) **(Other) Capital Assets:** Could be written off over a number of years, as set out in a number of “capital consumption allowance” schedules, depending on the type of capital.
- (5) **Interest expenses:** Deductible as incurred. No deduction was allowed for the return on equity capital.
- (6) **Payments to other governments:** Rentals, royalties, and bonus bids were deductible as incurred. (This only applied after April 1962, for bonus bids.)
- (7) **Other deductions:** Mineral industries, including petroleum, were allowed an additional deduction, called the ‘depletion allowance,’ equal to one-third of profits (revenues less costs as specified in the tax code). This was a ‘net’ depletion allowance, as compared to the U.S. ‘gross’ allowance, which was a certain percentage of revenues. Other allowable deductions have included an “investment tax credit,” which reduced the corporate income tax owing on the basis of new investment spending, with a higher credit if spending occurs in parts of the country that are economically depressed.
- (8) **Loss carry forward:** Since there are no provisions for ‘negative taxes’ (payments by the government if taxable corporate profits are negative), there were provisions to carry negative taxable income values (“losses”) forward indefinitely as deductions in later years.

The corporate income tax itself and the depletion allowance in particular have been the source of much controversy. Many dimensions of this dispute have been captured in the studies of, hearings before, and reports of the federal Royal Commission on Taxation

(the Carter commission), which reported in 1966. The main arguments in these debates are noted, briefly.

Corporate Income Tax. Economists have not generally been enamoured of the corporate income tax. The public popularity of this tax is easy to see: “I’d rather corporations pay taxes, than I do.” This is a myopic view because ultimately it must be people who pay taxes. If the tax is viewed as one on the profit income of the owners (shareholders) of corporations, it may involve double taxation of income, since the dividends and increased share values that flow from higher corporate profits are themselves (potentially) subject to taxation under personal income tax regulations. Moreover, theoretical and empirical evidence both dictate that the broader impacts of the corporate income tax may be quite different than is generally thought. In particular, the mobility of capital across sectors (e.g., the corporate and non-corporate parts of the economy), and internationally, must be considered. In the extreme, if capital were perfectly mobile and Canada were such a small part of the world economy that events here had minimal effects upon rates of return earned elsewhere, then the after-tax return to equity capital would have to be the same both in the presence and the absence of the corporate tax. (Otherwise capital would leave the country until the reduced level drove returns up to the world level.) But this implies that the money to pay the tax must come from the tax being shifted forward onto consumers in higher prices and/or back onto input suppliers (e.g., wages) in lower prices. (This is typically effected in part by abandoning investments which fail to earn enough to cover the required minimum return plus the tax.) From this point of view, the corporate income tax is, in fact, largely a mix of a sales tax and a wage tax, rather than a tax on capitalists!

Some critics of the corporate income tax have suggested that there may still be two valid reasons for the tax, though one might ask whether special taxes rather than a general corporate income tax might not be a better means. The first reason relates to returns accruing to foreign capital since shareholders in foreign countries are not subject to Canadian personal income taxes. The second relates to that portion of profits in excess of the ‘normal profits’ to owners of equity capital. This would include, for example, monopoly profits, short-term high profits and (most importantly in the case of petroleum) any economic rents from mineral production. From an ‘ability to pay’ view of taxation, such rents are a particularly attractive tax base, for reasons clearly discussed in Section 1 of this chapter. The Carter Commission favoured a complete

integration of corporate and personal income taxes to avoid any double taxation, and the favourable treatments of capital gains and dividend income in the personal tax code have moved the Canadian system in that direction.

Depletion Allowance. Accepting the existence of a corporate income tax, further controversy was aroused by the depletion allowance accorded to mineral industries. Some flavour of this debate in the United States can be found by reading McDonald (1963, 1970). For Canada, see the studies for the Carter Commission by Bucovetsky (1964) and Burton (1966). Most economists were not convinced by the argument that, since it was necessary to allow companies to deduct from their revenues an allowance for the declining value of all their capital assets (a capital consumption allowance or CCA), and the oil or gas pool was obviously the most important asset of petroleum companies, there should be a special allowance in addition to the usual CCAs. Companies were already allowed to deduct the capital expenditures necessary to find and develop the pool. If taken literally, the argument would say that economic rents from petroleum deposits (i.e., the ‘value’ of the asset) should not be taxed at all, even though economic rents are usually viewed as a very attractive tax base.

Hence debate about the depletion allowance shifted to arguments about whether there were specific characteristics of the petroleum industry that justified special tax treatment. Discussion followed two broad paths, the first whether the corporate income tax itself discriminated unduly against the oil industry and the second whether there were externalities in oil production that justified a tax incentive. Along the first stream, proponents of the depletion allowance argued that the high capital intensity of the oil industry, its reliance on equity financing, and the high degree of risk meant that the corporate tax fell particularly heavily on the petroleum industry and that the necessity of passing on the resultant high income taxes would generate a contraction in the petroleum industry relative to other sectors of the economy. Opponents of the depletion allowance pointed out that many other industries are also risky and that there are numerous ways in which companies may share or spread risk in petroleum investment. Several studies of stock market prices, using the ‘capital asset pricing model’ (CAPM) of efficient capital markets, suggest that oil companies, particularly smaller crude producers, do seem to require a somewhat higher rate of return than many other industries reflecting somewhat greater undiversifiable risks in crude oil investment (Quiran and

Kalyman, 1977; DataMetrics, 1984). However, Cairns (1985) argues that risk arguments for preferential taxation of resource industries have little justification.

The CAPM suggests that in a well-developed economy, with extensive and well-functioning capital markets, opportunities exist for risk-averse investors to diversify their portfolios. For example, they may invest in many different projects or put their funds into mutual funds where their money is pooled with that of many other investors and spread over many ventures. Thus, for example, the risk of finding no oil on a wildcat well can be reduced if a large number of wells are drilled at a variety of locations. A large company may be able to do this by itself; a smaller company may accomplish the same thing by entering into joint ventures with other oil explorers. If individual investment risks can be offset by combing the investment with a larger portfolio, then risk-averse investors do not require extra compensation for the risk of their specific projects. Only risk that cannot be so diversified will require a risk premium.

The second line of argument proposed special tax incentives for the petroleum industry in order to generate additional net social benefits in the form of corrected externalities such as greater national security or increased economic activity in petroleum-producing regions. Critics, in turn, pointed out the contradictory aspects of national security arguments (e.g., greater production now uses up resources more quickly, thereby running the risk of increasing later dependence on imports) and questioned any plans to stimulate further reserve additions when prorationing was already holding oil capacity out of production and reserves to production ratios for natural gas were so high. Some proponents of special tax treatment for mineral industries argued that they were justified on grounds of both efficiency and equity since other major Canadian industries already obtained government support in such forms as subsidies or price supports (for some agricultural goods) and high tariffs (for some manufacturers, as initially adopted in John A. McDonald's National Policy of the 1870s).

The effectiveness of the depletion allowance was also questioned. For one thing, the tax deduction accrued as a result of past activities (i.e., those generating current revenue) and so were not obviously tied to current exploration and development investment. In fact, by reducing taxable income, current investment made it more difficult for companies to claim the depletion allowance. In a similar manner, the depletion allowance was less valuable to companies that had not yet moved into a taxable position and more valuable to older, established, and larger producers,

especially those with downstream income against which the depletion allowance might be claimed. These larger, vertically integrated companies typically had significant foreign ownership as well.

It is hardly surprising that the debate over the depletion allowance became highly politicized. Consumer and taxpayer groups, and political representatives from constituencies where such interests predominated, generally expressed opposition, while mineral industry groups and most spokesmen in regions with good mineral prospects offered support. Our general view is that neither side convincingly proved its case in economic terms but that cases for special treatment of one group should be soundly founded before they are enshrined in the tax code.

In any event, in the early 1970s, the effective rate of corporate income tax on the crude petroleum industry was low. (That is, the ratio of taxes paid to reported profits was low.) In part, this reflected the depletion allowance provision, which, by itself, reduced the effective rate of taxation by a third. In part, the low rate was misleading, simply reflecting anticipated conditions in a capital-intensive industry that had been growing rapidly so that much of the expected income tax to be paid was deferred to a later date when revenues would exceed deductions. Another reason for low income tax payments (though not for a low effective rate) was the deductibility of rentals, royalties, and bonus bids as an expense. Bonus bids, in particular, tend to eat up anticipated pre-tax profits, if they are deductible. (Consider for example a company facing a 33 $\frac{1}{3}$ % corporate income tax, and looking at a project with an expected before-tax profit of \$1 million. The after tax profit, then, would be \$666,667. What is the maximum amount the company would be willing to bid? The answer is not \$666,667, but \$1 million, with zero income tax anticipated.)

Volume 4 of the *Carter Commission Report*, in 1966, had reviewed arguments about the depletion allowance and pretty much accepted Bucovetsky's (1964) conclusion that the allowance was not warranted. The commission therefore recommended that the depletion allowance be phased out. It also recommended that both development expenditures and bonus bids (and other costs of acquiring a petroleum property) should be subject to capital consumption allowances spread over time, rather than deducted immediately. The petroleum industry reacted vociferously to these proposals. In fact, many of the Carter Commission proposals were extremely controversial, so much so that no major changes were immediately forthcoming in the tax code. The provisions with respect to the oil industry finally introduced in the

1971 budget announced that the net depletion allowance would be replaced in 1976 by an 'earned depletion allowance' of one-third of intangible exploration and development expenditures (subject to a ceiling of 33 1/3% of net income); acquisition costs of properties (e.g., bonus bids) would not earn depletion, nor would depreciable assets as compared to the intangible development expenses.

The result of these tax provisions was that, up to 1972, Ottawa earned little revenue from the crude petroleum industry, compared to Alberta or the oil companies. It is difficult to determine the rent shares for the three parties (Ottawa, Alberta, and the oil companies) and even more difficult to decide what 'fair' shares would be. We will return to these issues below.

B. 1973-1985

1. 1973-1980

The explosion in international oil prices beginning in 1973 detonated the latent federal concerns about Ottawa's share of petroleum rents. At one level, the key policy issue was the precise meaning of the objective of fairness or 'equity.' It can readily be appreciated that not all Canadians would exhibit the same preferences. The industry was inclined to argue that its efforts and willingness to bear risk should guarantee it a significant share of any unanticipated profits. Moreover, the logic of decision-making under uncertainty implied that it was only fair that the industry be allowed to earn above-normal profits if they accrued as a result of a favourable state of the world which had been seen as possible but given a probability of occurrence smaller than one; after all, this was the meaning of risk-sharing. Governments, on the other hand, saw large sums which had to be unexpected windfalls. (They might also have argued that it would have been a foolish company indeed that did not factor higher expected taxes into any scenarios based on these high price levels.) However, Ottawa and Edmonton would not necessarily agree on how any extra revenues going to government should be divided between them. Edmonton saw the resources as a part of the provincial wealth, a status recognized in the *BNA Act* (as amended, in 1930), and particularly so for the provincial Crown land. Ottawa, on the other hand, recognized provincial primacy but saw the resources as a part of the natural heritage of the larger Canadian community. Ottawa also viewed its position as unfairly weak by virtue of the chance historical development of petroleum tax regulations.

The federal share of revenues was very low as a result of the provincial tax treatment accorded the industry, where the main provincial fiscal tools (royalties and bonuses) pre-empted the federal tax base. Large revenue increases for the petroleum-producing provinces also had implications for Ottawa's expenditures, as the equalization payments to 'have-not' provinces depended on average revenue receipts of all provinces. Hence, sharply rising payments to the western provinces, as petroleum prices increased, left petroleum receipts by Ottawa largely unchanged, while generating expenditure obligations to Ottawa under the equalization program.

We have noted that the oil price controls, which began in 1973, can be seen, at least in part, as one of the federal responses to the rent-sharing problem. These applied across Canada and can be seen as a combined gross production tax (or royalty, which reduces the gross revenue to producers) and consumption subsidy. (As was discussed, this policy also drove the government to introduce an export tax on oil to ensure that U.S. consumers paid the OPEC price; the government also decided to subsidize oil use for consumers who purchased imported oil.)

Ottawa also moved on the tax front. The November 1974 budget of the newly re-elected Liberal government under Pierre Trudeau re-introduced a number of proposals from the May 1974 budget that had not passed Parliament prior to dissolution. It brought in earned depletion at once (instead of delaying until 1976), and imposed a ceiling of 25 per cent of net income (instead of 33 1/3%). Intangible development expenditures were now to be treated as depreciable expenditures, written off on a 30 per cent declining balance basis; land acquisition costs such as bonus bids were also to be depreciated in this way. These changes could be argued to reduce somewhat the special tax status accorded the petroleum industry, and to make the main remaining stimulus – the depletion allowance – more directly related to the increased activity it was designed to encourage. The government may have viewed these changes as desirable in themselves or may have felt that special status was less necessary as oil and gas prices rose.

A second avenue of change in the 1974 budget was far more controversial; it was aimed at curbing somewhat the ability of the provinces to appropriate entirely the federal corporate income tax base. Royalty payments to provincial governments would no longer be deductible as an expense. The measure was designed largely to ensure a federal tax share in additional profits resulting from future price rises. Since it would mean an immediate rise in the

petroleum industry's tax payments, even at low oil prices, Ottawa also moved to reduce the federal tax rate on petroleum profits by about 20 per cent. (The nominal corporate income tax rate of 50 per cent was already cut back by 10 percentage points as an "abatement" to the provinces for their own corporate income tax; a further 10 percentage points were now allowed on oil and gas production profits. The abatement was 15 points for tar sands mining projects.) In June 1975, this abatement procedure was replaced by a new deduction in calculating taxable income; this was a "Resource Allowance" equal to 25 per cent of net oil and gas income, defined as revenue less operating costs and capital consumption allowances, but not the depletion allowance, the intangible exploration and development costs, or interest payments. (As noted above, the Government of Alberta had responded in December 1974 with a "royalty tax deduction" to reduce the industry's royalty payments by an amount equivalent to the provincial corporate income tax receipts derived from royalty revenues.)

The combined effects of price controls, higher provincial royalties, and the non-deductibility of royalties for the federal corporate income tax allowed governments to capture significant shares of the much-larger petroleum rents due to rising world oil prices. However, the new measures raised concerns that the real after-tax return to new exploration and development was no higher than it had been in the early 1970s. As was discussed above, Alberta responded to this with royalty regulations that set lower rates for "new" oil and gas and royalty credit schemes, including a variety of exploration incentive programs. Ottawa also responded with an investment tax credit of 5 per cent of tangible asset expenditures (June 1975 and March 1977) and a higher additional depletion allowance for very high-cost wells (two thirds of the cost of a well in excess of \$5 million) (May 1977). (The latter was called "superdepletion" by some, and the "Dome" allowance by others, since it would apply only to the very high-cost wells drilled in frontier areas like the Arctic, where Dome Petroleum was particularly active. Dome Petroleum was widely viewed as one of the few Calgary oil companies to have particularly close ties to the federal Liberal party! The federal government had an obvious interest in spurring development on federal Crown lands.)

Then, beginning in late 1978, the second international oil price explosion began. This overlapped with federal elections, including the replacement of the Liberal government with a minority Progressive Conservative government under Joe Clark, a government defeated in the House of Commons in

December 1979 in a vote on the budget. Alternative energy policies were a major election issue, with the Liberals formally defending the "made-in-Canada" pricing policy that they had been following since 1973. (See Chapter Nine, on oil prices. It should be noted that the Clark government had reached an agreement with Alberta on oil and gas price increases but with Canadian oil prices still held below world levels. Amongst the numerous books covering this period are Simpson, 1984, Foster, 1982, and Doern and Toner, 1985.) In April 1980, the newly elected Liberal majority government implemented several measures from the defeated Clark government budget, including adoption of a 10 per cent declining-balance capital consumption allowance for bonus bids and other land-acquisition costs.

Then the government launched the National Energy Program as a part of the October 28, 1980, federal budget.

2. The NEP: 1980-85

The complex petroleum pricing provisions of the NEP, with its many modifications, were already discussed in Chapter Nine. The tax provisions related to three main objectives: generating revenues for Ottawa, furthering Canadianization of the industry, and encouraging the discovery and development of new oil and gas reserves.

a. Incentives

The incentives included the introduction of a new incentive program based on subsidies, rather than reduced taxes as before, combined with reductions in the depletion allowance. The depletion allowance on development expenditures would be eliminated immediately (except for "integrated oil sands projects, enhanced recovery projects and heavy crude oil upgrades," which still qualified for a 33⅓% allowance; NEP, p. 39). The depletion allowance on exploration would be retained for "Canada Lands" (i.e., areas of federal Crown land, mainly the frontiers in the north and offshore); earned depletion on exploration expenditures would be phased out over four years for other areas, including provincial Crown and freehold land.

The new subsidies came in the form of the Petroleum Incentives Program (PIP), with grants that varied depending on the type of activity (exploration or development), the location of activity (Canada Lands or not), and the ownership of the company (Canadian ownership ratio [percentage] or COR): the grants varied as a percentage of expenditure from 0 to

80 per cent and were higher on Canada lands, higher for exploration expenditures, and higher for companies with greater Canadian ownership. On “provincial Lands” (provincial Crown and freehold), no grants were available to companies with less than 50 per cent COR. Exploration expenditures received a PIP of 15 per cent (rising from 0 per cent in 1981 to 10 per cent the next tax year as depletion was phased out) for companies with a COR between 50 and 75 per cent. If COR was over 75 per cent, the grant rose to 35 per cent of expenditures. For development (including tar sands projects, crude oil upgrades, and tertiary oil projects), the PIP rate was 10 per cent for COR between 50 and 75 per cent, and 15 per cent if COR exceeded 75 per cent. (Remaining depletion allowances applied to expenditures net of the PIP grants.)

b. New Federal Taxes

The NEP introduced a Petroleum and Natural Gas Revenue Tax (PGRT), a Natural Gas and Gas Liquids Tax (discussed in Chapter Twelve), a Canadian Ownership Charge (COC), and a Petroleum Compensation Charge (PCC). The last two (previously discussed in Chapter Nine) involved additions to field prices in obtaining delivered prices of crude. In brief, the COC was developed to help cover the costs of acquisition for Petro-Canada as it expanded by purchasing assets from other companies; the PCC passed on to Canadian consumers the costs involved in buying higher-priced oil in the form of imports and tar sands output and were an essential part of the ‘blended’ oil price system. It will be recalled that there had also been in place, since 1973, an oil export charge to capture the difference between Canadian border prices and the value of oil in the United States as set by world prices. The NEP announced that oil export tax revenue would be split equally between Ottawa and the provinces.

The PGRT was “set at a rate of 8% of net operating revenues related to the production of oil and gas, including income from oil and gas royalty interests. Deductions such as those for exploration and development expenditures, capital cost allowances, and interest, will not be allowed” (NEP, p. 38). The PGRT would not be deductible in calculating income taxes. The PGRT was a slightly modified version of a gross *ad valorem* royalty, modified in that it allowed the deduction of operating costs (other than royalties).

Alberta’s reaction was immediate and negative. Two days after Ottawa introduced the NEP, Premier Lougheed announced cutbacks in conventional oil production (a total of 180,000 b/d, to be implemented in three stages from November 1980 to July 1981) and

the cessation of any approval for new tar sands projects. These steps clearly demonstrated Alberta’s priority over natural resources but, in practice, led mainly to reduced revenues for the province and allowed Ottawa to complain about the increased cost of higher oil imports.

Negotiations led to the September 1, 1981, *Memorandum of Agreement* between the two governments. Alberta agreed to maintain its existing royalties and incentive programs and “not to adjust or modify its current royalty and freehold tax system so that it will generate more revenue for the Government of Alberta than continuance of the system now in effect would yield” (p. 13). Alberta also took over administration and payment of the PIP grants in Alberta (p. 16). Ottawa’s PGRT was maintained, with the PGRT rate increased to 16 per cent, but subject to a further deduction, a “Resource Allowance” (p. 10); the Resource Allowance was to be 25 per cent of production revenues, in effect reducing the PGRT rate to 12 per cent (p. 17). In addition, Ottawa was to introduce a new tax, the Incremental Oil Revenue Tax (IORT), “at a rate of 50% on incremental old oil revenues after deduction for the related Crown royalties” (p. 10). Old oil was that “from a pool initially discovered prior to January 1, 1981” (p. 2) but excluding oil revenues in “old” pools that came from additional EOR schemes, other than water flooding, after the end of 1980. The incremental revenue to which the tax applied was the increase in old oil revenue (under the *Memorandum*) above that generated by the October 1980 NEP price schedules; as noted, incremental royalties, but not the PGRT, were deductible from this incremental revenue (pp. 17–18).

It will be recalled that international oil prices did not rise as quickly as projected in the NEP or *Memorandum*, and frequent modifications were made in the NEP provisions. Some changes occurred in the 1982 NEP *Update*. The IORT, which began at the start of 1981, was suspended after May 1982 (p. 74). In addition, the PGRT rate was reduced for one year to 14.67 per cent (effectively 11 per cent after the resource allowance) (pp. 74–75). In addition, companies were allowed a \$250,000 PGRT credit (p. 74); this was raised to \$500,000 at the start of 1985. In the 1983 budget, the PGRT was waived on EOR projects that were granted provincial royalty relief, up to the time of recovery of all expenditures that qualified for earned depletion.

c. Impact of Regulations

Two issues should be discussed: the effect of the federal tax regulations in terms of economic efficiency, and their impact upon rent sharing (which might be

labelled an 'equity' matter). The two issues are, in fact, interdependent, just as the tax provisions of the NEP are interconnected with the pricing regulations.

The complexity of the federal tax laws can, at one level, be viewed in the same way as the increasingly complex pricing provisions of the NEP. Policies designed to capture some of the gains from higher international oil prices – controlled domestic prices and the PGRT – offered disincentive effects to incremental investment that called forth new incentive measures – higher prices on “new” oil, the PIP grants. The PGRT was subject to particular criticism. Watkins and Scarfe (1985) remark that its impact on well abandonment was probably small, since operating costs (but not royalties) were deductible, but that it had a disincentive effect on exploration and development since these costs were not. PIP grants, like depletion allowances, are a rather blunt instrument for stimulating investment, since they are available to all eligible projects, even if the project is one that would have been undertaken in the absence of the incentive program. (We would note that a part of any 'excessive' subsidy maybe transferred to landowners through the bonus bidding process.) These programs may exist to offset inefficiency in the rent-collection system, but economists frequently argue that it would be preferable – both more efficient and cheaper in administration costs – to have a tax in the first place that is efficient. The preferred alternative is a profit-based tax, rather than a gross royalty or close-to-gross royalty like the PGRT.

It is also evident that the PIP grants, 'superdepletion,' and revised earned depletion provisions were discriminatory since they offered higher return to investment on Canada Lands and by companies with higher Canadian ownership. How the Canadianization provisions will be viewed is of course a function of how sympathetic one is to the underlying objective. Canadian firms did expand during this time period relative to foreign-owned ones, though part of this came through the acquisition activities of Petro-Canada. The extra incentive to invest on Canada Lands (or in ventures like tertiary recovery projects, which received special tax or price treatment) would tend to generate excessively high costs for petroleum to the extent that funds flowed to these projects rather than lower-cost more-conventional projects, which did not have the same advantages.

The actual rent-distribution impacts of the overt control period are more difficult to assess. In part, this is because there are no firm criteria for evaluating the fairness of rent divisions: Ottawa and Alberta, citizens

of Calgary and those of Halifax, shareholders in oil companies, and self-employed truckers may well have quite different ideas of what is 'fair.' It certainly seems true that the Government of Alberta relied strongly on its constitutional ownership of the resource base as support for a large provincial share, while Ottawa stressed the communal nature of the Canadian federation and the extreme and exceptional nature of the OPEC oil price rises. The companies were inclined to see both governments as ganging up on them – sometimes separately (as in the new Alberta royalty schedules in 1973 and 1974 and Ottawa's NEP), and sometimes in tandem (as in the 1981 *Memorandum of Agreement*). While accepting that desires about rent division are likely to differ among various parties, it seems germane to ask whether there might not have been some reasonable compromise that would have avoided the prolonged and bitter fifteen-year battles of the 1970s and early 1980s and the very complex and problematic regulatory environment that ensued.

An early interesting suggestion came from Gainer and Powrie (1975), who noted that it might be useful to separate Alberta's policies into those of the mineral rights owner and those of the provincial government. If mineral rights were privately owned, the royalty revenue received by the landowner would be taxable as income (of the mineral rights owner, of course, not the oil company). Hence Ottawa, through its income tax provisions, would receive a share of the increased value of oil. This result was circumvented in the case of provincial petroleum land by the constitutional prohibition of one level of government taxing the other. An agreement between Edmonton and Ottawa might have been reached in the mid-1970s, after the OPEC oil price rises began, with the problem resolved as follows: investment incentives are no longer needed at these prices (depletion goes); provincial royalties should not be deductible in calculating income taxes; and any new taxes on the industry should be shared in the same proportion as these arrangements implied. For example, if the corporate income tax rate were 50 per cent, with four-fifths going to Ottawa, and if the Alberta royalty took 40 per cent of any increase in price, then of every \$1 rise in price, 50 per cent would go to Alberta, 40 per cent to Ottawa and 10 per cent to the industry. (Edmonton's share would be higher and the industry's lower to the extent that firms' bonus bids on new projects increased; Ottawa's share would also be lower since bonus bids were deductible for income tax purposes.) However, it should be emphasized that, while this proposal might meet some views of fairness, it has the effect – already noted

above – of increasing the significance of the royalty. (In the example, the royalty is effectively raised by the income tax rate of 50 per cent.) But gross royalties are not an efficient means of collecting economic rent because of their inhibitory effects on investment and production. In addition, Boadway et al. (1983) note that the Gainer/Powrie approach of treating provincial resources as if privately held is only one way of viewing the fairness of regional taxation shares; they also argue that the Gainer/Powrie suggestion fails to give adequate weight to the legal basis for the allocation of resource property rights and equalization payments in Canada.

The impact of the federal tax initiatives on the sharing of economic rent is difficult to assess precisely. The issue at hand is not the distribution of the current year's petroleum revenue amongst industry, Ottawa, and the provincial governments. Economic rent refers to the present value of the future stream of revenues in excess of costs. Hence it is necessary to allocate some portion of past expenses to future output so that quasi-rents are not included in the measure of profits. Even more difficult is the task of estimating the future profits that are to be shared; those depend on uncertain future prices. And the amount of economic rent, and its shares, will also change as the level of industry activity changes.

Three approaches were used to estimate the impacts of the various royalty, tax, and pricing provisions of the overt control period. The first looked at total industry revenue (or revenue less certain costs) and asked how this revenue was divided amongst the two levels of government and industry. The second approach defined specific petroleum investment projects and assessed how actual or proposed fiscal regimes affected project profitability. The third approach was conceptually most appealing, but by far the most complicated; it involved the construction of a detailed model of the entire petroleum industry, and then simulating the overall effects of alternative fiscal regimes.

The first approach was used in many of the government documents issued during the overt control period. For example, in the 1980 NEP, the government focussed on the sharing of "oil and gas production income" (p. 13), noting that Ottawa's share had been very low, though rising from 5.3 per cent in 1972 to 8.8 per cent by 1977. (The industry share fell from 69.2% to 40.7% while the provincial governments' increased from 25.5% to 50.5%.) Under the NEP, it was estimated that the federal share of revenues would rise to 24 per cent for the years 1980–83, with the industry at

33 per cent and the provinces at 43 per cent. (Since industry would have to pay costs out of its revenues, so rent is less than 'production income,' this clearly understates the government shares of rent and overstates the industry's.) Under the *Memorandum of Agreement* of September 1981, revenue shares were estimated for the 1981–86 period at 25.5 per cent to Ottawa, 44.3 per cent to Alberta and 30.2 per cent to the industry (p. 22). Modifications of the forecasts in light of lower oil prices in the *NEP Update 1982* gave shares for the 1981–86 period of 19.3 per cent for Ottawa, 28.4 per cent for the provinces, and 52.3 per cent for the industry (p. 77, with operating costs included, as in the *Memorandum*, to give consistency with the previous shares). The sharply reduced government share reflects both the lower oil prices (to which provincial royalties and the PGRT are very sensitive) and also the increased incentives to the industry, which began after 1981. It is important to realize that these shares underestimate the government rent shares for two reasons: as noted above, there is no allowance for costs, and the impact of the policy of holding prices below world levels are not included in the analysis. The *Update* estimated that industry revenues would be some 31 per cent higher over the 1981–86 period if international pricing set petroleum values. This benefit of holding oil prices down accrued to all Canadian consumers, including those in the petroleum-producing provinces. (As indicated above, the price-control policy was equivalent to a royalty on oil production and a subsidy to oil consumption.)

A second approach to gaining a handle on the rent-sharing complexities of the various federal and provincial energy policies was to analyze specific petroleum investment projects. These might be either hypothetical new investment projects or some sort of hybrid average project. One way to do this was to examine 'netbacks' on oil projects, where the netback was usually defined as the price after taxes and royalties. The results, under the NEP, hinged on the taxation status of the producer, as well as on the extent of Canadian ownership (if PIP grants were considered). The June 1982 *NEP Update*, for instance, estimated 1982 netbacks for a 'large producer' ('small producer') at \$6.57/b (\$10.75/b) on oil classified as 'old' under Alberta royalties, \$10.57/b (\$14.78/b) for 'new' oil (post April 1, 1974 under Alberta regulations), and \$17.04/b (\$25.89/b) for NORP oil (p. 80). Wilkinson (1984, p. 61) shows actual and projected netbacks from 1975 to 1986, drawn from Scarfe and Rilkoff's work (1984). He reports netbacks on old oil for a large producer starting at \$5.23/b in 1975, hitting \$6.49 in 1980, then

falling to \$4.20 in 1981, and recovering to \$5.88 in 1982. The values on new oil for a large producer show more improvement (\$6.52/b in 1975; \$8.53/b in 1980; \$7.20 in 1981; and \$9.35 in 1982). These are all in nominal dollars, so make no allowance for inflation from 1975 to 1982. It is clear that the rise in netbacks is much smaller than the increases in the world oil price.

But such netbacks are just a preliminary step on the way to calculating project rent shares: project costs must be incorporated, and future prices and taxes included. (It should be noted that such calculations, if based on the price forecasts of the various NEP documents, would turn out to considerably overstate revenues and any taxes [like the IORT] closely tied to revenue gains; this is because the NEP was wildly optimistic in its oil price forecasts.) Numerous such analyses were undertaken by governments, industry, and private researchers. Examples include DataMetrics (1984), Copithorne et al. (1985), MacFadyen et al. (1985) and Kemp (1987; see especially the discussion by Watkins, 1987b).

By way of illustration, the studies by Copithorne, MacFadyen, and Bell simulate the distribution of economic rent for two different size oil pools under a number of different prices and fiscal regimes. One pool was labelled 'prolific.' It had an assumed total exploration cost of \$53 million, and contained fifty identical wells with drilling costs of \$1.1 million each and operating costs of \$53,500/well/year; each well had an initial output rate of 175 b/d (27.8 m³/day) and an annual exponential decline rate of 10 per cent. (All dollar values are in 1982 Canadian dollars.) The 'modest' pool also held 50 wells declining at 10%/year, but with a much lower initial output rate of 60 b/d/well and lower costs (\$26 million in exploration, development costs of \$937,000/well, and operating costs of \$44,500/well/year). Ten different fiscal regimes were considered, as were three different prices (\$135, \$270, and \$405/m³). The project was assumed, for corporate income tax purposes, to be entirely equity financed, and investors were assumed to be in a taxable position for the corporate income tax. Total economic rent at a 15 per cent discount rate, and the division of the rent amongst companies, Ottawa, and Alberta were calculated for each of the sixty cases (two pools times three prices times ten fiscal regimes). At the lowest price of \$135/m³ (about \$21.50/b), which is most representative of crude oil prices immediately after 1985, the prolific pool had a total profit (economic rent) of \$167 million; profit for the modest pool was \$16 million.

Table 11.3 summarizes rent shares at this lowest price for the two pool types under six different fiscal regimes:

- (i) The Canadian corporate income tax with a 47% rate (using tax provisions as of 1985);
- (ii) Fiscal regime (i) plus the 1973 Alberta 'basic' royalty;
- (iii) Fiscal regime (ii) plus the Alberta 'supplemental' royalty for 'new' oil (using the 1981 values for the royalty factor and 'Par Price');
- (iv) Fiscal regime (ii) plus the Alberta 'supplemental' royalty for 'old' oil;
- (v) Fiscal regime (iv) plus non-deductibility of royalties for the federal portion of the corporate income tax (including the 'Resource Allowance' as introduced in 1975); and
- (vi) Fiscal regime (v) plus the PGRT and PIP grants as in the 1981 *Memorandum of Agreement*.

In the table, the italicized values are the cases in which the after-tax expected profit is negative, so that one would anticipate that the project would not be undertaken and no rents would actually accrue to governments. (Data from MacFadyen et al., 1985, p. 131.)

Comparing fiscal regime (i) to regimes (ii), (iii) and (iv), it is easy to see the effect of provincial royalties in reducing the federal tax base. Similarly, comparing regime (iv) to regime (v) and (vi), the recovery in Ottawa's share with non-deductibility of royalties and the PGRT is evident. The basic corporate income tax and the Alberta 1973 'Basic' royalty left a high rent share with the private investor (over one-third of the rent in the case of the prolific pool); hence the move by governments to increase rent shares as the oil price rose in the early 1970s. However, the table also makes clear the dangers of a high reliance on royalties or near royalties like the PGRT. Otherwise, profitable pools may be made uneconomic, in which case companies will be unwilling to invest, and no payments will accrue to governments, as was the case under all royalty regimes for the 'modest' pool.

Kemp's (1987) analysis was similar. It involved two steps. The first looked at 'rental' shares under three different fiscal regimes (pre-NEP [1979], NEP [1984], and post-NEP [1986]) for the half-cycle economics (excluding exploration costs) for three Alberta oil pools of different size. Three different investment cost levels are considered, as are four different oil price forecasts: (i) \$27/b, (ii) \$27/b rising at 2% per year, (iii) \$27/b falling at 3% per year, and (iv) \$17/b for

Table 11.3: Rental Shares for Two Hypothetical Alberta Oil Pools Under Six Different Fiscal Regimes (Copithorne, MacFadyen and Bell) (%)

<i>A. Prolific Pool</i>	<i>Companies</i>	<i>Ottawa</i>	<i>Alberta</i>
(i) Corporate Income Tax (CIT)	52.1	36.6	11.3
(ii) CIT and Basic Royalty (BR)	33.0	23.7	43.3
(iii) CIT, BR and Supplemental Royalty (SR) ('new' oil)	23.6	17.4	59.0
(iv) CIT, BR, SR ('old' oil)	11.8	9.6	78.5
(v) CIT, BR, SR ('old') royalties non-deductible for federal CIT (ND)	(1.7)	22.9	78.8
(vi) CIT, BR, SR, ND and PGRT and PIP grants	(4.0)	37.4	66.6

<i>B. Modest Pool</i>	<i>Companies</i>	<i>Ottawa</i>	<i>Alberta</i>
(i) Corporate Income Tax (CIT)	45.1	43.2	11.7
(ii) CIT and Basic Royalty (BR)	(0.1)	11.6	89.0
(iii) CIT, BR and Supplemental Royalty (SR) ('new' oil)	(23.3)	(3.1)	126.4
(iv) CIT, BR, SR ('old' oil)	(51.5)	(22.7)	174.2
(v) CIT, BR, SR ('old') royalties non-deductible for federal CIT (ND)	(78.9)	0.3	175.8
(vi) CIT, BR, SR, ND and PGRT and PIP grants	(64.0)	60.2	103.7

Notes: Assumes an oil price of \$135/m³.
A value in parenthesis indicates a loss (negative rent share).

1986 and \$20/b after (all prices are in real dollars). On the basis of this information, Kemp could calculate revenue and costs, including tax payments for many different cases. (There are 108 cases: a three [fiscal regimes] times three [pool types] times three [cost conditions] times four [oil prices] design.) The lowest volume oil pool was generally uneconomic, even at the \$27/b price, so only the other two pool sizes are shown. Table 11.4 reports the shares of 'profits' (or Net Present Value or 'economic rent') accruing to the companies, Ottawa, Alberta, or consumers at a 10 per cent real discount rate, assuming a \$27/b price, and for various combinations of type of pool, level of development cost, and fiscal regime. (The numbers are approximations, since they have been read off graphs in Kemp's book. Recall that these are based on half-cycle costs, so make no allowance for exploratory costs. Some of the rent was captured by consumers under the pre-NEP fiscal regime since oil prices were held below world levels, and the world price is taken as the determinant of oil values. There is not a similar consumer share under NEP regulations, even though the average price of oil in Canada was held under the world price; this is because the pools were assumed to qualify for 'NORP' (the New Oil Reference Price), which was, essentially, the world price. 'Low,' under

NEP, refers to low Canadian content and, hence, low PIP payments; 'High' means high Canadian content and higher PIP grants.)

Unlike with the MacFadyen, Copithorne, and Bell pools, none of the fiscal regimes make the higher-cost pool uneconomic. (But remember that the half-cycle analysis does not include exploration costs. That is, if a pool were discovered of the sizes considered by Kemp, his analysis suggests that the company would be willing to develop the pool under all four fiscal regimes.) The output sensitivity of the royalty regimes and the profit sensitivity of the corporate income tax are shown by the higher company shares for the smaller pool than the larger. However, the company's rent share tends to become smaller as pool development costs rise. (Kemp and Watkins call this a 'regressive' feature of the fiscal regimes.) Higher Canadian ownership raises the company share marginally in the NEP cases; the effect is small because in Alberta the PIP grants associated with development were small. The table makes clear the dramatic impact of the NEP in increasing Ottawa's share of the economic rent, at the expense of the company. Finally, it is noteworthy that the company's share of rent is higher under the post-NEP than the pre-NEP (1979) regulations. Since Ottawa's share is also slightly higher, one might think

Table 11.4: Kemp's Rental Shares under Different Cost Conditions and Fiscal Regimes (%)

<i>Fiscal Regime and Rent Recipient</i>		<i>A. LARGE POOL</i>					<i>B. SMALL POOL</i>				
		<i>Low Cost</i>	<i>Medium Cost</i>	<i>High Cost</i>	<i>Very High Cost</i>	<i>Very Very High Cost</i>	<i>Low Cost</i>	<i>Medium Cost</i>	<i>High Cost</i>	<i>Very High Cost</i>	<i>Very Very High Cost</i>
Pre-NEP:	Company	30	29	28	26	23	38	37	36	31	25
	Alberta	39	40	41	43	47	32	33	34	38	44
	Ottawa	23	23	22	22	21	23	22	22	21	21
	Consumers	8	8	9	9	9	7	8	8	10	10
NEP (Low):	Company	15	14	13	10	8	20	20	21	15	6
	Alberta	42	42	44	45	50	36	36	37	41	50
	Ottawa	43	44	43	45	42	44	44	42	44	44
NEP (High):	Company	17	17	16	13	9	20	19	18	16	10
	Alberta	41	41	42	43	45	35	35	36	38	40
	Ottawa	42	42	42	44	46	45	46	46	46	50
Post-NEP:	Company	39	39	39	36	31	49	48	48	45	40
	Alberta	36	36	36	39	42	25	26	26	30	37
	Ottawa	25	25	25	25	27	26	26	26	25	23

Notes: 'Low' and 'High' refer to COR (Canadian Ownership Ratio).
Price of oil is \$27/b.

that all of the increase in private share came at the expense of Alberta. However, a significant part of the higher corporate share can be seen to have come from the removal of price controls; these reduced benefits to consumers should be seen as a reduced rental share for Ottawa. Finally, in comparison to the NEP fiscal regime, the post-NEP period shows that higher company profits came mainly out of Ottawa's share.

Overall, it looks as if, during the period from 1975 through deregulation, Alberta maintained a relatively constant share of the economic rent, while Ottawa and the companies traded off shares. This accords with the feeling that many companies seem to have had in the NEP days that Alberta was more concerned with protecting its petroleum revenues than it was in fighting Ottawa on behalf of the petroleum companies. (Note that the Kemp analysis, unlike that of MacFadyen, Copithorne, and Bell, begins after Ottawa had increased its petroleum revenues by the non-deductibility of royalties for corporate income tax purposes.)

The second step in Kemp's analysis involves the addition of the exploration decision. This has three features: first, the cost of the exploratory effort (geological and geophysical activity and exploratory drilling) must be considered; second, there is the

probability that any given exploratory venture will come up dry; and third, if a discovery is made it could be small or large. With respect to the third of these characteristics, Kemp assumes conditional probabilities of discovery for thirteen different possible oil pools, a mix of three possible pool sizes and five possible cost conditions. (The sum of these probabilities is one; the smallest pool size is regarded as uneconomic ['dry'] in the two highest cost cases, reducing the fifteen possible cases to thirteen.) With respect to the first of the exploratory factors, Kemp looks at two cases, a \$1 million or a \$5 million exploratory program. And for the second, he considers three different drilling success rates (one in 5, one in 10 and one in 20). Finally, he does calculations for four different annual discount rates (0, 5, 10, and 15%), and considers both low and high Canadian ownership under the NEP. Kemp shows results for many possible cases. (With two oil prices used [\$27/b and a 'collapsed' price scenario of \$17/b rising to \$20/b], four fiscal regimes [as in Table 11.4], two levels of exploration cost, three success rates, and four discount rates, there are 192 possible cases.)

Table 11.5, above, shows the shares of economic rent going to governments (Alberta and Ottawa combined) at a 10 per cent discount rate for a \$5 million

Table 11.5: Kemp's Government Rent Shares for a \$5 million Exploration Program under Four Different Fiscal Regimes at High and Low Prices (10% discount rate) (%)

Fiscal Regime	A. High Oil Price (\$27/b)			B. Low Oil Price (\$17/b rising to \$20/b)		
	Success Rate 1:5	Success Rate 1:10	Success Rate 1:20	Success Rate 1:5	Success Rate 1:10	Success Rate 1:20
Pre-NEP	67.7	74.7	122.8	71.5	150.0	0
NEP-Low Canadian Ownership	90.9	105.0	203.0	100.8	149.1	0
NEP-High Canadian Ownership	85.1	91.4	136.0	89.5	111.1	0
Post-NEP	67.5	74.3	121.5	75.1	100.8	0

Note: A value in italics means that governments capture more than 100% of the hypothetical economic rent. Therefore, the private investor would be unwilling to undertake the project and the government would receive no revenue.

exploration program. Results are shown for both a 'high' (\$27/b) and 'low' (\$17/b for a year rising to \$20/b) oil price. It is important to know that no allowance is made for bonus bids, so the Alberta share of rent would be higher than implied by these numbers. In Table 11.5, a 'o' means that this exploration project would not be undertaken even if no payments were made to governments; that is, the before-tax expected profit is negative. Numbers in italics indicate that governments would take more than 100 per cent of the available rent, so that companies would not be expected to invest under this fiscal regime (and governments would get no revenue).

Once again, the very high shares of rent going to the government under the NEP are apparent. The importance of the Canadian content provisions of the PIP grants are also clear, especially as the success rate falls (so exploratory drilling expenses are more significant). It is also demonstrated, once again, that high fiscal burdens can easily discourage investment. Comparison of Table 11.4 with Table 11.5 also shows that what may appear to be a fair and reasonable fiscal take for governments based on the operating and development costs of a pool (as in Table 11.4) may well be excessive when the necessity of exploration is taken into account (as in Table 11.5).

The third approach to assessing the impact of the varied Canadian oil industry fiscal regimes from 1973 to 1986 was to build a model of the entire petroleum industry and simulate the impact of actual and proposed tax, pricing, and royalty changes. Such work was undertaken by John Helliwell of the University of British Columbia and a number of academic colleagues. Helliwell et al. (1989) provides an example of this approach. (For other examples, see Helliwell

and McRae, 1981, 1982; Helliwell et al., 1983; 1986.) These researchers have built a large-scale model they call MACE (for Macro and Energy), which explicitly embeds energy supply and demand behaviour within a macroeconomic model of the Canadian economy. While a Canadian model, rather than an explicitly Alberta model, it does provide results for the Canadian petroleum industry that are broadly representative of what one might expect in Alberta (as the largest petroleum-producing province in Canada). We will summarize some of the key rent-sharing findings of Helliwell et al. (1989). Here the MACE model was used to compare five regulatory regimes for the Canadian petroleum industry. The first is labelled 'Actual' and shows the observed historical experience (with an appended forecast for 1987 to 1990). We shall consider three of the four hypothetical regulatory regimes with which they deal:

- (i) A '**Price Deregulation**' case in which historical fiscal and export policies were the same as the actual, but Canadian oil prices were allowed to follow world levels while natural gas prices in Toronto were set at 85 per cent of the cost of an equivalent amount of delivered energy in the form of crude oil;
- (ii) A '**Pre-Reform**' case utilizes the pricing and fiscal regimes of 1970, prior to the provincial royalty revisions of the early 1970s and such federal programs as price controls, earned depletion (as opposed to 33.33% net depletion), and non-deductibility of royalties for the federal share of the corporate income tax;
- (iii) A '**Current**' case, with provisions as of 1987, after deregulation.

Table 11.6: Flow Rent Shares under Four Regulatory Regimes, 1974, 1981, and 1986 (Helliwell et al.) (%)

1974	Producers	Provinces	Ottawa	Consumers
Actual	5.0	60.0	15.0	20.0
Price Deregulation	25.0	62.5	25.0	(12.5)
Pre-Reform	57.1	41.1	14.3	(12.5)
Current	42.9	50.0	19.6	(12.5)

1981	Producers	Provinces	Ottawa	Consumers
Actual	12.9	34.7	12.9	39.6
Price Deregulation	35.5	50.5	14.0	0.0
Pre-Reform	135.2	46.3	(83.3)	1.9
Current	58.0	48.2	(8.6)	2.5

1986	Producers	Provinces	Ottawa	Consumers
Actual	5.0	60.0	15.0	20.0
Actual	(142.9)	342.9	71.4	(171.4)
Price Deregulation	(1800.0)	2600.0	0.0	(700.0)
Pre-Reform	97.8	(71.1)	57.8	15.6
Current	142.1	(152.6)	73.7	36.8

Note: Numbers in parentheses are negative shares, that is, a net loss. The two italicized cases have a negative total flow rent, with the parenthesized values showing a positive rent amount.

(In all cases we consider Canadian export provisions for oil and natural gas are assumed to hold as they did historically.)

From their model, Helliwell et al. can estimate the amount of economic rent generated by the Canadian petroleum industry and the divisions of that rent amongst interested parties. It must be noted that their measure of economic rent in this large-scale model is different from the measure of real (or potential) total discounted profits on oil projects as utilized by Kemp and MacFadyen, Copithorne, and Bell. Instead, they estimate 'flow rents' on an annual basis from 1974 through 1990. These flow rents are, in effect, the consumers' surplus generated by the difference between regulated and unregulated petroleum prices, producer profits, and the revenues received by governments from the petroleum industry. As noted, the MACE model includes the entire Canadian economy, so it considers the general level of taxes, including excise

(sales) taxes and the corporate income taxes generally paid by industries in Canada; their measures of rent include adjustments to allow for both of these factors. For example, unusually high excise taxes on oil would raise prices, generating losses of flow economic rent (consumers' surplus) for consumers. Also, opportunity costs on capital are allowed as a cost for both private producers and for governments on tax revenue collected. For details, see Helliwell et al. (1989, p. 193). Table 11.6 provides estimates of shares in annual flow rents for three years (1974, 1981, and 1986) in the four cases noted above. (Numbers are approximate, as estimated from graphs in Chapter 10 of Helliwell et al., 1989. Dollar amounts in the model are in real 1971 dollars. The total flow rents in the Actual case were about \$4.0 billion in 1974, \$10.1 billion in 1981, and \$0.7 billion in 1986. The amount of rent each year differs in the other cases because changes in the regulatory climate change the levels of petroleum consumption, production, and investment. The italicized values are in cases where the total flow rent from the petroleum industry is negative; in such cases, a negative share indicates a positive rent flow.)

The 1986 numbers are difficult to interpret because the total flow rents were small (leading to large percentages for the components) and negative under two of the regulatory environments (reflecting the lower prices in 1986 than 1981 and even, in real 1971 dollars, lower than in 1974). The numbers show that the pre-reform (1970 regulations) rents to the federal government were low (the federal share is defined as that for Ottawa plus consumer rents). In both 1974 and 1981, the rent share actually received by the federal government was greatly increased from what it would have been under the 1970 regulations. This increase was due in large part to the price-control regulations; for example, in 1981, the federal government share was 52.5 per cent of the flow rents, whereas it would have been only 14 per cent without the price control regulations. It can also be seen that the current regulations imply a higher share for governments than the 1970 regulations but leave appreciably more for the industry than did the regulations in the overt control period (that is, the Actual case).

3. 1985-2010

The March 1985 *Western Accord* between Ottawa and the petroleum-producing provinces ushered in the current 'deregulated' environment. The PGRT was to be phased out over three years, and the IORT, PCC,

COC, and NGGLT were abolished, as was the PIP grants system. Removal of PGRT was accelerated, with the tax abolished as of October 1, 1986.

With these changes, the federal government once again was in the position of obtaining revenue from the crude petroleum industry largely through the mechanism of the corporate income tax. It is also important to recall that under deregulation Ottawa no longer 'collects' a share of petroleum industry (potential) revenues by holding domestic oil prices below the international level. (We do not consider other features of the general tax system as federal sales taxes which apply to input purchases by all industries. We are also looking at the oil industry in Alberta, so exclude consideration of federal government regulations on companies exploring federal Crown land.) Unlike in the pre-1973 period, the rent-capturing effectiveness of the corporate income tax was increased since the depletion allowance had been phased out, and royalty payments to provincial governments were no longer deductible as a cost in calculating the income taxes owing to Ottawa. (Remember that royalties were still deductible, in effect, for the Alberta government portion of the corporate income tax.) However, the policy since 2000 of significantly reducing corporate tax rates has reduced its effectiveness as a tool for capturing economic rent.

Since 1986, with one major exception, the main changes affecting the petroleum industry have been the same changes in corporate tax regulations that affect all industries, as well as occasional modifications in the capital consumption allowance deduction schedules for equipment classes of special importance to the petroleum industry. The 2002 federal budget introduced a significant change, essentially reverting to the pre-1974 situation, as the Resource Allowance was removed, and the deductibility of royalties was re-instated; these changes have been phased in, becoming entirely effective in 2007.

In 2013, the federal corporate income tax rate was 15 per cent, and it had been falling for a number of years; the Alberta provincial corporate income tax rate was 10 per cent. (Small businesses pay even lower rates.) The reductions in the corporate tax rate were one of the reasons that the Alberta government share of economic rent fell after 2000; this contributed to the royalty modifications discussed above. Mintz and Chen (2010) find that the 'effective marginal tax rate' for the conventional petroleum industry is lower than the average rate for corporations, largely due to favourable capital depreciation provisions. (They also argue find that the combined income tax and royalty

burden on a marginal investment is higher for petroleum than the industrial average.)

5. Conclusion

Economic rent lies at the heart of the most controversial aspects of Canadian petroleum policies.

Since petroleum is a depletable natural resource, or, more precisely, since petroleum is a resource of limited extent and with considerable heterogeneity amongst deposits, it is to be expected that conventional crude oil and natural gas will earn revenues in excess of the expenditures and normal return on capital required to produce them. Since the price of oil tends to the level required to cover the cost of the last unit of production needed to meet market demand at that price (except in price-influencing OPEC nations), all the units of production with a cost lower than this marginal unit will earn a profit (or 'economic rent'). But this definition just begins to uncover the complexities attendant to the concept of economic rent. In a world of uncertainty, for example, it is important to distinguish between the anticipated (*ex ante*) economic rent, which stimulates behaviour, and the actually occurring (*ex post*) economic rent, which depends on how natural, engineering, economic, and political uncertainties actually unfold. Further, economic rent may be defined as the excess of revenues above costs (including as a cost the risk-adjusted 'normal profit' return required on investment), but it also serves an allocative role. Thus, the anticipation of such rents is a primary stimulus to investment. (The suggestion, implicit in the world of many simple economic models, that \$1 of extra profits is just as motivating as \$10 million, does not ring true.) And anticipated profits across time play a key role in the scheduling of reserve depletion. More formally, another component of economic rent is the user cost (sometimes called 'replacement cost') that typically accrues to even the highest cost unit because petroleum is a non-renewable resource. This user cost is an excess of revenue above costs, but it performs an important allocative role in the intertemporal depletion of oil reserves. For these reasons, there is some uncertainty about how much of the economic rent should be left in the hands of the private petroleum companies in order to ensure economically efficient resource production.

To these ambiguities must be added those attached to the key 'equity' question: "Which parties

have claims on the economic rents and in what proportions?” Competing claims might reasonably be entered by petroleum producers, holders of the mineral rights on petroleum-bearing lands, petroleum consumers, and governments (on behalf of citizens and taxpayers generally). In Canada, most mineral rights are Crown rights, so the mineral rights owner and government roles are often exercised by the same party. In the Canadian federal system of government, claims on the economic rent might be made by one or both levels of government (i.e., Ottawa or Alberta).

Prior to 1973, when the economic rents from the petroleum produced in Alberta were relatively small by later standards, the federal government was willing to exercise a modest claim on industry profits, through a corporate income tax that offered incentives to invest in the oil industry. Alberta gained significant revenue from the industry largely through its role as the main holder of mineral rights (using bonus bids, rentals, and royalties).

However, the surge in international oil prices in the early 1970s increased petroleum rents dramatically and ushered in more than a decade of turmoil in which governments moved to increase their share of economic rents far above what they would have earned under the pre-1973 arrangements and in which Ottawa and Alberta jockeyed for position. Ottawa, in particular, thought that Canadians ‘in general’ (as represented by the federal government, of course) should obtain significantly more of the petroleum industry’s economic rents. However, Ottawa faced the problem that its primary means of generating revenue (the corporate income tax) used a tax base that could be entirely pre-empted by the provinces’ main ways of generating more revenue (i.e., bonuses and royalties). The industry felt itself caught in the middle of this intergovernmental battle, facing a dizzying array of new and higher fiscal burdens and a growing complex of incentive programs designed to offset the disincentive effects of the higher government revenue claims.

Deregulation in 1985 brought a return to the simple fiscal arrangements that had been in force before 1973 but with the differences that: (i) royalty rates in Alberta were considerably higher, except on very-low-output wells; (ii) the special provisions in the corporate income tax favouring the crude petroleum industry were largely gone, apart from some rapid depreciation allowances; and (iii) the federal government ensured a share of the economic rent for itself by

the disallowance (until 2007) of full deductibility as a cost of royalties paid to provincial governments.

On balance, the current (2013) fiscal regime for the Alberta conventional petroleum industry, while consisting of a complex web of royalty, tax and incentive programs, generates a large revenue flow to governments without imposing large inefficiencies in terms of reduced or biased industry behaviour. But it should have been possible to get to this point without the massive pains inflicted in the ‘overt control’ period from 1973 to 1985. The reliance on *ad valorem* royalties (based on total revenue rather than profits) contributed to a system of considerable complexity, with royalties varying across four classes of oil (three vintages of light oil plus heavy oil) plus a number of specific royalty-reduction ‘incentive’ schemes designed to recognize categories of presumed higher-cost oil.

The major rises in oil prices after 2004 brought that scheme under some pressure, as the regulations implied that, at best, the government royalty would capture 35 per cent of a price increase, while industry would receive 65 per cent (which would, however, be subject to the corporate income tax). In October 2007, the Alberta government announced acceptance for conventional crude oil of the main recommendations of a Royalty Review Panel, simplifying royalties, effective at the start of 2009, by removing vintage and incentives schemes and modifying the royalty rates to reduced rates on low-output wells, but applying significantly higher rates (a maximum of 50%), on higher-output wells at high prices. However, within two years, the government backed off, reintroducing a number of incentive programs and cutting back on the royalty increase (primarily by reducing the maximum to 40%), in effect reverting to regulations close to those pre-2007, with a marginally higher ceiling rate (about 14% larger, effective at high crude oil prices and/or more moderate prices for high-output wells) and reduced rates for low-output wells and at lower prices (prices within the historical range prior to 2004).

After deregulation in 1985, the federal government relied on the corporate income tax for its share of economic rent from Alberta conventional crude oil. (The province also has a corporate income tax.) However, the policy of reducing the corporate tax rate has reduced its effectiveness as a rent-collection device.

Appendix 11.1: Alberta Crude Oil Royalty Regimes, 1951 to 2012

A. Royalty Regulations

June 1951 Regulations

<i>X: Output Rate (b/month)</i>	<i>Royalty (Barrels, the number before X is the marginal Royalty Rate)</i>
0–600	5%X
600–750	30 + 14%(X–600)
750–950	51 + 17%(X–750)
950–1,150	85 + 18%(X–950)
1,150–1,500	121 + 19%(X–1150)
1,500–1,800	12.5%X
1,800–4,050	225 + 20%(X–1800)
4,500–	16.667%X

April 1, 1962 Regulations

<i>X, Output Rate (b/month)</i>	<i>Royalty (Barrels, marginal royalty rate is the % number)</i>
0–750	8%X
750–2700	60 + 20%(X–750)
2700–	16.667%X

January 1, 1973 Regulations

<i>Output Rate (b/month)</i>	<i>Royalty (Barrels)</i>
0–1200	$\left(\frac{X}{120} + 5 \right) \frac{X}{100}$
4500–	180 + 25%(X–1200)

April 1, 1974 Regulations

Royalty (b/month)

$$S + \frac{kS(A - B)}{A}$$

Where S is the January 1973 royalty, A is the Par Price, B is the Select Price and k is the Royalty Factor.

Notes:

- (1) The Par Price (A) is the selling price of the oil. The Select Price (B) is a price lower than the selling price, selected to derive a base above which revenue increases ($A-B$) can be derived.
- (2) The second part of the royalty formula is designed to capture part of the revenue increase due to higher oil prices ($A-B$). The royalty factor (k) is set to allow the government to capture the desired amount of the revenue increase. Lower royalty factors were set on 'New Oil' (that discovered after March 1974) than on 'Old Oil' (that discovered prior to April 1974).

- (3) After 1974 the Par Price (A), Select Price (B), and royalty factors (k) were subject to periodic change, as was the definition of oil that qualifies for the lower 'New Oil' royalty rate.

Briefly, starting in 1982, a new oil category was created called 'NORP Oil,' which was assessed as 'New Oil' but allowed a higher Par Price; essentially this was oil discovered after 1980 and allowed the world price under the National Energy Program (NEP, see Chapter Nine for details).

- (4) As noted, the Par Price (A) was the selling price of oil (defined as the average Alberta wellhead price). The Select Price (B) was initially set at \$4.11/b, raised to \$4.71/b on January 1, 1975, and then again to \$6.50/b on April 1, 1982.
- (5) As noted, the royalty factor (k) was designed to take as royalties some percentage of the revenue in excess of the Select Price, but a smaller percentage for 'New' than 'Old' oil. A complication arose because this 'supplemental' royalty was based on the 'basic' 1973 royalty, which was output sensitive. Accordingly, it was necessary to define the k factors both with reference to the following variables: the Par Price (A), the Select Price (B), the type of oil (New or Old), the proportion of incremental revenue the government wished to capture, and the output rate of the 'reference' well for which the incremental revenue share was defined. As a result, the royalty factors (k) were changed frequently. (They are not reported here but can be found in Lewis and Thompson). Several of the key changes (apart from changes in the selling price of oil) will be noted here. Initially, royalties were based on the average output of an Alberta oil well, but in 1979 the government began to base the royalty on a 'reference well' with an output of 3,600 b/month. Initially, royalty factors were set so as to capture 65 per cent of the incremental revenue on 'Old' oil and 35 per cent on 'New.' For 'Old' oil, the government share of supplemental revenues was reduced to 50 per cent (July 1, 1975), then 45 per cent (April 1982), then 40 per cent. The 'New' oil percentage was reduced to 27 per cent at prices below \$30/b and 30 per cent of extra revenue above \$30/b.

July 1, 1979 Regulations

The 1974 royalty formula was retained but the 'basic' royalty (S) was changed from the 1973 regulations. (The formula was set out in cubic metres per month, but we show it in barrels for comparability with the previous royalty formulae.)

<i>Output Rate (X) (b/month)</i>	<i>Royalty (b/month)</i>
0–1200	$X^2 / 8000$
1200–	$(.25)(X-1200) + 180$

Note:

In this formula, as the output rate tends to 0, so does the royalty rate, whereas the previous formula had a minimum rate of 5 per cent. A well with 100 b/month would have a royalty of 1.25 b/month under the 1979 regulations and 5 b/month under the 1973 regulations. Since the supplemental royalty is applied to the basic royalty, the supplemental royalty is also lower for low-output wells under the 1979 regulations.

January 1, 2009 Regulations (as amended in 2010)

Royalty rate = $r_p + r_q$, (minimum 0%, maximum 40%)

Price Component (r_p), (maximum 35%):

Par Price(PP) < \$250/m³:

$$r_p = ((PP-190)*.0006)*100$$

\$250.00/m³ < Par Price(PP) < 400.00/m³:

$$r_p = (((PP-250)*.001) + .036)*100$$

\$400/m³ < Par Price(PP):

$$r_p = (((PP-400)*.0005) + .186)*100$$

Par Price(PP) > 535/m³:

$$r_p = (((PP-535)*.003) + .2535)*100$$

Quantity Component (r_q), (maximum, 30%):

Q < 106.4 m³/month:

$$r_q = ((Q-106.4)*.0026)*100$$

106.4 m³/month < Q < 197.6 m³/month:

$$r_q = ((Q-106.4)*.001)*100$$

197.6 m³/month < Q < 304 m³/month:

$$r_q = (((Q-197.6)*.0007) + .0912)*100$$

Q > 304 m³/month:

$$r_q = (((Q-304)*.0003) + .1657)*100$$

B. Comparative Royalty Payments

One way to compare the various Alberta oil royalty regulations is to calculate the royalties owing under a number of different royalty schemes. It is also desirable to look at royalties under different conditions since the royalty rates have been output and price sensitive.

We consider ten different royalty regimes, as follows:

- R51: June 1951 Regulations
- R62: April 1962 Regulations
- R73: January 1973 Regulations
- R74O: April 1974 'Old' Oil Regulations
- R74N: April 1974 'New' Oil Regulations
- R82O: April 1982 'New' Oil Regulations
- R82N: April 1982 'Old' Oil Regulations
- R91O: Regulations in effect as of Dec. 31, 1991, on 'Old' oil.
- R91N: Regulations in effect as of Dec. 31, 1991, on 'New' oil.
- R2011: Regulations in effect as of January 1, 2011.

It must be remembered that the supplemental royalty from 1974 on included a royalty factor that was adjusted as the price of oil changed, so the royalties were aimed at the price level in effect at the date the scheme was applied. The approximate prices were: \$6.50/b in April 1974, \$23.00/b in April 1982 for old oil and \$40.00/b for new, \$21.00/b in December 1991, and \$85/b in January 2011.

Four price levels per barrel are considered, representative of prices over most of the period from 1947 through to 2000:

- P1: \$2.50
- P2: \$6.50
- P3: \$13.00
- P4: \$25.00

Four output levels for the well are also considered:

- O1: 100 b/month
- O2: 1,000 b/month
- O3: 10,000 b/month
- O4: 20,000 b/month

Output Level 1 (100 b/month)

Royalty Scheme	P1: \$2.50	P1: \$2.50	P2: \$6.50	P2: \$6.50	P3: \$13	P3: \$13	P4: \$25	P4: \$25
	Royalty \$/b	Royalty Rate (%)	Royalty \$/b	Royalty Rate (%)	Royalty \$/b	Royalty Rate (%)	Royalty \$/b	Royalty Rate (%)
R51	\$0.125	5	\$0.325	5	\$0.650	5	\$1.250	5
R62	\$0.200	8	\$0.520	8	\$1.040	8	\$2.000	8
R73	\$0.146	5.8333	\$0.379	5.8333	\$0.758	5.8333	\$1.458	5.8333
R74O	\$0.146	5.8333	\$0.557	8.5648	\$1.512	11.6299	\$3.275	13.1011
R74N	\$0.146	5.8333	\$0.392	6.0295	\$0.900	6.9148	\$1.835	7.3397
R82O	\$0.031	1.25	\$0.081	1.25	\$0.250	1.92	\$0.562	2.25
R82N	\$0.031	1.25	\$0.081	1.25	\$0.213	1.63	\$0.455	1.82
R91O	\$0.031	1.25	\$0.081	1.25	\$0.231	1.78	\$0.508	2.03
R91N	\$0.031	1.25	\$0.081	1.25	\$0.183	1.4	\$0.369	1.48
R2011	0	0	0	0	0	0	0	0

Output Level 2 (1,000 b/month)

<i>Royalty Scheme</i>	<i>P1: \$2.50 Royalty \$/b</i>	<i>P1: \$2.50 Royalty Rate (%)</i>	<i>P2: \$6.50 Royalty \$/b</i>	<i>P2: \$6.50 Royalty Rate (%)</i>	<i>P3: \$13 Royalty \$/b</i>	<i>P3: \$13 Royalty Rate (%)</i>	<i>P4: \$25 Royalty \$/b</i>	<i>P4: \$25 Royalty Rate (%)</i>
R51	\$0.235	9.4	\$0.61	9.4	\$1.222	9.4	\$2.35	9.4
R62	\$0.275	11	\$0.715	11	\$1.430	11	\$2.750	11
R73	\$0.333	13.33	\$0.867	13.33	\$1.733	13.33	\$3.333	13.33
R740	\$0.333	13.33	\$1.485	22.84	\$4.032	31.01	\$8.734	34.94
R74N	\$0.333	13.33	\$1.045	16.08	\$2.397	18.44	\$4.893	19.57
R820	\$0.313	12.5	\$0.813	12.5	\$2.500	19.23	\$5.615	22.46
R82N	\$0.313	12.5	\$0.813	12.5	\$2.125	16.35	\$4.548	18.19
R910	\$0.313	12.5	\$0.813	12.5	\$2.313	17.79	\$5.082	20.33
R91N	\$0.313	12.5	\$0.813	12.5	\$1.825	14.04	\$3.694	14.78
R2011	0	0	0	0	0	0	\$0.820	3.28

Output Level 3 (10,000 b/month)

<i>Royalty Scheme</i>	<i>P1: \$2.50 Royalty \$/b</i>	<i>P1: \$2.50 Royalty Rate (%)</i>	<i>P2: \$6.50 Royalty \$/b</i>	<i>P2: \$6.50 Royalty Rate (%)</i>	<i>P3: \$13 Royalty \$/b</i>	<i>P3: \$13 Royalty Rate (%)</i>	<i>P4: \$25 Royalty \$/b</i>	<i>P4: \$25 Royalty Rate (%)</i>
R51	\$0.417	16.67	\$1.083	16.76	\$2.167	6.67	\$4.167	16.67
R62	\$0.417	16.67	\$1.083	16.76	\$2.167	6.67	\$4.167	16.67
R73	\$0.595	23.8	\$1.547	23.8	\$3.094	23.8	\$5.950	23.8
R740	\$0.595	23.8	\$2.650	40.77	\$7.200	55.36	\$15.59	62.36
R74N	\$0.595	23.8	\$1.866	28.7	\$2.279	32.91	\$8.734	34.94
R820	\$0.595	23.8	\$1.547	23.8	\$4.760	36.61	\$10.690	42.77
R82N	\$0.595	23.8	\$1.547	23.8	\$4.046	31.12	\$8.659	34.63
R910	\$0.595	23.8	\$1.547	23.8	\$4.403	33.87	\$9.676	38.7
R91N	\$0.595	23.8	\$1.547	23.8	\$3.475	26.73	\$7.034	28.14
R2011	\$0.488	19.5	\$1.372	21.1	\$3.055	23.5	\$7.000	28.0

Output Level 4 (20,000 b/month)

<i>Royalty Scheme</i>	<i>P1: \$2.50 Royalty \$/b</i>	<i>P1: \$2.50 Royalty Rate (%)</i>	<i>P2: \$6.50 Royalty \$/b</i>	<i>P2: \$6.50 Royalty Rate (%)</i>	<i>P3: \$13 Royalty \$/b</i>	<i>P3: \$13 Royalty Rate (%)</i>	<i>P4: \$25 Royalty \$/b</i>	<i>P4: \$25 Royalty Rate (%)</i>
R51	\$0.410	16.67	\$1.083	16.67	\$2.167	16.67	\$4.167	16.67
R62	\$0.410	16.67	\$1.083	16.67	\$2.167	16.67	\$4.167	16.67
R73	\$0.610	24.4	\$1.586	24.4	\$3.172	24.4	\$6.100	24.4
R740	\$0.610	24.4	\$2.717	41.8	\$7.378	56.75	\$15.983	63.93
R74N	\$0.610	24.4	\$1.913	29.42	\$4.387	33.74	\$8.9454	35.83
R820	\$0.610	24.4	\$1.586	24.4	\$4.880	37.54	\$10.961	43.84
R82N	\$0.610	24.4	\$1.586	24.4	\$4.148	31.91	\$8.877	35.51
R910	\$0.610	24.4	\$1.586	24.4	\$4.514	34.72	\$9.920	39.68
R91N	\$0.610	24.4	\$1.586	24.4	\$3.562	27.40	\$7.211	28.84
R2011	\$0.488	19.5	\$1.372	21.1	\$3.055	23.5	\$7.000	28.0

Comments

- (1) The price insensitivity of the royalty rate in the 1951, 1962, and 1973 regulations is apparent. The addition of the supplemental royalty in 1974 served to increase the royalty rate as the price of oil rose above a specified level. This level was increased from \$4.11 in 1974 to \$6.50 in April 1982, as is evident in the tables. (Under the 1982 and 1991 regulations, the royalty rates are the same at the \$2.50 and \$6.50 prices.)
- (2) Since the supplemental royalty in the 1974–2009 period was based on the basic royalty, it too was output-sensitive, but it increases the basic royalty by the same percentage for all output levels. The basic royalty is given by S so the percentage rise in royalty (with the supplemental royalty) can be represented as follows:

$$\frac{S + S \left(\frac{k(A - B)}{A} \right)}{S} = 1 + \frac{k(A - B)}{A}$$

Thus the percentage increase in the royalty is not sensitive to the output rate (though the base royalty is). It is affected by k (for example, whether the oil is ‘new’ or ‘old,’ the former assessed a lower royalty increase) and by the level of oil prices (a higher price [A] means a greater percentage increase in the royalty). Note, however that the increase in the royalty rate slows as the price becomes higher. (This can be seen in the table; compare, for example, the royalty change as price rises from \$6.50 to \$13.00 with the change as the price rises from \$13.00 to \$25.00. More formally, the derivative of the royalty formula with respect to price changes can be shown as (where R is the royalty):

$$\frac{\partial R}{\partial A} = \frac{skB}{A^2}$$

- (3) The low-output case (O1, 100 b/month) illustrates the increased rate sensitivity at low-output rates of the 1979 change to the basic royalty, with the rate falling from 5.8 per cent to 1.25 per cent. The 2011 regime eliminates royalties entirely on low-output wells, even at higher prices than considered here. That is, the new regulations will generate reduced revenue at price levels observed prior to 2000; the higher ceiling

royalties become effective only at prices above the highest (\$25/b) shown in these tables.

- (4) The general reduction in royalty rates at higher prices from 1974 to 1982 to 1991 is also apparent, particularly for ‘old’ oil between 1974 and 1982. It is important to note that the royalty rates at the \$13.00 and \$25.00 prices under the 1974 regulations are somewhat misleading since regulators selected the royalty factors (k) in light of prevailing prices, which in 1974 were closer to \$6.50.

C. Royalty Inefficiencies

If the industry were assumed to be operating in an efficient manner in the absence of royalties, their imposition might change industry behaviour, creating economic inefficiencies. There are three main examples:

1. Investment Disincentives

Since Crown royalties are payments made to the Alberta government, they are seen as costs by the company and therefore reduce the anticipated profits from investment. Hence, higher-cost projects may be made unprofitable by the royalties. This would be the case if the expected rise in royalty payments exceeds the expected profits from the investment. As the tables above illustrate, royalties are especially high for high-output projects, so investment disincentives would be especially high for projects expected to produce a lot of oil (per well) but which have relatively low anticipated profits. This could be because their oil-production costs are high, as is often true for deep wells in hostile environments (the foothills or far north of the province) and for EOR projects. This may also be true for projects that have a high dry-hole risk (e.g., new field wildcats aimed at new geologic plays), though it must be noted that the anticipated royalties must also be adjusted by the probability of success.

A simple investment model may help illustrate these points. Suppose a company foresees only two possibilities, a dry well or a productive one, and that p is the expected probability of success. Let I represent the expected cost of drilling the exploratory well, PVR represent the expected present value revenue of a successful well, and PVC represent the incremental present value costs of a success (i.e., completion, development and operating costs). Assume, for

simplicity, that the royalty is a flat r per cent of revenue, so the present value royalty is given by $rPVR$. Let $EMV(b)$ stand for the expected profit of the project before the royalty is imposed, and $EMV(a)$ be the expected profit after the royalty. Then we can represent the percentage change in expected profit due to the imposition of a royalty as:

$$\frac{EMV(a) - EMV(b)}{EMV(b)} = \frac{-(p)(rPVR)}{(p)(PVR - PVC) - I}.$$

If the royalty makes the project unprofitable (i.e., $EMV(a) < 0$), then the absolute value of the numerator will exceed the value of $EMV(b)$, and the expression will be smaller than -1 ; investment will not proceed. The numerator will be higher in absolute value terms the higher the royalty rate and the higher the probability of success. A value of -1 or less is also more likely the higher are exploration, development, and/or operating costs.

It might be noted that this formulation ignores 'option value' considerations. The presence of royalties, which are subject to unilateral change by the government, may increase the perceived risk of investment in the industry. Since an investment in oil exploration cannot be reversed once it has been undertaken, companies may prefer not to invest immediately (that is, invest less), thereby keeping the irreversible investment option open pending a reduction in uncertainty about what the government's intentions are.

2. Output Timing Inefficiencies

Crude oil pools can be drained in a number of different ways, depending on the number of infill wells drilled. Generally speaking, a greater number of wells will deplete the deposit faster (increase the initial pool output rate, but with a higher decline rate); but the average well-output rate will be smaller. The investment decision asks whether the increased present value of revenues from faster depletion compensates for the higher costs of more wells. With an output-sensitive royalty, there is an extra inducement to infill drilling, since the lower average well-output rate will reduce the royalties paid. However, the existence of royalties (apart from their output-sensitivity) exerts a contrary influence. Output generates royalty obligations, which are a cost; by delaying production, the present value of this extra cost can be reduced, offering an incentive to reduce initial output levels. This

could be accomplished most readily by drilling fewer wells, though it could also be attained by having more infill wells, but running them at less than capacity (which also keeps the royalty rate down). Given these contrary impulses of a crude oil royalty, generalizations are difficult, with the effects of the royalty regulations hinging on specific reservoir characteristics.

3. Pool Abandonment Inefficiencies

By increasing the producer's operating costs, a royalty will induce earlier abandonment of the pool, with an attendant loss of output and reserves. We can set up a simple example to illustrate the effects under a number of circumstances.

Recall that a well is normally abandoned when its output rate falls to the level where the revenue generated just covers operating costs. The effect of a gross *ad valorem* royalty is to reduce the amount of output that remains with the producer (at a royalty rate of r per cent, the producer keeps $[1-r]$ of the output). Thus we could approximate the effect of a flat rate royalty in the following manner: if $q(T)$ were the output rate at which abandonment would occur in the absence of a royalty, then with a royalty the well would be abandoned when the output rate is $(1+r)q(T)$. (We implicitly assume that both price and per unit operating costs are constant across time.) We could then ask how much sooner the well is abandoned as a result of the royalty. This is clearly a function of the production decline rate (a ; we assume exponential decline). How long does it take for output to fall from $(1+r)q(T)$ to $q(T)$ if the annual decline rate is a per cent? In other words, solve for t in the following equation:

$$q(T) = (1+r)q(T)e^{-at},$$

whence (taking the natural logarithm of both sides):

$$t = \frac{\ln[(1+r)q(T)] - \ln q(T)}{a}.$$

For example, if the abandonment rate without a royalty were 100 b/month (1,200 b/year), the royalty rate were 6.5 per cent and the well decline rate were 10 per cent per year, then abandonment would occur 0.63 years earlier due to the royalty. One could now ask how much cumulative output is lost as a result of earlier abandonment. This would be t years of output starting at level $(1+r)q(T)$ with an a per cent decline rate. Or:

$$\int_0^t (1+r)q(T)e^{-at} dt = \frac{(1+r)q(T) - (1+r)q(T)e^{-at}}{a}$$

In the previous numerical example, this would total 780 barrels. (This is for one well; most oil pools contain more than one well.)

The following tables illustrate the effects of a flat rate royalty on abandonment under a variety of conditions:

Number of Years Earlier Abandonment Occurs

Royalty Rate, r	Abandonment Output Rate, $q(T)$	Decline Rate		
		$a = 5\%$	$a = 10\%$	$a = 15\%$
6.5%	100 b/month	1.3	0.6	0.4
7.5%	100 b/month	1.5	0.7	0.5
19%	1,000 b/month	3.5	1.7	1.2
31%	10,000 b/month	5.4	2.7	1.8
44%	10,000 b/month	7.3	3.7	2.4

Reserves Lost (Barrels)

Royalty Rate, r	Abandonment Output Rate, $q(T)$	Decline Rate		
		$a = 5\%$	$a = 10\%$	$a = 15\%$
6.5%	100 b/month	1,560	780	520
7.5%	100 b/month	1,800	900	600
19%	1,000 b/month	45,600	22,800	15,200
31%	10,000 b/month	744,000	372,000	248,000
44%	10,000 b/month	1,056,000	528,000	352,000

Reserves losses are higher, as would be expected, at higher royalty rates and for wells with higher abandonment rates (i.e., wells with higher operating costs). The lower the well's decline rate, the higher are the reserve losses. A sliding-scale royalty based on output means that royalty rates fall as wells undergo production decline, thereby lessening the incentive to early abandonment.

Part Four: Overview

Thus far, this book has concentrated mainly on the crude oil industry. Part Four goes beyond crude oil to consider three other issues.

The petroleum industry is complex in any number of ways. At the beginning of activities, a major source of complexity lies in the joint-product nature of the industry. A joint-production process is when one product cannot be produced without another. The petroleum industry produces liquid ('crude') oil and natural gas. Both consist of hydrocarbon compounds and have often been generated by the same prehistoric forces. Moreover, pools of liquid oil invariably hold natural gas ('associated gas'), and many natural gas pools ('non-associated gas') include some liquid products ('natural gas liquids' and 'condensate'). Exploration companies may have expectations (and hopes) about which product their efforts will yield – certain areas, for example, may be thought 'gas-prone.' But the inevitable uncertainties of exploration mean that attempts to direct effort to one product rather than another are imperfect. Hence it is inevitable that oil-producing companies (or regions) are also natural gas producers. Oil and natural gas are strongly linked beyond the joint-production phase. They are both valued largely for their energy content.

However, while the crude production linkages are largely complementary, the consumption linkages are primarily competitive (substitutive). Chapter Twelve provides an overview of the Alberta natural gas industry. Of course the joint-product relationship means that much of what we have said about the 'crude oil industry' is relevant to the 'natural gas industry.' In this chapter, we shall discuss natural gas in a manner broadly analogous to our discussion of oil in Parts Two and Three. We will look initially at the historical development of natural gas reserves, production, and prices. Then we will move to the regulatory environment with particular emphasis upon trade and price controls and royalty provisions.

Chapter Thirteen is concerned with the 'macro-economic' role of the petroleum industry. Since it is a major industry, its activities will affect the Alberta provincial economy. This chapter examines the contribution of the petroleum industry to the Alberta economy and explores several important policy issues related to this contribution, illustrating once again the importance of 'petropolitical' concerns.

Finally, in Chapter Fourteen we briefly speculate on the lessons that other jurisdictions might take from Alberta's experience with the petroleum industry.

CHAPTER TWELVE

The Alberta Natural Gas Industry: Pricing, Markets, and Government Regulations

Readers' Guide: Crude oil and natural gas are different products, but highly interconnected. At the consumption level, they are both used primarily as energy products and hence are highly competitive in many uses. Thus the prices of the two products exhibit interdependency, though not a fixed ratio. On the production side, both are naturally occurring hydrocarbons, so a region with resources of oil typically also has natural gas resources, as has been the case in Alberta. This chapter examines the evolution of natural gas markets and regulations in Alberta over the lengthy history in which natural gas moved from being a relatively unimportant by-product of crude oil to a product of greater value to Alberta than conventional crude oil. Many of the regulatory issues with respect to natural gas mirror those discussed with respect to crude oil in previous chapters, so the analytical arguments about oil often apply also to natural gas. However, unlike crude oil policies, both Alberta and Canada have had direct regulations on natural gas sales outside the region that have been based on anticipated natural gas consumption needs within the region. This chapter provides a detailed review of these regulations.

1. Introduction

This chapter parallels the discussion of oil in previous chapters, but with respect to natural gas production. As above, we focus on natural resource production,

with only the briefest attention to the downstream activities of natural gas processing, transmission, and distribution. Nor do we investigate such joint products of lifting natural gas as natural gas liquids (NGLs) or sulphur; and, as noted before, the environmental impacts of the petroleum industry are outside our purview. (Guichon et al 2010, provide a review of a number of important issues in Alberta regarding the ownership of NGLs and their removal from the gas stream.)

As with oil, government involvement in the Canadian natural gas industry is pervasive, not only concerning what might be viewed as normal practice, such as the setting of taxes, royalties, and the like (fiscal systems) and utility regulation (pipeline tariffs), but extending to specific policies directed towards natural gas exports, both in terms of quantities (export licensing) and pricing – even within the prevailing climate of deregulation. These are the issues covered here. As was the case with crude oil, the threads of development, markets, and regulation tangle in a complex petropolitical web.

Following several preliminary comments in this Introduction, the chapter is organized in five sections. Section 2 looks at the evolution of natural gas output and prices. Section 3 examines policies governing the quantity of Alberta natural gas exports at both the provincial and federal levels. Section 4 concerns government controls on the price of natural gas, as well as fiscal systems, including royalty regulations. Section 5 is a brief conclusion.

By way of introduction, however, several comments should be made about natural gas transmission.

Shipment is, arguably, a more important stage of the natural gas industry than of the crude oil industry. This is because gas is a more volatile product than crude oil, and also less concentrated in energy content, so that a larger volume of gas than oil must be transported to deliver the same quantity of energy. High volume, long-distance shipment of natural gas lagged many decades behind such shipments of oil, awaiting technical developments in high-pressure pipelines, and transmission charges normally make up a higher proportion of delivered gas costs than oil costs. Since the volume of gas shippable by a pipeline rises more than proportionately to the diameter of the pipe, pipeline transmission exhibits economies of scale. (That is, the unit cost of shipment falls as the quantity of gas moved increases.) This 'natural monopoly' aspect of gas pipelines has given rise to public interest concerns. One response was the regulation of gas transmission tariffs on a cost of service basis. Despite this, as will be discussed below, the Government of Alberta and many natural gas producers worried that the main interprovincial gas transmission companies (especially TransCanada PipeLines [TCPL], now called TransCanada Corporation, which moved gas eastward from Alberta) had market power that allowed them to keep Alberta gas prices artificially low.

Also, in the 1950s, the Alberta government granted a single company almost exclusive rights to gather and move natural gas to the provincial border for export. (The company was Alberta Gas Transmission Limited, AGTL; in the 1970s, this company diversified considerably, including into ex-Alberta gas transmission and petrochemical production, and was renamed NOVA Corporation of Alberta; NOVA merged with TCPL in 1998. Throughout this period relatively small volumes of gas have been moved to Alberta gas consumers by Alberta natural gas distribution companies instead of by AGTL/NOVA.)

AGTL, and its successors, have transported gas on a regulated cost of service basis, but there has been much controversy about the nature of the transmission charge, which, for much of the period, was set on a 'postage stamp' basis; that is, all Alberta gas paid the same tariff regardless of the transportation distance involved. The field price received by a natural gas producer is usually a 'netback' price, the price in a major 'market' area, for example, the main gathering terminal for export sales at the Alberta border, less the transmission tariff to that market. Hence a postage stamp tariff, in contrast to one where each producer pays the transmission cost associated with moving its gas, tends to favour producers more distant from

markets and using more expensive newer facilities relative to producers close to the border gathering terminals or using older largely depreciated facilities. (Since the freehold leases tended to be concentrated in the more southern part of the province, it also involved their cross-subsidizing the more distant Crown leases.) Discussions amongst NOVA and assorted interested parties after 1996 yielded no agreement on this controversy, and in 1999 NOVA applied to change the pipeline tariff process. Decision 2000–2006 by the Alberta Energy and Utilities Board (EUB) allowed replacement of the postage stamp tariff with "Receipt Point Specific Rates," which could vary with distance and volume of gas moved, and also removed NOVA's monopoly on the construction of 'lateral' pipelines to connect gas pools to the main NOVA pipelines. (NEB, 1996, provides a useful review of changes in natural gas pipeline regulation, and the declining role of transmission companies in contracting natural gas, in the decade following deregulation in 1986.) In 2009, after application by TCPL/NOVA, regulation of the Alberta system was transferred from the ERCB to the NEB on the grounds that it formed an integral part of TransCanada's intercontinental gas transmission network.

From this brief review of gas transmission, we now turn to more detailed discussion of other issues. (In addition to other references in this chapter, Helliwell et al., 1989, chaps. 4 and 5, provides a good survey of Canadian natural gas market evolution and regulations up to 1990. See also Winberg, 1987, chaps. 3 and 4. Angevine, 2010b, provides an overview from the perspective of the year 2010.)

2. Natural Gas Production and Pricing

Table 12.1 includes summary statistics on key dimensions of the Alberta natural gas industry for years since 1947. Much of the data parallels that for crude oil in earlier chapters of this book. Our discussion of the natural gas industry will be much less detailed than that of oil and will emphasize the features of natural gas markets and regulations that differ from crude oil.

A. Resources and Reserves

In ground natural gas resources in Alberta can be divided into 'associated' and 'non-associated' categories. The former are the gas volumes within crude oil pools,

Table 12.1: Alberta Natural Gas Reserves, Production, Deliveries and Prices, 1947-2012

	Established Marketable Reserves (10 ⁹ m ³)	Remaining Marketable Reserves Additions (10 ⁹ m ³)	Marketable Production (10 ⁶ m ³)	R/P Ratio (Years)	Deliveries (10 ⁶ m ³)			Average Wellhead Price		Gas Price/ Oil Price
					Alta	Other Canada	U.S.A	(\$/ 10 ³ m ³)	(\$/mcf)	
1947	n.a.	n.a.	924	n.a.				2.40	0.07	0.14
1948	112	n.a.	1,062	105.1				2.32	0.07	0.11
1949	129	18	1,150	112.1				2.24	0.06	0.12
1950	145	17	1,425	101.8				2.08	0.06	0.11
1951	207	61	1,607	128.8				2.17	0.06	0.14
1952	295	88	1,785	165.2				3.32	0.09	0.22
1953	372	76	2,043	182.1				3.29	0.09	0.21
1954	431	59	2,453	175.7	2,291	15	0	3.28	0.09	0.20
1955	490	59	3,002	163.2	2,730	19	0	3.32	0.09	0.22
1956	520	65	3,208	162.1	2,948	26	0	3.42	0.10	0.22
1957	582	65	3,781	153.9	3,229	639	4	3.22	0.09	0.22
1958	686	110	5,242	130.0	3,362	2,036	4	3.23	0.09	0.24
1959	768	89	7,074	108.6	3,738	3,498	3	3.22	0.09	0.23
1960	879	120	9,058	97.0	4,000	5,264	3	3.22	0.09	0.23
1961	880	13	11,868	72.5	4,012	4,744	2,803	4.29	0.12	0.29
1962	912	50	17,504	50.3	4,319	5,426	7,191	4.51	0.13	0.32
1963	928	36	19,532	47.6	4,555	6,415	8,115	4.94	0.14	0.32
1964	992	86	21,903	45.3	4,649	7,589	8,747	5.17	0.15	0.32
1965	1,058	90	24,039	44.1	5,032	8,746	8,693	5.10	0.15	0.32
1966	1,073	41	25,409	42.4	5,346	8,999	9,673	5.33	0.15	0.33
1967	1,119	74	27,400	40.8	5,646	9,251	11,152	5.49	0.16	0.35
1968	1,224	135	31,038	39.5	5,827	10,198	13,407	5.51	0.16	0.35
1969	1,273	88	36,735	34.7	6,474	12,974	14,948	5.46	0.16	0.35
1970	1,279	46	42,874	29.8	6,835	15,655	17,531	5.69	0.16	0.36
1971	1,276	45	47,529	26.9	7,164	16,366	20,879	5.60	0.16	0.32
1972	1,269	45	52,189	24.3	7,926	19,941	21,457	5.89	0.17	0.33
1973	1,397	183	55,521	25.2	8,266	22,734	21,672	6.62	0.19	0.30
1974	1,487	147	56,817	26.2	8,646	24,272	20,562	10.46	0.30	0.29
1975	1,451	21	58,142	25.0	9,213	24,319	21,125	21.79	0.62	0.48
1976	1,502	106	59,456	25.2	9,656	24,749	21,783	35.34	1.00	0.67
1977	1,568	128	62,666	25.0	11,388	25,740	22,571	45.69	1.29	0.72
1978	1,665	163	61,600	27.0	12,588	25,642	20,402	52.57	1.49	0.69
1979	1,718	123	66,200	26.0	13,185	25,554	22,946	59.84	1.69	0.73
1980	1,747	92	62,070	28.1	13,465	24,703	19,356	82.51	2.34	0.85
1981	1,795	117	61,950	29.0	13,362	25,716	18,434	87.19	2.47	0.74
1982	1,853	119	64,113	28.9	14,069	25,318	19,937	94.31	2.67	0.59
1983	1,826	39	60,590	30.1	13,721	24,241	17,771	100.39	2.84	0.51
1984	1,798	41	65,819	27.3	15,086	27,112	19,057	103.28	2.92	0.50
1985	1,768	43	72,849	24.3	15,881	27,368	23,155	99.00	2.80	0.47
1986	1,720	22	64,945	26.5	15,109	27,416	18,236	77.74	2.20	0.66
1987	1,652	0	69,940	23.6	14,541	25,763	24,979	59.98	1.70	0.43
1988	1,628	65	80,963	20.1	16,679	26,616	32,694	54.02	1.53	0.52
1989	1,649	108	83,479	19.8	17,527	26,952	33,367	54.73	1.54	0.44
1990	1,647	88	84,578	19.5	17,340	25,966	35,706	55.18	1.56	0.36
1991	1,626	58	89,286	18.1	16,941	24,897	40,193	48.65	1.38	0.39
1992	1,595	73	98,860	16.2	17,809	27,973	48,801	48.68	1.38	0.38

/continued

Table 12.1/continued

	Established Marketable Reserves (10 ⁹ m ³)	Remaining Marketable Reserves Additions (10 ⁹ m ³)	Marketable Production (10 ⁶ m ³)	R/P Ratio (Years)	Deliveries (10 ⁶ m ³)			Average Wellhead Price		Gas Price/ Oil Price
					Alta	Other Canada	U.S.A	(\$/ 10 ³ m ³)	(\$/mcf)	
1993	1,535	59	110,658	13.9	17,963	30,437	55,573	60.08	1.71	0.52
1994	1,496	74	119,688	12.5	18,067	31,805	64,530	68.07	1.93	0.55
1995	1,489	123	124,024	12.0	18,905	32,095	67,195	49.99	1.41	0.37
1996	1,378	10	131,743	10.5	22,197	36,184	68,834	58.90	1.67	0.36
1997	1,284	30	133,243	9.6	20,643	37,352	69,167	70.96	2.01	0.48
1998	1,240	93	136,782	9.1	16,730	43,028	67,040	69.70	1.97	0.67
1999	1,207	110	141,034	8.6	20,805	43,813	67,184	88.68	2.51	0.58
2000	1,211	144	142,239	8.5	23,054	45,028	66,064	162.34	4.59	0.67
2001	1,184	116	139,942	8.5	20,513	42,136	64,359	198.39	5.61	1.01
2002	1,171	134	137,483	8.5	21,403	39,190	78,015	139.48	3.95	0.65
2003	1,122	87	134,732	8.3	25,431	29,574	74,460	224.62	6.36	0.97
2004	1,127	146	135,824	8.2	24,225	30,572	75,713	228.84	6.48	0.83
2005	1,120	126	136,838	8.2	22,744	36,037	72,943	301.75	8.54	0.86
2006	1,115	126	136,261	8.2	27,697	34,720	73,979	240.86	6.82	0.64
2007	1,069	95	135,735	7.9	28,180	35,322	72,294	235.66	6.67	0.58
2008	1,098	155	127,953	8.6	31,223	37,529	62,119	283.86	8.03	0.49
2009	1,056	82	118,374	8.9	32,361	36,651	52,366	142.86	4.04	0.38
2010	1,025	83	112,804	9.1	32,107	29,352	49,552	137.98	3.90	0.29
2011	945	70	104,975	9.0	34,137	29,682	45,397	125.36	3.22	0.22
2012	916	58	n/a	n/a	35,402	29,775	39,817	n/a	n/a	n/a

Notes and Sources:

Column (1): From EUB, ERCB, and OGCB *Reserves Reports* (ST-18 and ST-98). Marketable gas excludes gas for reinjection purposes and NGLs that will be removed at gas plants.

Column (2): From EUB, ERCB, and OGCB *Reserves Reports*. 1949 and 1950 were estimated as the change in remaining reserves plus production.

Column (3): From CAPP *Statistical Handbook*.

Column (4): Column (1) divided by Column (3).

Columns (5), (6) and (7): From ERCB and OGCB *Alberta Oil and Gas Annual Statistics*, and *Cumulative Annual Statistics of the Alberta Oil and Gas Industry*; from 1993 on, ERCB/EUB, *Alberta Energy Resource Industries Monthly Statistics* (ST-3). Deliveries generally add up to less than marketable production (Column (3)) because of line losses, pipeline fuel, and other shrinkage, and because the figures come from different sources. Data are not available on deliveries prior to 1954, but marketable production went almost entirely to Alberta.

Column (8): CAPP *Statistical Handbook*. The Alberta average wellhead/plant gate price.

Column (9): From Column (8). 1 cf = .0283 m³.

Column (10): Derived from data in CAPP *Statistical Handbook*. The Alberta average wellhead/plant gate natural gas price and average wellhead crude oil price were translated into dollar costs per joule of energy and the ratio taken.

lying as a gas cap and/or dissolved within the crude oil. Output of such gas, associated with crude oil, is governed by oil output rates. Moreover, this natural gas is often re-injected back into the oil reservoir ('recycled') to aid in the recovery of the oil.

Non-associated gas is derived from deposits that are predominantly gaseous hydrocarbons (methane, for the most part). However, natural gas pools will hold varying amounts of hydrocarbons heavier than

methane (e.g., natural gas liquids [NGLs] comprised of ethane, butane, propane, and pentanes plus). The 'wetter' the gas pool, the higher the proportion of these NGLs, and the more likely it is that the development and output levels for the pool will be affected by market conditions for these products as well as those for natural gas. Natural gas normally passes through a processing plant to remove some or all of the NGLs before the gas is moved to market. Natural gas plants

have included field plants and 'straddle plants' located at several points on the main NOVA transmission lines. In a series of decisions starting in 1981, the ERCB approved construction of 'deep-cut' natural gas plants that remove almost all the non-methane hydrocarbons. (These plants were controversial because the gas moving from the deep-cut facilities to the straddle plants had little NGL content, so the straddle plant was not needed for this gas. The board affirmed that the gas producer retained ownership rights for the gas and NGLs until the gas was sold, so could remove NGLs prior to sale of the gas. As mentioned above, we shall not discuss gas processing or NGL markets and regulations.)

The volume of hydrocarbons in place in a pool (the natural gas 'resource') forms the basis for 'marketable' natural gas reserves. In place volumes must be adjusted for the recovery factor (the proportion of in place gas that will be lifted) and for losses and shrinkage in operations (e.g., volumes that will be injected back into the ground for conservation reasons, adjustments to volumes due to differences in temperature and pressure in the reservoir and at the surface, and the NGLs that will be removed before the gas goes to market). (See the ERCB, 2010, *Reserves Report*, ST-98, pp. 5.13–15.) Non-associated natural gas reservoirs show higher recovery factors than crude oil reservoirs (about 80% in Alberta as compared to 25%).

The most recent estimate of the conventional Alberta natural gas resource base is that it holds $9,203 \times 10^9 \text{ m}^3$ of conventional natural gas. Of this, there are $6,528 \times 10^9 \text{ m}^3$ (232 Tcf) of potentially marketable reserves (ERCB, 2013, *Reserves Report*, ST-98, p. 5-23; and EUB/NEB, 2005); this is a 'medium-case' estimate. Cumulative production up to the end of 2012 has been $4,425 \times 10^9 \text{ m}^3$ and $916 \times 10^9 \text{ m}^3$ was estimated to lie in established reserves, leaving $935 \times 10^9 \text{ m}^3$ (14%) still to be added. (The EUB/NEB estimated 'low' case marketable reserve potential at $5,765 \times 10^9 \text{ m}^3$ and 'high' case potential at $7,134 \times 10^9 \text{ m}^3$.)

Columns (1) and (2) of Table 12.2 show the changes since 1948 in Alberta's remaining conventional marketable natural gas reserves and reserves additions. As can be seen, gas reserves grew rapidly through to 1970, and again in the mid- to late 1970s, hitting a peak of $1,853 \times 10^9 \text{ m}^3$ (65.4 Tcf) in 1982. In twenty-six of the thirty years from 1982 to 2012, marketable gas reserves declined; that is, production exceeded reserves additions. However, the decline is not as pronounced or as long-standing as that for conventional crude oil. Recall from Chapter Five that Alberta's conventional crude oil reserves have been

in decline since 1969; by the start of 2013, remaining oil reserves were at about 22 per cent of the peak 1969 level. Remaining gas reserves in 2012 were at 49 per cent of their 1982 peak. In other words, since the early 1970s, Alberta's conventional petroleum reserve base has been shifting more towards natural gas.

Reserves additions for gas, as for oil, show great year-to-year variation, as would be expected in an industry with pervasive geological uncertainty. In contrast to the conventional crude oil industry, natural gas reserves additions do not show as dramatic a decline over time as do liquid hydrocarbon reserves additions. Obviously, natural gas has been of increasing relative importance at the exploration level over the past two decades.

The rising importance of natural gas relative to oil could reflect a variety of factors including: (i) a larger and more homogeneous group of undiscovered natural gas reservoirs, so that depletion effects in the discovery process are less significant for gas than oil; (ii) a larger inventory by 1970 of observed, but not developed or proved up, natural gas pools as compared to oil pools; (iii) gas-pool-specific technological changes in exploration and development; and (iv) a shift in industry effort away from exploration and development of crude oil toward natural gas. These are not independent factors. For example, a more attractive remaining gas reserve base would induce a shift in relative industry effort toward gas. We are unaware of any empirical model that provides valid measures of these four factors but believe that the first is of particular significance, followed by the fourth and then the second.

Non-conventional sources of natural gas have been growing in significance within North America, including Alberta. (We consider gas from the Alberta 'deep basin,' in the northwestern part of the province, much of which lies in small pools in low permeability rock and is therefore difficult to produce, to be conventional gas.) Non-conventional natural gas is a heterogeneous category including coal bed methane, gas trapped tightly in shale (where it is typically spread thinly through the shale rather than occurring as a concentrated pool), gas hydrates, and various synthetic gases (e.g., biogas or gasified coal). Since the turn of the century, two of these, coal bed methane and shale gas, have attracted significant investment within North America and appear to be available in large volume at costs that are within the range of historical gas prices. Alberta's ERCB has studied only coal bed methane in any depth. (Alberta has uncharted shale gas potential as well. In its 2011 *Reserves Report*,

the ERCB indicated that, while it “expects to publish in-place resource estimates soon, the estimate of established reserves will likely be delayed until sufficient data are available to conduct a reasonable assessment of shale gas recoverability,” p. 5-20.) Methane may be held in coal seams either as free gas or within the coal itself. Vast coal resources lie beneath much of central and southern Alberta, as has been demonstrated in core samples from many wells drilled by the petroleum industry. Many producing (conventional) gas wells pass through coal seams; some of these have been modified to allow commingled production of conventional gas and coal bed methane.

In 2010, the ERCB provided an ‘initial determination’ of Alberta’s coal bed methane resource in place, based on a study from the Alberta Geological Survey, of $14 \times 10^{12} \text{ m}^3$ (500 Tcf), which is a third larger than its estimated resource base for conventional natural gas (ERCB, 2010, *Reserves Report*, ST-98, p. 5-9). What portion might ultimately be recoverable is unknown, and only a small part is included in reserve estimates; the ERCB reported (p. 5-2) 2012 remaining recoverable reserves of coal bed methane as $56.7 \times 10^9 \text{ m}^3$, 6.2 per cent of conventional gas reserves. Thus, as of early 2013, there is large potential for coal bed methane (and for shale gas) in Alberta, but insufficient development to permit large volumes to qualify as reserves.

B. Production and Delivery

Column (3) of Table 12.1 shows Alberta marketable natural gas production from 1947. Output grew tremendously to a peak in 2000, at an average rate of over 9 per cent per year. Except for the decade from 1977 to 1987, rapid growth was the norm up to the mid-1990s. (1957 output was 310% more than 1947; 1967 was 620% higher than 1957; 1977 was 130% over 1967; and 1992 was 40% over 1987; but 1987 was only 10% above 1977.) However, in the later 1990s, growth slowed, hitting a peak output rate in the year 2000 and then trending downward, albeit relatively slowly. One might expect production to follow the decline in remaining reserves, and at some point it must. However, continued development investment can delay or reduce the output decline as reserves are used more intensively. (In this case, the reserves to production [R/P] ratio will fall, as happened in Alberta from 1983 to 2007, as shown in Column (4) of Table 12.1.) After 2007, however, this ended and output of natural gas fell markedly.

Coal bed methane (and a minimal amount of shale gas, for the last few years) is included in Column (3). The ERCB estimated coal bed methane production at $5.6 \times 10^9 \text{ m}^3$ in 2012, just under 6 per cent of Alberta’s natural gas production (ERCB, 2013, *Reserves Report*, ST-98, pp. 5-2 and 4). In 2012, the board noted (p. 5-19) that commercial coal bed methane production began in 2002, very much aided by horizontal well-drilling advances that allow multiple completions within a single horizon. In contrast to conventional gas output, that from coal bed methane has been increasing since 2002 and is expected to make up a rising share of Alberta’s natural gas production. The ERCB has examined the appropriate regulatory framework for non-conventional gas and issued a report looking at other regulatory approaches within North America (ERCB, 2011).

The production rises in the first two decades, as with crude oil’s first decade after Leduc, are closely tied to the extension of pipeline linkages from Alberta, particularly the TransCanada PipeLine (TCPL), east to Ontario, which was begun in 1957 and completed in 1958, and the Alberta and Southern connection to California, completed in 1961. (Alberta and Southern operated as a gas purchaser. It was a wholly owned subsidiary of Pacific Gas and Electric, a Northern California distributing company, which also owned Alberta Natural Gas and Pacific Gas Transmission, the two pipeline companies that moved gas from the Alberta border to California.) Gas exports to Montana began in 1951 in small volumes through the Canada–Montana Pipeline. In the late 1960s, Consolidated Natural Gas began to contract Alberta natural gas reserves for a new export pipeline to the mid-western United States. However, for reasons discussed in Section 3, this project was not approved by the National Energy Board.

We would emphasize three ways in which Alberta natural gas and its associated market development differed from convention crude oil. Natural gas was initially viewed as a by-product; regulation of the natural gas industry was greater and earlier; natural gas had a more limited market.

The natural gas reserves to production (R/P) ratio provides an initial introduction to these points (Column (4) in Table 12.1). Until the 1990s, Alberta’s gas R/P ratio was far higher than that for conventional crude. The ratio exceeded 100 from 1948 through 1959 before the completion of the TransCanada PipeLine; it fell sharply after that but remained at twenty-four years or greater through 1986. After 1986, it fell again,

and by the mid-1990s was approaching the level of the conventional crude oil reserves-to-production ratio.

Looking at the R/P values in excess of 100 prior to 1960, one might ask: Why would companies add more to natural gas reserves if inventories (reserves) were so high relative to output? And why wasn't output increased much more rapidly in these circumstances? The answers, in essence, are that "they didn't" and "they couldn't." At the time, natural gas reserves were largely the unintentional by-product of crude oil. Exploration (and development of associated gas in crude oil reservoirs) is a joint product process that generates both crude oil and natural gas reserves in a petroleum basin. Natural gas reserves rose rapidly as a result of the active corporate search for crude oil reserves. In other words, the build-up of natural gas reserves in the 1940s and 1950s was unintentional.

Opportunities for exploitation of natural gas pools were more limited than for oil pools. Both had to await the development of large-diameter continental pipelines from Alberta, and so entry into new markets was delayed. And the natural gas market was continental, not overseas. The high cost of moving gas, especially by ocean, makes transportation a more critical component of delivered price. As a result, it was harder for natural gas, than for crude oil, to break into more distant markets. Since transmission costs are relatively high, the difference between developed prices in central Canada and field prices in Alberta must be higher for natural gas than for crude oil. Consequently, there was increased likelihood either that delivered prices would be too high to capture sales as large as might be hoped or that the field price would be so low that rapid development did not appear an attractive proposition.

The nature of regulation in gas markets provided further restraints on increased output, particularly with respect to exports. Specifically, both the Alberta Oil and Gas Conservation Board (OGCB), in 1950, and the federal National Energy Board (NEB), in 1959, introduced requirements that further gas exports from a region would be allowed only if they were seen as surplus to regional requirements. In effect, this required the maintenance of large inventories (reserves) before ex-regional sales could occur. Such surplus tests were in existence through the mid-1980s and served to keep the gas R/P ratio high. Gas exports rose tremendously in the 1960s, but, beginning in 1970, a period ensued in which new gas export permits were denied. (These tests are discussed in detail in Section 3 of this chapter.)

The gas market, like crude oil, was subject to strict price regulation from the mid-1970s to the mid-1980s. Table 12.1 shows that gas exports fell sharply after 1979; the decline was to levels well below authorized volumes, indicating that export prices had been set higher than compatible with allowable exports. After 1986, the gas market, like oil, moved to deregulation and exports could rise without rigid surplus test requirements; sales to U.S. customers increased and the R/P ratio fell.

The nature of the relationship between buyers and sellers also differed greatly between the Alberta crude oil and natural gas markets as the Alberta petroleum industry grew after 1950. For oil, as discussed in Chapter Six, refiners bought from crude oil producers (often within a single vertically integrated company) and hired the use of transmission facilities. There were long-standing trading relationships but long-term contracts were rare, and the price paid for crude was the current posted price. From the 1940s through the 1960s, natural gas was purchased from the producer by a natural gas transmission company (or a local Alberta utility) under a long-term contract with relatively rigid prices for the contract term. The transmission company, in turn, signed long-term contracts with local gas distribution companies. Since there were few transmission companies, and since the surplus regulations hindered those aimed largely at exports, the Alberta natural gas market was oligopsonistic (tending toward monopsony when only TransCanada was actively contracting). This market structure, and the surplus regulations, made it difficult for producers to market natural gas.

It has been argued that natural gas requires long-term contracts because pipelines and distributing utilities must install so much capital to service customers and because customers are so dependent on the natural gas they receive. Many public regulatory bodies required that utilities sign long-term contracts to ensure gas supplies. Such contracts also contributed to high R/P ratios and dictated a somewhat different development pattern for natural gas pools than oil pools in North America. Natural gas reservoirs generally commenced with a lower initial output rate relative to reserves; further, rather than allowing production decline to begin relatively early in the pool's life, the producer often continued development drilling so as to maintain a constant output level for a number of years.

The thesis that natural gas requires long-term contractual arrangements and oligopsonistic purchasing

was not much challenged until the 1970s. However, developments in the late 1980s saw gas markets evolving toward the more open, competitive, short-term sales arrangements common in crude oil markets and a far greater number of companies involved in active trading of natural gas. In its assessment of the first decade of deregulation in the Canadian natural gas market, after 1986, the NEB noted that the share of gas purchased for customers by local utilities had fallen from 91 per cent of the market in 1985 to 41 per cent, that short-term sales arrangements were of increasing importance, that many companies now purchased natural gas in the producing region and purchased transmission services from the pipeline company, and that even long-term natural gas sales contracts typically had prices that were wholly or partially tied to natural gas spot prices (NEB, 1996).

In summary, the pattern of change in Alberta gas production and deliveries can be divided into four periods. A by-product phase held from 1947 to the late 1950s, characterized by growing local sales and high and generally rising R/P ratios as gas discoveries followed from oil-directed exploratory activity. There was a market penetration phase from 1959 through 1971 when pipeline links to other Canadian and U.S. market areas allowed rapid production growth and declining R/P ratios. Natural gas was developing as a product itself, beyond by-product status. A tightly regulated period ensued from 1972 to 1986 when prices and exports were strictly controlled, with relatively constant R/P ratios and less sales growth. Finally, deregulation began in 1986 with rapid output growth directed mainly to exports, a falling R/P ratio, even greater independence of natural gas and oil supply decisions, and the entry of many new players into buying and selling natural gas in Alberta.

Sections 3 and 4 will discuss the changing government regulations that attended these developments in the natural gas markets.

C. Prices

1. Market Expansion, 1947-71

Alberta natural gas prices from 1947 are shown in Table 12.1, columns (8) and (9). Column (8) shows average prices at the wellhead or plant gate in dollars per thousand cubic metres (10^3 m^3); dollars per thousand cubic feet (Mcf) are shown in column (9). Column (10) compares average Alberta field natural gas and crude oil prices, by looking at the price of a

given quantity of energy in the form of natural gas as a proportion of the price of the same amount of energy from crude oil.

The nominal (current dollar) price of natural gas fell somewhat immediately after 1947. It jumped sharply (by over 50%) in 1952, as buyers began to contract large volumes in anticipation of large shipments from Alberta. From 1952 to 1971, nominal prices tended upwards, but at a slow rate (less than 3% per year, just about the average inflation rate) so that in 1971 the real average wellhead price of gas in Alberta was almost exactly what it had been in 1952 (using the Consumers Price Index). Output grew by almost thirty times over this period, suggesting that the evolution of the Alberta natural gas market over the first twenty-five years after Leduc was predominantly supply driven, with large reserves seeking market outlets. This interpretation is consistent with the high R/P ratios observed. Purchases of natural gas for sale outside Alberta were normally under long-term contracts between the gas producer and the major natural gas pipeline companies (TransCanada for shipments east and Westcoast for shipments west). The contracts established relatively fixed prices for natural gas, with a base price (in cents per Mcf) and small periodic increases, as can be seen in Column (9) of Table 12.1 for years from the early 1950s through to the end of the 1960s. Contracts sometimes included a 'most-favoured-nation' clause, which would accord higher prices in newly signed contracts to the gas sold under older contracts. This is a clear disincentive to the buyer to offer higher prices on new contracts.

By the early 1970s, natural gas producers and the Alberta government were expressing concern about the 'low' level of natural gas prices and the inflexibility of pricing provisions in the long-term contracts, which were common at the time. (Hamilton, 1974, provides a good review of the Canadian situation at this date.) These concerns were stimulated in part by the rise in oil prices, which began in the early 1970s, and were the subject of investigation in a report of the Stanford Research Institute (1972). As is shown in column (10) of Table 12.1, the prices of Alberta natural gas relative to crude oil had been rising consistently from 1948 to 1970. In 1971, this was reversed. Increasingly the presumed undervaluation of natural gas was tied to what was called its high 'commodity value'; this valuation concept was given a prominent role in Alberta legislation in the early 1970s governing the arbitration procedure to be used in renegotiating gas sales contracts. However, as a basis for pricing, the concept of the commodity value of natural gas turned

out to be hopelessly ambiguous. What might the term mean? A brief discussion in general terms will help set the stage for the later discussions of Alberta natural gas policies in the 1970s.

2. A Digression on 'Commodity Values'

The appeal of the term 'commodity value' in the early 1970s was clearly related to differences in the prices of crude oil and natural gas and was a shorthand way of saying that natural gas is an energy commodity like oil, so its price should be closely connected to the oil price. In other words, it was implied that in a well-functioning natural gas market, gas should not be viewed as a separate commodity, but as part of a larger energy commodity. The most simplistic view runs as follows. Consumers demand and are willing to pay for energy. It is possible to substitute other goods or services for energy, but generally this cannot be done very easily; so energy has no perfect and few close substitutes. Within the energy category, however, consumers just need a power source and different energy products are close substitutes in this regard. Therefore, energy products should be priced at much the same level per unit of energy content. The implicit view of the natural gas market is given in Figure 12.1. Here P_{CO} is the price of natural gas if it were at the same level per joule of energy as current crude oil prices. The simple commodity pricing argument views the demand curve for natural gas as D_{NG} ; it is very elastic around P_{CO} because of the assumed almost perfect substitutability of crude oil and natural gas. Then, as shown, the supply curve for natural gas could vary widely, and the price of natural gas would still be near the oil-based price. Some observers further argued that, because of its convenience and clean burning properties, natural gas was actually a 'premium' fuel relative to oil, so should command a higher price than the thermal equivalence price. The appeal of the argument to Alberta gas producers and the rent-collecting Alberta government is plain; after all, gas prices in 1972 were just one third of crude oil prices (in the field) on the basis of thermal content (joules or Btus). Of course, the simple commodity price theory would require an explanation of why natural gas prices were not at their 'true' commodity value. Part of any explanation lies in the difference between short-run and long-run equilibria. In the short-run market, participants are constrained by existing capital equipment. In particular, pipeline and distribution facilities may not be in place, and consumers may not possess gas-fired equipment. Thus, the short-run demand

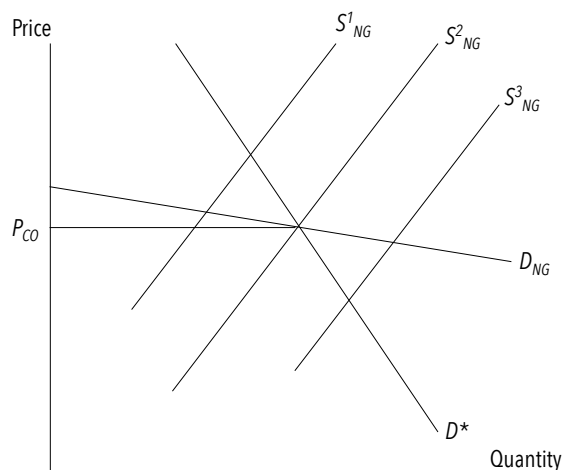


Figure 12.1 Commodity Pricing of Natural Gas

curve is much more inelastic than the long-run one (like curve D^* in Figure 12.1). If gas supply were large, the natural gas price could be well below the oil-based "commodity" price. However, in Alberta in 1970 natural gas prices had been far below that value for at least twenty years (since the Leduc find). That was plenty of time for most long-run capital investment decisions to be undertaken. Why had gas prices risen so little compared to oil? And why was the relative price falling in the early 1970s? Explanations typically emphasized four linked factors: (i) the oligopsonistic nature of the industry, with a few gas purchasers able to force low prices; (ii) the presence of long-term contracts, which tied up large gas volumes at low and rigid prices for many years; (iii) limitations on the freedom to export gas, which inhibited new buyers from entering the market; and (iv) inherent differences in transportation costs.

Now let us consider some flaws in the simple commodity-pricing argument. Two related problems stand out: complications posed by geographically separate markets and problems related to energy substitutability. Geographic differences highlight the transmission cost differences between crude oil and natural gas. If natural gas were priced at the energy equivalent commodity value for crude oil in Alberta, then its price would be relatively higher than crude oil in markets outside Alberta, and it would be overpriced. Proponents of simple commodity-value pricing quickly conceded this point but went on to suggest that natural gas should be priced at the oil level in the most distant major market (e.g., Toronto or Montreal). This would imply a field price for

natural gas lower than crude oil but still higher than historical levels.

It would also imply, if the simple commodity-value approach were correct, that markets closer to Alberta than the distant ones would rely entirely on natural gas to the exclusion of oil. That this would not be the case (was not the case at even lower gas prices) highlights the other main weakness of this approach.

Natural gas and crude oil are not perfect substitutes in use. For one thing, energy consumers buy natural gas but almost never use crude oil; they purchase various refined petroleum products (RPPs). One might think that this gives an advantage to natural gas, allowing a higher energy price than crude oil, since oil must incur additional refining charges before it gets to consumers. Remember, however, that refining is a joint product process; while the entire slate of RPPs must, in the long-run, earn sufficiently more than crude costs to cover refining costs, not all individual RPPs must be priced above crude. RPPs exhibit a wide range of prices per unit of energy content. Under the simple commodity theory, with which of these should natural gas be commodity-priced?

The presumed perfect energy substitutability of natural gas and crude was too unrealistic an assumption to serve as a basis for gas pricing. We mentioned that many gas producers were quick to argue that gas had a cleanliness and convenience advantage over oil in the eyes of most households, so might be expected to enjoy a 'premium' over crude oil prices. This observation did not take the argument far enough. For example, for a rural farmhouse far from a natural gas distribution system, natural gas would be far more 'inconvenient' than light fuel oil. The fact is that there are many different energy (and non-energy) uses of RPPs and natural gas and the different fuels are substitutable to varying degrees in these uses, and only occasionally close to perfect substitutes. For virtually all the main uses of natural gas, there are RPPs that are technologically capable of serving as substitutes, though convenience factors may lead customers to prefer one fuel to another. (Some cooks swear by gas stoves in preference to electric, kerosene, or wood ones.) However, there are RPPs for which natural gas is not an attractive substitute (e.g., aviation fuel, motor gasoline, asphalt).

As a result, one would not expect the long-run demand curve for natural gas to be perfectly elastic at the crude oil energy price. Some users would be willing to purchase gas even if it cost more than this, while many oil users would need prices of natural

gas far lower before they would shift. Berndt and Greenberg (1989, p. 84), for example, report long-run own price elasticity of demand estimates for natural gas in Canada ranging from -0.3 to -0.7 ; those are not even elastic, let alone perfectly elastic. To return to Figure 12.1, the long-run demand curve for natural gas will look more like D^* than D_{CO} , and it would only be by purest chance that supply conditions were such as to give a price at P_{CO} . We do not deny that natural gas demand is affected by oil prices, as would be expected of goods which are substitutable. (Higher crude oil prices generate an increase in the demand for natural gas, and higher competitive gas prices; but only by chance would the higher gas price be an energy equivalent to oil.)

What, then, of the commodity value approach to natural gas pricing? One might hold on to the concept in one of two ways, but neither is particularly useful. The simple approach might be saved by saying that there is some use of gas in a market (at the margin) in which one expects that the long-run equilibrium prices of natural gas and some RPP would be equal in energy terms. Presumably, this would be a relatively important (large) market for gas and one in which natural gas and the RPP are close to perfect substitutes. Some analysts, for instance, focused on the market for low temperature process heat in large industrial uses in the Toronto area, in which natural gas competes with heavy fuel oil. There are always marginal uses, but which they are, and whether or not any of them involve near-perfect substitutability with an oil product, will be a function of the entire constellation of factors determining the supply and demand for natural gas. Therefore, the simple commodity-values approach does not serve as a general method for determining natural gas prices. Rather, the appeal of the concept in Alberta in the early 1970s seemed to be much more political, as a way for critics to emphasize the presumed monopsony power of TransCanada PipeLine as a buyer, transporter, and seller of natural gas.

Alternatively, one might turn to a more complex 'commodity-value' approach, which is, in concept, a reversal of the previous one. Here, one argues that natural gas is a commodity whose value should be determined by the free interplay of demand and supply factors. In other words, rather than tying the gas price directly to some other commodity, this approach stresses the separation (or uniqueness) of gas as a commodity. In fact, the prevailing view of the natural gas market has evolved since 1970 from the

simple commodity-value theory to this more complex one, but it seems somewhat disingenuous to still claim to be using a 'commodity-value' approach!

However, this view of natural gas as a commodity does tie into the research that emphasizes the "commoditization" of the world crude oil market (Verleger, 1982, 1986). In this context, the term 'commodity' refers to a relatively homogeneous and storable product that is widely traded within a market setting that exhibits significant price variability. "Commoditization" of a market refers to the transition from a rigid, highly controlled market with relatively fixed prices to a more flexible market. The price flexibility is generally associated with a heavy reliance on spot sales, in preference to long-term contracts with inflexible prices. The instability in prices that results serves as a stimulus to the development of futures and options markets. It is sometimes suggested that such commodity markets must be effectively competitive, so that prices will tend to equilibrium values where supply equals demand. In fact, this need not be the case, as is illustrated by the commoditization of the world oil market. OPEC clearly exercises oligopolistic power, but so long as it functions as a quantity-fixing cartel there may be large numbers of traders in spot markets and oil prices will be very flexible. (See Chapter Three.) In retrospect, it is the idea of 'commoditization' rather than the idea of 'commodity value' that captures the essence of concerns about low natural gas prices in the early 1970s. What was really at issue was not, in fact, the precise correspondence between crude oil and natural gas prices but the inflexible nature of the long-term purchase contracts and oligopsonistic price rigidity in the market.

3. Price Controls, 1972-86

a. Domestic Prices

On January 17, 1972, Alberta premier Lougheed announced that the ERCB would be instructed to investigate the pricing of Alberta natural gas. Order in Council 204/72 of February 16 made this official, with the ERCB directed to advise the government on four matters:

- (a) factors that influence field prices for natural gas and their suitability in the Alberta public interest,
- (b) the pricing provisions of prevailing contracts for the purchase of natural gas for marketing outside the province and their suitability in the Alberta public interest,

- (c) present and anticipated field prices of natural gas in Alberta and their suitability in the Alberta public interest,
- (d) possible modifications or alternatives to current practice affecting field price, which would enhance the benefit to all residents of the province.

The ERCB immediately commenced public hearings, which lasted until June, and issued its *Report* in August (ERCB, 1972b). This lengthy report provided a review of the Alberta natural gas marketing and contracting procedures. It discussed a variety of factors influencing natural gas prices, with particular emphasis on the demand for gas and the degree of competition in the market. With respect to the latter,

the Board does not agree that prices would have reached their present level without purchasing competition among Trans Canada, Alberta and Southern and Consolidated. The Board agrees with the producers that competition in field purchasing has declined since the refusal by the NEB of the authorization of increased exports of gas to the United States. The Board considers that competition in field purchasing of gas is vitally important to the Alberta public interest. (p. 7-4)

In discussing factors that should influence price, the board argued that

it is in the Alberta public interest for gas to be priced at its commodity value in the marketplace. The Board accepts that in some end uses gas may be priced lower than alternative fuels, while in other applications it may be priced higher. In the Board's view it is important, however that, for the aggregate market the price of gas be comparable to that of alternate fuels. Further, the Board believes it to be in the Alberta public interest that the field price of gas reflect its field value – the commodity value less adjustments for transmission and distribution.

The Board expects that under the pressure of the gas shortage in North America, the field price of gas in Alberta will be influenced increasingly by its commodity value in all market areas. The Board recognizes that because of the long term contracts common in

the gas industry, and the regulatory time lag, gas prices cannot under present circumstances, be expected to adjust immediately to changing market conditions. It believes changes are required in contracts and in regulatory process to permit a quicker response of field price to changing conditions in the market. (p. 7-8)

On the natural gas supply side, the costs of exploration through to field processing of gas were seen

as the factor which determines, whether, at any level of price, a sufficient incentive exists for a producer to explore for and develop new reserves.... The Board does not believe that costs have had much direct effect on field prices in the past nor that they will or should have much direct effect in the future. (p. 7-24)

Since the board acknowledged that gas supply costs varied across deposits, the implication is that Alberta was seen as a price taker in natural gas markets and that the value of alternative fuels would determine the appropriate gas price. The board did note that

the term commodity value was used extensively at the hearing but not defined in any precise manner. The Board believes that most people using the term meant by it the maximum price that could be obtained in a specific regional market area having regard for the mix of end use and the prices of competitive fuels in the area. Commodity value does not imply that gas be priced equivalent to competing fuels in each class of applications in the market area but rather that it be so priced on a total or overall basis. (p. ii)

The board's emphasis upon the demand side of the market as determining values was somewhat contradicted by its suggestion that gas prices would have to be much higher by the early 1980s, essentially to cover the costs of Arctic gas (ERCB, 1972b, p. 9-13).

After looking at prevailing market conditions, and the level of prices and other contract provisions for Alberta gas exports, it concluded "that the actual field price for Alberta gas is less than the field value by some 10 to 20 cents per Mcf... [A]nd therefore concludes that current field prices are not suitable in the Alberta public interest" (p. 9-9). Established price escalation factors would leave gas prices well below these field values. Most contracts (governing some

85% of Alberta's gas exports) included renegotiation clauses, such that "the Board believes that providing there is free negotiation between seller and buyer and effective competition in buying the future field prices will approach the future field value and thus be in the Alberta public interest" (p. 9-14). However, effective competition required the removal of restrictions on exports from Canada on gas where removal from the province of Alberta had already been approved. Moreover, in many contracts with provision for renegotiation, this happened at five-year intervals, so that there could be considerable time lags in attaining appropriate field prices. The board noted that only 30 per cent of contracted gas volumes were governed by most-favoured-nation clauses (which passed on to this contract any higher prices offered by the buyer in another gas purchase contract) (ERCB, 1972b, p. 8-13).

The board recommended that "competition in the buying of Alberta gas be increased" (p. 11-4), which would require authorization for increased exports to the United States. It also recommended that governments act to remove "unnecessary restrictions and delays operating against the realization of the field value of gas" specifically better monitoring of export prices and values and quicker responses of public utility regulators in passing on gas price increases (pp. 11-4, 5). The board did "not believe Government intervention with respect to the contract provisions is necessary or desirable" so long as the government let producers and purchasers know that contracts should reflect full field values when first negotiated, have adequate price adjustment clauses (plus 3-4% per year), and include provision for price redetermination of field values as frequently as practicable (at least each five years) (pp. 11-7, 8).

On November 16, 1972, the provincial government essentially endorsed the board's findings, urging the renegotiation of contracts in light of field values higher than prices. Renegotiation each two years should be a standard feature of contracts. The ERCB was asked to provide a report in spring 1973 assessing the status of old and new contracts in light of the government's gas pricing objectives (i.e., attainment of prices at higher levels equivalent to "commodity values"). The board's July 1973 *Report* found that prices in new contracts were noticeably higher and that many old contracts had been renegotiated with higher prices and generally with two-year price renegotiation provisions (ERCB, 1973). Some 52 per cent of authorized gas removals reflected such higher prices, although many of the contracts still had prices less than the board's estimated commodity value.

A follow-up *Report* by the ERCB (ERCB, August 1974) found that the field value of natural gas had risen sharply due to “interfuel competition” (i.e., OPEC oil price rises), from \$0.29/Mcf at the start of July 1972 to \$1.12/Mcf at the start of July 1974 (p. 2-7). These were based on a weighted average cost of refined petroleum products to Toronto users less an allowance for natural gas distribution costs in Toronto. The board thought that commodity values would be about the same in Montreal and much higher in California, where oil prices were higher (p. 2-8). The board noted that prices had been renegotiated, and two-year price redetermination accepted, in contracts covering some 96 per cent of gas leaving Alberta. The board estimated the average field price of gas leaving Alberta would be \$0.46/Mcf, as compared to \$0.16/Mcf two years earlier. The increases were clearly viewed as desirable by the provincial government but had come about largely through supplier–purchaser contract negotiations.

The government had not been entirely passive, however. It had announced that the level of prices would be a key ingredient in the assessment of new permits to remove natural gas from the province, and requests by TransCanada Pipelines (TCPL) for additional gas to be placed under permit were shelved by the government on the grounds of inadequate prices. Moreover, legislation was introduced (the *Alberta Arbitration Amendment Act*, RSA 1973, chap. 88, Section 16.1) to ensure that price redetermination clauses in energy contracts would be applied in such a way as to ensure prices for gas at a level consistent with what would be expected under effective competition. The legislation saw this as the “commodity value,” which would be derived from the price of substitutable fuels plus premiums reflecting “inherent special qualities of gas.” Prices on new contracts rose sharply in the summer of 1972 when a new purchaser, Pan Alberta Gas Ltd., entered the market, offering an initial field price of \$0.38 per Mcf, some \$0.15 more than TCPL was offering. TCPL’s lower offer prices are consistent with the behaviour anticipated of a monopolistic buyer; TCPL’s preference for lower prices was strengthened by the presence in some of its existing long-term purchase contracts of most-favoured-nation clauses.

Thus, despite TCPL’s dominance as a purchaser, which the NEB’s denial of new gas export permits in 1971 had reinforced, there was inexorable upward pressure on gas prices, and from a variety of sources. Purely economic forces included rising prices for crude oil, which increased the attractiveness of natural

gas as a fuel, and the entry of a major new gas purchaser (Pan-Alberta). Regulatory pressures came from the acceptance of the Alberta government of a commodity value standard for gas prices, which was utilized by the government in assessing gas removal permits and formalized as the proper basis for gas price redetermination procedures. As shown in Table 12.1, the average field price of Alberta natural gas rose from \$0.17/Mcf in 1972 to \$0.19 in 1973, \$0.30 in 1974, and \$0.62 in 1975. In the spring of 1975, an arbitration board awarded a price of \$1.15/Mcf, effective November 1975, in a price renegotiation dispute between TCPL and Gulf Oil Canada.

The reliance upon market-pricing procedures for natural gas (albeit with strong pressure for higher prices from the governments of Alberta and B.C.) contrasted sharply with the regulated pricing environment for crude oil, which had been in place since the September 1973 oil price freeze. Gas prices could have been left unregulated, as with coal, another energy product that competes with oil-based fuels. This, however, was unlikely, given that most of the factors that had led Ottawa to regulate crude oil prices also held for natural gas: it provided a large share of Canadian energy in markets west of Quebec (far larger than coal, and higher than oil in more western markets); the value of natural gas was strongly affected by oil prices, which in the absence of oil price regulation in Canada meant OPEC prices; Canada was a large natural gas producer, and net exporter, so that a “made-in-Canada” price was feasible. The fact that Canadian natural gas producers were also crude oil producers may have led policy-makers to feel that symmetric regulatory treatment was desirable. At a more political level, the rapid increase in natural gas prices after 1972 could be seen as pitting the interests of natural gas producers concentrated in Alberta and northeast B.C. against the interests of natural gas consumers spread across a much larger part of the country (i.e., in markets as far east as Montreal).

In 1975, Ottawa passed the *Petroleum Administration Act*. (Edie, 1976, summarizes the main legal issues associated with the federal and provincial gas pricing provisions in this period.) Under Section 52, this gave Ottawa (through the NEB) the power and responsibility to set the price of gas crossing provincial boundaries. Section 50 gave the minister responsible for energy the power to enter into gas-pricing agreements with any province. The June 1975 federal budget announced that Ottawa and Alberta had reached an agreement on natural gas prices under which they would set gas prices. The exact regulations and the

Table 12.2: Regulated Natural Gas Prices, 1975 to 1985

		<i>Domestic Gas Prices</i>		<i>Export Gas Price³</i>	
		<i>Toronto Gate¹ (\$/10⁶ BTU)</i>	<i>Alberta Border² (\$/10⁶ BTU)</i>	<i>U.S. (\$/10⁶ BTU)</i>	<i>Canadian (\$/10⁶ BTU)</i>
1975	(November 1)	1.25	0.78		1.60
1976	(July 1)	1.405	0.92		
1976	(September 10)				1.80
1977	(January 1)	1.505	0.99		1.94
1977	(August)	1.68	1.16		
1977	(September 21)			2.16	2.36
1978	(February 1)	1.85	1.26		
1978	(August 1)	2.00	1.41		
1979	(May 1)			2.30	2.68
1979	(August 1)	2.15	1.54		
1979	(August 11)			2.80	3.29
1980	(November 3)			3.45	4.05
1980	(February 1)	2.30	1.64		
1980	(February 17)			4.47	5.20
1981	(September 1)	2.60	1.94		
1981	(April 1)			4.94	5.95
1982	(September 1)	2.96	1.82		
1982	(February 1)	3.55	2.07		
1983	(August 1)	3.80	2.32		
1983	(February 1)	3.99	2.57		
1983	(April 12)			4.40	5.43
1983	(July 13)			Base 4.40 VRIP ⁴ 3.40	5.43 4.20
1983	(August 1)	3.99	2.82		
1984	(February 1)	3.99	2.98		
1984	(August 1)	4.15	2.98		
1984	(November 1)			*	
1985	(February 1)	4.14	2.98		
1985	(June 1)	4.06	2.98		
1985	(November 1)	4.06**	2.98**	***	

Source: Royal Bank, "The North American Natural Gas Industry," and DataMetrics Limited.

Notes:

1. After September 1981, the Toronto city gate price was set by adding transportation charges and the excise taxes to the regulated Alberta border price.
2. Prior to September 1981, the Alberta border price was determined by netting transportation charges from the Toronto city gate price.
3. After 1977, the Canadian export price was set in U.S. dollars.
4. VRIP is 'volume related incentive price.'

* Canadian exporters were given the option of negotiating gas prices with the proviso that these prices not be less than the wholesale price of gas at the Toronto city gate.

** Domestic prices frozen until November 1, 1986, when full deregulation took effect.

*** Floor price for exports is the adjacent border domestic price.

economic implications will be described in more detail in Section 4 of this chapter. From November of 1975 through November of 1986, Canadian natural gas prices were set by governments. The Government

of Alberta allowed a discount on gas sold within the province. Alberta gas sold elsewhere in Canada was at price levels set, for the most part, by joint Alberta-Ottawa agreement. Average wellhead price levels are

shown in Table 12.1, rising to a peak of \$2.92/Mcf in 1984, before falling back, with oil prices, to \$2.20 in 1986.

Regulated prices for domestic and export gas over the price control period (November 1, 1975 through October 31, 1986) are shown in Table 12.2 in dollars per million BTU (which is approximately the same as the price per Mcf). From 1975 to the September 1, 1981, *Memorandum of Agreement* between Ottawa and the Alberta government, the price of natural gas was fixed at the Toronto city gate; the Alberta border 'price' was the Toronto price net of transmission charges from Alberta to Toronto. After September 1981, the Alberta border price was fixed by regulation and the Toronto city gate price was the Alberta price plus transmission charges, plus a new federal tax on natural gas (discussed in Section 4.6.2). As can be seen, natural gas prices increased sharply under regulation, just as crude oil prices were increased. (See Chapters Six and Nine; recall that Canadian domestic crude oil prices were held below international crude prices.) After 1983, as world crude oil markets weakened, gas prices were held constant at the Alberta border at \$3.00/Mcf.

b. Export Prices

As Section 4 will set out in more detail, the National Energy Board was given the responsibility for overseeing natural gas export prices (*NEB Act*, Section 83(a)). In the 1950s and 1960s, natural gas for export was purchased on much the same basis as gas for domestic use, that is, under long-term contracts with quite rigid pricing provisions. The OPEC-induced oil price increases of the early 1970s increased the attractiveness of Canadian gas to U.S. users but did not immediately generate higher contract prices. In September 1970, the federal government ordered the NEB to monitor export prices; "where in the opinion of the Board there has been a significant increase in prices for competing gas supplies or for alternative energy sources, the Board shall report its findings and recommendations to the Governor in Council" (*NEB*, 1970, p. 2-1). In its July 1974 *Report on Natural Gas Export Pricing*, the board concluded "considering that in all cases the border price has fallen well below the Board's estimate of the current value of the gas, it would seem that a major increase in price to a uniform border price for all export licenses is appropriate to the circumstances" (*NEB*, 1974a, p. 5-28). The board recommended a minimum price of \$1.00/Mcf. On September 20, 1974, Ottawa, after consultation with the producing provinces, set a one dollar per Mcf

border price effective January 1, 1975. In its March 1975 *Report*, the NEB recommended that the price be increased to \$1.60/Mcf, and the federal government concurred. Table 12.2 shows gas export border prices from November 1975 on, as set by regulation. It was noted above (see Column 7 of Table 12.1) that gas exports fell after 1979. Effective July 13, 1983, gas exporters were given more flexibility in negotiating export prices. Initially, this involved a VRIP (volume related incentive price), which allowed reduced prices on volumes in excess of a certain amount (e.g., 50% of authorized exports). In November 1984, export price regulations were further relaxed; buyers and sellers were free to negotiate prices with a floor equal to the Toronto city gate price, and later (November 1985) a floor equal to the domestic price at the export border point. The average export border price peaked at \$6.06/Mcf in 1982, falling each year after that to \$3.35/Mcf in 1986 (Watkins, 1989, p. 120).

4. The Deregulated Era, 1986-

Many economists would argue that the period of natural gas price controls beginning in 1974 sowed the seeds of its own destruction, much as had the overt oil control period discussed in Chapter Nine. Gas pricing and export provisions were subject to ongoing review and modification as new 'problems,' such as falling exports and rising excess deliverability, manifest themselves. The industry, the government of Alberta, and many independent analysts argued for a dismantling of controls and acceptance of a deregulated natural gas market. The *Western Accord* of March 1985, which accepted June 1, 1985, as the date for deregulation of the oil market, also stressed the need for a more "flexible and market oriented pricing system" (p. 3) for gas (Canada, 1985a). On October 31, 1985, Ottawa and the three natural-gas-producing provinces (Alberta, B.C., and Saskatchewan) signed an *Agreement on Natural Gas Markets and Prices* (sometimes called the *Halloween Agreement*), following recommendations of a task force established under the Western Accord (Canada, 1985b). The intent of the agreement was to "foster a competitive market for natural gas in Canada, consistent with the regulated character of the transmission and distribution sectors of the gas industry." Furthermore, "effective November 1, 1986 the prices of natural gas in interprovincial trade will be determined by negotiations between buyers and sellers," as had been the case since 1984 for gas exports (though exports were subject to a price floor).

However, natural gas could not be deregulated with the same ease as crude (see Watkins, 1991a). Amongst reasons for this were:

- (i) The **different nature of natural gas regulation**, in particular the export regulations, which had encouraged very high reserves to production ratios for gas. Deregulating natural gas was, in this respect, analogous to tearing down a dam, something that might best be carried out in a series of careful steps rather than at once as with crude oil.
- (ii) The very **concentrated buyers' side of the market**, in which TCPL had long operated both as the major gas transmission facility and as the prime buyer of natural gas in the field. In contrast, oil pipelines functioned as common carriers.
- (iii) The **prevalence in the market of long-term contracts** between natural gas producers and the purchaser, so that neither volumes produced nor prices paid exhibited immediate flexibility in response to changing market conditions, although most contracts had moved to two-year price renegotiation just prior to the price control regime of 1975.

More detail on how deregulation of natural gas actually occurred will come in Sections 3 (on export limitations) and 4 (on prices). (See also Watkins, 1991a, and Bradley and Watkins, 2003.) At this point, we will simply remark that since 1986 North American natural gas markets have been revolutionized. (Since the late 1980s the NEB has produced a continuing series of useful reports on Natural Gas Markets; NEB, 1992, 1996, 1997, and 2002 are particularly good reviews of the evolution of Canadian gas markets after 1986.) Canadian export limits have been largely dismantled – a result which has been entrenched in the Canada–U.S. FTA and NAFTA. The large transmission companies have been joined by numerous other buyers of natural gas in the field, including large consumers and a variety of gas trading companies. At the same time, the transmission companies have shifted to common carrier status; tariffs are still regulated, but others have right of access to ship gas. Rigidities in sales arrangements have been largely eliminated, as increasing volumes of natural gas are exchanged in the spot market, and as long-term contracts have adopted increasingly flexible pricing arrangements. The transmission and gas trading activities of the major transmission companies have been separated ('debundled');

for example, in 1986, TCPL set up Western Gas Marketing Limited (WGML) as a wholly owned subsidiary to handle its purchases and sales of natural gas.

Table 12.1 shows changes in the average field price of Alberta natural gas since 1986. Prices fell dramatically after 1985, as did oil prices internationally and in Canada. In part, the lower gas prices reflected the decreased value of crude oil, but increasing deregulation also led to rapid increases in the production of natural gas, putting downward pressure on the price. Natural gas prices remained lower throughout the 1990s than they had been in the first half of the 1980s, even in nominal terms. The price of natural gas relative to oil varied as a function of different market developments for the two products; in general, from 1985 through the 1990s, gas was relatively lower-priced than it was in the price control period. This is not surprising given the very high R/P ratio for gas relative to oil at the start of the deregulation period and the relatively greater ease of natural gas reserve additions in the province.

However, the average field price of Table 12.1 covers a wide variety of sales arrangements, not all at identical prices. For instance, by the mid-1990s, significant volumes of gas were moved under four different types of sales arrangements (NEB, 1992, 1997).

- (1) In part as a legacy of the long-term contractual agreements common in the 1950s, 1960s, and early 1970s, companies such as WGML and Pan Alberta acted as '**supply aggregators**,' which purchase gas from large numbers of separate gas pools for resale, largely to natural gas distribution companies ('LDCs' or local distribution companies that operated as '**demand aggregators**' for large numbers of individual consumers). The field price for gas traded in this manner was usually negotiated annually between the supply aggregator and the pool of gas purchasers, and held for a November 1 to October 31 contract year; beginning in the 1990s, more and more of these contracts moved to agreed-upon flexible pricing provisions tying prices to Alberta spot market natural gas prices.
- (2) **Individual term contracts** (for longer than 30 days) have been negotiated between an individual producer and a purchaser (which may be a natural gas user or a trading company that operates as a market intermediary) for sale of gas **in the producing region**. Typically the field price of this gas is tied to a thirty-day average of reported spot market price.

- (3) **Individual term contracts** between a producer and a purchaser for sale in the consuming region. Typically the price in the consuming region is tied to spot markets, and the field price received by the producers will be this price less the transmission cost for the gas. For a producer that has contracted space over the long-term on a pipeline, the transmission charge will normally consist of a small “commodity charge” to cover the fuel and other operating costs of the pipeline plus a larger “demand charge” to cover the capital cost of the pipeline. If the producer has not already contracted pipeline space, it must be purchased at current prices, which may be the very low commodity charge if the pipeline has spare capacity, but much more if there is none.
- (4) A **spot sale** (for less than thirty day’s exchange) may be negotiated between a producer and an interested buyer. As the number of intermediary trading institutions (e.g., electronic bulletin boards) has increased, it becomes increasingly likely that spot sales occurring at any point in time will all be at ‘identical’ prices (allowing for any gas quality differentials). The tendency to equal prices was also facilitated prior to 2000 by NOVA’s reliance on a ‘postage stamp’ tariff for gas shipped within Alberta.

In a well-functioning, fully integrated North American natural gas market, one would expect that natural gas field prices under these various sales arrangements would be relatively close to one another, since the various alternative sales arrangements are close substitutes for one another from either a buyer’s or a seller’s point of view. Some field price differences would remain, reflecting varying transmission costs, depending upon how transportation is handled (i.e., paid by the producer or the buyer; bought on a longer-term contract or at prevailing rates). In addition, less flexible pricing arrangements will generally differ from spot prices; thirty-day averages will lag any spot price trends, and one-year prices should approximate expected average spot prices but not reflect any unexpected (random) market developments. In a well-functioning market there could also be some small differences between prices in different contracts reflecting differing risk preferences (e.g., one-year contracts have a reduced risk of price change as compared to a series of spot contracts over the year). The growing commoditization of gas markets, for example NYMEX natural gas futures, offers other ways for

companies to reduce market risks. Another indication of increased commoditization is the major rise in gas storage capacity, which is serving to reduce the seasonal variation in natural gas prices.

On balance, by the early 1990s, Alberta natural gas had become part of a flourishing and flexible integrated North American natural gas market. This implied that Alberta natural gas prices would be closely tied to those in the United States, with price changes reflecting all supply, demand, and transportation changes across the continent. Traditional trading regions will tend to evolve over time along with the integrated market. Deregulation has seen a rapid rise in exports relative to domestic Canadian sales. By 1995, there had been new pipeline links established between Ontario (the largest market for Alberta natural gas from the early 1960s on) and U.S. producing centres, providing further evidence of today’s interdependence in continental natural gas markets, and harkening back to Waverman’s hypothetical analysis of efficient, integrated North American gas markets in the 1960s (Waverman, 1973). The rise in exports of Alberta gas was indeed dramatic, as exports more than tripled from 1986 to 1993.

In the 1990s, increased attention was focused on the market impact of transmission facilities. Spare capacity in transmission out of the province leaves field prices and production volumes very sensitive to supply and demand changes elsewhere on the continent. This is particularly true as increased competition enters the transmission industry. In this respect, the opening of the Alliance pipeline in late 2000 was important, running from Alberta to Illinois, connecting with the U.S. Midwest pipeline grid, and offering competition to TCPL on eastward natural gas shipments. Spare capacity in the pipelines means that space can be purchased for ‘commodity’ charges only (i.e., pipeline operating costs); if this is done by gas producers, it implies higher field values (netbacks for the gas). On the other hand, if there is no excess pipeline capacity then Alberta sales volumes and field prices will be less responsive to changes in market conditions elsewhere in North America. Furthermore, shipment costs will reflect operating and capital costs (commodity and demand charges), implying a larger gap between delivered prices and field values than if spare pipeline capacity exists.

Natural gas producers will favour spare pipeline capacity under these conditions. Of course, transmission companies will be willing to install new capacity only if they expect to recover both operating and capital costs. These complications would not exist if

we lived in a world of perfect certainty and with perfectly malleable capital: in such a world, new pipeline capacity could be constructed (and deconstructed) exactly as required. However, with both demand and supply uncertainties, and economies of scale in natural gas pipelines, new facilities must be large and are planned and constructed over a number of years in anticipation of future market conditions. The regional gas market may, then, operate for some period of time in a short-run equilibrium that differs from the anticipated long-run equilibrium. For example, this could be with unused pipeline capacity and 'higher' netback prices. Such a situation typically conveys its own market message, inducing adjustment towards the long-run equilibrium; in this case, a higher field price attracts more output that will fill the spare pipeline capacity. Similarly, if pipeline capacity is fully booked, a rise in market prices may fail to translate back into higher field prices, but the increased margin between market and field prices serves as an incentive to contract new supplies and construct additional pipeline facilities.

The commoditization of the North American natural gas market has raised these new uncertainties for participants in the market, a major change from the days of long-term contracts with almost all gas brought and sold by the pipeline companies. Moreover, the adjustment problems seem to be more pronounced in the North American natural gas market than in the crude oil market, where prices are primarily determined by the world market and where domestic markets are ready to accept any domestic crude available before drawing on OPEC supplies.

As Table 12.1 illustrates, starting in 1999 Alberta natural gas prices began to rise dramatically, to the highest level they have attained (at least in nominal dollars); the average price in 2006 was \$8.54/Mcf, and it had been as high as \$11.38/Mcf in October of 2005. (See the Alberta Department of Energy, *Alberta Gas Reference Price History*.) These high prices reflected increasing tightness in North American natural gas markets and the loss of upward flexibility in production as reserves-to-production ratios in both Canada and the United States fell below ten. In the early years of the new century, there was much uncertainty about whether these high prices would be temporary or long-lived. Economists would expect that significant price increases will generate long-term production increases and consumption declines. However, some industry spokesmen suggested that geological prospects for large increases in low-cost production were unlikely, and that North America would have to rely increasingly on gas that is high cost (e.g., hard

to produce 'tight' gas that is in reservoirs with low permeability and such non-conventional sources as coal bed methane, shale gas, or new supply sources that have high transmission costs, such as Alaska and Arctic gas or imported liquefied natural gas [LNG]). On the consumption side, the sharp rise in oil prices starting in 2003 inhibited substitution out of natural gas into refined petroleum products.

As Table 12.1 shows, natural gas prices fell from the October 2005 peak; by 2009, the average well-head price in Alberta was \$4.04/Mcf. The Alberta Department of Energy reported a monthly natural gas price below \$4/Mcf for every month from April 2010 to February 2013, ranging from \$1.58/Mcf to \$3.69/Mcf. Price expectations by 2013 were much less optimistic than they had been several years earlier, reflecting in large part the increased availability in North America, despite falling gas prices, of non-conventional gas from coal bed methane and, especially, U.S. shale gas. Horizontal drilling techniques have been particularly critical in lowering costs of these non-conventional gas sources. Vidas and Hugman (2008) provide a useful survey of North American non-conventional gas resources and possible producibility. U.S. shale gas output rose by 25 times from 2000 to 2012, rising, from 1.67 per cent of U.S. natural gas supply to 34 per cent (EIA, 2013, Figure 91, p. 79).

We might return to the issue of 'commodity pricing,' or, more generally, the relationship between natural gas and oil prices. As Table 12.1 illustrates, in the late 1990s, the price of natural gas relative to crude oil increased sharply in Alberta, from less than 0.4 in the mid-1990s to just over 1 by 2001; it remained at relatively high levels for about five years, before plunging down, below 0.3, by the year 2011. It is clear that full commodity pricing equivalence has not held in Alberta (where the price of natural gas and oil would exhibit the same price per unit of energy content, so the relative price would always equal one). Nor is there a one-to-one correspondence in changes in crude oil and natural gas prices on an energy-content basis (where the relative price would remain unchanged). Plourde and Watkins (1998) utilized statistical co-integration analysis to examine the link between crude oil and natural gas prices from late 1975 through 1999. They found that the prices moved together during the regulated price period (1975 to mid-1985); this would be expected, since gas prices tended to be set in relation to oil prices, as mentioned above and reviewed in more detail in Section 4, below. Similar connections were found in what they labelled the deregulated period (from 1988 on), but "a rather

different picture emerges when the deregulation period is split into earlier and later parts. The relationship between upstream prices of crude oil and natural gas has weakened as deregulation has progressed.” This suggests that the natural gas market has become increasingly sensitive to supply and demand factors specific to natural gas as the time since deregulation has lengthened and is consistent with a gas market in which pricing and contract volumes have become increasingly flexible and short-term. Serletis and Rangel-Rui (2004) also find increasing independence of oil and natural gas prices in North America; however, Brown and Yücel (2008) and Hartley et al. (2008) argue that a long-term link still exists, so long as allowance is made for such factors as weather and storage.

Finally, we should briefly discuss the increased role of natural gas storage within North America. Markets for Canadian natural gas generally exhibit significant seasonality, with particularly high demand from residential and commercial users during the winter season, as much as six times higher than in summer (NEB, 2008, p. 17). In the absence of ready and costless production variability or storage capabilities, this seasonality generates seasonal price variability and higher transmission costs. (The former because prices are higher during the peak season; the latter because pipeline facilities must meet peak demand and are not fully utilized throughout the year.) While gas can be stored in containers, most gas storage is below ground. Gas storage facilities increased particularly rapidly in North America with the deregulated markets that developed beginning in the mid-1980s. (EIA, 1995 and 2006 provide a good overview of natural gas storage. Hartley et al. 2008, and Brown and Yücel, 2008, provide statistical analysis showing that storage affects natural gas prices.) By storing gas during off-peak times (seasons) and releasing it during peak times, the seasonal variability in gas prices can be reduced; of course, gas stocks are also available to meet unexpected events (e.g., unusually cold weather). Storage facilities have been installed in both gas-producing and consuming regions and have been built by gas transmission companies, gas producers, and other parties who hope to profit from owning such facilities either for their own gas trading or by leasing space to other parties.

In Alberta, a number of old reservoirs have been converted to gas storage, with a total capacity at the end of 2012 of 11,417 10^6 m³, and a maximum deliverability of 178.7 10^6 m³/d (ERCB, 2013, *Reserves Report*, ST-98, Table 5.8). At this deliverability rate, the facility would be drained in two months; storage facilities are

capable of much faster drainage than a conventional gas pool but have correspondingly higher lifting costs.

3. Alberta and Canadian Natural Gas Protection Policies

We use the term ‘removal’ to refer to the movement of natural gas beyond Alberta’s borders, irrespective of whether it is destined for markets in other parts of Canada or in the United States. We use the term ‘export’ to refer to the movement of natural gas to the United States. After the 1950s, no distinction was made at the provincial level in terms of gas removals, whether to other regions of Canada or to the United States. The national controls solely relate to exports destined for foreign markets. Any party wishing to export gas from Canada must surmount both relevant provincial and national hurdles.

Alberta’s policies governing removal of natural gas are outlined below. These policies are crucial, not only because about 85 per cent of Canada’s established gas reserves are located in Alberta, but because the policies initially followed at the national level by the National Energy Board (NEB) after its inception in 1959 were closely allied to those of Alberta – and indeed after that remained in symbiotic relationship with them. Policies pushed by the NEB are dealt with after the discussion of Alberta’s initiatives in the protection arena. (This discussion is largely based on Watkins, 1982a, 1990. See also Winberg, 1987, chap. 5.)

A. Development of Alberta Policy

The growth in Alberta’s reserves of natural gas was sufficiently rapid after the Second World War that by 1950 they represented a very considerable inventory in relation to existing markets. This build-up in reserves provoked plans for large-scale removal of gas from the province. The Alberta government became concerned about future shortages if use of the province’s gas reserves were not adequately controlled.

1. The Dinning Commission and Early Alberta Legislation

In November, 1948, the Alberta government appointed a commission headed by Robert J. Dinning to investigate the province’s natural gas situation. The ‘Dinning Commission,’ as it became known, submitted a report in March 1949 that strongly recommended

that Albertans have first claim on the province's gas reserves. This recommendation did not fall on deaf ears, and in 1949 the Alberta Legislature passed the *Gas Resources Preservation Act*.

The intent of the act was outlined by Premier Manning in his Budget Address of 1950 (March 3, 1950, p. 6):

The Government's first and foremost responsibility is to protect the interests and welfare of the people of this Province.... To this end, no application for the export of natural gas will be given favourable consideration until such time as the Government is satisfied beyond question that ... there are sufficient gas reserves to meet the present and future domestic and industrial requirements of this Province. When fully satisfied that a surplus exists over and above these requirements, the Government will approve the export of such surplus with each application being considered on its own merits and in the light of all prevailing circumstances.

The key passages of the act were (Chapter 157, Statutes of Alberta):

The Board shall not grant a permit for the removal of any gas or propane from the Province unless in its opinion it is in the public interest to do so having regard to:

- (a) the present and future needs of persons within the Province and
- (b) the established reserves and the trends in growth and discovery of reserves of gas or propane in the Province.

The board referred to here was the Alberta Oil and Gas Conservation Board (OGCB; after 1970, and again in 2007, it was renamed the Energy Resources Conservation Board, ERCB, and, from 1994 to 2007, the Energy and Utilities Board, EUB).

The 1949 act was amended frequently. However, its overall nature and purpose did not change materially. Significantly in 1984 another clause was added to considerations (a) and (b) listed above, namely: "(c) the expected economic costs and benefits to Alberta of the removal of gas or propane from Alberta" (*Gas Resources Preservation Act*, 1984, Section 5(3)). Moreover, conditions to be attached to a permit were to refer to the price of the gas and to "other factors relevant to the expected economic benefits to Alberta"

(Section 6(d)). In 1986, clause (c) was replaced by a general criterion, which will be discussed later.

2. Initial Policy of the Alberta Conservation Board

The intent of the *Gas Resources Preservation Act* – adequate protection of Alberta consumers – was clear, but the manner by which such protection would be implemented was not. In essence, it was left for the Conservation Board to adorn the legal skeleton with regulatory flesh.

Initially, the board interpreted its mandate conservatively, and as a result most early applications to export gas from the province were refused. The original regulatory framework required the board to be satisfied that Alberta's established gas reserves were sufficient to meet the province's forecast annual gas requirements, including peak day, for a period of thirty years, plus any extant export commitments (including their peak-day requirements), before authorizing gas exports (OGCB, 1961, pp. 4–5).

In essence, then, the protection formula was a straightforward comparison of stocks and future demands on them. If the bins (established reserves) were full – exceeding thirty years of estimated future consumption plus any already authorized exports – the harvest was available for export. In symbols, the export formula was:

$$G_s = R_{EST} - \sum_{i=1}^{30} A_i - E - f(PD_{30}) \quad (1)$$

where

- G_s = surplus gas.
- R_{EST} = established gas reserves, Alberta.
- A_i = estimated Alberta gas requirements, year i .
- E = remaining authorized exports.
- $f(PD_{30})$ = reserves necessary to protect Alberta peak-day requirements in the thirtieth year.

The figure for established reserves was adjusted by deducting reserves found but considered beyond economic reach. The reserves set aside to meet peak-day requirements were often called 'cushion' gas.

Because of constraints on distribution systems within the province, protection of the province's gas requirements was also considered on a detailed regional basis. Thus, even if Alberta enjoyed an overall gas surplus under the formula, removals from a

particular area might be denied because of a perceived local shortage.

The reason for selecting thirty years as the period of protection was not identified at the time of adoption, but it seemingly was largely a matter of judgment, based on the life of a typical gas reservoir, the period of amortization of a major investment and the period over which new technology and developments would be expected to influence energy supply (G.W. Govier, interview, *Canadian Petroleum*, November 1978, pp. 61–64).

Exporters needed to ensure most of their gas supply was under contract – the guideline evolved by the board eventually became 80 per cent of the prospective export volumes (OGCB Report 69-D, 1969c, p. 63). This provision was intended to avoid distributing export permits in a way tantamount to the award of hunting licences.

In addition to protecting Alberta requirements under the surplus formula, the removal permits themselves provided for local utilities to access gas under permit in the event of local shortages. These ‘fail-safe’ clauses were:

... a condition that the permittee will supply gas or propane at a reasonable price to any community or consumer in Alberta that is willing to take delivery of gas or propane at a point on the pipeline transmitting the gas or propane or at a processing plant producing the propane and that, in the opinion of the Board, can reasonably be supplied by the permittee; ... (*Gas Resources Preservation Act*, 1984, Clause 6(f))

3. Policy Developments in the 1950s

The decade was marked by gradual relaxation by the board of the strict canons of policy it initially adopted. Relaxation was consistent with continued growth in Alberta’s gas reserves, the development of transmission and distribution systems within the province, and the attachment of firm markets outside the province. The way the policy was relaxed is outlined below.

First, the Alberta Gas Truck Line Company Limited (later NOVA and now part of TransCanada), a common carrier under provincial jurisdiction and control, was established in 1957 to serve as an efficient means of gathering gas from various fields within the province for transportation to points of removal. The inception of the trunk line system, the further growth and geographical scatter of the province’s reserves, and the extensions in utility company distribution systems

increased the degree of supply flexibility within the province and enabled the board to put less weight on regional discrepancies in both supply and future requirements. Later, regional aspects were virtually eliminated from the board’s deliberations.

Second, the consistent growth in the province’s gas reserves resulted in the board adopting a less conservative approach in estimating the supply available to meet future requirements. By 1958, the board allowed for satisfying some part of future Alberta requirements from new discoveries. In this vein, established reserves were allocated to meet annual requirements for twenty-six to thirty years and peak day requirements for twenty-five years. Reserves to be developed in the future were assumed to meet the remaining annual and peak-day requirements at the end of the thirtieth year, as long as reserve growth remained consistent. Such reliance on new discoveries to satisfy a portion of future Alberta requirements marked a significant policy change.

Third, before 1959, the board recognized preference for ex-Alberta Canadian requirements for Alberta natural gas before recommending removal of gas to foreign markets. Thus the policy made only gas surplus to Alberta’s needs plus the immediate contractual requirements of other Canadian provinces eligible for export from Canada and required that adequate future reserves based on growth trends be available to satisfy estimated Canadian requirements (other than Alberta’s) over a twenty-five-year period. Such responsibilities were effectively transferred to the federal government’s National Energy Board (NEB) in 1959.

Fourth, by 1959, the Conservation Board considered that the trends in reserves growth were sufficiently well founded to justify giving full weight to reserves to be developed in the next two to five years in assessing total reserves available to satisfy requirements. Specifically, in applying the gas removal formula after 1959 the board formally included a two-year reserve growth figure to meet future demand. In the vernacular, this allowance became known as ‘trend gas’ (OGCB, Report 66-C, 1966, pp. B2–B3). Typically, this meant protection of future Alberta requirements from established reserves was set at the equivalent of about twenty-five years.

In effect, then, the Alberta export formula which held sway when the NEB entered the fray was:

$$G_s = R_{EST} + 2T_g - \sum_{i=1}^{30} A_i - E - f(PD_{30}) \quad (2)$$

where T_g = annual allowance for ‘trend gas,’ and other symbols are as before.

$$F_s = T_g - \left(\sum_{i=1}^{30} A_i - 30A_1 \right) - f(PD_{30}) \quad (4)$$

where F_s = Future Surplus

4. Policy Changes in the 1960s

Two main policy changes were made in the 1960s: one in 1966, the other in 1969. The first was designed to increase near-term protection for Alberta consumers, and the second was to increase reliance on future discoveries in assessing gas supply. In addition, an adjustment was made in 1964 to established reserves to add back a proportion (usually 50 per cent) of established reserves ‘beyond economic reach’ that might land up as ‘within economic reach’ over the thirty-year protection period, and to subtract reserves deferred for conservation reasons (OGCB, Report 64-1, 1964c).

a. 1966 Changes

The 1966 change introduced a two-tiered definition of surplus, distinguishing between a ‘contractible’ and a ‘future’ category (OGCB, Report 66-C, 1966). The contractible surplus compared established reserves with contractible requirements, where the latter was defined as thirty times Alberta’s first-year requirement ($30A_1$) plus permit related requirements. Thus, the contractible surplus was:

$$C_s = R_{EST} - 30A_1 - E \quad (3)$$

where C_s = contractible surplus, and other symbols are as before.

Any gas surplus to the contractible requirements was presumed to be available for contracting to meet Alberta’s future requirements.

The future surplus compared future reserves with future requirements. The former were primarily the ‘trend gas’ allowance, plus certain reserves subtracted from established reserves that may be available within the thirty-year period, mainly ‘deferred’ gas plus discovered gas that may become within economic reach over thirty years. Future requirements were the thirty-year projected Alberta requirements less requirements already included in the contractible category ($30A_1$), plus reserves required to meet estimated peak-day demand in the thirtieth year. (Actually, the portion of these requirements that reserves dedicated to them could deliver over the thirty-year period.) An allowance was made here for contractible reserves still available to meet peaking requirements in the thirtieth year. The future surplus formula can be approximated by:

Issuance of a permit required a positive contractible and overall (contractible plus future) surplus.

The intention of the contractible surplus initiative was to “focus on the established gas available for immediate contracting to meet Alberta requirements” (OGCB, Report 66-C, 1966, p. 30).

The concern the board saw was that its previous test did not evaluate the ability of local utilities to contract for future supplies. The board concluded (OGCB, 1966, p. 30) “that a method of assessment which would focus on the established gas available for immediate contracting to meet Alberta requirements is desirable and would to some extent afford a greater degree of protection to local consumers of gas.”

At this junction, the board also slightly opened the door for more reliance on ‘trend’ gas, a chink that in 1969 – as described below – became wider. No changes were contemplated for reserves set aside in the future surplus calculation to satisfy requirements for delivery, that is, requirements other than those for ‘cushion’ gas. But to provide for peak-day deliverability, the board decided: “to give weight to more than the two-year growth in reserves when considering the cushion gas protection” (OGCB, 1966, p. 30).

b. 1969 Changes

The main change in 1969 was to the calculation of ‘trend’ gas, of which two elements were identified: the average annual reserve growth rate and the number of years to which the growth rate was to apply (OGCB, Report 69-D, 1969c, pp. 17–18). The board decided the growth rate in gas reserves should be based on the most recent ten-year period, not the long-term post-1950 period, but retained some flexibility in just how it would project the growth rate. In terms of the number of years of growth, the board saw its use of two years as conservative and adopted instead a formula that used estimated ultimate reserves to indicate the extent “to which reliance may be placed on future gas reserves” adding, however, that “prudence dictates that potential reserves should be assessed on a conservative basis” (OGCB, 1969c, p. 25). The formula adopted by the board was:

$$T_g = ((R_{POT} - R_{EST})/Q)/10 \quad (5)$$

where

- T_G = years of reliance on future gas reserves; rounded up or down to the nearest half year.
- R_{POT} = estimated potential, initial marketable Alberta reserves.
- R_{EST} = established initial marketable reserves in Alberta at the time of application of the formula.
- Q = current output

It noted the formula has (OGCB, 1969c, p. 26) “the desirable characteristics of reducing the number of years of such reliance as the remaining potential reserves of the Province decrease. The Board believes the denominator of 10 used in the formula is reasonable at the present time.”

Under this mechanism, then, the future gas reserves used in the future surplus was calculated by extending historical growth T_G years into the future. At the time of its implementation, the new formula increased the number of years of reliance on new discoveries from the earlier two years to about five years: a substantial adjustment.

5. Policy Changes in the 1970s

The board’s procedures for determining surplus gas were reviewed in 1976 and 1979. The changes adopted in 1976 were modest; those in 1979 were substantive. In addition, the question of gas pricing intruded in the early 1970s.

a. Natural Gas Pricing and Removals

Before 1972, the Alberta Board’s evaluation of removal proposals made no specific reference to price, although as part of its broad understanding of the economic feasibility of a proposal, the board reviewed pricing information. This situation changed after the gas-pricing imbroglio of 1972, when on the grounds of price the Alberta government withheld the approval of permits to TransCanada PipeLines Ltd. (TCPL). (For more discussion, see Section 4 on natural gas pricing. Basically, rising oil prices in the world and North America were felt by many to increase the value of natural gas, but prices in natural gas contracts, both old and new, were slow to rise.) At this time, the board had also reviewed the question of Alberta gas pricing, and, after issuance of its report in August 1972 (ERCB, Report 72-E-VG, 1972b), a policy statement was tabled in November in the Alberta legislature called “Alberta Government Statement on New Natural Gas Policies for Albertans.”

Here the government urged accelerated price re-determination on all gas contracts and required purchasers of gas for removal to file pricing information with the board. Moreover, the government indicated its intent to “assess pending and future permits for export of gas from the Province in light of this policy statement.” Given this injunction, the board as part of its export application review began to “offer its views on the suitability of the field prices, in the contracts of the applicant, in relation to the Alberta Government policy” (ERCB, Report 74-G, 1974, pp. 1-6, 1-7).

Inclusion of pricing as a removal criterion continued until the 1975 gas-pricing agreement between the Alberta and federal governments made it irrelevant. With deregulation, it emerged again, albeit in a somewhat subdued form (see below).

b. 1976 Changes

The two main issues were how reserves under contract to holders of removal permits in excess of permit authorizations should be treated and how detailed ‘deliverability’ schedules should be used in determining any surplus.

The first issue arose because of a perception that it would be desirable to have most of Alberta’s requirement met by direct contracts with producers, while at the time evidence had suggested local utilities were experiencing difficulties in contracting for gas.

In essence, no changes were proposed to the extant procedure for determining current, future, and overall surpluses (see equations (3), (4), and (5), above). Attention focused on a refinement to the ‘current surplus’ test component, which did not identify the volumes of gas actually available for contracting by local utilities but was a key indicator of whether there were proved reserves surplus to current requirements. The new hurdle introduced by the board, called the ‘availability for contracting test,’ was intended to determine (ERCB, Report 76-C, 1976, p. 3-5) “whether there are sufficient reserves available to permit the Alberta Utilities and other Alberta consumers to contract directly for the province’s general requirements ($30A_1$).” The mechanism was to deduct from the current reserves used in the ‘current surplus’ calculation (namely, proved reserves within economic reach less those deferred for conservation reasons), those reserves under contract to holders of removal permits, to identify reserves available to Alberta users; from this figure “reserves required for contracting by Alberta users” ($30A_1$) was subtracted to then define “the surplus of reserves available for contracting” (ERCB, 1976, p. 3-5).

The policy implications of this embellishment were as follows: if the ‘contracting’ surplus were zero or positive, enough gas would be available for contracting to satisfy the $30A_1$ requirement; if the figure were “modestly negative,” the board would look at the gas that might be made available by permit-holders to Alberta utilities; if a significant deficit existed, no new permit volumes would be authorized even if the contractible and overall surplus calculation were positive (ERCB, 1976, p. 3-5).

The question of deliverability arose because of declines in the productivity of older gas reservoirs. The board rejected deliverability as a separate surplus test but intended to develop more detailed deliverability schedules as part of its background analysis. And if a serious deliverability problem became apparent, “the Board would likely refuse a removal application even if current, future and availability for contracting surpluses were found to exist” (ERCB, 1976, p. 3-10).

c. 1979 Changes

The 1979 changes reshaped the board’s methodology for determining surplus gas and were comparable in extent to the adoption of the dual surplus calculation in 1966. The major changes were to (ERCB, Report 79-1, 1979):

- continue with the current surplus test but to reduce the associated protection allowance for $30A_1$ to $25A_1$;
- replace the future and overall tests with a deliverability test to assess whether long-term annual requirements can be met (deliverability is a general term used to denote an actual or expected rate of gas production);
- suspend the “availability for contracting” test.

The reduction in protection under the current surplus test presumed conditions had changed quite radically from when the $30A_1$ formula was introduced: there was greater confidence now in estimates of reserves and requirements; and long-term consumer protection might increasingly devolve on gas supplies from the substantial coal deposits with which the province was endowed. The supposition was that the level of protection should “have regard for the normal contracting period.... In the Board’s view this suggests protection in the order of $20A_1$ to $25A_1$. In recognition of the NEB’s adoption of $25A_1$ (see below), the Board also decided to select $25A_1$ as an appropriate protection period” (ERCB, 1979, p. 4-2).

The future surplus test was seen by the board as “not completely successful” (ERCB, 1979, p. 4-4), and the “method of allowing for future reserve growth is very conservative and consequently, yields misleading results” (ERCB, 1979, p. 4-6). The board suggested the purpose of the future surplus test could be achieved more successfully by a “broad assessment of demand and supply” (ERCB, 1979, p. 4-4). The availability for contracting test was dropped because the circumstances that led to its implementation were no longer present “nor ... likely to occur in the foreseeable future” (ERCB, 1979, p. 4-6).

The supply side of the long-term assessment of gas supply–demand relationships was to be handled by a deliverability test, involving (ERCB, 1979, p. 4-7):

... the best estimate of the annual productive capacity of both established and future reserves and would be compared to forecast Alberta requirements. The forecast period should be at least as long as the term of the requested permit but the Board for its own analysis probably would make its projection for a 25-year period.

The precise degree of reliance on gas discoveries was not identified in the report. Apparently the board was to make its best estimate of future reserve growth over the period of analysis without tying the estimate into any specific ‘trend’ gas formula.

The board expected that if the future deliverability test disclosed a significant supply deficit, conditions would be placed on permits and lesser volumes for removal would be authorized, but the board wanted to (ERCB, 1979, p. 4-8) “retain sufficient flexibility in interpreting the deliverability test so that it could judge each application on its own merits and authorize such volumes as it considers to be appropriate under the circumstances.”

No changes were made to the Alberta surplus test between 1979 and 1986, but in 1987 the test was reviewed – a commitment made by Alberta in the October 1985 *Agreement* with Ottawa to make the controls more compatible with a ‘market oriented pricing system’ (*Agreement*, 1985, clause 23(1)).

Changes have been made to the legislation and most recently to that governing the issuance of export permits from Alberta. The latter was quite important in terms of accommodating deregulation. Moreover, the Alberta government issued a policy statement on long-term protection of Alberta natural gas consumers. All these matters are reviewed below.

6. Post-1979 Legislative and Policy Resonances

As mentioned earlier, in 1984, the *Alberta Gas Resources Preservation Act* was amended. The provision for diverting exports to meet any local shortages was written into the act, rather than simply appended to export permits. More importantly, a cost-benefit criterion was added to the requirements and reserves features to which the board was to “have regard” in granting permits, namely, “(c) the expected economic costs and benefits to Alberta of the removal of gas or propane from Alberta” (*Gas Resources Preservation Act*, 1984, Section 5(3)).

To accommodate the intent of the 1985 federal-provincial *Agreement*, the act was amended in 1986 to remove the clause (c) criterion in granting a removal permit and replaced with a general criterion, namely, “(c) any other matters considered relevant by the Board” (*Gas Resources Preservation Act*, 5A 1986 C1753). The former clause (c) (cost-benefit) criterion has since been included as one of the ministerial conditions attached to removal permits. The new general criterion left the board with quite a lot of latitude.

Under the revised act, gas could not be removed from Alberta unless under a permit issued by the ERCB. Once the ERCB granted a permit, the permit was forwarded to the Alberta Minister of Energy for final approval. It is at this stage that conditions can be imposed if the government so chooses. Until the start of the one-year transition for implementing the October 31, 1985, *Agreement*, no conditions were attached to the permits, with the exception of a now-defunct British Columbia LNG project for which Alberta natural gas was to be supplied.

However, ministerial permit conditions emerged during the transitional period. They include:

- (a) **Surplus test requirement** – gas should not be removed from Alberta after July 1, 1987, unless the Minister of Energy was satisfied with the surplus test review then being undertaken by the NEB and the ERCB.
- (b) **Market requirements** – permittees could not serve a market other than the one filed by the permittee with the Department of Energy.
- (c) **Incrementality condition** – permittees were not allowed to displace an existing market served under a contract in force on October 31, 1985, unless the Minister allowed so.
- (d) **Delivery commencement** – gas would not be removed if pipeline deliveries did not

commence within the ninety-day period following permit issuance.

- (e) **Contract carriage condition** – if gas were moved in a provincial distributor’s system outside Alberta, then the law in that province must provide for the possibility of the transporter of the gas being able to arrange for transportation service on that distribution system.

At the same time, the federal authorities urged the Alberta government to give heed to the following principles in revising its surplus determination procedures (letter from Marcel Masse, Minister of EMR to Neil Webber, Alberta Minister of Energy, undated but October 1986).

- Market forces will ensure that natural gas supply and demand will balance.
- Certain categories of end users will continue to require explicit supply protection because of their inability to switch readily to alternate fuels and to contract directly with producers for their supply needs. It can be assumed that the period of protection required by those consumers will correlate to the contractual arrangements entered into on their behalf.
- However, where end users elect to contract directly for gas supply on a short-term or a long-term basis, it was assumed these contractual arrangements would provide the level of supply protection desired.
- Natural gas marketed for sale outside of Canada, should be presumed to be protected by the contractual arrangements underlying the sale.
- Natural gas imported to Canada can be presumed to contribute to the protection of reasonably foreseeable requirements.
- Surplus determination procedures should not be considered as a substitute for private sector contractual arrangements.

Subsequently, the Alberta government issued a “directive” that the ERCB consider certain policy parameters in its review of natural gas protection, all in the context of the intent of the *Agreement* to provide freer access to domestic and export markets and to achieve a market-oriented pricing system (letter from Neil Webber, Alberta Minister of Energy to Vernon Millard, Chairman ERCB, October 28, 1986).

Specifically, the Alberta government suggested that provision be made for “reasonable needs” of end

users unable to contract directly with producers (typically residential, commercial, and small industrial users served by utilities), but not for end users (typically industrial users) capable of arranging security of supply through their own contracting activities. The latter were seen as not requiring mandated protection. Moreover, the government thought it possible to devise surplus procedures that would not distort market forces, which were seen as reliable arbiters to balance supply and demand. Surplus determinations were not to be viewed as a substitute for private-sector contractual arrangements to meet market requirements (*Policy Statement by the Government of Alberta Respecting Long-Term Protection for Consumers of Natural Gas*, October 1986).

7. The 1987 Alberta Surplus Test

Not surprisingly, the climate of natural gas deregulation initiated in 1985 and the policy directives of both the federal and provincial governments described beforehand fostered further relaxation of Alberta policies. The 1987 policy afforded a fifteen-year period of protection for Alberta's so-called "core" markets (residential, commercial, and small industrial), plus protection of non-core contracted requirements, in contrast with the previous twenty-five-year protection period for all (core and non-core) markets (ERCB, 1987).

In more detail: at any point in time, the gas reserves available for export from Alberta were defined as the difference between total available reserves and Alberta's requirements for the core market, plus amounts under contract to non-core (larger industrial) Alberta markets, plus remaining export permit commitments. Symbolically, the formula looked like:

$$G_s = R_{EST} - 15C_1 - CNC - PFS - E \quad (6)$$

where:

- G_s = surplus gas.
- R_{EST} = established gas reserves.
- C_1 = core market requirements, current year.
- CNC = contracted non-core market requirements.
- PFS = permit related fuel and shrinkage.
- E = remaining authorized exports.

At that time, the following values approximately held for each component of (6); units are in trillions of cubic feet (Tcf's) at 1,000 BTU/cf.

$$R_{EST} = 59.2; 15C_1 = 3.5; CNC = 1.7; PFS = 4.0; \text{ and } E = 40.0$$

Inserting these values in (6) yielded a volume of gas reserves available for inclusion in new export permits of some 10 Tcf.

However, while the Alberta government blessed relaxation of the surplus test, at the same time it tightened controls over the conditions governing removal of gas from the province. An amendment to the *Gas Resources Preservation Act* was passed in June of 1987, which gave the Alberta government the power to impose ministerial conditions on all gas removal permits, including permits issued before enactment of this amendment. This retroactive feature was intended to prevent gas from flowing to domestic markets at "discount" prices under certain existing gas removal permits that had hitherto provided for gas sales under virtually any terms. The government also moved (in 1988) to base royalties on natural gas from Crown leases on the highest of the actual sales price or 80 per cent of the average Alberta field price, hence discouraging "excessive" price discounting.

In early 1995, the Alberta government dropped the permit removal conditions for short-term contracts, thereby giving producers greater flexibility in negotiating gas sales. Also, Alberta core market users were given freedom to enter into direct gas purchase arrangements. In the event that Alberta domestic use began to impinge on available supplies, short-term permits would be the first to be relinquished, particularly as Alberta users bid on available supply. Should market disruptions lead to local shortages, legislation provides for diversion to the local market of gas licensed for removal, although the proportionality provisions of the Free Trade Agreement among Canada, the United States, and Mexico may then kick in. (See the discussion of the Free Trade Agreements in Chapter Nine.)

This section has reviewed the details of the Alberta policy to regulate ex-provincial natural gas sales to 'protect' Alberta consumers. The complexity of the protection formulae and their frequent modification attest to the difficulty of the task and may partly explain the willingness to allow a greater reliance on market mechanisms in the natural gas market as deregulation gained favour after 1984. Section C, below, offers some evaluative comments on the gas protection policies, but before doing that we will review the federal export control policies for natural gas.

B. Development of Federal Policy

As mentioned above, initially the Alberta Board included protection for Canadian requirements in its removal formula, but inevitably this responsibility devolved on the federal government itself, and specifically on the National Energy Board (NEB), established in 1959. (McDougall, 1982, chaps. 4, 5 and 6, discusses Canadian policy with respect to exports from before 1959 and up to 1971. He also reviews the Borden Commission's recommendations on natural gas.)

The motivation for federal policy can be traced back to the *Report* of the Royal Commission on Canada's Economic Prospects, which contained the following recommendation (Royal Commission on Canada's Economic Prospects, 1957, p. 146):

In order that a sound and comprehensive policy may be worked out with regard to development, exports, imports and consumption of forms of energy in Canada, we propose that a national energy authority be established which would be responsible for:

- (a) advising the Federal Government and, upon request, any provincial government in all matters connected with the long-term requirements for energy in its various forms and in different parts of Canada; methods of promoting the best uses of energy sources from a long-term point of view; export policy, including such questions as the further refining of oil and gas in Canada and the disposal of by-products; coal subsidies, etc.
- (b) approving, or recommending for approval, all contracts or proposals respecting the export of oil, gas and electric power by pipeline or transmission wire.

As Bradley remarks (1972, p. 3), "the recommendation displays primary concern with establishing policies that make certain that Canadian energy resources be developed with regard to Canadian needs for these resources, and it implies that one way in which this goal might be frustrated would be by excessive exportation."

1. The Legal Framework

Control by the federal government on exports of natural gas was implemented by the *National Energy*

Board Act of 1959. Section 81 provides that no export of gas from Canada shall take place except under licence, while Section 82 provides for issuance of licences under such terms and conditions as prescribed by the regulations. Section 83 of the act said:

Upon an application for a license the Board shall have regard to all considerations that appear to it to be relevant and, without limiting the generality of the foregoing, the Board shall satisfy itself that:

- (a) the quantity of gas or power to be exported does not exceed the surplus requirements for use in Canada having regard to trends in discovery of gas; and
- (b) the price to be charged by the applicant for gas or power exported by him is just and reasonable in relation to the public interest.

Note the similarity between the wording of clause (a) and Alberta's *Gas Resources Preservation Act*. However, the specific reference to price in clause (b) did not correspond to the Alberta statute; in Alberta, the price issue was subsumed at that time in the general admonition of public interest.

The duration of any export licence was not to exceed twenty-five years (see *Act*, Section 85(b)). The act also enabled the NEB to revoke or alter any export licence it may issue, but (NEB, 1970, p. 10-2):

... it is a premise of the Board's approach ... that once a license for firm export for a fixed period has been issued, it should not be diminished in effect or put in jeopardy so long as the conditions of license are observed. (Reliability of licenses was seen as desirable both) ... in equity to producers, exporters, United States importers and consumers of gas licensed for export, and in the interest of orderly development of relations between Canada and the United States in respect of natural gas.

Originally the Federal Power Commission in the United States had viewed Canadian natural gas supplies as insecure. To the board, this also entailed the use of "reasonable caution" in assessing Canadian requirements to avoid any potential conflict between reliability of exports and first preference being given to Canadian customers. This is important in terms of interpreting the mechanisms that emerged.

The treatment below of federal policy is not quite as detailed as that for Alberta. The interested reader is referred to Watkins (1982a) for further details.

2. Initial Policy and Policy Changes in the 1960s

Again, it was up to a regulatory board to develop procedures to apply the statute. The procedures developed by the National Energy Board (NEB) were very similar to Alberta's – a characteristic not entirely divorced from the fact that the NEB's first chairman was formerly chairman of the Alberta Conservation Board. Thus, in its first gas export report in 1960, the NEB saw a thirty-year period as appropriate for calculating "reasonably foreseeable" Canadian gas requirements (NEB, 1960). An allowance for Canadian requirements and proposed exports was deducted from established reserves, but a more distinct division was made between the current and an overall or future surplus calculation than employed by the Alberta Conservation Board at that time.

A twenty-one-year period (1960–80) was selected as that for which requirements should be met from presently established reserves. In the case of Alberta, such protection, necessitated by provincial policy, was extended to thirty years. The requirements elsewhere in Canada were levelled at the 1963 rate for the balance of the twenty-one-year period. The NEB's rationale for selecting 1963 as a base was (NEB, 1960):

... in general it has not been practicable for pipeline companies to obtain contracts for the purchase and sale of gas for incremental requirements commencing three or four years in the future. Incremental requirements beyond the 1963 level accordingly have been allocated to future discoveries of gas. In every case, all requirements accruing after 1980 are assumed to be met from future reserves.

Note here the intention that, excepting Alberta, the protection for ongoing requirements from established reserves over the twenty-one-year period was dictated by commercial contractual practices.

Symbolically, the current surplus calculation was:

$$C_s = R_{EST} - E - \sum_{i=1}^3 A(EA)_i - 18A(EA_4) - \sum_{i=1}^{30} A_i \quad (7)$$

where

$$C_s = \text{"current" surplus.}$$

$A(EA)_i$ = requirement for all provinces excluding Alberta, year i .

$A(EA)_4$ = fourth-year requirement for all provinces excluding Alberta.

A_i = Alberta requirement, year i .

E = authorized exports, and other symbols as defined previously.

The future surplus calculation effectively embraced the current surplus calculation. The increment in gas demand for all Canadian provinces other than Alberta between the fourth year (1963) and the twenty-first year (1980), plus all demand from the twenty-second year (1981) to the thirtieth year (1989), plus thirtieth-year, peak-day requirements were to be satisfied from yet-to-be discovered reserves (i.e., trend gas). The trend gas allowance was set at some 2.5 trillion cubic feet (Tcf) per annum for at least the next ten years, and thereafter on a somewhat decreasing scale. Thus the "future" surplus was:

$$F_s = C_s + 30T_g - [\sum_{i=1}^{30} A(EA)_i - 18A(EA_4)] - f(PD_{30}) \quad (8)$$

What is significant in this formula is that while the framework remained the same as Alberta's the provisions were considerably more liberal. Established reserves only protected the equivalent of about twenty-one to twenty-two years of the first-year gas requirements for provinces other than Alberta, compared with some twenty-five years of cumulative projected requirements in Alberta, while continuous extrapolations of trend gas – not just for the two years in the Alberta future surplus calculations – were used to protect all future demand (excluding Alberta) from year four to year twenty-one.

Interestingly, the export permits issued by the NEB never provided a loophole similar to that in the Alberta permits, whereby local utilities could access export gas in the event of local supply exigencies. But the NEB Act gave the NEB the right to alter any licence it issued, which allowed for possible diversion of gas to the domestic market. In effect, this was a "force majeure" type of clause.

Some minor adjustments were made in 1965. More substantive changes were made in 1966 (NEB, 1966). In essence, the "current" surplus formula simply became the difference between established reserves and twenty-five times the fourth-year requirement (a_4) plus already authorized exports, thus:

$$C_s = R_{EST} - 25a_4 - E \quad (9)$$

In terms of the future surplus calculation, the 1966 report of the NEB treated future supply as comprising: available reserves; established reserves to become contractible between the fifth and thirtieth year, comprising nearly all the reserves currently beyond economic reach plus all deferred gas; and twenty years of long-term trends. Future requirements were: Canadian requirements projected over thirty years; terminal-year peak-day protection; and existing export licences. Thus, the future surplus was approximated by:

$$F_s = R_{EST} + 20T_g - \sum_{i=1}^{30} A_i - E - f(PD_{30}) \quad (10)$$

In 1967, price entered the picture. (See Section 4.2, for more detail.) The NEB adopted three specific price guidelines, which in effect fleshed out clause 83(b) of the *NEB Act*. The adopted guidelines were as follows. The export price (1) should cover all costs, (2) should be fair compared to prices charged to customers in Canada next to the export point, and (3) should not be noticeably lower than the prices of substitute fuels (NEB, 1967, p. 3-19).

Subsequently, the second price test was more formally defined as 5 per cent above the “adjacent” Canadian price (NEB, 1971). To facilitate application of these guidelines, in 1970 the *NEB Act* was amended to ‘unhook’ the gas export price set by the board from any price written into gas export contracts.

3. Policy Changes: The Formula in 1970

In 1970, the NEB’s current surplus calculation remained similar to the Alberta Board’s then “contractible” surplus calculation, namely, total existing supply – consisting of established reserves, less adjustments for deferred reserves, reserves beyond economic reach, and pipeline losses and shrinkage, plus imports of gas (mainly minor amounts into Ontario) – was compared with current Canadian requirements plus authorized exports. Canadian requirements distinguished between other areas of Canada and Alberta.

The NEB did not use a formal future surplus calculation comparable with that employed by the Alberta Board. Instead, the current surplus test was extrapolated, with established reserves augmented by a fixed long-term growth rate of 3.5 Tcf per year (NEB, 1970, pp. 4-40 and 4-41). The policy implications of the results of the extrapolation were left quite open, but, of course, satisfaction of the current surplus test remained a necessary condition for any award of

export permits. In the main, the extrapolation was used to determine by how much the long-term growth rate in reserves might have to vary to provide the same degree of protection fifteen to twenty years in the future as the policy granted in the initial year (NEB, 1970, p. 10-13).

The NEB’s policy at that time also covered some more peripheral aspects, including the need for (NEB, 1970, p. 10-15):

... sound development of those pipeline transmission systems which are the means of providing gas service to Canadian consumers. The carrying of export gas should be a profitable activity, which, when undertaken by transmission systems serving Canadian customers, should make available to such customers a share in the economies of scale and such benefits as may arise from the contribution of exports to the financial health of the transmission system. In effect this means that where a choice has to be made between licensing exports by a project wholly oriented to export and a project which serves Canadian customers and export customers, if all other factors were equal the choice would have to be in favor of the project serving Canadian as well as export customers.

Also, in 1970, the NEB recognized that established transmission systems may receive licences for less than the twenty-five-year maximum provided by the statute but a new export system might have to be given a longer initial licence to enable the project to be financed. One concern was that too great a dedication of gas reserves to export commitments could force Canadian requirements beyond the short term to be met from gas discoveries in relatively high-cost, remote areas. Shortening the export permit period would assist in meeting this kind of objection, and fifteen years was the period the NEB thought appropriate, except possibly where extension would be necessary to finance new pipelines or major looping programs (NEB, 1970, p. 10-21).

In essence, the 1970 formula held until a substantial change was made in 1979. But after denial of export applications in 1971, the formula was effectively in abeyance during most of the 1970s.

4. The 1979 Changes

The NEB issued some criteria for determining surplus, on which the 1979 formula review was predicated. The

criteria were that the surplus formula should: be easily understood and applied; incorporate gas deliverability rather than reserves in the supply considerations; be flexible to respond to changing circumstances; provide continuing protection for Canadian demand throughout any period of export; provide incentive and encouragement to the gas industry; satisfy licensed export commitments to the extent possible; and reserve to Canadians any benefits from conservation restraints undertaken by Canadians (NEB, 1979b, p. 94).

After an extensive review, the NEB adopted a tripartite test procedure: current deliverability, current reserves, and future deliverability. Under current deliverability tests (NEB, 1979b, p. 95):

... it would be necessary to demonstrate a surplus of annual deliverability from established reserves in excess of the sum of total annual Canadian requirements and authorized exports for a minimum period of highly assured protection. This test would be used to determine the upper limit of the maximum annual quantities that might be surplus during a period of highly assured protection.

The NEB set the “highly assured” protection period as a minimum of five years.

Surplus deliverability – an annual quantity – would be:

$$S_{Di} = D_{Ei} - A_i - E_i \quad (11)$$

where

- S_{Di} = surplus deliverability, year i .
- D_{Ei} = Deliverability from established reserves, year i .
- A_i = Canadian requirements, year i .
- E_i = authorized exports, year i .

The NEB suggested tests solely relying on deliverability could lead to excessive industry activity to increase deliverability at the expense of developing new reserves. Thus, a reserves test was deemed necessary to maintain a “reasonable relationship” between established reserves and deliverability, defined as:

$$C_S = R_{EST} - E - 25A_1 \quad (12)$$

Licences for export of gas could be granted but should not exceed the maximum total quantity surplus under

the reserves test and should fall within the limits established by the current deliverability test.

In considering new exports that met both the current deliverability and the current reserves test, the NEB was concerned to ensure such exports would not result in deficiencies over the longer term. Accordingly, under the future deliverability test (NEB, 1979b, p. 95),

... annual quantities of gas could be deemed to be surplus if the forecast deliverability from established reserves and reserve additions, etc., exceeded expected Canadian demand plus authorized exports for a reasonably foreseeable period. At present the Conservation Board believes this period of future deliverability protection should be some ten years.

Thus the future deliverability was to ensure: first, that any proposed exports that might satisfy the first two tests would not cause a future deliverability shortfall within a ten-year period; and second, if the NEB granted a licence term in excess of that indicated by deliverability from established reserves, the extended licence would be limited by projected deliverability from future reserves. The NEB indicated “frontier” natural gas reserves would not be included until it was satisfied that the transportation facilities would be constructed.

5. The 1982 Policy Change

In the early 1980s, significant underlifting of authorized exports, along with slow growth in domestic natural gas demand and relatively abundant supply, triggered another review by the NEB of its export formula.

As discussed, the 1979 decision involved a triumvirate of tests – current reserves, current deliverability, and future deliverability – all of which required satisfaction. Moreover, for any exports dependent on reserve additions, the export licence was conditional. If gas deliverability were less or if Canadian requirements were greater than estimated when the licence was granted, these conditional export authorizations could be reduced or revoked (NEB, 1982, p. 12).

In its 1982 decision, the NEB renamed and modified the current reserves test, now calling it the “Reserves Formula” (NEB, 1982, p. 16). The modification related to the allowance for existing licensed exports: the amount set aside was adjusted to reflect the maximum quantities exportable under existing

licence conditions; previously, the amount set aside reflected the remaining licensed quantities, whether exportable or not. The Reserves Formula set the maximum surplus available for export and could be written:

$$C_S = R_{EST} - E' - 25A_1 \quad (13)$$

where

E' = quantities exportable under existing licences and other symbols as previously defined.

The current deliverability test adopted in 1979 was dropped. Instead, a deliverability evaluation was adopted involving “best” estimates of future gas supply and demand, comprehending: (a) deliverability from established reserves and future reserve additions; (b) expected Canadian requirements; and (c) estimated exports under existing licences. In essence, points (a) and (b) subsumed elements in the 1979 current and future deliverability tests. The allowance for exports was a forecast by the NEB of exports that would be taken under existing licences, rather than the maximum annual exports licensed. The decision in 1979 to exclude supply from frontier regions unless transportation facilities were to be constructed was upheld in the 1982 decision.

The new deliverability appraisal did not cite minimum protection periods – the five- and ten-year periods previously adopted in the 1979 current and future deliverability tests. Rather, “the Board will use its judgment to determine the annual deliverability profile which may be deemed surplus to Canadian needs” (NEB, 1983, p. 17).

The intention of the revisions was to provide more flexibility in determining surplus gas, subject to the upper limit represented by the Reserves Formula. The NEB noted that its new procedures were similar in structure to those of the Alberta Conservation Board.

The specific export surplus tests were used for awarding export licences. In addition, the NEB made provision for limited short-term exports for up to two years – a new departure. Such flexibility was intended to expeditiously permit exports to “replace quantities foregone because of regulatory or construction delays associated with long term licenses, or to take advantage of a new market opportunity” (NEB, 1983, p. 21).

On the pricing front, the 1970s saw emergence of uniform border prices for all gas exported to the United States (Watkins and Waverman, 1985). It

was not until July 1984 that a more flexible pricing policy was adopted. And in 1985 export gas prices were deregulated subject to the adjacent border price test that the price to U.S. buyers be not less than the price for Canadian buyers purchasing gas near the border-crossing point (Canada, Western Accord, 1985).

6. The 1986 Policy Change

Deregulation of the Canadian petroleum industry in 1985 provoked a further review of the export formula. The changes mark elimination of the cherished reserves test, a test that was seen as resulting in excessive inventory carrying costs and as not being needed in a market-sensitive pricing environment. The NEB pronounced its expectation of being “able to place increasing reliance in the future on the responsiveness of supply and demand to price and less reliance on the size of currently established reserves in protecting future Canadian requirements” (NEB, 1986c, p. 23).

The new surplus determination procedure was based on the ratio of reserves to production, called the R/P Ratio Procedure, entailing four steps. First, the maximum potential surplus is calculated for each year as the amount by which annual supply, defined as remaining reserves divided by a stipulated R/P ratio, exceeds estimated annual demand (domestic demand plus already authorized exports). The stipulated R/P ratio was set at fifteen. The second step consisted of an array of trial “profiles and durations for possible additional exports” to identify years in which the R/P ratio might drop below fifteen. The third step was the “Productive Capacity Check,” replacing the Deliverability Appraisal. Here productive capacity would be assessed to see whether forecast demand could be met, especially for years during which the actual R/P ratio might fall below fifteen. The final step is to determine the “most appropriate” export profile predicated on the preceding steps and on security of supply if the R/P ratio dips below fifteen, on the capacity of the existing infrastructure to produce and transport new exports, and on the estimated net economic benefits to Canada.

The procedure was intended to embody “a combination of security of supply and flexibility which the Conservation Board considers to be appropriate in the context of market sensitive pricing and the maturity of the Western Canada Sedimentary Basin” (NEB, 1986c, p. 24).

In essence, then, the (upper bound) total surplus was:

$$S = \sum_{j=1}^n \left[\frac{R_{ESTj}}{15} - A_j - E_j \right] \quad (14)$$

where

j = year counter.

n = projection period, and other symbols, as defined earlier.

Although the NEB had adopted an R/P ratio of fifteen, this ratio was seen as one varying over time in response to changing conditions, especially to reflect the desired margin between actual and stipulated R/P ratios. The adjacent border price test was dropped in October 1986. Instead, general surveillance of export pricing was instituted (letter from Marcel Masse, Minister of EMR to Roland Priddle, Chairman of the NEB, October 29, 1986).

7. Mandated Surplus Test Abandonment, 1987

Almost as soon as the ink was dry on the 1986 policy change, a further review was set in motion. Hearings on prospective revisions were completed in May 1987.

The federal government – which in effect initiated the review – mentioned some parameters it felt should be considered. These include the implications for surplus determination of: growth in direct sales to domestic customers; imports of gas from the United States; and renegotiation of domestic prices under long-term “system” gas contracts. Moreover, the then Minister of Energy had clearly indicated that as market forces increase more emphasis should be given to contractual arrangements – distinguishing between core and non-core customers – than to the formalities of surplus calculation. The implication seems to be that it might be desirable for the government to monitor the market to ensure that buyers of natural gas enter into contracts that protect the long-term interests of their core customers.

In light of the minister’s pointed strictures, it was not altogether surprising that the NEB had decided to eliminate the mandated surplus test entirely and allow gas exports to be determined in large part by market forces (NEB, 1987, pp. 24–27). No transition period was provided in this move to deregulate gas exports.

Under the new market-based procedure (MBP), the NEB would hold public hearings on any application to export natural gas under contracts lasting at least two years. The hearings would include a complaints procedure to ensure that all Canadian users can gain access to additional supplies of gas under the

same terms proposed for the export sale. Prospective gas exporters had to submit an export impact assessment at the hearing demonstrating that the proposed exports are surplus to Canadian gas requirements. As well, exporters had to provide evidence to the board that the proposed sales are in the Canadian public interest.

The MBP also required the NEB to monitor Canadian energy markets on an ongoing basis. And the board was to conduct periodic studies analyzing natural gas supply, demand, and prices to determine whether Canadian gas requirements continued to be met under this new policy.

Note that, although the surplus formula was dropped, the legislation still enjoins the NEB to only approve exports surplus to ‘foreseeable’ requirements. In effect, the meeting of the surplus test devolved on the prospective exporter with the NEB appearing to act more as an adjudicator between domestic and exporting interests.

On March 15, 1989, the reliance upon MBP was furthered when “the Board decided it would no longer use benefit-cost analysis in considering gas export license applications and decided that, with respect to contract flexibility, it would operate on the presumption that, where contracts are freely negotiated at arm’s length, they would be in the public as well as the private interest” (NEB, 1990, p. 31).

As was noted in Section 2, following deregulation, the natural gas market continued to evolve toward greater contractual flexibility, including greater reliance on spot markets. A growing volume of gas was exported under short-term contracts. The 1994 *Annual Report* of the NEB noted that 35.4 billion cubic metres of gas in 1994 would be exported under contracts of two years or less. This was about one half of total exports, as contrasted with 30 per cent of exports in 1986. No public hearing was required, and, while the NEB presumably continued to monitor the gas prices, such exports were generally presumed to be in the public interest. By 2001, about 80 per cent of Canadian gas exports were short-term.

NEB hearings were still held for gas exported under contracts with duration longer than two years. Most frequently, these were associated with the construction of new facilities either to move the gas or for consumption (e.g., a gas-fired electricity generating plant). Presumably, the buyer and/or pipeline desired an assurance of gas supply before financing and/or building the new facility. The appropriate focus of such hearings was left somewhat vague under the MBP, with its presumption that freely negotiated

deals are likely to be in both the private parties' and the public's interest. Formal criteria for establishing whether a "surplus" exists have been dropped, leaving some domestic interests worried about long-term Canadian supplies but with no obvious procedure for showing that exports are excessive. A party applying for a long-term export licence was obliged to inform potential Canadian purchasers of the intent and that they were offered access to the gas on the same terms as the U.S. buyers. This amounts to a 'complaints procedure', and if no prospective Canadian buyer offers objections, the licence will normally be granted. (This 'complaints procedure' to market-based exports differs in basis from the 'fair market access procedure' for crude oil discussed in Chapter Nine.)

Some government export hearings have seen intervenor groups arguing that the environmental impacts of natural gas exports should be assessed so that the full social costs and value of the gas are taken into account before export authorization is given. The environmental concerns expressed relate in part to any damage caused to the Canadian ecosystem by gas production that would imply a social cost of gas higher than private production costs, apart from royalty (tax considerations). Concern has also been expressed about the effects of gas utilization in the United States (e.g., if conservation or benign renewable energy forms are abandoned), where the price paid may exceed the social value of gas consumption. Thus far, the NEB has not been persuaded that these concerns are significant enough to warrant formal modification of the MBP.

Now that the gas protection policies of Alberta and the federal government have been described, we will offer some evaluative comments.

C. Economic Analysis of Natural Gas Protection Policies

The obvious complexity of the regulations to generate protection for natural gas consumers – and the frequent modifications to the regulations – makes detailed analysis difficult and tedious. Instead, we focus on two related issues: (1) what were the general effects of the regulations? and (2) were they a desirable form of regulation?

1. Reserves and Supply

The natural gas protection policies involved potential restrictions on sales to customers outside the region

(ex-Alberta or ex-Canada). They operated by comparing 'available' natural gas volumes to projected regional consumption in order to determine whether a surplus existed. The initial regulations used a 'stock' concept of availability, by employing reserves. As time passed, more 'flow'-related concepts were admitted to measures of availability, beginning with the admission of projected future discoveries and eventually leading to more emphasis upon deliverability than on reserves. Despite such changes in regulations, their primary effect was to require large industry inventories in support of current sales. (The discussion below draws substantially on that in Bradley, 1972. Waverman 1972, 1973, considers the trade effects of the policies.)

All the surplus formulae identify current stocks as one element and then make varying provisions for future stocks. Current stocks correspond to the notion of working inventory. In the context of surplus policies, they normally consisted of established reserves less certain volumes deferred for conservation reasons and less an allowance for reserves currently uneconomic, called 'beyond economic reach' reserves. An example of conservation reasons would be cycling schemes, where natural gas is cycled back into the reservoir to recover liquids that might otherwise be lost if the reservoir were produced on a normal basis. Established reserves comprise both proved reserves – those believed to exist with virtual certainty under prevailing economic conditions and technology – and a proportion of probable reserves. Probable reserves are those that may be recovered in the vicinity of proved reserves but where there is some degree of geological, engineering, or operational risk.

Established reserves do not constitute the resource base. The latter is at the behest of nature: the total amount present in the earth's crust within a given geographic area. Established reserves are only a fraction of reserves that might become available if prices rose or technology improved, quite apart from those reserves that may be added in the normal course of exploration under prevailing conditions.

The distinction between proved reserves and beyond economic reach reserves – expected reserves in discovered but undeveloped reservoirs – is shown in Figure 12.2. Here, the current price is designated P_c . To the left of the vertical broken line, proved reserves are shown in blocks of ascending cost, all with costs lower than P_c . To the right of the line are shown blocks of reserves with costs exceeding P_c , the beyond economic reach category. Figure 12.2 is static, simply classifying established reserves according to whether they

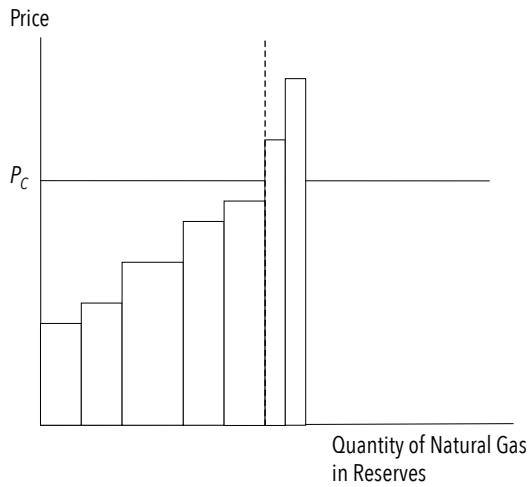


Figure 12.2 Natural Gas: Economic and Beyond Economic Reach Reserves

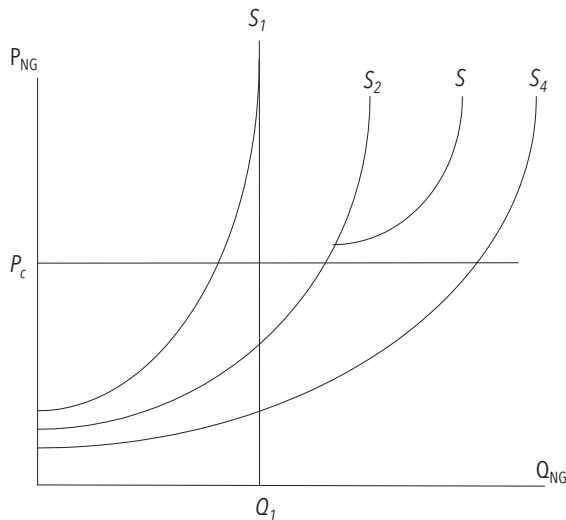


Figure 12.3 Natural Gas Supply

are economic to produce at prevailing prices or not; it is an example of what, in Chapter Four, was called a 'resource stock supply curve.'

Another way of looking at supply is to map stocks of reserves into rates of output and examine dynamic aspects over time. This is done in Figure 12.3, where various conventional supply curves are shown. The leftmost curve, labelled S_1 , relates to output from established reserves given installed capacity. It is long-term in the sense that the prevailing price, P_c , is sufficient to cover both operating and investment costs, but the fixed installed well capacity precludes any

increase in output beyond Q_1 , irrespective of price. The curve labelled S_2 represents additional capacity added by more intensive development of reserves already economic to produce. The assumption is that additional development can take place at much the same unit cost of output as beforehand.

The curve in Figure 12.3 labelled S_3 extends the S_2 curve by including output from known discoveries not economic to develop at prices below P_c . The curve S_4 illustrates the outward shift in supply in response to exploration, at various price levels. More generally, the curve S_3 , which represents supply from current established reserves, can be viewed as shifting to the left as these reserves are depleted, but this may be offset by shifts to the right as new reserves are discovered and developed.

Overall, it is fair to say that the basic uncertainties governing the exploration process make supply analysis difficult. Hence, widely accepted estimates of the price elasticity of supply are elusive. Figure 12.3 suggests such elasticity arises not only from new exploration inspired by higher prices but via increased recovery from existing reserves. An indication that the latter is not trivial is provided by estimates of the Energy Resources Conservation Board (ERCB) in 1972 that an increase in the field price of gas would lead to a lower abandonment pressure, improved economics of developing marginal gas reserves, and increased recovery of oil field solution gas (ERCB, 1972b, p. 6-12). At that time, the ERCB estimated that an increase in the field price of gas of 10 cents would increase Alberta's established reserves by about 10 Tcf (ERCB, 1972b, p. 6-14). Given a field price at the time of about \$0.16/Mcf and initial recoverable reserves of some 60 Tcf (ERCB, *Reserves Report*, 84-18, Table 8-2), this translates into a crude supply elasticity of 0.27 with respect to established reserves. A higher elasticity would result from the inclusion of reserve additions associated with higher prices.

That the surplus tests were associated with unusually high inventories is strongly suggested by the much higher reserves to production (R/P) ratios of natural gas than crude oil from the late 1950s on, after connections to ex-Alberta markets had been established. The R/P ratio was also lower for the U.S. natural gas industry than the Canadian (e.g., 10 in the U.S. in 1980, and 28 in Alberta). This evidence would be stronger if there were a 'natural' R/P ratio that might be used as a standard of reference. For example, at what R/P ratio would a unitized, effectively competitive industry operate? It has been suggested that an R/P ratio in the order of ten would be likely. Much

lower and intensive use of reserves probably damages ultimate recovery. Much higher and the investments to establish reserves would be waiting unnecessarily long for payout. Despite these arguments, it is impossible to be precise about a 'natural' R/P ratio. For one thing, the ratio is bound to be affected by short- and medium-term lags and uncertainties. Large discoveries, for instance, may have to wait a number of years for the development of transmission facilities and new markets. Beyond this, the optimal drawdown of reserves (especially via infill drilling) should vary with current and anticipated market conditions. For example, suppose new discoveries generate production increases and begin to drive down current prices, while leaving longer-term price expectations relatively unchanged. Then future profits will begin to appear relatively more attractive (the 'user cost' becomes a more significant proportion of cost) and the optimal R/P ratio will rise. In spite of these caveats, an Alberta natural gas R/P ratio consistently in excess of twenty-five throughout the period of regulatory gas protection policies is remarkable.

The reader may well ask the question: why would there be any excess or surplus of established reserves at any point in time, as the various surplus formulae discussed earlier presume? The reasons are fourfold. First, some natural gas reserves occur in conjunction with oil reserves and so their availability is not calibrated to natural gas market requirements. Second, the exploration process is not well defined directionally. While some areas are more gas prone than others, it is not possible to channel exploration activity specifically towards gas. Indeed, the initial build up of Alberta's gas reserves after World War II largely resulted from what was intended as oil-directed exploration. Third, surplus policies themselves could encourage accumulation of reserves in excess of those required on a normal commercial basis. In other words, such policies can become self-fulfilling. Fourth, market imperfections may preclude market clearance. The first two of these reasons would account for surplus reserves for some period of time, but not persistently over the thirty-five years from 1950 through 1985. The last two reasons could explain continuing excess stocks.

2. Analytics of Gas Export Limitations

At the most basic level, the natural gas protection policies served to limit shipments of gas from the region (Alberta or Canada, depending upon whether the regulations were by the Alberta government or

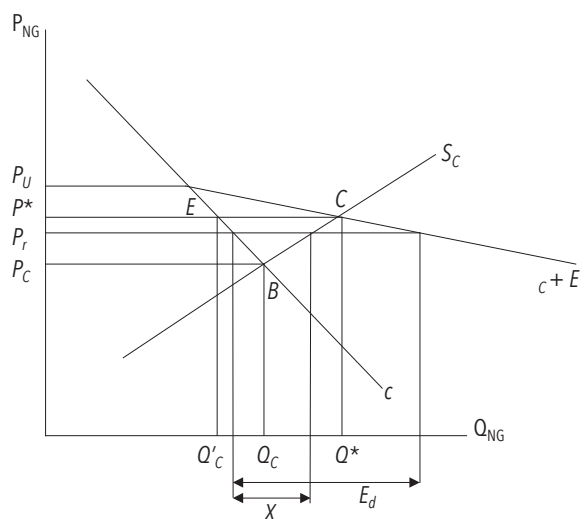


Figure 12.4 Natural Gas Export Limitations

the NEB). The impact of policies to restrict exports can be examined in the context of resource rents (see Bradley, 1972). The illustration below is couched in terms of exports from Canada, for ease of exposition. But the analysis would apply equally to removal of gas from Alberta.

The following analysis compares two extreme possibilities, no exports and completely unrestricted exports. The latter has been approximated since deregulation and the FTA in the late 1980s, although, as we shall see, short-run and long-run adjustments differ. Prior to that, exports from Canada were limited by the gas protection policies but were not nil.

Figure 12.4 compares the two cases. D_C is the Canadian demand for natural gas. P_U is the price at which the U.S. natural gas market would clear if no imports were allowed. At lower prices, U.S. consumers want more gas and producers provide less. The lower the price, the higher the 'excess demand' in the United States. This excess demand (E) translates into a demand for Canadian gas. In Figure 12.4 the total demand for Canadian gas is shown by $D_C + E$.

In reality not all of such excess demand in the U.S. market would be added to the demand for Canadian gas. There could be other sources of gas available to the United States, for example offshore (LNG) and Mexico. Moreover, regional aspects and constraints on the flexibility of pipeline systems would preclude Canada filling the entire gap. But our exercise is theoretical and such adjustments would not detract from the implications of the analysis.

Given a Canadian policy that prohibits exports, the market clearing price would be P_C and Q_C .

Given an open, competitive market, the equilibrium price and output as shown in Figure 12.4 (at point C , where S_C intersects $D_C + E$) would be P^* and Q^* respectively. Output absorbed by the domestic market would be Q'_C , which would be lower than the quantity (Q_C) absorbed domestically when exports are inhibited and the equilibrium is where domestic supply (S_C) meets domestic demand (D_C). The reason for the reduction in domestic consumption with an open market is of course the impact of higher prices compared with the case of the closed economy. The quantity of exports is $Q^* - Q'_C$.

Who might be the gainers and losers under a permissive export policy? The immediate gainers would be the Canadian natural-gas-producing sector. The producing sector embraces the interests of privately and publicly owned companies and governments that obtain revenues from it. In comparison with a closed market, production sector rents increase by the area $P_C B C P^*$ in Figure 12.4. Natural gas consumers in the United States would also gain since some portion of their excess demand would be satisfied.

The losers would be Canadian natural gas consumers. The reduction in consumer surplus (compared with a closed market) is represented by the area $P_C B E P^*$ in Figure 12.4.

Since the welfare loss felt by consumers is more than offset by production-sector gains, ostensibly a sufficient portion of the extra revenues enjoyed by the production sector could be transferred to consumers to make them as well off or better off than under a closed economy (Kaldor-Hicks Compensation Principle). The net improvement in rents and thus welfare is represented by the area $E C B$ in Figure 12.4.

In this sort of calculus, what happens to the economic rents is crucial. Bradley (1972) outlines two extreme cases. The first is where the additional production-sector rents escape any taxes and royalties, where the entire industry is foreign-owned, and where all the rents leave the country. The second extreme case is where all the additional production-sector rent accrues to governments that redistribute monies to consumers to ensure they are no worse off than under a closed system.

The realities, since large-scale exports of Canadian natural gas commenced in the 1950s, lie between these two extremes. Exports have been permitted but are nevertheless restricted by the surplus and other policies. The tax system does capture considerable amounts of economic rent via lease sales, royalties,

permits and rentals, and income taxes. Not all the industry is foreign-owned, and foreign owners do not immediately repatriate additional rents. Note that when the surplus policy is binding, this can have repercussions for domestic prices if domestic consumers enjoy some monopolistic power. Certainly the regime prevailing at the time of writing under the North American Free Trade Agreement (NAFTA) is the nearest Canada has had to a totally permissive export policy.

One modification to the analysis of Figure 12.4 should be introduced. It is well established that U.S. natural gas pricing regulations in the 1960s and 1970s served to hold prices below market clearing levels (MacAvoy and Pindyck, 1975). In Figure 12.4, this is shown by P_r . If this price also applied to imports from Canada, as was the case, then P_r would serve as an equilibrium price (due to U.S. regulations). There would be excess demand in U.S. markets equal to E_d , of which an amount X would be met by imports from Canada.

3. Impacts of the Gas Protection Policies

The Alberta and Canadian policies did not in fact prohibit exports – the regulations were more complex than an absolute prohibition and operated more indirectly. Thus the analysis above illustrates the type of effects expected but fails to provide a reasonable explanation of how the surplus policies operated. That the general effects were as illustrated is suggested by Waverman's (1973) linear programming model of North American natural gas flows in the 1960s. He finds that more Canadian gas was used in domestic markets, and less exported, than would be expected in a deregulated North American gas market. Exactly how the surplus policies operated to generate these results is less clear. For example, exactly why did the natural gas protection policy generate large reserves relative to production? The explanation must lie in the behaviour of the various market participants. There is no full behavioural model of the Alberta natural gas industry, including wide latitude in development options for natural gas producers. Rowse (e.g., 1986, 1987, 1990) has built an ambitious and valuable operations research model of the Canadian gas industry that develops conditional forecasts of both production and consumption behaviour, but it assumes elasticity and resource cost parameters, rather than estimating them historically, and contains limited reserve development options. The same can be said of the Canadian components of the North American

Regional Gas (NARG) model developed by a private consulting firm, Data Resources Inc., and widely used by Canadian private firms and governments (including the NEB in its *Supply/Demand Reports*). However, economic analysis provides some guidance as to the effects of the natural gas protection policies.

Historically, the consumption side of the market for Alberta natural gas has included a limited number of buyers, thereby taking an oligopsonistic form. Within Alberta, most of the gas has been purchased by the two main utilities. (Known as Northwestern Utilities and Canadian Western Natural Gas for much of their lives, they were acquired by ATCO in 1980.) Buyers for removal of gas from the province have mainly been the large gas transmission companies, TransCanada Pipe Line (for sale in Canada and the United States east of Alberta), Westcoast Transmission (which primarily contracts gas in north eastern B.C., for sale in B.C. and the U.S. Pacific Northwest) and Alberta and Southern (for sale on the U.S. Pacific coast, mainly California). All these large buyers have been rate-regulated on a cost of service basis.

At first glance, the Alberta and NEB surplus tests for export of natural gas might be viewed as a controlling device that allowed buyers to obtain an oligopsonistic result of lower prices. (Here, lower prices means in comparison to an effectively competitive market.) The necessity of preserving sufficient supplies to meet internal needs would serve as a significant barrier to entry to buyers from outside the region who could not be guaranteed regulatory approval for gas removal from Alberta or Canada. However, the usual oligopsonistic preference for low prices on inputs is not fully operative in this case; since the utilities and transmission companies are rate-regulated, they cannot generate higher profits by buying inputs (i.e., field gas) low and then selling output (i.e., delivered gas) high. Hence, the impact of the natural gas protection policies on the buyers' side of the market must be somewhat more subtle than this.

We would emphasize two effects. First, the restrictions did imply a potential (or binding) limitation on competition between regional and ex-regional buyers, and hence may have allowed lower prices within the region than outside, as the analytical model suggested. A gas seller would prefer a lower-priced contract with a buyer from within the region to a higher-priced contract with an ex-regional buyer that ran some probability of being overturned because there was no regional gas surplus. However, one would expect these price effects on new contracts only when the region was judged to have a very small or no export surplus.

(This held for Alberta only in the early 1980s, and for Canada as a whole after 1970.) In the 1980s, the gas surplus tests may have had a positive effect on the appearance of gas export pipelines since they helped to ensure that exports would not be interrupted and such reduced risk made the financing of the pipelines easier.

A second effect of the surplus tests was the stimulus it offered to long-term contractual arrangements between buyers and sellers and to the appearance on the market of uncontracted reserves. Until the 1980s, the gas-protection policies essentially required twenty-five or more years of reserves in support of current sales. Buyers may have been induced to contract volumes for this length of time, thereby removing the reserves from the hands of other potential buyers. However, given the limited number of buyers, especially when the gas surplus restrictions were binding, the regional buyers could afford to leave some reserves uncontracted. The seller would have no alternate buyer within the region, and ex-regional buyers would be disallowed if there were no gas surplus. Long-term contracts plus any uncontracted reserves would contribute to a higher R/P ratio.

Moreover, the long-term contracts tended to have inflexible pricing terms. In contracts signed in the 1950s and 1960s, prices were often fixed with small escalation factors, and there was generally no provision for frequent or drastic renegotiation of price. This likely reflected the risk preferences of the regulated utilities: stable prices meant that sales were also likely to be stable, and the risk of losses in demand reduced. Sellers may also have preferred relatively stable prices, but even if a seller did not, the oligopsonistic nature of the market would give it little choice. As was discussed in Section 2 of this chapter, the inflexibility in gas contracts, and limitations in Canadian exports under the gas surplus tests, posed a real dilemma for Alberta energy policy-makers when international crude oil prices began to shoot up in the early 1970s, pulling the value of natural gas along.

Our discussion of the natural gas protection regulations have dealt primarily with the buyers' side of the market. It has been noted that the regulations probably served to strengthen the position of buyers in their negotiations with natural gas producers. At any given level of natural gas prices, the export surplus regulations would tend to increase the effective cost of reserves and to reduce their effective price. The regulations raised the investment cost of gas reserves since reserves would have to be carried for longer before sale (Hamilton, 1973). This could come about in two

ways. First, the regulations led to contracts in which relatively high reserves were held per unit of output (i.e., pools tended to be depleted slower rather than faster). Second, new reserves might go uncontracted for a longer time. With respect to price, unless the natural gas price was expected to rise very rapidly, the present value of the revenue received from the reservoir is reduced when the gas output is delayed; that is, the effective value of a unit of gas reserves is reduced.

Our argument may begin to seem contradictory. If the gas-protection regulations tended to inhibit investment in reserve additions, how can they contribute to higher than expected R/P ratios? In part, the response lies in the individual contracts, which, as noted above, tended to involve large reserves in support of production, as was, in fact necessitated by the gas-surplus regulations. But part of the answer must also lie in the aggregate market results of the gas-surplus policies. Here, we would suggest that these policies, for natural gas, served to induce significant price stability (rigidity) in the natural gas market, much as market-demand prorationing did for crude oil. Hence one does not observe the downward pressure on natural gas prices in the 1950s that the rapid growth in gas reserves might have led one to expect. The higher gas prices meant somewhat less consumption. In addition, higher prices increase the attractiveness of reserves additions, tending to offset the negative stimulus of delayed production. Both reduced consumption and higher reserves additions operate to increase the R/P ratio.

We hesitate to offer a complete normative analysis of the gas-protection policies that were in place from 1950 to the mid-1980s. Some comments are in order. A number of observers (e.g., Hamilton, 1973) have stressed the negative effects of the increased costs associated with high R/P ratios. More inputs than were necessary were drawn into the natural gas industry, when society might have used them elsewhere.

Economists are generally critical of policies that reduce the reactivity of markets, thereby inhibiting consumer and producer responses to changes in underlying market conditions. In the case of inflexibility in natural gas prices, the beneficiaries would seem to be the natural gas consumers at the expense of producers, as the analytical model suggests, although it is hard to be definite in this regard. (The view that gas-surplus tests must benefit consumers is suspect since the policies also induced high reserve levels in support of consumption, and therefore did not necessarily generate lower prices.) We judge it likely by the late 1960s that the policies were probably holding prices lower than they would otherwise have

been. From the mid-1970s to 1986, as Section 4 of this chapter details, natural gas prices were fixed by the government. Thus the gas-protection policies may have redistributed some of the benefits of Canadian natural gas to Canadian consumers and away from U.S. consumers and producing interests (including the Alberta government and foreign shareholders in the petroleum companies).

As was discussed above, deregulation brought the loosening and eventual abandonment of the long-standing gas-protection policy. This occurred in conjunction with other changes in North American natural gas markets, including the Canada–U.S. Free Trade Agreement (FTA) and NAFTA. Beginning in the 1970s, new buyers had begun to appear for natural gas. This accelerated in the 1980s in both Canada and the United States as high-volume gas consumers, marketing consortia, and other trading partners began to contract for natural gas and lease-delivery space in the major transmission lines. Long-term contracts were revised to become much more flexible, shorter-term contracts became increasingly common, and an active spot market for natural gas developed.

The result was a revolution in Canadian natural gas markets even greater than that in crude oil markets. Canadian gas sales, particularly exports to the United States, rose rapidly after 1986, as shown in Table 12.1. The R/P ratio fell dramatically, from 24 in 1985 to 8.3 by 2003. And natural gas prices became much more flexible as increasing volumes are sold under shorter-term (e.g., two years or less) contracts or under longer-term contracts with prices renegotiated frequently.

And what of protection of gas supplies for Albertan and Canadian consumers? The changes in the late 1980s and early 1990s have led to a situation in which natural gas consumers are protected in much the same manner as they are in the consumption of any other commodity – by the market. Impending scarcity puts upward pressures on prices, which induces consumers to conserve natural gas and draws forth greater supplies. Consumption by Canadians is warranted only if Canadians are willing to pay as much as foreign buyers; otherwise, the gas is exported and Canada derives the export revenue. McDougall suggests that the NEB's policies in the 1960s were biased towards encouraging exports, as indicated by the loosened restrictions in estimating domestic supply, and that price tests were never taken very seriously, at least so far as determining the economic value of gas in the export market is concerned (McDougall, 1975, chap. 5). He interprets the prime purpose of the exportable surplus policy as the “protection” of Canadian gas

consumers, but expressed largely as trying to ensure access to low-cost supplies. Exports, he argues, draw on low-cost supplies and therefore force domestic consumers to rely on higher cost volumes.

This raises a fundamental question: are there any reasons that natural gas should not be treated as another economic commodity? The gas-protection regulations implied that there were, though exactly what these were was not made clear. Three possibilities come to mind, all related to prohibition of gas removal (exports), although are all debatable.

First, natural gas is a depletable natural resource and therefore, it might be argued, should be reserved for Canadians, especially if the free market is unable to allocate depletable resources efficiently and equitably. We have touched on variants of this argument numerous times with reference to oil, so we will only reiterate some of the earlier responses briefly. In Canada, many other depletable resources are handled by relatively unrestricted markets. Producers of natural gas do have a strong profit incentive to take likely future market conditions into account and therefore do have 'conservation' tendencies. Whether depletable or not, many people feel that the resource should be used where it generates the greatest value for Canada, even if that is by means of generating foreign exchange on export sales. We have also emphasized that exhaustibility of petroleum resources is primarily a physical phenomenon, rather than an economic one, while production and consumption are economic activities. From a dynamic point of view, greater sales and higher prices resultant from exports will call forth additional supplies and encourage faster adoption of any new technologies that have a strong 'learning-by-doing' component. There are a number of contentious arguments related to the possible undervaluing of future consumption needs, but if these arguments are accepted they apply to current domestic sales as well as to ex-regional sales. On balance, we view the depletable argument as a weak basis for petroleum export limitations.

Second, natural gas might be argued an essential good for home heating and for many industries. But there are substitutes for natural gas in virtually all uses, at least in the long run. Moreover, there are many 'essential' goods (e.g., food stuffs) and we neither limit the export of these nor would we be very understanding if some other country severely restricted our ability to buy from them.

Third, natural gas is a continental rather than international product and involves very capital-intensive transmission and consumption capital; therefore, it could be argued that domestic consumers,

once linked to supplies, need to be assured of continued accessibility. Economists may argue in response that capital intensity is not peculiar to the use of natural gas, and that natural gas can be imported or produced from other sources such as grain, peat, or coal. Moreover, one advantage of well-functioning economic markets is exactly that they make gas available to anyone who 'needs' it (and is willing to pay!) and that the market facilitates the gradual adjustment to changing conditions such as growing scarcity. We would reiterate that there are equity effects of a decision to follow open markets, with the producers of an exported product benefiting at the expense of domestic consumers. This has implications for taxation policies, especially those on economic rents, but is, in our view, an insufficient reason to impose export limitations.

Overall, we are not convinced by the arguments that natural gas is somehow special and cannot be allocated through traditional economic markets. The recent rapid evolution of active and flexible natural gas trading institutions provides evidence in this regard.

This section has focused on the export volume limitations. The next section considers pricing issues, including export pricing.

4. Price Controls and Other Market Regulations

This section deals with those government regulations that impacted significantly upon the market for natural gas other than the export surplus rules discussed in Section 3. We are primarily concerned with regulations impacting upon natural gas prices. Of necessity, some of this material was presented above, in Section 2C, in the discussion of natural gas prices. This section draws upon Helliwell et al. (1989, chap. 4), Plourde (1986), Watkins (1977a, 1981, 1987a, 1989, 1991a), and Watkins and Waverman (1985).

A. Market Regulations

1. Domestic Pricing

As will be recalled, domestic natural gas prices were quite stable in the 1960s, and NEB denial of export permits commencing in 1970 removed the stimulus of growing U.S. demand for gas in the interstate markets. TransCanada Pipelines (TCPL), the major buyer of Alberta gas, was left in a situation tantamount to

Table 12.3: Relationship between Natural Gas and Crude Oil Prices, Toronto, 1970 to 1987 (\$/GJ)

	<i>Refinery Average City Gate Gas Price (1)</i>	<i>Acquisition Cost Crude Price (2)</i>	<i>Ratio of Gas to Crude Oil (3) = (1)/(2)</i>
1970	0.36	0.56	0.64
1971	0.44	0.56	0.78
1972	0.45	0.56	0.80
1973	0.52	0.64	0.81
1974	0.55	1.05	0.52
1975	0.82	1.32	0.62
1976	1.24	1.52	0.82
1977	1.47	1.81	0.81
1978	1.77	2.15	0.82
1979	1.92	2.40	0.80
1980	2.23	2.91	0.77
1981	2.42	4.52	0.54
1982	2.80	5.46	0.51
1983	3.38	5.93	0.57
1984	3.71	6.01	0.62
1985	3.76	6.25	0.60
1986	3.85	3.43	1.12
1987	2.84*	4.07	0.70

* direct selling price at Toronto, upper scale.

Sources:

- (1) 1970-74 – based on ERCB and DataMetrics Limited; 1975-87 – Petroleum Monitoring Agency, *Monitoring Survey*, Annual 1986; *Texaco Energy & Economic Data Book*; and *Corpus, Energy Pricing News*, 1987 issues.
- (2) 1970-73 – wellhead price & IPL tariff – ERCB and *IPL Annual Reports*; 1974-87, and Energy, Mines and Resources, *Energy Statistics Handbook*.
- (3) 1970-78 – Industry Source; 1979-87 – EMR Ottawa. Note that 1979-87 prices are based on Ontario value/volume data.

monopsony. Rising oil prices at the start of the 1970s had minimal impact on natural gas prices, which rose, on average, from \$0.16/Mcf at the wellhead in 1970 to \$0.17/Mcf by 1972. In 1972, the Alberta government began a campaign to increase gas prices by asking the ERCB to study field prices, as was discussed in Section 2, above. There we noted that gas prices began to increase in 1973, and contract provisions moved to greater flexibility in prices.

In the spring of 1975, a price of \$1.15/Mcf was awarded by an arbitration panel in a dispute between TCPL and Gulf Oil Canada. This was widely interpreted as representing a suitable commodity value for gas in line with the sharp increases in oil prices, which

had taken place since 1972. The sevenfold increase over the 1970 natural gas price focused the attention of the federal government, much as had rising oil prices. The June 1975 budget announced that Ottawa and the producing provinces had agreed on a government-fixed price effective November 1, 1975. The price would be 85 per cent of the price of crude oil, on a Btu parity basis, at the Toronto city gate, rising to 100 per cent of the crude price over three to five years. Initially, the price would be \$1.25/Mcf. The Alberta border price for natural gas would be the Toronto city gate price less transmission charges; the field price would be the border prices less the NOVA transmission charge within Alberta and gas-processing-plant charges. Note that the full brunt of any transmission cost rises fell on the natural gas producer.

As Table 12.2, shows, Toronto city gate prices were increased a number of times by federal and provincial government agreement over the November 1975 to February 1980 period; the increases followed agreed-upon oil price rises and attempted to keep the natural gas price at 85 per cent parity with crude oil in Toronto. Table 12.3 looks at the Toronto market in more detail, including average city gate natural gas prices in comparison to the average cost of crude oil to refineries for years 1970 through 1987. It can be seen that gas prices were well below 85 per cent crude oil equivalence in 1970 but had risen close to that level by 1973. However, rising oil prices in 1974 and 1975 left gas prices behind the standard until the November 1975 increase.

Government authority to set natural gas prices was derived from Ottawa's 1975 *Petroleum Administration Act* and from Alberta's *Natural Gas Pricing Agreement Act* (RSA, 1975, chap. 38), which overrode any award under arbitration or other price redetermination agreement.

As was discussed in Chapter Nine, the inability of Ottawa and Edmonton to reach agreement on oil prices in 1979 and 1980 led Ottawa to introduce the National Energy Program (NEP) in conjunction with its October 1980 budget (Energy, Mines and Resources, 1980). The NEP noted that

... pricing policy for natural gas must meet two needs: provision of adequate incentive to production and strong encouragement for consumers to use natural gas in preference to oil. Producers' returns from natural gas have risen dramatically since the mid-1970s – in fact, faster than oil prices, despite a growing surplus of gas. (p. 31)

The desire to reduce reliance on oil imports also influenced policy under the NEP.

Linking Canadian natural gas prices to world oil prices is also unwise, because Canadian endowments of oil and gas resources differ: we have, judging from evidence thus far, abundant supplies of natural gas that could be produced at moderate prices, but less certain prospects for oil. Linking Canadian prices to world prices would keep the price of gas to the consumer rising at the same rate as the price of oil. This would inhibit the massive-scale substitution away from oil that must take place if Canada is to achieve energy security.

Increased use of gas would be encouraged by subsidies to pipeline extensions east of Montreal to keep city gate natural gas prices at the Toronto level (p. 58), and consumer grants would encourage substitution away from oil to other fuels, including natural gas (p. 56).

Under the NEP, natural gas prices would fall somewhat relative to crude oil at the Toronto city gate. From 1975 to 1980, every \$1/b oil price rise gave a \$0.15/Mcf gas price increase; under the NEP, for three years from 1981 through to 1983, gas prices would rise \$0.10/Mcf for every dollar per barrel increase in domestic oil prices; this meant gas price increases of \$0.45/Mcf per year for the three years. Alberta border prices, however, would not rise for the first year in order to make room for a \$0.45/Mcf Natural Gas and Gas Liquids Tax (NGGLT), “which will be applied in lieu of a gas export tax” (p. 31), on all Canadian-produced natural gas. As can be seen in Table 12.3, the price of natural gas in 1981 was at 54 per cent of the crude oil price at Toronto, as compared to 80 per cent in 1979.

The NEP also set up a “Canadian Ownership Account, to be financed by special charges on all oil and gas consumption in Canada, to be used solely to finance an increase of public ownership in the energy sector” (p. 51). City gate gas prices were increased in May 1981 by \$0.15/Mcf for the Canadian Ownership Special Charge (COSC).

Chapter Nine outlined Alberta’s outrage at the NEP, and the program of oil output cutbacks introduced in protest. The two governments reached accommodation in the September 1, 1981, *Memorandum of Agreement relating to Energy Pricing and Taxation*. The *Memorandum* switched the geographical bias for pricing from Toronto to the Alberta border and agreed upon a new pricing

schedule in which the price would rise by \$0.25/Mcf every six months through to the end of 1986 (starting on February 1, 1982) (p. 7). The *Memorandum* further specified the intent “to establish the level of the NGGLT on domestic sales so that, taking into account a range of factors, including gas transportation costs, the parity relationship between the wholesale price of natural gas at the Toronto city gate and the average price of crude oil at the Toronto refinery gate will be approximately 65%” (p. 9). (Presumably the COSC would also fill the gap between the Alberta and Toronto prices.) Table 12.3 shows that the Toronto gas price had fallen to 51 per cent of the crude cost by 1982 and rose again to 60 per cent in 1985, the year of crude oil price deregulation.

It will be recalled that the domestic oil price schedule in the *Memorandum* soon proved to be too high, as world oil prices began to weaken in 1983. Similar problems arose with domestic natural gas prices. The upshot was an amendment to the agreement for the eighteen-month period starting July 1, 1983. Alberta agreed to modify the schedule to the lesser of (i) 65 per cent of the Btu equivalent of the blended oil price at Toronto, less transportation charges and COSC, or (ii) the level given by the increases of \$0.25/Mcf as previously agreed upon. The implication was that the NGGLT would gradually decrease as the border price rose but was not matched by the rises in Toronto city gate prices (i.e., at 65 per cent of crude costs). By February 1, 1984, the NGGLT had fallen to zero, so that the Alberta border price was governed by the 65 per cent rule. In fact, from February 1984 on, Alberta and Ottawa agreed to keep the Alberta border price at \$3.00/Mcf, which held until November 1, 1986, and gas price deregulation. (The Toronto city gate price changed slightly, as Table 12.3 shows, due to changes in transmission tariffs and COSC.) The one-year lag in deregulating natural gas prices as compared to oil prices (November 1986 opposed to June 1985) meant that gas prices were above Btu parity with crude in Toronto in 1986.

The price regulations in place from 1975 to 1985 held domestic Canadian natural gas prices below natural gas export prices and below Btu equivalence with imported (and domestic crude) in central and eastern Canada. Within Alberta, prices were held even lower for consumers from 1975 through 1995 under the *Natural Gas Pricing Act*. The mechanism in this case was not reduced payments to natural gas producers but a subsidy from general tax revenues that was paid to buyers of Alberta gas (largely to natural gas distribution utilities).

Section 2 of this chapter provided information on the process of natural gas deregulation, which occurred November 1, 1986, against a backdrop of high gas reserves to production ratios, significant excess deliverability with spare capacity both in the field and in transmission facilities, and a high degree of concentration on the buyers' side of the market. The Alberta government and producers were particularly concerned that 'excess supplies' and oligopsony would force gas prices down to unreasonably low levels. There was widespread feeling that the market might require considerable guidance if it was to evolve in a smooth manner to effective competition; expressed in other terms, judicious regulation might be an essential ingredient of the transition to a deregulated natural gas market.

Naturally, much attention focused on TCPL, which had been seen as a near-monopsonist buyer of Alberta natural gas in the years immediately before price regulation. The opening up of export markets offered more competition, and several new large buyers and large sellers of natural gas offered potential competition to TransCanada; these included the Alberta Petroleum Marketing Commission, which had been set up by the Alberta government to handle the sale of the oil and gas from Crown lands during the years of regulated prices. Companies such as Pan Alberta and ProGas had also been controlling natural gas supplies. TransCanada's decision, at the start of 1986, to separate transmission and gas trading activities, with the creation of WGML as the natural gas buyer and seller, helped clear the way to more open access to TCPL pipeline facilities.

During the transition year, November 1, 1985, to October 31, 1986, direct sales were made at prices negotiated between producers and large industrial gas users; and several Competitive Marketing Programs allowing system gas sales to offer competitive discounts were put in place. (System gas refers to the gas bought and sold by a transmission company as a demand and supply aggregator.) WGML, the marketing arm of TCPL, renegotiated sales contracts with the four major natural gas distributors in eastern Canada. These two-year contracts offered residential and small commercial customers an immediate discount of \$0.21/Mcf off the \$3.00/Mcf frozen Alberta border price, followed by price stability over the contract term. Price flexibility was provided by allowing distributors to match direct sale prices in their respective industrial markets. These contracts could result in substantial discounts off the Alberta border price. On the regulatory side, the NEB ruled that the TCPL

system should be accessible to all users and ordered changes to TCPL's tariffs to open up the pipeline (NEB, 1986b).

At the provincial level, as noted above, provisions in Alberta's *Gas Resources Preservation Act* linking the award of removal licences to economic benefits accruing to Alberta were removed, only to be replaced by new latitude given to the Alberta Energy Resources Conservation Board to consider "other matters," including price, in evaluating gas removal applications. The *Alberta Arbitration Act* was amended to allow arbitrators to consider a much broader range of criteria than "commodity value" in redetermining Alberta field prices (a commitment made under the 1985 *Agreement on Natural Gas Markets and Prices*).

Thus, during the transition period, blocks of gas for industrial customers in eastern Canada were sold at prices below the prescribed Alberta border price of \$3.00/Mcf. Indeed, by September 1986, TCPL's average Alberta border netback on domestic sales was already \$2.64/Mcf.

With deregulation on November 1, 1986, the prescribed Alberta border price for natural gas leaving the province was abolished. Domestic (and export) gas prices were now negotiated between producers and purchasers. Although the environment was competitive, pricing information was not transparent as selling prices of Alberta natural gas were generally confidential.

Renegotiation of pricing provisions in TCPL's contracts with Ontario and Manitoba utilities resulted in creation of funds by TCPL to finance the discounting of gas. These funds distinguished between customer-specific funds, operated by WGML, and a utility-wide market fund. However, the latter was still to be disbursed on the basis of criteria established between the distributor and TCPL. There was a strong stipulation that the funds not be spread over all customers – they were to be devoted to meeting individual competitive circumstances. In short, they were to be used on a discretionary basis. These arrangements resulted in price discounts at the Alberta border varying from \$0.16 for small industrial customers to \$1.07 per thousand cubic feet for large industrial users (Ontario Energy Board, 1986).

Several provincial regulatory bodies developed policies concerning the cost of gas purchased by utilities under their jurisdiction and the availability of transportation services on local distribution systems.

The Ontario Energy Board's (OEB) decision in 1986 on the two-year gas-price agreement between WGML and Ontario distributors focused on the

board's jurisdictional mandate to determine rates for all customers in Ontario. In particular, the OEB wanted all natural gas purchased by utilities to be delivered to Ontario without being streamed to specific customers and customer groups.

As well, in early 1987, the OEB ruled that all natural gas consumers had freedom of choice in selecting gas supply purchasers; this ruling in effect broke the marketing monopoly held by distribution utilities (Ontario Energy Board, 1987). While the distribution companies retained their franchises on moving gas, the decision opened up the entire provincial market to increased gas sales competition by allowing purchasing entities, such as school boards, municipalities, hospitals, households, and small business co-operatives, to enter into contracts with any supplier. The effect of these arrangements would be to shrink distributor core market requirements for higher-priced system gas and to drive gas prices toward the levels large industrial users pay, as long as appropriate "removal permits" were available from the Alberta government and access to transportation capacity was enjoyed.

The Manitoba government also objected to the segmentation of markets under the 1986 renegotiated gas pricing agreements between WGML and the Manitoba distribution utilities.

Thus, downstream authorities do not like upstream price discrimination. Partly this is pique – if price discrimination were to take place, they would rather it be theirs than someone else's. But also it does represent a valid objection – that upstream discrimination is not consistent with fostering a competitive market since the essence of competitive price formation is that differentials for a homogeneous product cannot be sustained.

Producing interests, on the other hand, were very much worried that customers would abandon their traditional supply sources like WGML, which had signed contracts for gas purchase, and enter into new contracts at lower prices, effectively displacing the gas under long-term contract. This could be a general problem in a deregulated environment unless the longer-term production contracts were matched by longer-term sales contracts by the supply aggregators. However, it was a particular concern during the transition period when the high gas R/P ratio was being worked down. In 1988, Alberta's Minister of Energy and Natural Resources wrote to the Ontario Minister of Energy indicating that Alberta had no objection to "core" gas consumers entering into direct purchases in Alberta, so long as they did so in the form

of ten- to fifteen-year contracts (APMC, 1988 *Annual Report*). This could be seen as a way of ensuring that small-volume customers had access to gas supplies that might be essential to them. However, in an effectively deregulated market, it is more accurately viewed as a prohibition on small consumers covering their needs through an ongoing sequence of spot or short-term purchases. In the context of the Canadian gas market in the late 1980s, it would blunt somewhat the downward price pressures.

After deregulation, a wide range of natural gas prices at the Alberta border emerged, with spreads between short-term and long-term prices in excess of \$0.50/Mcf (EMR, 1987). This in part reflected the degree of market segmentation and volatility that existed. But note that price variations do not themselves indicate lack of competitive price formation or market imperfections. They may simply reflect different terms and conditions, such as manner of delivery (storage costs), reliability of services (continuous or interruptible supply), length of service (short- or long-term contracts), load factors, and the like. Price differences arising from such product variations do not constitute price discrimination.

In the late 1980s, TCPL system-gas contacts showed appreciable Alberta border price differentials between various categories of end users. Such a degree of price differentiation was not compatible with a competitive market-pricing regime unless sustained by variations in the service offered between customers. It is unlikely that differences in load factors or other service features between customers were sufficient to account for the degree of discount differentials shown. Moreover, the main basis for the award of discounts was the price of competitive fuels, a criterion that has little to do with service characteristics. It follows that such differentials do demonstrate market power – the desire to impose different prices on customers according to their ability to pay. In short, they represent monopolistic, not competitive, pricing practices. What lay behind TCPL's position?

TCPL occupied a very strong market position through WGML. But the dominant supply position of TCPL created serious problems for the company, with weak gas markets eroding the take-or-pay position of Canadian gas purchasers.

The legacy of take-or-pay arrangements was particularly serious for TCPL since it had entered into area-purchase contracts committing the company to purchase a proportion of all reserves developed in a relatively large geographical area. For example, TCPL's contractual purchase obligations during the 1977

contract year totalled 1.3 Tcf. Although the company had not signed any new contracts by 1986, contractual obligations amounted to some 2 Tcf. The take-or-pay wedge developed because gas supplies increased just as markets were levelling off. (As Table 12.1 shows, Alberta's production in 1983 was less than in 1978.) By the early 1980s, TCPL could not meet its take-or-pay obligations, which were then taken over by a consortium of banks. Under the negotiated TOPGas (the acronym stood for take-or-pay gas) agreements, the principal on monies paid to producers was recovered by TCPL through the sale of prepaid gas and transferred to the TOPGas consortium. Producers enjoyed any surplus between the ongoing gas price and the (initial) price received under the TOPGas advances. However, if the selling price was less than the initial price, producers were liable for the difference, and TCPL had the right to make up any deficiencies by retaining monies from other gas deliveries by producers. But in the event that producers default on repayments of the principal, TCPL was liable to the TOPGas consortium for up to \$355 million. Recovery of the principal was on a first-incurred/first-recovered basis. For example, prepayments for gas made in 1979 were recovered before prepayments made in 1980. The 1987 recovery of prepayments would appear to have been based on advances made to producers in the 1979/80 contract year. These advances were predicated on prices of about \$1.70/Mcf (at the gas plant gate exit).

The TOPGas prepayment schedule had implications for netback prices from eastern markets requiring approval by TCPL's TOPGas producers. Such prices will tend to be sticky since producers were liable for any deficiencies on the sale of prepaid gas. Thus, TOPGas producers and TCPL would be reluctant to indulge in price cutting unless compelled, and especially not in a way that would involve reducing prices to all customers – the competitive market solution under surplus conditions.

In contrast to the position of system-gas producers and TCPL, consuming interests in eastern Canada sought non-discriminatory prices, prices at the city gate that did not distinguish between end-use customers except insofar as they reflect different terms and conditions of sale. Ontario dismantled the gas-marketing monopoly previously conferred on its gas utilities. Manitoba initially sought to take action by purchase of the provincial natural gas utility and delegation of buying and selling gas solely to a Crown corporation to provide one city gate price for natural gas. After a change in government, these intentions were dropped.

As was noted at the end of Section 2, the Alberta government conducted a rearguard action to hold up prices. The mechanism was the imposition of pricing and volume conditions on gas removal permits. A 'ghost' floor price of \$1.45/Mcf was said to be held; volume restrictions tended to preclude all but large individual customers making deals with producers. And beginning January 1, 1988, royalties were based on reference rather than actual prices, with the intention of discouraging discount sales and preserving reserves. (Under this provision, royalties are assessed on the higher of the actual price or 80 per cent of the average Alberta field price.) Alberta required long-term permits for core customers seeking gas-removal permits, and such permits were not given for any volumes that displaced TCPL/distributor contracts prevailing before the October 31, 1985, federal-provincial Gas Agreement.

The Alberta permit-removal conditions remained in place until 1995. In that year, the government also moved for the first time to allow domestic Alberta core gas users to enter directly into gas-purchase contracts with marketers or producers. As argued in Section 2, by 1995, Alberta was part of an integrated North American natural gas market with a large number of gas producers, interacting with many more gas purchasers than in the past, and an even larger number of potential purchasers. The gas-trading and transmission activities of the major pipelines had been largely separated ('debundled'), and access to pipeline facilities made more readily available to all shippers. Natural gas price exhibited significant flexibility, including a large volume of gas traded on a spot basis or tied to spot prices with only a month's lag. As noted above, since 1986, there has been a significant growth in natural gas storage capacity, both in producing and consuming regions. This began to dampen the seasonal swings in natural gas prices and to allow production, gathering, processing, and pipeline facilities to operate at closer to capacity throughout the year, thereby reducing the costs associated with spare capacity. (Higher annual throughput allows fixed charges to be written off over more units of output, effectively reducing the cost of shipment.)

The change from the rigid long-term contractual world of the 1960s could hardly be more complete.

2. Export Pricing

As early as 1907, in the *Exportation of Power and Fluids and Importation of Gas Act*, Ottawa had specified that natural gas should not be exported without a licence

or at a price lower than it was sold for in Canada under similar sales conditions. (See McDougall, 1975, chaps. 5 and 6, for a review of gas pipeline and export issues prior to 1970.) Section 83 of the 1984 *National Energy Board Act* re-entrenched this concern, giving the NEB responsibility to ensure that natural gas export prices were “just and reasonable in relation to the public interest.” In the gas export applications that the NEB approved in the 1960s, the main emphasis was put on the surplus tests discussed in Section 2 above, with the board generally accepting the negotiated prices. In 1967, the Federal Power Commission (FPC) in the United States disallowed prices that Westcoast Transmission and El Paso Natural Gas had renegotiated in a gas-export contract. (Prices charged by Westcoast in the original contract of 1957 were lower than those charged to Canadian customers; McDougall, 1973.) As was summarized in Section 2, the NEB in turn enumerated three formal criteria that would be applied to judging the reasonableness of prices in gas-export contracts (NEB, 1967, p. 3-19):

1. the export price must recover its appropriate share of the costs incurred;
2. the export price should, under normal circumstances, not be less than the price to Canadians for similar deliveries in the same area; and
3. the export price of gas should not result in prices in the United States market area materially less than the least cost alternative source of energy.

The first two tests established a floor price; the third was more in the nature of a price ceiling or a target price. In 1970, the board elaborated on the second test, suggesting that the export price should not be less than 105 per cent of the price in the domestic market area adjacent to the border where the gas was sold (NEB, 1970). McDougall (1982) points out that in both the Westcoast export case of 1967 and in the Alberta and Southern export application of 1970, the NEB acknowledged that the third of these tests did not appear to be met with alternative energy sources costing more to energy users in the export market than the Canadian gas.

The contradictions here foreshadow the gas pricing issues that became central in the early 1970s. The third test clearly points to a commodity value pricing criterion. The question of contractual rigidity also enters. For instance, there is obviously no guarantee that a contract with a relatively rigid price and small escalations will pass the third test after a

number of years, even if it did when signed. Moreover, gas pipeline companies may have been reluctant to sign much higher prices on new contracts than old, especially if older contacts had most-favoured-nation clauses, or if they fed into higher prices as well on domestic contracts that domestic consumers and public utility boards would have been reluctant to accept. There were also regulatory problems in that the FPC was reluctant to approve imports to the United States at gas prices appreciably higher than interstate U.S. gas prices, which had, since 1954, been set by the FPC on a ‘cost of service’ basis. By the late 1960s, however, it was becoming evident that the FPC had set such prices too low. (This, of course, helps explain why the cost of alternatives to Canadian gas might exceed prevailing interstate prices in the U.S. natural gas market.)

Tensions with respect to natural gas export pricing were becoming apparent by the early 1970s. As with so many other energy questions, rising OPEC prices brought the issue to the boil. Since the NEB had ruled in 1971 that no exportable surplus existed, the question was not about the suitability of price in new gas export applications being considered by the board. Rather, it was what should be done about prices on previously approved exports. Contracts were being renegotiated, but the Canadian government felt driven to take action.

In July 1974, the NEB submitted a report on natural gas export pricing. This followed from a 1970 government order that “where in the opinion of the Board there has been a significant increase in prices for competing gas supplies or for alternative energy sources the Board shall report its findings and recommendations to the Governor in Council” (NEB, 1974a, p. 2-1); the government could in turn order increases in the gas export price. The NEB recommended a gas export price of at least \$1.00/Mcf, which the government ordered on September 20, 1974, effective on gas exports January 1, 1975. The same price applied to all exports; as the board said “considering that in all cases the border price has fallen well below the Board’s estimate of the current value of the gas, it would seem that a major increase in price to a uniform border price for all export licenses is appropriate to the circumstances” (NEB, 1974a, p. 5-28). In determining the value, the board looked to “commodity values” in main export markets, noting that these values would differ in different markets. “While the Board relies primarily on the weighted average estimate of the commodity value of the natural gas, it has also used more approximate but more readily available measures based on prices

of crude oil and no. 6 fuel oil” (NEB, 1974a, pp. 17–18). (One small export permit to Minnesota (GL-29) was consistently given a lower export price on the grounds that the buyer – a pulp mill – would otherwise be likely to switch from Canadian gas to coal.)

Until July 1983, gas export prices continued to be set at a uniform border price by the Canadian government at prices based on recommendations by the NEB. Alberta and other producing provinces concurred in this arrangement. Unlike crude oil, the excess of gas export prices over domestic prices flowed back to the producing provinces. After 1975, Alberta (the APMC) allocated these funds across all Alberta natural gas producers, so that those companies lucky enough to have sold gas under contracts destined for export markets did not solely benefit from the higher export prices. In its March 1975 to April 1977, reports on natural gas export prices, the NEB shifted from a “commodity value” approach to a “substitution value” or “replacement value” emphasis, where the value of Canadian gas exports was based on the cost of a unit of energy delivered to Toronto in the form of imported crude oil (NEB, 1975a, pp. 4–5). The NEB also noted (NEB, 1981a) that the U.S. government requested that Canada apply uniform border pricing on gas. Table 12.2 shows changes in the uniform border price. In 1975 and 1976, the price was set in Canadian dollars; after that U.S. dollar pricing was utilized.

On September 21, 1979, U.S. Secretary of Energy Duncan sent a letter to Canada’s Minister of Energy, Mines, and Resources proposing a “discounting pricing mechanism.” The NEB argued that this was not in Canada’s interest at the time but the NEB was prepared to review the need for discount pricing in the future, particularly if export markets became scarce at existing prices – a harbinger of later developments and perhaps an implicit admission that there is no fixed relationship between oil and gas prices.

A gas-pricing agreement called the Duncan-Lalonde formula was reached March 24, 1980, between the U.S. and Canadian governments. Under the agreement, the United States accepted the oil price substitution formula for the pricing of Canadian natural gas exports. In return, Canada agreed to certain price-increase deferral arrangements. Later in 1980, the NEB deferred two increases in the export price of gas called for under the substitution formula, amounting in total to some (US)\$0.75/10⁶ Btu. This price plateau was prompted by a sharp decrease in Canada’s natural gas exports to the United States. In April 1980, U.S. gas distributors took only about 57 per cent of gas

available to them; their average take in 1979 had been about 90 per cent.

On April 1, 1981, the NEB announced that the Canadian border price would rise to (US)\$4.94/10⁶ Btu (see Table 12.2). This was in response to further increases in world oil prices but did not impose full oil substitution value. Partly induced by depressed gas export sales, the federal government waived an October 1, 1981, export gas price increase. Other contributing factors were a desire to avoid aggravating already-strained energy relations with the United States and a desire to maintain momentum to remove legislation hampering the Alaska Highway Natural Gas Pipeline Project.

In response to declining markets, the Canadian government reduced the export price from (US)\$4.94/10⁶ Btu to (US)\$4.40/10⁶ Btu in April 1983. However, it soon became apparent that this decrease was not enough to stimulate export demand. Therefore, in July 1983, a volume-related incentive price of (US)\$3.40/10⁶ Btu was adopted, but the kicker was that it could only apply to volumes exceeding 50 per cent of those authorized under existing licences or to volumes exceeding actual 1982 sales, whichever was lower. To some degree, the two-tier system was little more than a sympathetic gesture, but it did demonstrate a less rigid attitude on the part of the Canadian government.

In July 1984, the Canadian government adopted a more flexible policy, allowing negotiated price contracts – subject to regulatory approval. Approval depended on satisfaction of certain side conditions, including: the border price must not be less than the Toronto city gate price (then (Cdn)\$3.15/10⁶ Btu); and the export price must at least equal the price of competing fuels in relevant U.S. markets (shades of 1967 price tests 2 and 3). Under this policy, exports of Canadian gas began to recover. By early 1985, about 95 per cent of existing export contracts had been renegotiated, and several long- and short-term new contracts had been drawn up under the July 1984 NEB provisions.

The federal–provincial natural gas pricing agreement of October 31, 1985, contained a new set of export price criteria (Canada, *The Agreement*, 1985, p. 4).

1. The price of exported gas must recover its appropriate share of costs incurred;
2. The price of exported natural gas shall not be less than the price charged to Canadians for

- similar types of service in the area or zone adjacent to the export point;
3. Export contracts must contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;
 4. Exporters must demonstrate that export arrangements provide reasonable assurance that volumes contracted will be taken;
 5. Exporters must demonstrate that producers supplying gas for an export project endorsed the terms of the export arrangement and any subsequent revision thereof.

Of these criteria, the first was straightforward in the sense that it reverted to the original 1967 provisions. The second criterion effectively replaced the Toronto city gate floor price with regionally variable adjacent domestic prices. The third criterion repeated the earlier July 1984 provision and echoed the flexibility demanded by U.S. import regulations. The fourth criterion was delightfully vague but reflected the demise of firm take-or-pay arrangements (and repeated a July 1984 clause). The fifth criterion was to ensure that producers were aware of commitments to which they subscribed!

Even more drastic steps towards export price deregulation were taken by the Canadian government on October 26, 1986. Federal Minister of Energy Marcel Masse revoked the specific contractual gas export price regulations and terminated the volume-related incentive pricing program. In terms of export pricing policy, Mr. Masse simply requested the NEB to monitor export contracts and prices and to provide advice. These latest policy changes seemingly left export prices wide open. However, genuflections were still made towards not exporting Canadian gas at prices less than those in domestic markets.

The transition to freer natural gas markets in North America at a time when major producing regions such as Alberta held excess deliverability raised some of the same controversies in export markets as in domestic markets. Some of the concerns related to pipeline regulations, where U.S. and Canadian approaches often differed. As occurred in Manitoba and Ontario, there were also pushes by U.S. consuming interests (particularly the California Public Utility Commission) to allow core gas users and utilities tied into long-term contracts access to the lower prices of new spot and short-term contracts. Alberta's permit removal conditions made this difficult and potential negotiation between the governments,

pipelines, and supply and demand aggregators were necessary to work out adjustments that largely maintained existing authorized export arrangements while allowing greater price flexibility.

By 1995, export pricing issues were effectively covered by the NEB's market-based procedure, discussed above. The board presumably monitors prices and sees information on prices as one component of the hearings into long-term (greater than two-year) export licences. However, the usual presumption, unless there is clear evidence to the contrary, is that freely negotiated export prices are "just and reasonable in the Canadian interest." In its 1996 review of changes in natural gas markets over the previous decade, the board stated (NEB 1996, 9. x) that:

... the current functioning of the Canadian natural gas market is consistent with the basic premise of the MBP. The market is generally working so that the requirements of Canadian natural gas buyers are being satisfied at fair market prices. There are no barriers which would prevent major gas buyers from accessing competitively-priced supplies from western Canada. The eastern Canadian LDCs continue to purchase almost all of their gas requirements from western Canada even though they have established a large import capacity from the U.S. Gas prices are set through the operation of competitive markets, and gas production and marketing are very competitive businesses which provide maximum choice to gas buyers. Finally, the available evidence indicates that domestic gas buyers have been able to obtain Canadian natural gas supplies on terms and conditions at least as favourable as those available to U.S. buyers.

3. Free Trade (FTA and NAFTA)

Chapter Nine, Section 5, reviewed the energy clauses of the Canada-U.S. Free Trade Agreement, and the successor NAFTA incorporating Mexico into the free trade zone. The main provisions relating to natural gas were discussed there and will not be repeated. A main impact of the FTA and the NAFTA is to commit Canada to an integrated North American market for natural gas without any discriminatory pricing provisions, except in clearly defined circumstances. Export surplus policies for gas are allowable, but subject to

the “proportionality” provisions in times of supply crises. As discussed in Chapter Nine, these ensure that in times of crisis export customers are ensured that their access to gas is not unduly restricted, so that they have proportionately as much access to supplies before and after the crisis on the same commercial terms as domestic energy users. (An indication that the proportionality provisions do not apply under normal market conditions can be seen in the fact that they did not apply between 2007 and 2009 when the U.S. share of Alberta natural gas production fell from 53% to 44%.) As noted above, provincial legislation in Alberta allows the government to shift ex-provincial sales to Alberta consumers in the event of a market disruption. It is not clear how this provincial regulation would operate under the federally negotiated NAFTA.

In addition, under the free trade agreements, national governments retain their jurisdiction over a number of matters where they have traditionally exercised power, such as in the authorization of pipelines.

B. Analysis of Natural Gas Pricing Regulations

In this section, the natural gas pricing regulations are analyzed. We do not discuss the free trade agreements or fiscal take as they apply to natural gas because the comments we would make are essentially the same as the ones made for crude oil in Chapters Nine and Eleven.

1. Domestic Pricing

Formal price regulation began in 1975 and continued through 1986 in the domestic market. Throughout this time span, domestic prices were held below export prices and values, though the differences became less pronounced with the adoption of the Volume Related Incentive Plan in July 1983 and the abandonment of fixed export prices in November 1984. As a first approximation, one might argue that the natural gas policy had much the same effect as the oil price regulations policy over the same period: by holding domestic prices below export prices, and limiting export sales by a licensing program, the policy transferred revenue from domestic producers and foreign consumers to domestic consumers. (See Figure 9.1 for graphical analysis of these effects.) Unlike the oil case, the revenue generated by an export price higher than the domestic price went to natural gas producers instead of governments. In efficiency terms, the key aspect is that the domestic price was held below

the free market value of the gas, which would reflect the value in U.S. markets where marginal gas values were strongly affected by OPEC oil prices. As a result, Canadian producers failed to produce some gas that had a cost less than the hypothetical market value, and consumers used gas that possessed a marginal value to them less than this market value.

This initial discussion of the effects of natural gas price regulations requires some qualification. One difference with the crude oil analogy is that gas export controls were in place before price regulation, whereas crude oil export volume limitations were an integral part of the oil-regulation policy. A second is that crude oil price regulation was already in place in November 1975 when domestic gas prices were first fixed by the government.

We have touched on a familiar point: to assess the impact of a policy, it is necessary to specify clearly what would have held in the policy's absence. Our preference is to view the natural gas price control policy as part of a broader energy policy, which, beginning with OPEC price rises in late 1973, elected to hold Canadian petroleum prices – for both oil and natural gas – below international market levels. The general effects of the earlier paragraph would hold.

Alternatively, the natural gas pricing policy might be viewed against a backdrop of two other policies – the gas export surplus policies discussed in Section 3 of this chapter, and the oil price and export controls that commenced in 1973. It is more difficult to assess the natural gas pricing regulations against this backdrop, but some sort of gas export pricing regulations makes sense. Recall that the export surplus requirements tended to generate relatively high R/P ratios for gas, and fed into an oligopsonistic market situation, particularly after 1970 when export permits were denied. Partly as a result of the regulatory environment – the gas export policy plus pipeline and natural gas distribution utility regulations – natural gas domestically was bought and sold under long-term contracts with relatively rigid pricing terms. By the early 1970s, it was widely accepted that Canadian natural gas prices were lower than they would have been had there been unrestricted access to the U.S. market and had contractual terms been more responsive to rising prices of oil, which was the main competitor to natural gas in many markets. Largely at the instigation of the government of Alberta, domestic gas contracts were being revised to higher prices and more frequent price renegotiation.

Two questions arise. The first is hypothetical: how would Canadian gas markets have evolved in the 1970s

in the absence of the domestic price regulations? The second is what effect the price regulations had relative to this hypothetical situation?

If a definite answer to the first question is required, it must be that no one knows how gas markets might have changed in the 1970s. However, if a more speculative response is allowed, the changes in the early 1970s could be seen as the first step toward a freer more competitive natural gas market; but real competition on the buyer's side of the market hinged on things that had not yet occurred – opening the market to U.S. purchasers and removing TCPL as an oligopsony buyer-shipper. In the absence of these changes, oligopsonistic power remained and price renegotiation was being driven mainly by Alberta's insistence on "commodity value." The domestic price controls adopted "commodity value" as a touchstone of sorts, with domestic gas prices tied to domestic crude oil prices in Toronto, at first with 80 per cent of Btu parity, then, after 1980, with 65 per cent. Market experience since 1985 suggests that the resultant prices overvalued natural gas relative to crude oil. After 1986, natural gas prices fell relative to crude and stayed at a lower relative level than under price controls until the year 2001. (See Table 12.1, Column 10.) That is, natural gas was somewhat overpriced during the price-fixing era, relative to what freer competitive market conditions would likely have generated. This would have been to the advantage of Alberta gas producers and the Alberta government and to the disadvantage of natural gas consumers. (It is notable that the policies to fix natural gas prices under the NEP were accompanied by measures to stimulate natural gas consumption beyond the level that prices generated. Ottawa indicated that the delivered price of gas in new markets east of Montreal would be held to the Toronto city gate price, and Alberta and Ottawa both agreed to contribute to a market development fund for natural gas.)

In conclusion, we would argue that the impact of the price-regulation period was to hold natural gas as well as oil prices lower than they would have been (assuming that steps were also taken to free up natural gas exports and increase competition in the gas market). However, the price of natural gas was held at a relatively higher level under regulation than they would have been without the energy price controls.

2. Export Pricing

Prior to 1975, and after 1984, the export price of natural gas was subject to indirect influence through the

NEB's export-licensing procedures, which required the NEB to ascertain whether export prices were "just and reasonable." For the most part, the NEB has applied this by seeing whether the export price is at least as high as the price paid by customers on the Canadian side of the border point. McDougall (1973) and McDougall (1982) point out that this condition was not met in the mid-1950s contract between El Paso Natural Gas and Westcoast Transmission until the contract was renegotiated in the mid-1960s. More problematic was a different pricing criterion, the third price test as formalized by the NEB in 1967 – that the export price should reflect the cost of alternatives to consumers in the export market, a 'commodity value' criterion. One could argue that the border price comparison sets a price floor for export of gas, but the alternative fuel comparison sets a price ceiling. So long as the ceiling is as great as the floor, the gas export should be allowed (i.e., so far as price is concerned), but it is in Canada's interest to obtain the ceiling price amount.

In a well-functioning, effectively competitive market, one expects that the two prices will converge. High values in the export market will draw incremental suppliers, serving simultaneously to reduce the marginal value in the export market, increase marginal costs and prices in the supply centre (as new sources of gas are tapped), and increase marginal values in domestic markets (as gas is diverted to the export market). This is how deregulated North American gas markets evolved after the mid-1980s.

However, this was not true of the North American natural gas markets in the earlier period. By the late 1960s, it was apparent – and recognized by the NEB even as it approved specific export licences – that the export price was lower than the price of the alternative non-gas energy sources in the U.S. market (McDougall, 1975, chap. 5). The board argued that the exports were in the Canadian interest since the second price test (a price higher than the adjacent Canadian one) was passed. Why was the third price test not insisted on? Three reasons suggest themselves. First, while the "commodity" pricing approach appears eminently reasonable, it turns out to be very difficult to apply and often somewhat ambiguous, for reasons discussed above. It is not as easy as one might initially assume to determine that export values exceed export prices. Second, prices in export contracts appreciably above prices in purchase contracts for domestic sale imply different netbacks for producers and raise concerns of fairness. (Which producers are lucky enough to get the higher netbacks? Netbacks accrue to

producers because the pipeline-purchasers are regulated on a cost of service basis.) Market forces did not eliminate the difference in netback values because the export surplus regulations blunt the forces of foreign demand. (In fact, the purpose of the removal permit restrictions is precisely to allow lower domestic than foreign marginal values!) Third, Canadian natural gas was demanded in the United States in part because of the regulation-induced shortages of interstate natural gas; customers in California and the U.S. Midwest had to turn either to Canadian gas or to more expensive non-gas substitutes. But, for political reasons that are easy to understand, the FPC was very reluctant to admit natural gas imports at prices higher than they would give to U.S. producers. Thus, while U.S. customers may have been willing to pay more for Canadian gas, regulatory permission for imports probably would not have been forthcoming from the FPC in the 1960s.

As with so much else in the world of energy, the OPEC price revolution starting in 1973 led the parties involved to change their mindsets. The potential export value of natural gas, in a world of high oil prices, was evident to Canadians. The advantage of Canadian gas over OPEC oil was apparent to the United States (though the price of Canadian gas relative to OPEC oil was obviously a consideration).

How effective was the Canadian export pricing policy for 1975 through 1986? The question has two parts. Was the price level selected by the Canadian government (on the advice of the NEB) the best one for Canada? Was a uniform border pricing policy appropriate? The latter question is important because the shift to a uniform border price was really an exercise in price discrimination. Readers may wonder how charging the same price to foreign customers can be price discrimination. The reason is that the cost of accessing different border points differs, with lower costs to border points nearer the producing region (i.e., Alberta). Hence non-discriminatory pricing implies lower border prices the closer the export point is to Alberta. Uniform border prices implies relatively higher prices close to Alberta and relatively lower prices further away; given any average export value, uniform border pricing discriminates in favour of U.S. customers who get their gas from the border points more distant from Alberta.

Our evaluation draws extensively on Watkins and Waverman (1985), who ask whether the Canadian natural gas pricing policy appears to have been more like monopolistic (oligopolistic) or effectively competitive behaviour. They start from the premise that there is a potential for monopoly-like profits on Canadian gas exports to the United States. In 1983, while Canadian

gas met only 4 per cent of total U.S. gas use, “in the Great Lakes and Rocky Mountain states it reaches about 6 per cent, while for the West coast region the proportion is as high as 12 per cent” (Watkins and Waverman, 1985, p. 416).

Watkins and Waverman assume that Canada could act to increase the returns to Canadian gas producers (and governments as rent collectors) by a dual price system in which export prices are at a higher level than Canadian prices. (Note that a dual price system is clearly inefficient if Canada does not possess significant market power, since lower-valued domestic consumption is then being encouraged at the expense of higher-valued export revenues.) Of course, short-run market power is often higher than long-run power, for example, if competing transmission systems are operating at capacity so that more domestic U.S. gas cannot readily flow into a market as Canadian gas prices increase.

The Canadian gas export pricing policy of 1975–83 is consistent with monopolistic behaviour by Canada. Watkins and Waverman conclude, however, that the natural gas policy did not maximize Canadian welfare in part because Canadian prices were fixed at artificial levels domestically and in part because export prices did not fully fit a monopolistic model. The latter assessment involved a number of comparisons. For instance, they note (p. 422) that “a monopoly seller would have ... aligned export gas prices to the highest cost source of gas in the United States market – the so-called Section 207 gas under the *Natural Gas Policy Act* (NGPA),” but this was not the criterion used by the NEB. (After 1977, it will be recalled, the NEB looked at a substitution or replacement value of Btu parity with crude in Toronto, though even here the government, especially after 1980, did not impose the full substitution value.) Moreover, Watkins and Waverman find that the pattern of price discrimination implied by uniform border pricing does not accord with that expected from an effective monopolist. Table 12.4 includes some relevant information. Watkins and Waverman calculated netback values for natural gas exports across various border points; these are Alberta netbacks equal to the average selling price of gas at the export point less transmission costs from the Alberta border to the export location. In Table 12.4, these netbacks are shown as a proportion of the netbacks at the Emerson, Manitoba, border point for two years, 1968 and 1983. The fourth column shows an estimate of the elasticity of demand for natural gas by end-users in that regional market in the year 1983.

The 1983 netbacks and elasticities are relevant to the uniform-border-pricing period. A monopolist

Table 12.4: Natural Gas Export Pricing: Netbacks and Elasticities

<i>Export Border Point</i>	<i>U.S. Markets Served</i>	<i>Alberta Netback Relative to Emerson</i>		<i>Estimated Price Elasticity of Demand</i>
		<i>1968</i>	<i>1983</i>	
		Huntingdon, B.C.	Pacific N.W.	
Kingsgale, B.C.	California	1.005	1.002	-1.31
Aden/Cardston, Alta.	Montana	1.202	1.020	-1.02
Monchy, Sask.	N. Central	n/a	0.984	-1.02
Emerson, Man.	Great Lakes	1.000	1.000	-1.02
Fort Francis, Ont.	Great Lakes	0.852	0.951	-1.02
Cornwall, Ont.	New York	0.623	0.866	-1.02
Phillipsburg, Que.	New York	0.585	0.849	-1.07

Notes: Monchy, Saskatchewan, opened as a border point in 1982. The Emerson price was \$0.183/Mcf in 1968 and \$5.09/Mcf in 1983.

Source: Watkins and Waverman (1985), Tables 1 and 2.

exercising effective price discrimination would take advantage of variations in demand responsiveness by charging relatively higher prices in the markets with the lowest price elasticities of demand. (In these markets, any given price rise generates a smaller percentage decline in sales.) However, as Table 12.4 shows, there was no tendency for netbacks to vary with the elasticity of demand.

Table 12.4 shows that the range of netbacks on natural gas exports was much narrower under the uniform-border-pricing policy of 1983 than in 1968. The wide spread of netbacks in 1968 is interesting. One would expect that an effectively competitive market, with price flexibility in contracts, would tend to exhibit identical netbacks on all sales. (Strictly speaking, the field netbacks should equalize, but, since most gas went through one of the straddle plants and NOVA used a postage stamp tariff, Alberta border prices and field netbacks should exhibit the same differences.) The netback variations in 1968 are consistent with an oligopsonistic market structure with an overhang of excess supply as characterized the market under the 1960s policies on export removal.

But how would we characterize Canada's export pricing policy from 1975 to 1983 if it was neither monopolistic nor effectively competitive? Watkins and Waverman (1985) suggest that some form of oligopoly market provides the best fit. Specifically, they suggest that a model with "zero conjectural variations"

provides a good fit. In this model, the decision-makers take other sellers' prices as fixed. Canadian authorities after 1977 (in setting prices for gas exported to the United States), focused on Toronto crude prices, rather than on U.S. natural gas prices, essentially treating U.S. gas prices as fixed. In this model, the oligopolistic supplier "will absorb transportation costs by accepting decreasing delivered prices as the distance to market rises (Phlips, 1983, p. 43)" (Watkins and Waverman, 1985, p. 422). Uniform border pricing of a good such as natural gas, with output concentrated in Alberta and Northwest B.C., exhibits just such a pricing pattern. Certain other features of uniform border pricing may have appealed to the NEB and the Canadian government. It was "easily computable" and readily changed and did not require detailed information on price elasticities; moreover, a uniform price "could be sold as 'non-discriminatory' (which it wasn't)" to U.S. authorities; and it did generate somewhat higher profits for Canada than sales at domestic Canadian prices would have (p. 424).

Overall, Watkins and Waverman give the Canadian natural gas export pricing policy a grade of B+ (p. 425). Canada could have charged higher prices to its benefit in the mid-1970s and probably should have charged somewhat lower prices in the early 1980s when exports fell to half of authorized levels. But the policy did generate higher gas revenues to Canada and did so without pushing U.S. authorities into retaliatory action.

A residual question remains. If a dual-price system for natural gas – low domestic prices and high export prices – was in Canada's interests in the 1970s and early 1980s, wouldn't it also be beneficial to the country after deregulation in 1986? Expressed in other terms, if Canada has some market power in U.S. gas markets, isn't it in the national interest to use that power? On the whole, deregulation, NAFTA, and the market-based export policy seem to argue against such an export pricing policy. In general, the exercise of market power in the pricing of a particular commodity by one country against a main trading partner is economically and politically dangerous since the trading partner may retaliate. There were special circumstances in the 1975–85 period in natural gas pricing that restrained U.S. impulses to retaliate. Most important was the wish of the United States to reduce reliance on OPEC oil, while seeing the OPEC price as setting the opportunity value of energy in general. (The confusion in U.S. natural gas markets after decades of FPC price regulation left no obvious U.S. natural gas reference price.) Accordingly, it was quite acceptable to U.S. authorities for Canada to

base natural gas export prices on OPEC crude oil prices, even while holding domestic gas prices lower. This unusual set of circumstances no longer exists. Moreover, it is arguable that the effective deregulation of U.S. gas markets has served to increase considerably the long-run elasticity of demand for Canadian natural gas in the United States, and hence to reduce considerably the scope for a dual-price policy.

C. Fiscal Take (Royalties and Taxes)

Chapter Eleven reviewed the conceptual basis for special taxation provisions governing the crude petroleum industry, as well as the characteristics of various types of taxes, royalties, and other mechanisms used by governments to capture economic rent or influence the behaviour of the industry. These conceptual arguments will not be repeated here. What follows is a brief summary of the major fiscal measures that apply specifically to the Alberta natural gas industry. Price controls, which may be used to capture and redistribute economic rent, were discussed above. The corporate income tax applies to total company operations, rather than natural gas specifically, and was discussed in Chapter Eleven. Bonus bids for petroleum rights cannot generally be ascribed specifically to natural gas as the bids are usually for petroleum rights including both oil and gas. However, as was noted in Chapter Eleven, Alberta has, on occasion, auctioned off leases or licences for natural gas alone from a specific formation. In 2008, the government announced that shallow mineral rights, above producing reservoirs, would revert back to the government for subsequent sale; this seems likely to involve mainly shallow gas deposits. The Petroleum and Natural Gas Revenue Tax (PGRT), the Petroleum Incentive Payments (PIP grants), and the Canadian Ownership Special Charges (COSC) of the National Energy Program (NEP) were also covered in Chapter Eleven; they applied to both crude oil and natural gas and will not be discussed further here. This leaves two fiscal measures specific to natural gas to be discussed: provincial natural gas Crown royalties and the federal Natural Gas and Gas Liquids Tax (NGGLT) of the NEP.

1. Alberta Crown Royalties

The Alberta government assesses a gross *ad valorem* royalty on natural gas produced from Crown leases, much as it does for crude oil. There has also been, since 1973, a Freehold Minerals Tax, which applies to

the more minor gas volumes produced from freehold leases in Alberta. As for crude oil, the government felt that the public, as well as private mineral rights owners, should benefit from the tremendous rise in the value of petroleum in the early 1970s. Tables 11.1 and 11.2 set out Alberta government petroleum revenues, including separate natural gas and NGL royalties from 1972 on. Prior to the mid-1970s, crude oil royalties were much higher than natural gas royalties, but after that gas royalties increased in relative significance, reflecting in part the rising value of gas relative to oil as seen in Table 12.1. In 1986 and 1988, natural gas royalties exceeded conventional oil royalties and did so every year except one from 1992 to 2008. In large measure, this reflects rising gas production and declining conventional crude oil output. By 2003, natural gas and NGL royalties were over five times higher than conventional oil royalties. However, in 2009, for the first time, oil sands royalties exceeded natural gas royalties and by a widening margin as natural gas production and prices fell.

The June 1, 1951, royalty regulations set a 15 per cent royalty rate for natural gas, with a minimum of \$0.0075/Mcf (which would apply if the price received for the gas was less than five cents/Mcf).

Effective April 1, 1962, the natural gas royalty rate was increased to 16 2/3 per cent, with the same minimum royalty as before. In addition, producers were allowed a Gas Processing Allowance, which was a deduction from the value of the gas to allow for any costs involved in processing the gas to remove sulphur or natural gas liquids. We shall not summarize all the details of regulations covering this Gas Processing Allowance, which proved to be rather complicated over the years. In effect, the allowance was designed to allow recovery of the costs for facilities that processed the gas. Most operators effectively contracted these processing services from operators of large gas-processing plants in the province and would claim an allowance on the basis of the costs of these large facilities. However, some gas producers built their own field processing plants and could claim a deduction on the basis of the costs of their plant. The process of calculating allowable gas-processing allowances became very complex as the number of processing plants rose and gas producers increasingly used a number of different facilities. Effective in 1994, Alberta simplified the regulations to base the Gas Processing Allowance on a provincial average processing cost, thereby removing the obligation for producers to file detailed statements documenting the various costs actually incurred on all the natural gas they produced.

On January 1, 1974, the province implemented a new natural gas royalty, which was a sliding-scale royalty based on the price of natural gas (and anticipating the forthcoming oil royalty regulations of March 1974, discussed in Chapter Eleven). There was a minimum royalty rate of 22 per cent, which applied when the price of gas was \$0.50/Mcf or less (\$17.75/10³ m³ or less). When the price exceeded this level, the royalty rate increased, with the royalty designed to capture a specific fraction of the higher revenue. A higher rate was assessed on 'old' gas, that discovered prior to 1974. Initially the royalty formulae were set up to capture 65 per cent of the 'additional' revenue on old gas when the average Alberta Market Price is above \$0.50/Mcf; on 'new' gas (gas discovered after December 31, 1973) 35 per cent of the higher revenue was collected as royalty.

The general nature of the natural gas royalty formula was unchanged from 1974 to 2008, but, as with crude oil, there were a number of adjustments over the years (Alberta Department of Energy, 2003, 2007a,b). For example:

- (1) the proportion of revenue above the minimum price taken in royalties was changed. On old gas it was reduced to 50 per cent in 1978, then 45 per cent effective April 1, 1982, and then to 40 per cent in June 1985 and 35 per cent in 1992. On new gas, the share of incremental revenue going to Alberta was cut to 30 per cent in June 1985. There were temporary further cuts in October 1986. Rates vary between 15 per cent and 30 per cent and were at an average rate of 20 per cent in 2005.
- (2) on July 1, 1978, a reduced royalty was introduced for low-output non-associated natural gas wells; if output was less than 600 Mcf/d (averaged over a month; this is 16.9 m³/day), the royalty rate was reduced in such a way that the royalty fell to 5 per cent as output fell to zero. In 1994, the low-output royalty was extended to associated gas from low-output crude oil wells.
- (3) With deregulation, natural gas pricing became much more diverse. As mentioned above, Alberta responded by specifying that gas revenue for royalty purposes must at a minimum be 80 per cent of the average Alberta field price in any year (effective December 1987). In 1994, the government decreed that a company could value all of the gas it sold at the company's average gas price, so long as this was at least 90 per cent of the average Alberta field price; if companies

did not elect to do this, they were to value gas at a 'reference' price that was the average price at the exit of gas plants. These modifications both offered some protection to the Alberta government in terms of minimum royalty receipts and also helped reduce the administrative costs to companies of calculating their royalty payments.

- (4) As of January 1, 1993, the gas royalty formulae were to be modified annually to allow for inflation, as seen in the GDP price deflator.
- (5) Effective in October 2002, natural gas also began to be assessed NGL royalties based on the NGL content of the gas.
- (6) In addition to a number of the incentive programs discussed in Chapter Eleven, there were several programs aimed explicitly at natural gas activities, in addition to the low-productivity allowance set out in (2). These included: a deep gas royalty holiday (1985); a royalty waiver on solution gas that was not flared (1999); a royalty credit for certain sulphur removal investments (1999); and a royalty credit on gas used in cogeneration projects (2001).

As was the case with conventional crude oil (Chapter Eleven), the fairness of the royalty share accruing to the province became an issue of concern as natural gas prices rose at the start of the new millennium. In 2007, the province commissioned a Royalty Review Panel, which issued a *Report* in September of that year. As was the case with crude oil, the panel found that Alberta collected a smaller share of the economic rent from natural gas than other regimes in North America and recommended a simplified royalty regime that would raise the anticipated government rent share from 58 per cent to 63 per cent (Alberta Royalty Review Panel, 2007, p. 7). The suggested royalty would remove the vintage distinctions and the special incentive programs and include a two-part royalty with sliding scales based on volume and on price, with the royalty rate varying from 2 per cent up to 50 per cent. (Alberta Royalty Review Panel, 2007, pp. 71–73).

In October 2007, the government announced its reaction to these recommendations (Alberta Department of Energy, 2007b). Effective in January 2009, there would be a new natural gas royalty that sounded close to what the panel had recommended: the vintage distinction would be eliminated and the royalty formula would have price and volume components, with rates ranging from 5 per cent to 50 per cent (the highest rate becoming effective at a price of

\$16.59/Gigajoule), and rates lowered for lower output wells. Although it had not been a recommendation of the Royalty Review Panel, the government announced that it would be implementing lower royalties for deep gas wells and 'lower-productivity' reserves, in recognition of their high costs. As was the case for conventional oil, Mintz and Chen (2010) found that, under these regulations, Alberta would have a 'marginal effective tax and royalty rate' higher than other provinces.

As was noted in Chapter Eleven, the new royalty regime occasioned criticism from industry and further study by the government. As with conventional crude oil, a 'transitional' option (up to January 1, 2014) for new wells deeper than 1,000 m was announced in November 2008, as was, in May 2010, a revised set of royalty rates, to be effective January 1, 2011. The new rates involved a larger reduction for natural gas than for oil. They maintained the 5 per cent minimum rate, but the highest rate was reduced to 36 per cent; there was, as in the 2007 plan, a separate ceiling of 30 per cent on each of the price and output components of the royalty. A 'depth factor' was incorporated into the output part of the royalty, reducing the rate for wells deeper than 2,000 m. The government expressed particular concern about the economic viability of deep gas reserves, culminating in a five-year royalty credit plan announced in late 2008 for gas wells deeper than 2,500 m. (This was in addition to the other incentive programs briefly outlined in Chapter Eleven.) For shallower gas wells, the minimum 5 per cent royalty would apply on low-output wells (60 Mcf/d or less) for prices as high as \$16.00/Mcf. A high-output well, of 1,000 Mcf/d, would not hit the ceiling royalty rate of 36 per cent until the price of gas was above \$6.50/Mcf. As was the case for crude oil, the new plan involved reduced royalties, compared to the pre-2009 regime, on lower-volume wells (below about 300 Mcf/d) and at lower prices (below about \$5.00/Mcf), but higher royalty rates for higher-output wells and at higher prices.

The prime impetus for the royalty changes was the desire for a new royalty regime as North American energy moved into a higher price environment, although, as noted in Chapter Eleven, the declining government rent share reflected in part the reductions taking place in corporate income tax rates. As discussed above, much higher than historical prices are far from certain; this is even more so for natural gas than crude oil, given the better geological prospects in North America for natural gas than oil, especially as large volumes of non-conventional gas prove

economic at relatively low costs. As seen in Table 12.1, natural gas prices in North America fell dramatically after 2008.

2. Natural Gas and Gas Liquids Tax (NGGLT)

The NGGLT was introduced by the federal government in its October 1980 budget as part of the National Energy Program. Since the size of the tax was intimately tied to the natural gas pricing provisions of the NEP, it was discussed above in the gas-pricing section. However, for the sake of completeness, we will briefly outline the main features of the NGGLT here, in the 'fiscal take' part of this chapter.

Prior to the NEP, the federal government had no specific fiscal measures assessed on natural gas. It did, of course, have its corporate income tax and, after 1974, natural gas royalties paid to provincial governments had not been deductible as a cost for the federal portion of the corporate income tax. (These issues were discussed in Chapter Eleven, with specific reference to crude oil.) Also, since 1973, the discrepancy between domestic and export prices for natural gas had not been set by an export tax (as was the case for crude oil), but rather by Ottawa directly fixing the export price.

The NEP introduced the NGGLT, which was to apply to all natural gas sales, including exports. (The application of the tax to exports was delayed until February 1, 1981, to allow the government to meet its obligation to the government of the United States to give ninety days notice before changing gas export prices.) The NGGLT was to be \$0.30/Mcf effective November 1, 1980, rising in three steps of \$0.15/Mcf on July 1, 1981, January 1, 1982, and January 1, 1983, to an ultimate level of \$0.75/Mcf.

In the NEP, Ottawa claimed that the stimulus for the NGGLT was the adamant refusal of the natural-gas-producing provinces to accept a gas export tax, even if Ottawa agreed to split the revenue with them. Ottawa argued that "there is no doubt of the federal government's constitutional right to impose export taxes on any commodity." However, it recognized "the strong opposition of Alberta and British Columbia to the gas export tax," and "is, therefore, not proceeding with a natural gas export tax." However, Ottawa did have to find additional revenues. "The Government of Canada lacks the revenues necessary to fulfill its national obligations. Some of these obligations flow from the same international oil crisis that provides growing revenues to the governments of Alberta and British Columbia." (Quotations from the NEP, p. 34.)

Hence, in Ottawa's view, the need for the new federal taxes on petroleum, the PGRT (discussed in Chapter Eleven) and the NGGLT.

Extensive negotiations between Ottawa and Alberta in 1981 led to the September 1981 *Memorandum of Agreement*. Alberta and British Columbia had been firm in their contention that a federal excise tax on natural gas (particularly exports) was a discriminatory attack on provincial natural resources, amounting to an attempt by Ottawa to override the constitutional provisions giving control of mineral resources to the provinces. In the *Memorandum of Agreement*, Ottawa preserved the right to set a natural gas export tax, but agreed to set the rate at 0 per cent; that is, the NGGLT was removed from natural gas exports. As discussed in the pricing section above, the NGGLT on domestic sales of natural gas would be set at the rate which would allow the Alberta border price to attain the levels agreed to in the *Memorandum*, given that the price of Alberta gas delivered to Toronto should reflect 65 per cent Btu parity there with crude oil. That is, the fixed rate NGGLT of the NEP was replaced with a variable rate NGGLT that depended on the petroleum pricing levels agreed to in the *Memorandum* and on the international price of oil. As it happened, by February 1984, the NGGLT had fallen to zero as international crude oil prices failed to rise to the levels anticipated. (Delivered prices of Alberta natural gas, at agreed-upon Alberta border prices, equalled or exceeded the 65 per cent Btu parity with crude in Toronto, so there was no room for a NGGLT.)

With deregulation of the oil market in 1985 (and the natural gas market with the 1986 *Halloween Agreement*), the special federal tax provisions of the NEP were dropped. Since then, Ottawa's revenue from natural gas production has, once again, derived essentially from the corporate income tax. Remember, however, that the federal corporate income tax is now a more effective rent-collection device than it was prior to 1972 since the depletion allowance has been phased out. As noted in Chapter Eleven, in 2002, the Resource Allowance was eliminated and provincial royalties on natural gas are now deductible as a cost.

5. Conclusion

Commercial production of natural gas began in the 1880s, when a water-directed well drilled by the CPR hit a gas deposit near Medicine Hat. From this

accidental birth, a major Alberta industry has grown. Five periods in the life of the industry can be discerned, though real-life distinctions are never quite as clear as such categorizations suggest.

Period 1. The local market era (1882–1946). The town of Medicine Hat began using natural gas in the 1880s. By the early 1900s, utility companies were being set up to explore for and contract gas from Alberta pools to service local markets, most notably, of course, Calgary and Edmonton.

Period 2. The by-product of oil era (1947–57). The rush of crude oil exploration engendered by the 1947 Leduc find and subsequent oil boom tremendously increased the availability of natural gas. This reflected both the output of associated gas produced along with crude oil and the discovery of non-associated natural gas pools by drillers looking for oil. Local markets could not absorb such large volumes of gas, and government regulations limited the ability of companies to burn it off (flare it), so increasing amounts accumulated as potentially accessible reserves but with no immediate economic value.

Period 3. A market expansion era (1958–71). Long-distance, high-diameter, high-pressure natural gas pipelines were completed, which allowed Alberta natural gas to establish itself as a valuable export product. TransCanada PipeLines (TCPL) reached the Niagara Peninsula in 1958. The decision to build the line involved a major political commitment from the federal government; it generated the most intense political debate of the 1950s and was partly responsible for the defeat of the Liberal Party in 1957 after governing continuously for twenty-two years. Access to California markets came with the Alberta & Southern and Pacific Gas Transmission lines in 1961, and TransCanada built a new link through the U.S. Great Lakes area (south of the original all-Canadian line of 1958), which opened in the late 1960s.

Period 4. A regulated-market era (1972–86). From the beginning, the natural gas industry had been more regulated than crude oil, including rate regulation of the major transmission and distribution companies and surplus test requirements for natural gas exports. Beginning in 1970, the regulations became even more stringent. Export permits for Alberta gas to the United States were denied (beginning in 1970) and government price regulation was instituted (1975–86). The forces of industry attention shifted from active

participation in natural gas markets to a more passive reaction to the government prices and various political and public relations activities designed to influence government policy. Production stagnated, and the industry saw the appearance of regulation-induced problems such as TCPL's take-or-pay difficulties and growing shortfalls of actual below authorized exports.

Period 5. A deregulation, "commoditization" period (1987–). Government price and market control regulations were removed, and Alberta natural gas was encouraged to integrate with a rapidly evolving North American gas market. The number of active buyers and sellers in the market has increased, as have such intermediaries as the NYMEX natural gas futures market and various computer bulletin boards to allow inexpensive rapid exchanges of market information. Transmission companies have been shifted to common carrier status, spot sales of natural gas have mushroomed, and both sellers and purchasers of gas under long-term contracts have accepted the inevitability of frequent price readjustment in light of prevailing market conditions. With the international crude oil market, the North American natural gas market has been evolving to very flexible market trading arrangements like those that characterize many other commodities and financial instruments.

Whether the natural gas market will evolve into an international one, like the oil market, is very much an open question. In the 2000s two quite different avenues to internationalization were suggested. One might be called a 'low availability/high price' possibility in which reduced supplies of North American

natural gas drive prices high enough that imports of liquefied natural gas (LNG) from overseas become economic. As natural gas prices rose after 2000, some observers saw this as a possibility. However, plummeting prices after 2008 suggested another possibility, which might be labelled 'high availability/low price', with low North American natural gas prices stimulating significant LNG exports. As of final editing in spring 2013, a number of LNG export proposals have been made to move B.C. and Alberta gas from terminals on the west coast to Asian markets. (In part, the appeal of these exports is based on very high gas prices in Japan and China where the gas price has been tied to international crude oil prices. It seems unlikely that this pricing formula would continue in the face of large-scale shipments of LNG to these markets.) Of course, neither of these cases may materialize, with North America continuing to function as a separate natural gas market with prices too high to stimulate LNG exports and too low to induce LNG imports. (In this case there might be some small scale LNG trade as companies continue to operate previously-constructed facilities, which they regret having built, so long as they can recover operating costs.)

The various problems that were apparent in the days of tighter regulation before 1987, plus the commitments to free markets implicit in the Canada–U.S. FTA and NAFTA, suggest that Alberta natural gas will continue to operate in a deregulated free-market environment through the indefinite future. The industry is adjusting to declining reserves of conventional natural gas, and moving into non-conventional resources.

CHAPTER THIRTEEN

The Petroleum Industry and the Alberta Economy

Readers' Guide: Petropolitics has been significant in the petroleum industry in part because the industry makes up an important part of many regional economies. In this chapter, we explore the broader economic linkages of the Alberta petroleum industry. The chapter examines the relative importance of the petroleum industry to provincial output and employment and how its role has changed over time. It also looks at related issues such as policies to encourage economic diversification in Alberta and to spread the receipt and use of government petroleum revenues more evenly over time.

1. Introduction

So far, we have emphasized the microeconomic dimensions of the Alberta petroleum industry – the operation of oil and gas markets and government regulations that have affected those markets. However, as mentioned several times, the petroleum industry is large enough that it may also have noticeable effects on the overall economy – macroeconomic impacts. This chapter looks at the interrelationships between the Alberta petroleum industry and the Alberta economy, although without any detailed examination of other industries, even those such as pipelines, natural gas processing, and petrochemicals that depend directly on crude oil and natural gas. The economic linkages generated by petroleum are complicated, but a useful distinction can be made between cyclical

impacts, especially those provoked by petroleum price fluctuations, and effects on overall economic growth. Our Introduction briefly sets out the main cyclical and growth effects. We then turn to the impact of petroleum on the size and development of the Alberta economy, concluding with consideration of the impact of unstable resource revenues on the provincial government and the government's actions to save some of its resource rents through the Alberta Heritage Trust Savings Fund.

A. Cyclical Effects

Some of the macroeconomic effects of the petroleum industry occur through the consumption side of the petroleum market since petroleum is such a significant energy source for most countries. When oil prices change dramatically, as they are prone to, expenditures on oil by consumers also change significantly, with attendant effects on their ability and willingness to spend on other goods and services. This effect is especially significant in the period immediately after a large oil-price change since the demand for oil products is highly inelastic in the short-run, meaning that consumption is quite unresponsive to price changes. Therefore, a major price rise, like in 1973/74 or 1979/80 or 1999 or 2006/08, will generate a dramatic increase in payments for oil. Economists refer to a changed willingness to spend on goods and services in general as a change in the quantity of 'aggregate demand.' If increased expenditures on oil products reduce the income left to spend on other things, a decrease in

the aggregate demand for goods and services in the economy occurs. This typically means a fall in Gross Domestic Product (GDP) and higher unemployment.

Inflation is a monetary phenomenon characterized by a general rise in price levels. A move in relative prices, resulting from scarcity or abundance of one product, is not inflation. Normally the increase in price of a single commodity implies, simply, an increase in the cost of this good relative to others, but with a negligible effect on the general level of prices (i.e., the inflation rate). However, energy prices also play a significant role in the price indices used to measure inflation in the economy. More importantly, higher energy prices may contribute to demands for higher wages, which contribute to higher prices for goods and services that employ labour. Thus rising oil prices may be seen as adding to inflation at the same time as they contribute to declining GDP, a situation referred to as 'stagflation.' (Helliwell, 1981, discusses the pathways to stagflation from higher oil prices; for examples of a macro model of higher oil prices in Canada, see Jump and Wilson, 1975, and Empey, 1981.) These effects of large oil-price changes would be expected to operate in opposite directions for large price rises and large price falls; there is some debate about whether the macroeconomic effects are symmetric in this way. Some analysts have accepted the stagflationary impacts of large oil-price rises but have questioned whether large price declines do in fact generate expansionary and deflationary impulses. This lack of symmetry may in part reflect the reduced share of oil in total energy use when oil prices fell (1985/86) as compared to when they rose in the 1970s and early 1980s. However, it also may suggest that the macroeconomic effects of oil-price changes are more complicated than in the discussion so far. Two additional factors must be considered.

First, it is important to realize that macroeconomic effects are the result of both oil-price changes and the macroeconomic policy response of the government. Appropriate use of monetary and fiscal policies, which are largely the responsibility of the federal government in Canada, may offset the aggregate demand and inflationary effects of the petroleum-price changes.

Secondly, there are also macroeconomic effects from the supply side of the oil market. Higher expenditures on oil by consumers is increased revenue to oil producers, and the higher oil prices make additional investment in oil exploration and development attractive. That is, oil-price increases lead to increases in aggregate demand in oil-producing regions, and therefore to increases in GDP.

There are, therefore, some uncertainties in the macroeconomic effects of major oil-price changes. The precise macro effects turn out to hinge on two important factors, geography and what has usually been called 'recycling.' Since oil deposits are so unevenly distributed beneath the earth's surface, the primary macro effects tend to be opposite in sign for regions that produce a lot of oil and those that do not and must import oil. It can be appreciated that these regional differences are not country-specific; within large countries like Canada, Russia, and the United States, there are oil-exporting regions and oil-importing regions.

The 'recycling' problem refers to the uses to which oil producers put their increased earnings from higher-priced oil. Is the additional money spent on goods and services from the oil-consuming region that provided the revenue to the oil producer? If so, then the aggregate demand effects in the consuming region will be minimal. The reduced spending by oil consumers is offset by the increased spending of oil producers. Of course, the oil producers are better off, and the consumers worse off, since some of the goods and services that residents of the consuming region used to buy are now being exported to the oil producers. However, there will be reduced aggregate demand in the consuming regions in total to the extent that oil producers save some of their increased earnings instead of spending them. The increased saving, as a supply of financial capital, may drive down interest rates, which may in turn stimulate more investment spending, but it is widely accepted by economists that, in the absence of offsetting government policies, such increases in saving will tend to reduce aggregate demand in the economy, at least in the short term. Of course, some consuming regions could actually see a net stimulus to the economy if increased spending in the region by oil producers (e.g., OPEC) is higher than the region's extra payments for oil imports.

From this more complete perspective, it is difficult to offer many generalizations about the macroeconomic cyclical effects of changing oil prices. While governments of oil-importing regions have been very concerned about the possibility of such effects (and they concerned Ottawa in the 'overt control' days of 1973 to 1985), we shall not investigate such cyclical economic effects in Alberta in any great detail. In part, this is because there are obvious limitations in the macroeconomic policy responses of a Canadian province, as compared to the federal government in Ottawa. It is the federal government that has access to

the levers of monetary policy and the main levers of fiscal policy. Furthermore, in an open provincial economy, it may be difficult for the provincial government to pursue an effective fiscal policy; cuts in provincial income tax rates to spur the local economy may lead primarily to an increase in imports into the province rather than much additional spending on locally produced goods and services.

Our main emphasis in this chapter will be on the longer-run impacts of the petroleum industry on the size and structure of the Alberta economy. The income and employment data we assemble will provide evidence on short-term cyclical performance. In addition, later in this chapter, we will consider how the provincial government might respond to the pronounced variability in the revenues it generates from the petroleum industry.

B. Growth Effects

In the remainder of this chapter, we shall be concerned primarily with the long-term effects of the petroleum industry on the economy of an oil-producing region, Alberta in particular.

This point seems intuitively obvious to residents of Alberta. Those with long memories can look back to the end of the Second World War, when the economies of Alberta and Saskatchewan bore a close resemblance. Populations were under one million in both provinces, and agriculture was the predominant industry. By July 1, 2012, Alberta had a population of almost 3,900,000 million, while Saskatchewan was still hovering near the one million mark. The most obvious difference between the two provinces is the development of the Alberta petroleum industry following the Leduc discovery of 1947. Saskatchewan has seen significant oil and gas investments since 1945 but not by any means of the same magnitude as Alberta's.

Thus, a sound working hypothesis is that the petroleum industry has served as a key engine of growth for the Alberta economy. Of course, the growth of the petroleum industry is not the only difference between the two provinces over this period. Alberta has its mountains in the west with good tourist potential; Saskatchewan has its potash deposits. Albertans often express pride in their province's frontier spirit and the individualistic values of its governments. Many in Saskatchewan are proud of a tradition of community spirit and communitarian government. Moreover, we must be careful not to equate increasing size with improved welfare. While Alberta's GDP grew at a far

faster rate than that of Saskatchewan, there were forces in play that kept average living standards closer to one another.

The main purpose of this chapter is to examine in more detail the role that the petroleum industry has played in the economy of the province of Alberta. The next part of this chapter will provide a brief overview of some of the models and concepts that economists have used to study the process of economic growth and the contribution of particular industries to the economy and its growth.

2. Models of Economic Growth

A. Concepts

An economy consists of people and their production and consumption activities. Analysts are interested in three somewhat different characteristics of an economy: (1) the total levels of production and consumption; (2) the average (per capita) levels of production and consumption; and (3) the equality of the distribution of productive activities and consumption. Our specific concern is the contribution of the petroleum industry to the economy. We will focus mainly on the first two characteristics.

Conceptually, our interest lies in anything that is perceived as having value to Albertans: How large is the value? How was whatever provides value produced? And what were the costs involved in producing it? Did this production process decrease or increase other things that Albertans value? It is a big step to move from this general conceptual framework to meaningful empirical analysis. Neither the concept of 'value' nor that of 'Albertans' is as straightforward as one might initially assume. (Here we repeat and elaborate on some of the issues that were initially raised in Chapter Four in our discussion of 'welfare economics,' and in the Introduction to Part Two of this book.)

Consider, first, the term 'Alberta.' Does this mean the productive activities within the geographical region ('domestic' activities), or the productive activities undertaken by people with declared residence in the region ('national' activities)? The two may differ because Alberta residents engage in production outside of Alberta; for example, an oil worker from Edmonton spends six months a year working in the Middle East, or a financier in Calgary loans money to a manufacturing plant in Nova Scotia. Even the notion of Alberta residents is ambiguous. Do we mean

all people living here? Or only Canadian citizens? Do we mean the people in Alberta prior to a change in the economy or those in the province after the change? (These differ if changes attract immigrants into Alberta or induce people to leave the province.) In what follows, we shall follow the main conventions and include all Alberta residents (a changing total, with interprovincial and international migration) and focus on the economic activities that take place within the borders of the province (a 'domestic' point of view).

The concept of 'value' has always attracted controversy. As was discussed in Chapter Four, we follow the pervasive utilitarian tradition in economics and accept that whatever individuals say is of value to them is therefore of value to society; the value of something is the amount that a person is willing to pay for it. This perspective is both individualistic and democratic. But it is not unassailable: individuals may be inconsistent in their preferences; they may exhibit weakness of will, behaving in ways their 'better' self cautions them against; and there are any number of reasons to question whether what people want is actually in their best interest. However, any paternalistic attempt to impose a different set of values is likely to be more controversial than simply accepting individuals' own evaluations. Hence, we accept the willingness to pay criterion of conventional welfare economics. Further, the use of money as a measuring rod is convenient in an advanced mixed-capitalistic economy such as Canada's since many of the things that people value are produced and exchanged through economic markets, and the dollar values (both positive and negative) that individuals place on things are provided by market prices.

The role of market prices in providing measures of value provides the basis for the most common measure of the size of an economy and its rate of growth: Gross Domestic (or Provincial) Product (GDP). We shall utilize GDP extensively in the remainder of this chapter but must initially provide some discussion of what it is (and is not). (More detailed discussion of the concept can be found in any introductory economics textbook; see also Statistics Canada catalogue #13-001.) GDP can be measured in two ways, one of which draws on the consumption side of the economy, and the other which draws on the production side.

From a consumption point of view, we ask: what is the total value to consumers of all the goods and services produced in the economy? Of course, we cannot simply add the value of all the goods that are marketed

since this would involve much double-counting. (We would, for instance, include the cost of the drilling rig services sold to an oil exploration company, then count it again when the crude oil producer sells its crude to a refinery and then again when the refiner sells its refined petroleum products to final users.) Rather, we want to add up the values of all the 'final' goods and services that people purchase. Final users are normally defined as consumers (who buy durable goods such as cars, non-durable goods such as motor gasoline, and services such as financial consultations), businesses that purchase capital goods to allow production of other things through the future (if the annual depreciation of these capital goods is deducted from GDP, one is left with NDP or Net Domestic Product), governments, and foreign buyers. Of course, some of the goods bought by local residents may have been imported rather than produced locally, so must be removed from spending if the size of the local economy is to be measured accurately. This generates the well-known equation: $GDP = C + I + G + X - M$. (Gross Domestic Product (GDP) is consumption spending (C), plus investment spending (I), plus government spending (G), plus export spending (X), less imports (M .)

From the production perspective, one wishes to measure the value that is produced in the economy by adding up the contributions of all producers (including producers of 'final' goods and services and of 'intermediate' goods and services). This would allow assessment of the roles of all the producers in the economy. From this point of view, GDP is the sum of the 'values added' by each producer on top of the purchases they make from other producers. Thus, for example, the value of the crude oil that an oil company sells to refiners includes the cost of purchases from other companies (e.g., the cost of hiring a drilling rig from an oilfield drilling contractor), but it also includes 'values' that the oil company 'added.' 'Values' are derived from the amount that people are willing to pay for the crude oil (which, in turn, derives from the values that final consumers put on the refined petroleum products). The 'additions' made by the crude oil producer (on top of its purchases from other businesses) include the oil company's purchases of labour, interest payments it makes on borrowed funds, rental payments it makes on land, and the profits it earns. The sum of these values added across all industries also measures GDP. For simplicity's sake, we have abstracted from such details as where taxes fit into this. In general, since the payments made by final

users cover taxes, they are also a part of value added. There is a particular problem in the crude petroleum industry with the significant payments made by producers to governments and private landowners from the economic rent earned on crude petroleum. These payments are largely in the form of royalties and bonus payments. The problem is in deciding which industry should be credited with these amounts as value added when they seem to lie in the qualities of the natural resource in the ground as much as in the activities of the crude oil industry. In Canadian National Accounts data, royalties and bonus payments are credited as value added by the “financial” sector.

In what follows, we will be using value-added measures of GDP as our main description of the contribution of the petroleum industry to the Alberta economy. Other measures are possible and will be referred to as needed. Thus, for example, one could also ask what proportion of the Alberta labour force is employed in the crude oil industry, or what the industry’s share is in the total stock of capital in the province. Readers will be aware that the oil industry is a ‘capital intensive’ industry with relatively few directly employed workers, so its share of the labour force is much less than its share of value added, but its share of the capital stock is higher.

We shall focus on three main questions: How important is the petroleum industry to the Alberta economy? How has the petroleum industry contributed to the growth of the Alberta economy (considering both total and per capita GDP)? And what has been the contribution of the petroleum industry to the ‘public’ through its impact upon provincial government finances? Our view is that dollar values – value-added measures of GDP, and the financial payments by the industry to the provincial government – are the best available tool to address these questions. Once again, however, it is wise, even when accepting this stance, to keep in mind the limitations of GDP as a measure of the value of a society’s economic consumption and production since, among other things, it excludes certain valuable ‘products’ such as leisure time, unpaid activities, and the quality of the environment. Critics of the concept have also argued that GDP includes undesirable elements; for instance, if drilling an exploratory well (which adds to GDP) generates an undesirable outcome such as a well blowout, the expenses to control the blowout will also add to GDP, so even bad outcomes may lead to higher GDP. Such criticisms need to be considered carefully. After all, there can be little doubt that controlling the blowout

does generate a gain to society; the real question is whether the potential environmental costs of oil industry activity are adequately recognized.

Possible modification of a country’s National and Provincial Accounts to better incorporate natural resources such as petroleum is an interesting issue (Hartwick, 1990, 1994; Diaz and Harchaoui, 1997; Smith 1992). At the conceptual level, one might suppose that the national balance sheet of a country’s assets should include the net value of the natural resource, which could be estimated as the anticipated economic rent from production (the present value of the excess of expected revenues above expected production costs). Then the annual flow of economic activity, as measured by GDP, could include the change in the asset value of the natural resource. (This is analogous to the change in inventory values for conventional businesses included as part of the investment component of GDP.) The depletable nature of the resources would suggest that the asset value should decline as the remaining stock is reduced. At the same time, the more dynamic view of resources that we have advocated in this volume suggests a number of reasons why resource asset values might rise, even above and beyond unexpected price increases: new knowledge and technology consistently add to the volume of recoverable resources and their value. The inclusion of natural resources into national accounts is very difficult to implement in practice for many reasons, including uncertainty about the size of the resource base and about future prices and costs that are needed to estimate expected future production and economic rents. Hence, conventional data as used in this chapter do not include values associated with the changing natural resource base of the province; rather, the petroleum industry is assessed in terms of its annual production activities. Diaz and Harchaoui (1997) provide an interesting analysis of Canadian petroleum in which they find that inclusion of the asset value of the natural resource would have a relatively small impact on Net National Product measures, but a more significant effect on Net National Wealth. We would note that explicit consideration of the asset value of petroleum resources provides one possible approach to the policy issue of the utilization of petroleum revenues. If oil and gas production reduce the value of the province’s wealth (including the value of petroleum assets in the ground), then it could be argued that only part of petroleum revenues received by the government should be utilized for current expenses. This perspective would suggest that

some portion should be invested in capital assets, which would provide ongoing revenues to compensate for the declining value of the natural resource stock. The Alberta Heritage Trust Savings Fund, which will be discussed later in this chapter, could be seen as an example of such use of petroleum revenues.

In conclusion, GDP is widely accepted as a measure of the size of the most obvious part of the economic system, that part which operates directly through economic markets (including labour markets). At its most basic level, an increase in real GDP, all else being equal, implies that society has increased its potential for producing things that members of society might value. As a measure of the actual efficiency of the economy in meeting the needs of its citizens, GDP is more problematic. Most economists regard it as one of the most useful indicators in this regard, but only one of them. One might also want to consider factors as diverse as the distribution of income, the state of the environment, the size of the natural resource base, the length of the average working day, the changing proportion of stay-at-home parents, the average health and educational level of the population, etc. All else being equal, higher real GDP per capita is commonly regarded as signalling an improvement in the economy's performance. We accept this conclusion. However, for some critics, the concept of GDP is so flawed that even this qualified conclusion is not warranted.

Input-output (I-O) tables are an extension of the value-added approach to measuring GDP, providing a 'snapshot' of interindustry connections in a particular year. They show how aggregate demand is spread across imports and different local industries and also how the expenditures of each industry are spread across other industries and various value-added categories (labour, profits, etc.). They give an idea of what an expansion in production of one industry will mean for other industries in the region. At the same time, there are limitations in the usefulness of I-O tables. For one thing, they reflect the unique features of the year in which they were constructed, including constrained short-run responses. The tables show the total of economic activity in the year and so can be used to understand total linkages or average linkages (e.g., that \$1 of crude oil exports required on average \$0.10 of Alberta well-drilling services). But economists are most often interested in marginal changes; unless production occurs under constant cost conditions, marginal costs and input requirements may differ from the average levels shown in I-O tables. Despite

these limitations, I-O tables provide a useful tool for examining the economic role of an industry within a region.

B. Models of Growth

In what follows, we present a brief and select review of some of the models that economists have used to explain the level and growth of GDP in an economy. The review draws on the literature on macroeconomic growth and on regional economic development.

1. Export Base Models

In these models, the growth of an economy is driven jointly by its natural resource base and by the external demand for these resources. The underpinnings of this model can be found in the "Staples" theory, a theory that is largely associated with Canadian economists (Innes, 1927; Easterbrook and Aitken, 1956; and M. H. Watkins, 1963, for example). In this model, the world can be divided into two categories, 'central' economies, which are populous, industrialized and diverse, and 'peripheral' economies, which depend upon trade linkages with the centre. The central economies draw on the peripheral economies for the natural resources needed to fuel their industries. A peripheral economy's growth is a function, therefore, of its resource base and the demands of the central economies. More specifically, growth will hinge on the size of export demand, the nature of the production technology for the natural resource, and the resource's 'backward' and 'forward' linkages in the local economy. The production function is important in large part because it indicates the local labour requirements to produce natural resources in the periphery. Are few local residents needed as in the case of fishing (where ships can come from the central economy and return without even having to land on the shores of the peripheral economy), trapping, and mechanized mineral production? Or are there significant numbers of workers needed, as in nineteenth-century agriculture and logging or mineral strip mines? Backward linkages refer to local producers who service the input needs of the staple resource-producing industry. This would include the provision of inputs for staple production itself (e.g., rafts to move logs to the export port), as well as the production of goods and services for labourers in the staple industry (clothing and grocery stores, saloons, seamstresses, opera houses, gambling

establishments, schools, churches, etc.). Forward linkages refer to industries that further process the natural resource before it is shipped to the central economy; sawmills and gas processing plants are examples.

The staples model was devised as a model of political economy; it purported to deal with more than the implications of production technologies and the resultant size of GDP. Inherent in the division of the world into central and peripheral economies were a host of questions related to political dependency and exploitation. Moreover, the demands for staples by the central economies and the ways in which they controlled production in the peripheral economies were also seen as determining cultural, social, and political institutions in the periphery. The flavour of the staples model lives on in approaches that emphasize the political significance of the resource industry, as in discussions of the 'petrostate,' which see the levers of government and the local political culture as captured by the interests and mindset of the petroleum industry.

The export base model is, in essence, the staples political economy model without the politics. That is, the primary forces shaping the local economy are the export demand for a locally produced good or service and the specific production technology and economic linkages of that export product. Caves and Holton (1959), for example, provide an economic history of Canada that is based largely on a succession of natural resource staples – first fish, then furs, then forestry, then agriculture (wheat), then mining and the petroleum industry.

There are problems with the export base/staples theory approach. The dichotomous separation of the world into central and peripheral economies seems extreme. These roles cannot be fixed forever, but at what point does the economy switch from being a periphery (e.g., Upper Canada in the early 1880s) to being a centre (e.g., Ontario in the second half of the twentieth century)? And is this an either/or categorization, or are there intermediate phases that might last for an extended period of time? Moreover, the implicit view of the central economies as independent, powerful importers driving growth processes in the periphery through their export demand is suspect. The central economies are exporters as well (and not only of manufactured goods); surely their economic structure and growth must be affected by the demand for their exports and the production technologies involved.

It may, then, be a matter of degree. Some economies may be natural-resource-rich but have very

small local markets (due to small populations and/or low standards of living). In such economies, growth will inevitably be heavily linked to trade, with the external demand for the region's resources determining the region's main industry and providing earnings for local residents to import the goods and services they consume. But as a region grows, even if stimulated by a resource staple, the local market will expand and more industries will develop at home to produce goods for local consumption. The economy is, then, less heavily dependent on the natural resource staple. Further, some of the goods manufactured for locals may become competitive as export products so that even the region's exports show less dependence on immobile natural resources and more on those industries that could, potentially, be located anywhere in the world. In this way, the economy, as it has grown, initially under the impetus of a natural resource staple, has become more diverse and less dependent on staple exports; it has developed a greater degree of autonomy. Consequently, the export base model would become less valuable as a way of explaining the region's continued growth.

2. Closed Economy Models

The previous paragraph suggests that the true opposite to the export base economy is not really a Central economy but a 'closed' economy, one that is completely self-sufficient so that it has no exports (and no part of the economy is 'based' on exports). Models of closed economies are, of course, unrealistic for the modern world, but much of the early development in modern macroeconomics and growth theory stemmed from simple closed economy models. It will be useful to comment briefly on the two most popular modelling frameworks. It should also be noted that there are open economy models of both types as well.

a. Keynesian Models

Keynesian models stress aggregate demand in the economy as the prime determinant of the levels of GDP, unemployment, and prices. These models provide the basis for the short-term cyclical phenomenon discussed in the first part of this chapter but also introduced concepts that have been applied in other modelling frameworks. The basic idea is that if aggregate demand is low (below capacity), there will be insufficient demand to purchase all that the society is capable of producing and there will be involuntary unemployment. Should aggregate demand be too

high, the economy would produce at potential GDP with full employment, but the excess demand would translate into rising prices (inflation). One element of the low-aggregate-demand case provides an interesting link to the export-base models with their emphasis on forward and backward linkages in the economy. In Keynesian theory, these linkages translate into a 'multiplier effect' whereby the impact on GDP exceeds the initial change in aggregate demand. Consider a fall in consumption spending, for example, if consumers for some reason decide to save more of their income. When consumers spend less, the producers they buy less from will in turn cut their workforces and reduce their purchasers from input suppliers, and the input suppliers and workers who are now unemployed will cut their spending, which further reduces demand, and so on, until these effects peter out. In many Keynesian models, the cyclical aspects of the economy are heightened by what is called an 'accelerator process,' where investment demand is driven by the *change* in the level of income. Thus, a rise in income stimulates investment, which, through the multiplier effect, generates a larger income rise, which stimulates a further increase in investment, accelerating the growth; but, as soon as the income growth slows, investment demand will decline, drawing the economy into a downward cyclical phase.

b. Neoclassical Models

Neoclassical models might be contrasted with Keynesian models by saying that the neoclassical models focus on aggregate supply rather than aggregate demand. The emphasis is on the productive potential of the economy and how it changes. Neoclassical models essentially assume that the economy operates at full employment. In the neoclassical closed economy model, the level of GDP is a function of the quantities of productive inputs in the economy and the efficiency with which they are used. GDP can increase if the quantity of inputs rises; that is, if there are more workers, or if the capital stock rises. The capital stock should be interpreted as including capital equipment, natural resource capital, and human capital (the knowledge and skills of the labour force). GDP can also rise due to technological change; this is new knowledge that increases the efficiency of utilization of a fixed quantity of inputs. The neoclassical model serves as the basis for 'general equilibrium' models of an economy, which set out (1) the ways in which the economy's productive inputs (labour, capital, and natural resources) generate output; (2) the division of this output amongst the inputs as income; (3) the

consumption and savings behaviour of individuals from their various sources of income; and (4) the way in which savings generate additions to the capital stock (i.e., investment), which allows more production in the next period. Obviously this is a complicated economic framework, but in recent years economists have greatly advanced the construction of empirical models (labelled 'computable general equilibrium' [CGE] models) to describe the operation of national and regional economies.

While neither of these closed economy models is appropriate to an economy like Alberta's, which is so open to exports and imports, they both have been extended in versions for open economies.

3. Open Economy Models

An open economy allows for trade of goods and services with other economies and for the import and export of financial capital. In addition, it is possible to supplement the quantity and quality of local inputs with inflows from outside the region, and local inputs could elect to leave for elsewhere. It should be noted that many open economy models have introduced the simplifying assumption that capital is very mobile between regions but labour is not. While this assumption about labour may have some validity when considering international trade, it is much less appropriate for a regional economy like Alberta's, which is part of a single country within which people are free to relocate.

At any point in time, the potential (full employment level) of GDP in the economy is determined by the quantity and quality of the inputs available in the region. The actual level of GDP will be heavily influenced by the level of aggregate demand in the economy, of which export demand is an important part. For many regions, export demand will consist in large part of demand for natural resource staples. Low aggregate demand, which might, for instance, come from a decline in export demand for the natural resource, will be associated with unemployment in the region. If this problem persists, it is likely that labour and capital will begin to leave the region.

If aggregate demand is excessive, there will be upward pressure on local prices, but this tends to be limited by the regional mobility of goods and inputs. Thus prices of goods and services that move easily and cheaply in trade cannot rise very far even in the short run because local consumers will turn to imports and external customers will stop buying from this region. For goods and services that are slow to move

in response to higher prices, increases in price can be somewhat greater; labour might be an example. Price increases can be still larger for non-tradable goods and services; housing is a prime example. (Non-tradable does not mean goods that cannot be exchanged in trade, but goods that are immobile.) In the longer run, the increased prices of local goods and services stimulate the in-migration of new productive inputs such as workers who are drawn by higher local wages and capital to produce those goods that have risen in price. Such inflows tend to drive prices back down. They also increase the quantity of inputs in the economy and hence raise the full employment level of GDP. These factors explain why the Alberta economy could increase in size so much relative to Saskatchewan but without extremely large and persistent difference between per capita GDP levels in the two provinces. Expansion of the local market can encourage in-migration and development of new industries to produce goods for local consumers; often these industries exhibit economies of scale so that a certain minimum size of the market is necessary before producers attain competitive costs. If this happens, the local economy will become more diversified and less trade-dependent.

4. Natural Resource Models

As was noted, export base models typically emphasize natural resources, although not all export industries need be natural resource producers. In this section, we briefly review two models of economic growth that are basically natural resource models.

a. Boom and Bust Models

These models are based on the exhaustible nature of mineral deposits. If this characteristic of minerals is a dominating feature, and if there is only the one significant resource available to a region, then one would expect the regional economy to follow a path of expansion followed by decline, as is seen in many mining towns. If this process is not handled carefully, the growth cycle may be very rapid (as production of the resource grows rapidly to meet large export demands) followed by equally rapid economic decline as resource deposits are exhausted. This cycle is likely to be very inefficient. There are problems in the boom phase in providing adequate social infrastructure for in-migrating labour; local inflation is likely to be high and social relations strained. Social ties are severely strained with the ensuing bust, and local infrastructure is abandoned long before it is physically

depreciated. These problems suggest that it would be socially desirable to force a more 'attenuated' resource development policy to smooth out resource production and so extend the (milder) boom and following (slower) contraction (Scott, 1973, 1976).

However, in many cases, the boom and bust model will not be relevant to regional economic development. (Nor need it apply solely to natural resource production; history is full of stories of once booming industries dying due to population movements, taste changes, or technological changes; think of blacksmiths and typewriter manufacturers.) The model seems to be most relevant to very small regions (for example, the isolated single-mine town). It fits larger regions less well for two reasons. First, as we have stressed in this book, the underlying concept of a depletable resource is not straightforward. In most oil-producing regions of any large areal extent (for example, Alberta or Texas), there is a very large resource base that will never be fully exhausted. As long as knowledge is generated and new technologies are developed, the oil industry may continue producing for many, many years. That is, there may be a boom, but the bust phase may be delayed almost indefinitely. Secondly, for larger regions, the presumption of a single natural resource is less likely to be met, and there are increased prospects that the region will grow prosperous and populous enough to become relatively self-sustaining, especially as agglomeration effects occur. Hence, we view the boom and bust model as being relatively unimportant for the Alberta economy, although it could be of some value in understanding economic conditions at a very local level (e.g., in a particular town).

b. Industrial Diversification and the 'Dutch Disease'

Governments in most regions that rely heavily upon a single industry are motivated to try to diversify the economy, thereby providing somewhat more cyclical stability. This is particularly true if the natural resource is a depletable one, as the government may then have concerns about declining production as reserves run out. This desire holds some contradictions because the stronger the single resource industry, the higher economic growth in the region will be, but the greater the share of GDP contributed by the extractive resource industry. Thus, Middle Eastern OPEC members such as Saudi Arabia appeared to have more diversified economies in the 1990s than the early 1980s in the sense that the relative contribution of the crude oil industry to their economies had fallen after oil prices collapsed. But GDP

per capita had also declined. Economic diversification may be desirable, but new industries should be commercially viable on their own merits if they are simultaneously to diversify the economy and contribute to economic growth in a meaningful way. This is not easy to accomplish!

The issues here are similar to those associated with the well-known ‘infant industry’ argument, that a new industry may require protection from imports until it has had time to establish itself as commercially viable; such viability may hinge on the industry expanding enough to realize economies of scale or to operate for a sufficient period of time to allow local inputs to gain the knowledge and skills required. The argument has been controversial. In a world of uncertainty, it is very hard for governments to pick ‘winners’; that is, it is easy to decide to protect or subsidize currently unprofitable businesses but hard to know which ones will become competitive in the future. Further, from a political economy point of view, virtually all producers (business owners and workers) have an incentive to claim that they need assistance to become more competitive; which of these claims the government responds to, and which it ignores, may relate more to political influence than to economic merit. Finally, it is hard to remove government support once it is established. Partly this is ‘political,’ in the sense that supported industries made more profitable by government assistance also have developed greater political power to fight against any removal of support. Further, the ability to operate under government support may have inhibited the necessity to become internationally competitive; that is, the government support itself allows the industry to remain an ‘infant’ requiring support.

The concept of economic diversification ties into what is called the ‘Dutch Disease’ (Ismail, 2010; Sosa and Magud, 2010). This refers to the economic adjustments that may occur in a relatively diversified economy when a new natural-resource-exporting industry comes into being. The term was applied to The Netherlands’ experience with the development of the gigantic Groningen gas field in the 1970s. Macroeconomic models suggested that development of the natural resource would tend to squeeze out other traditional export industries (manufacturing, for example). This could happen partly through ‘external’ economic adjustments if inflows of financial capital and growing resource exports increase the exchange rate and make it harder for traditional exports to compete. Some of the economic adjustments would

be ‘internal,’ with expanded resource production driving up input prices and raising production costs for traditional exports and for non-tradable goods and services. As a result, capital-intensive resource industries expand and traditional labour-intensive industries contract. Note that these effects would be less if there were relatively easy in-migration of inputs to the economy; that is, the ‘Dutch Disease’ argument, in the sense of a pathological outcome, has particular force in a closed economy. In effect, addition of the new resource industry might reduce the diversity of the economy. This was seen as a particular concern by those who foresaw a sharply peaked production profile for the natural resource; then, when depletion effects reduce production of the natural resource, the traditional export industries are no longer there to fill the economic gap, nor, for some reason, are they able to redevelop quickly. This presumes an asymmetrical response, with manufacturing contracting quickly as petroleum production increases, but failing to expand when petroleum output declines; reasons to expect such asymmetry have often not been clearly set out. The Dutch Disease might lead to an extreme result often labelled ‘the resource curse’ in which development of a large natural resource endowment actually leaves a nation worse off; Frankel (2010) provides a survey of this literature, while Alexeev and Conrad (2009) examine this proposition empirically for oil and argue that it is not valid.

In a neo-classical framework, these economic adjustments also impact on the distribution of income. Thus expansion of a capital-intensive resource industry would increase the demand for capital relative to labour, generating a decrease in the wage rate relative to the ‘prices’ of capital (interest rates, dividend rates, and retained earnings). The intersectoral production shifts (expansion of natural resource exports and contraction of other export or import-competing industries) would also be affected by these input price changes. Overall, one would expect the share of capital in national income to rise and that of labour to fall. The impact of these structural changes might be mitigated by appropriate government policies, particularly monetary policy, which can help to offset (or ‘sterilize’) the interest rate and exchange rate effects. However, a subregion such as Alberta has no control over monetary policy.

Literature on the Dutch Disease suggested, once again, that an attenuated (more drawn out) resource depletion path might be optimal, thereby reducing the structural shifts in the economy. On the other hand,

these broad macro concerns seemed less immediate to those who were relatively optimistic about the size and expandability of the petroleum resource base. In light of this, we prefer the term ‘Dutch Adjustment’ to ‘Dutch Disease’ to refer to contraction of other sectors of the economy to make room for expansion of the petroleum industry, unless there is clear evidence that this process is pernicious.

We are not of the opinion that the Boom and Bust or Dutch Disease models, in their pure forms, are of much importance to the Alberta economy, so we shall rely on more traditional macroeconomic analysis in the material that follows. However, readers should keep in mind the general insights of the models in terms of the possible impacts of a non-renewable natural resource.

3. The Petroleum Industry in the Alberta Economy

As preamble, we summarize Eric Hanson’s well-known research from 1958 arguing that the petroleum industry was proving to be a vital export-base, stimulating rapid growth in the Alberta economy. We then go on to provide a brief overview of the province’s economic development since the 1940s and the role of the petroleum industry. Then we turn to several more specific topics such as economic diversification, transfers from Alberta to the federal government during the years of the National Energy Program, macroeconomic fluctuations associated with the changes in the oil market, and the Heritage Trust Fund.

A. The First Ten Years: Eric Hanson’s *Dynamic Decade*

The modern Canadian crude oil industry is normally dated from the 1947 Leduc discovery, which stimulated a sequence of significant oil plays. While local residents and governments were optimistic about the province’s economic future, some economists were less enthralled. Thus, for example, in their highly regarded economic history of Canada, Caves and Holton (1959, p. 215) compared the petroleum industry to other historically significant resource staples and argued that the impact on the Alberta economy might be relatively small. Crude oil and natural gas were normally exported as raw materials, so forward linkages

would be minimal, and the capital-intensive nature of their production implied a very low demand for labour and heavy reliance on imported capital equipment so that backward linkages would also be small. The pipelines used to ship oil and natural gas were also very capital-intensive and required little labour to operate; they could only be used to move petroleum. Caves and Holton argue that the contrasts drawn with the wheat boom, and associated construction of the railways, were marked. (Growing wheat required large numbers of farmers; equipment suppliers and grain-processing facilities did not exhibit strong economies of scale so were easily established; the rail links necessary to move grain and flour to markets were also ideal for bringing people to the region. Owram, 1982, provides a useful overview of economic development in western Canada.)

In 1958, Eric Hanson, an economist at the University of Alberta, published *Dynamic Decade*, the first extensive economic survey of the Alberta petroleum industry. Hanson included estimates of the economic impact of the petroleum industry on the Alberta economy, using a Keynesian economic multiplier approach as applied to an open economy. In this approach, it was assumed that the direct expenditures of the industry in Alberta had an income multiplier effect of approximately two; that is, \$1 in expenditures in Alberta by the petroleum industry would generate a \$2 increase in Alberta income (Personal Income). (Hanson used a multiplier that fell from 2.3 to 2 over the decade from 1946 to 1956.) Petroleum industry expenditures stimulated capital inflows into the province, which would not have occurred without the development of the industry. In order to estimate expenditures in Alberta, Hanson drew upon estimates from the Alberta government and information he gathered from interviewing oil industry personnel to estimate the proportion of direct industry expenditures that flowed immediately out of the province. His income multiplier was applied to the residual of industry expenditures in the province.

To illustrate the significance of the petroleum industry to Alberta, Hanson sets up a counterfactual history in which the population of Alberta follows a path similar to that of Saskatchewan, starting at 803,000 in 1946, and falling gradually to 775,000 in 1956. Alberta’s actual population in 1956 was 1,123,000. He then estimates the impact of the petroleum industry on the Alberta economy by deducting the contributions of the petroleum industry (the multiplier income contributions) from the actual income levels

(Hanson, 1958, p. 271). On this basis, the Alberta economy would have been 98 per cent of the actual size in 1946, if the petroleum industry had not been present. This percentage fell over time, so that in 1956 Hanson estimated that, without the petroleum industry, the level of Alberta Personal Income would have been only 55 per cent of that recorded. The values for per capita income are less dramatic since the growth of the oil industry attracted immigrants, but he estimates that by 1956 personal income was \$275 higher per capita (at \$1,370, a gain of 20%) than it would have been without oil (Hanson, 1958, p. 273).

Hanson's perspective is consistent with the export base model, as suggested by one of his concluding paragraphs (Hanson, 1958, p. 293):

The Alberta economy is no longer dependent on the export of any one staple. Less than one-fifth of its income is subject to the vagaries of wheat growing. Another fifth or so is derived from livestock raising and processing, activities which are relatively stable. About one-quarter is generated from the land acquisition, exploration and development activities of the petroleum industry. A fifteenth is provided by the producing activities of the petroleum industry and by its capital and operating expenditures for transportation, refineries, natural gas plants and petrochemical plants. Finally, there is a miscellany of activities, many of which are derived from oil operations, providing the rest of the income of the province.

Hanson was sceptical about the possibility of Alberta moving beyond an export-base economy, with a high dependence on natural resource exports, arguing that its "location precludes the economical manufacture of a great many commodities" (p. 293); presumably this also reflects a judgment that the local economy was too small to realize economies of scale in the production of many manufacturing commodities. He concluded that "the major basis for the development of Alberta lies in its potential natural resources" (p. 293), although he saw Alberta developing as the centre for exports of petroleum services to an expanding northern Canadian petroleum industry.

Dynamic Decade provides a convincing portrayal of the petroleum industry as a strong export-base growth engine for the Alberta economy in the decade following the Leduc discoveries.

B. The Role of the Petroleum Industry

This section will provide some basic statistical information about the petroleum industry in relationship to the Alberta economy.

1. Background and the Alberta Economy

Obviously, it is very difficult to estimate with reliability the contribution of the petroleum industry to the economy since we have no way of knowing exactly what Alberta would have been like without the industry. While it is possible to use input-output tables to see the interindustry linkages of an industry, it is hard to determine the full extent of the induced growth effects and even harder to assess whether petroleum industry activities might have displaced other economic activities. Here we look at the most immediate measures of the economic activities of the Alberta petroleum industry: direct contributions to provincial GDP, capital accumulation, and employment. We also provide some comparisons to Saskatchewan and Canada as a whole and look at several key economic indicators over time. (Emery and Kneebone, 2008, look at the differing economic development paths of Alberta and Saskatchewan and emphasize the differences in resource endowments.)

This chapter does not provide a complete survey of the Alberta economy and its features in comparison to other parts of Canada. Readers can find useful surveys in Mansell and Percy (1990), and Polèse (1987a, especially the chapter by Mansell), Norrie (1986), Richards and Pratt (1979), and a number of the Working Papers for the Economic Council of Canada's study of regional economic disparities in the early 1980s (Norrie and Percy, 1981, 1982, 1983; Owram, 1982); Melvin (1987) provides an interesting review of regional economic differences; Emery (2006) provides a survey focusing on the changes following the price collapse of 1985. We have not attempted to build an econometric model of the Alberta economy so our observations are based upon relatively simple observations about the connections between key variables and our knowledge about what was happening at various points in time. Therefore, our observations, about what is, after all, a complex developed economy, should be regarded more as plausible hypotheses than established conclusions.

We will begin with some time series data for the period since 1947 to provide a broad overview of the Alberta economy. Then, we provide a brief review of a

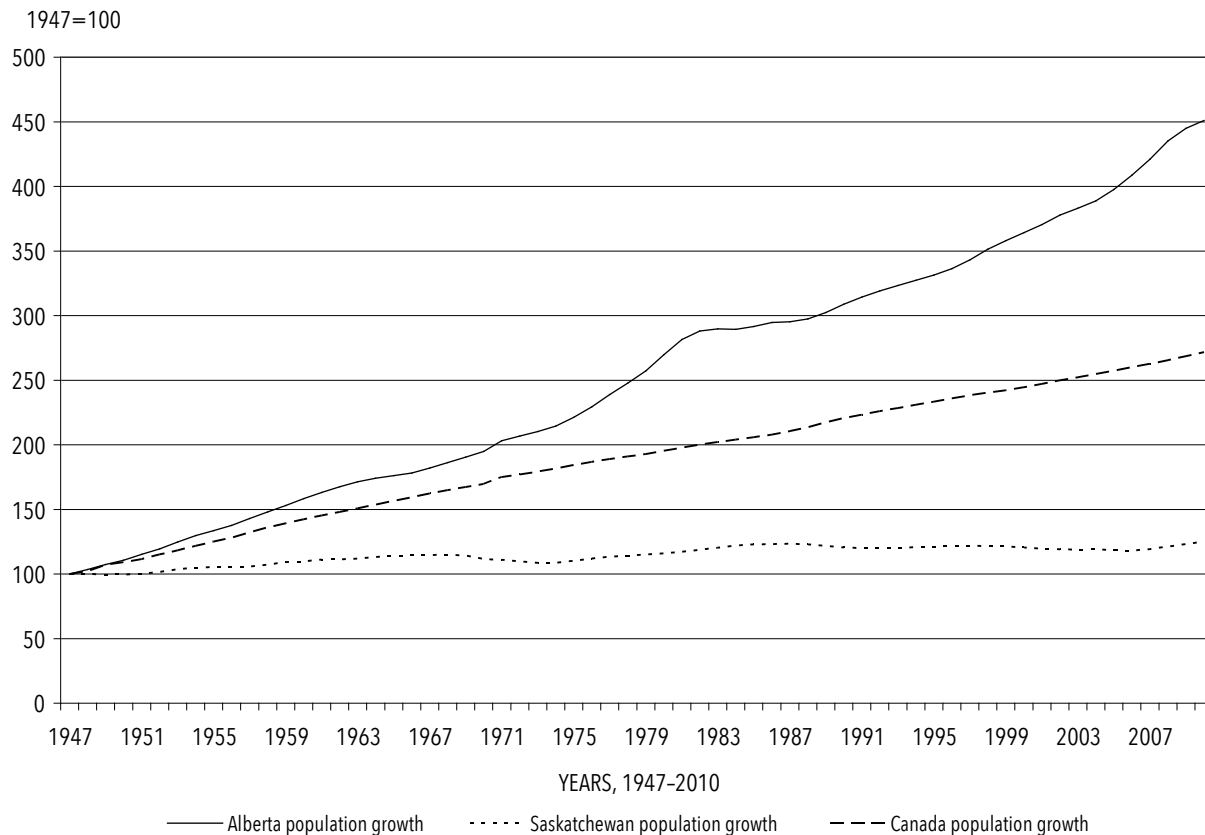


Figure 13.1 Population Growth, 1947-2010

number of observations made by other analysts about the performance of the Alberta economy relative to other parts of Canada. Next, we turn to the relative magnitude of the petroleum industry as a part of the provincial economy. Following this, we examine a number of specific issues that have been raised about the role of the petroleum industry.

a. Alberta's Economic Development, 1947-2012

In this section, we provide information about the development of the Alberta economy since 1945, using a number of common economic indicators. In some cases, comparisons will be made between Alberta and Saskatchewan, which were at similar stages of economic development at the end of World War II. We also include some comparisons to Canada as a whole. For the most part, the data are depicted in a graphical manner.

Population. Figure 13.1 shows population growth since 1947 for Canada, Alberta, and Saskatchewan, with the 1947 value set at 100. (At that date, Alberta held about

825,000 people, and Saskatchewan 836,000.) By 2012, Alberta's population had grown to more than 3.8 million, an increase of four times, much higher than the Canadian average. Saskatchewan still held barely more than one million, showing much slower population growth than Canada as a whole. Figure 13.2 makes the differences between the two prairie provinces clear. It shows that the ratio of Alberta's population to Saskatchewan's rose from about 1 in 1947 to well over 3 by 2007. Alberta's share of the Canadian population rose from under 7 per cent to more than 10 per cent, while Saskatchewan's share fell. However, it is also apparent that the growth in Alberta's population was not constant over this period. Thus, for example, the 1950s and 1970s saw particularly rapid growth, corresponding to the initial surge in petroleum discoveries after Leduc in 1947 and the rapid international price rises in the later period. On the other hand, from 1982 through 1988, population growth was slow; this followed the imposition of the National Energy Program (NEP) in 1980 and the substantial fall in international oil prices in 1985.

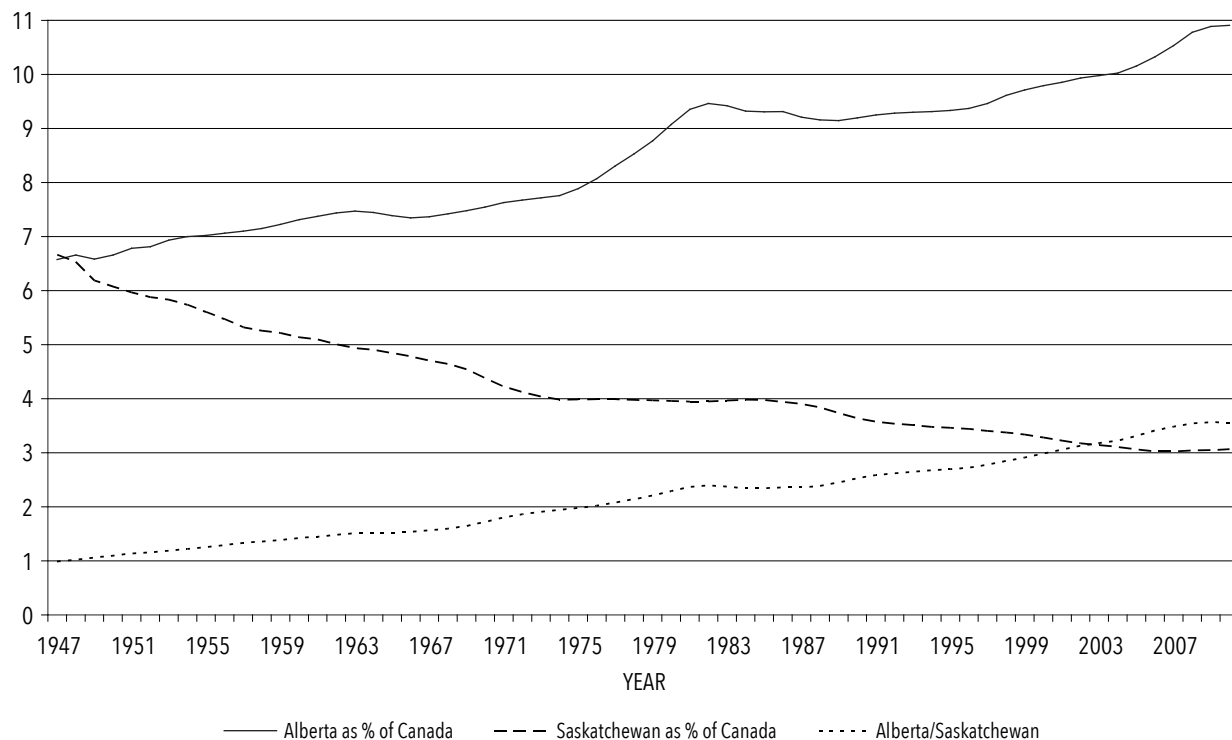


Figure 13.2 Alberta and Saskatchewan Relative Population, 1947-2010

Gross Domestic Product (GDP). Figure 13.3 shows the increase in real GDP for Alberta, Saskatchewan, and Canada, with 1951 set at a base value of 100. (Real GDP values for all three regions were obtained by applying the Canadian GDP price deflator to nominal GDP for the region, thus showing the increase in output after allowance for inflation.) As would be expected from the population trends, since more people normally generate more economic activity, Alberta's GDP increase exceeded that for the entire country, which was, in turn, higher than that for Saskatchewan. However, it was not until after 1972, when crude oil prices began to rise sharply, that Alberta's growth in GDP began to significantly exceed Canada's. Figure 13.3 makes very clear the rapid rise in Alberta's GDP from 1972 until 1980. However, this was followed by a period of no growth, then actual decline in GDP, until relatively rapid growth commenced again in 1993. As mentioned above, this period saw the implementation of the NEP, from October 1980 through to mid-1985, and the sharp decline in international oil prices in 1985. It is noteworthy that the mid-1990s did not see a sharp rise in the real price of crude oil or natural gas. Rather, it looks as though the Alberta economy took

some time to adjust to the transition from a period of high and optimistic oil prices and, perhaps, the 'excessive' boom that had been generated. Once 'on track' again, the economy resumed robust growth, with the rise in oil prices after 2003 providing a further boost.

It is difficult to separate out the impacts in the 1980s of government regulatory programs (such as the NEP) and falling oil prices. Helliwell et al. (1984) suggest (partly by comparison with the United States) that the NEP had an immediate depressing effect on oil-industry activity in Alberta (in 1981 and 1982) but that this was short-lived, offset by the subsequent modifications in the NEP, and that by 1983 the most important depressing factor was declining natural gas prices. A comparison of Alberta's falling and static GDP after the oil and natural gas price declines of 1985 with the growth in total Canadian GDP, as seen in Figure 13.3, points out the quite different impact of lower petroleum prices: the effect is deflationary in a petroleum-producing region such as Alberta but has a net stimulatory impact on a developed industrial economy such as Canada's. (For a summary of economic models assessing the impact of lower oil prices in Canada, see, for example, Waverman, 1987.)

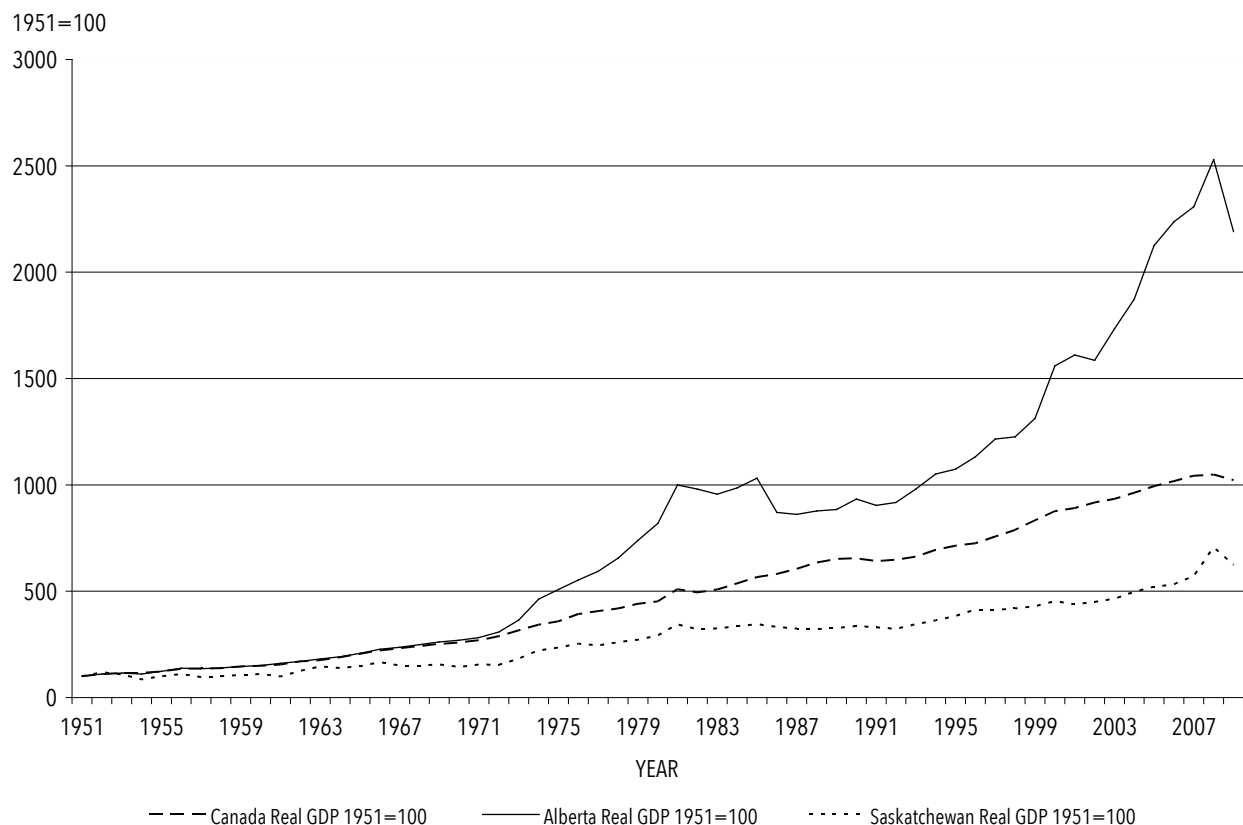


Figure 13.3 Canada, Alberta and Saskatchewan Real GDP, 1951-2009

Unemployment Rates. Figure 13.4 includes the annual unemployment rates for Alberta, Saskatchewan, and Canada. Prior to 1966, Statistics Canada provided this data only for the combined Prairie provinces (Alberta, Manitoba, and Saskatchewan), so this value is shown for years from 1947 through 1966. It can be seen that unemployment was almost always lower in Alberta and Saskatchewan than in Canada as a whole, the Canadian value, of course, being coloured by the generally high unemployment rates in Atlantic Canada. The rates for the two western provinces generally follow movements for the country at large, reflecting business cycle trends and structural changes (such as modifications in employment insurance regulations). The Alberta unemployment rate was usually a little higher than Saskatchewan's, but the reverse was true after 1996 and through to 2008, when Alberta's rate rose appreciably more than that of its neighbouring province; by 2012, Alberta's unemployment rate was slightly lower than Saskatchewan's again. The varying size of the difference between the Alberta

and Canadian unemployment rates indicates that unemployment has been more variable across time in Alberta. Two periods can be seen in which the unemployment rate for the province approached the Canadian average: briefly in the early 1970s (just prior to the large international oil-price rises) and in the decade from 1983 to 1992 (which was marked by stagnant GDP, as noted above). The Alberta unemployment rate actually exceeded the Canadian average briefly in the late 1980s, but after 1993 the Alberta rate once again fell well below the Canadian average.

Per capita Income. Figure 13.5 shows per capita GDP, Personal Income (PI) and Personal Disposable Income (PDI) in Alberta and Saskatchewan relative to the Canadian average for years from 1947 to 2010. (A value greater than 1 obviously means that the province exceeds the Canadian average.) Detailed definitions of these income measures can be found in assorted Statistics Canada documents; we will provide a brief overview. GDP is a measure of total economic

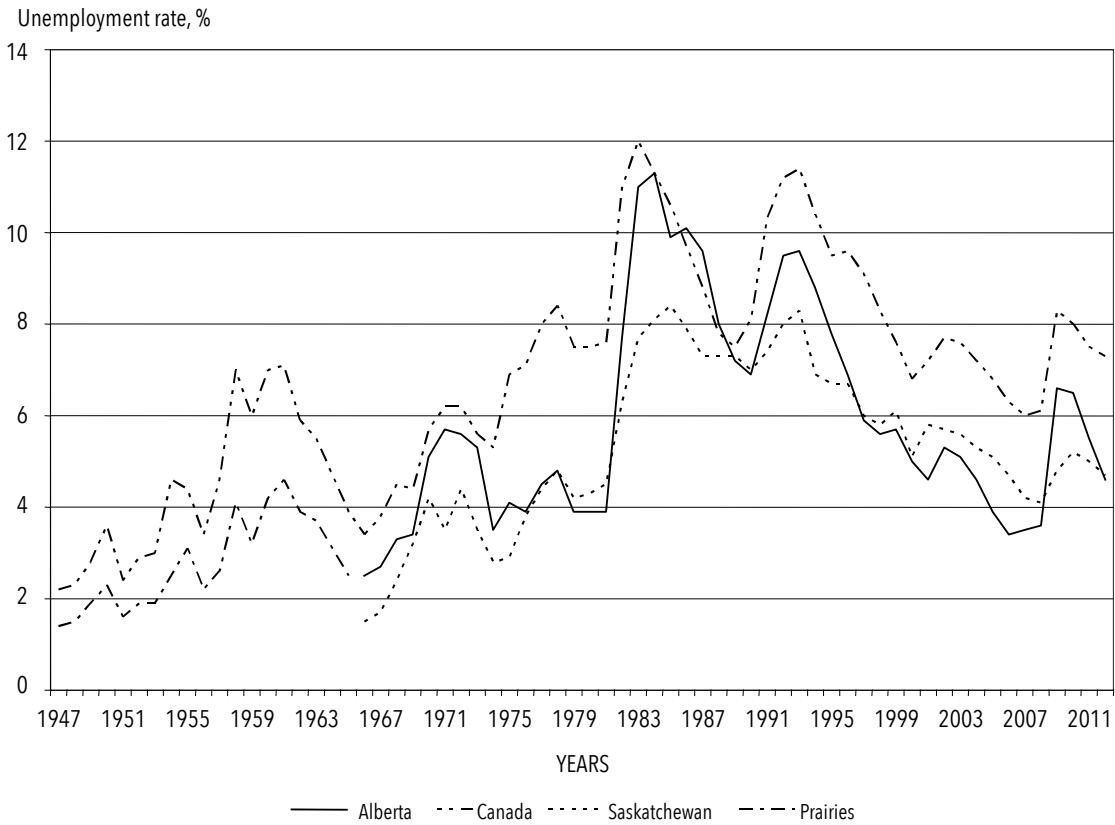


Figure 13.4 Unemployment Rates: Canada, Alberta and Saskatchewan, 1947-2012

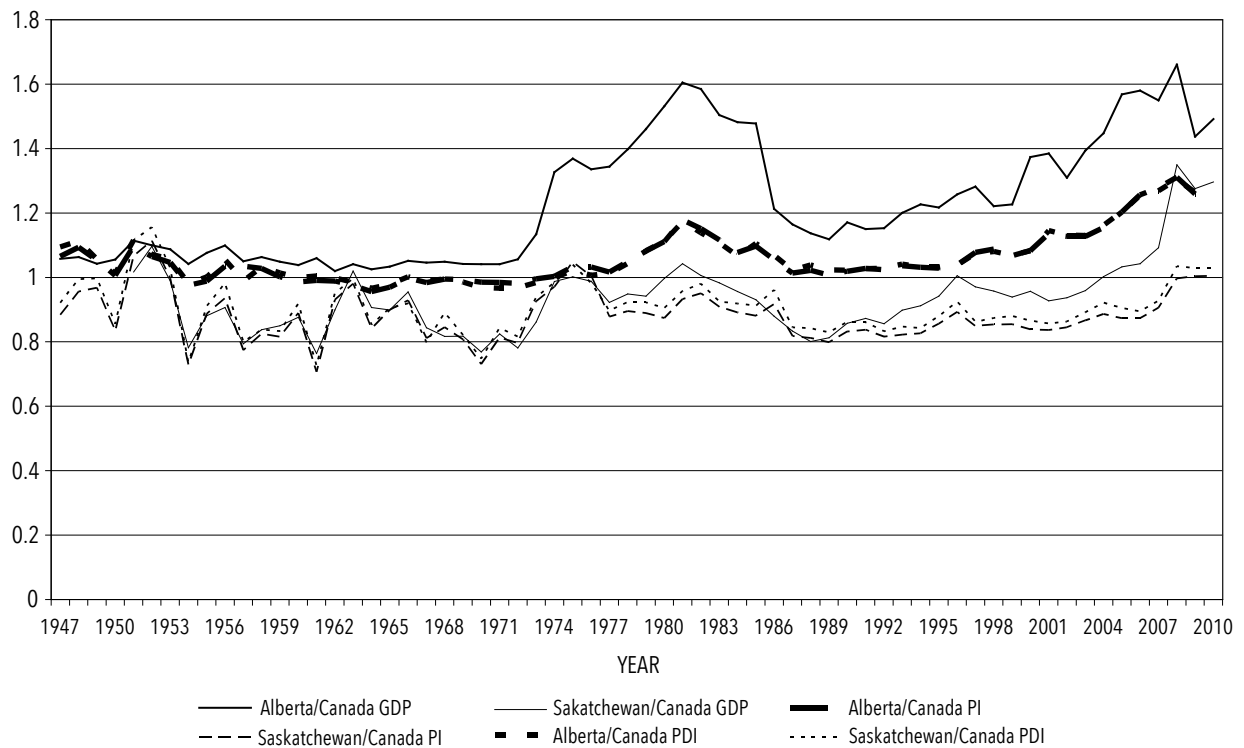


Figure 13.5 Relative per capita GDP, PI, and PDI: Alberta and Saskatchewan, 1947-2010

activity in the region; the meaning of the concept was discussed in more detail above. Personal income differs from GDP largely by the exclusion of depreciation and corporate taxes and retained earnings plus reductions for income generated in the region which leaves (e.g., payments to non-resident owners) and additions for income from outside which flows to people in the region (e.g., federal welfare benefits and interest payments received from non-resident entities). Disposable income excludes direct payments to governments, including personal income taxes, and payments to governments for social insurance and pension plans; it is, essentially, the income households have to spend on consumption or saving.

As can be seen in Figure 13.5, since 1947 Alberta's per capita GDP has always been above both the Canadian average and that for Saskatchewan. (Values are available for Saskatchewan only from 1951 on, and that province, in most years, had a per capita GDP below the Canadian average.) Until 1973, Alberta's per capita GDP was no more than 10 per cent above the Canadian average. This was the year in which international oil prices increased dramatically, and since then, Alberta's per capita GDP relative to Canada's has been much higher, as much as 60 per cent greater in the early 1980s and again in 2006/7. The sharp fall after 1983 and much lower relative values for the next decade (but still higher than before 1974) are not surprising in light of the previous comments about this period.

Patterns for Personal Income and Personal Disposable Income per capita are similar to one another but somewhat different than for GDP. The Alberta values are almost always higher than the values for Saskatchewan, but the differences between the two provinces are not as marked as for GDP, largely reflecting the exclusion of much corporate income. And the Alberta values are much closer to the Canadian average than they were for GDP, with personal income values up to the mid-1970s sometimes falling below the Canadian average. As with a number of the other economic indicators, a sharp rise is noted in the late 1970s, followed by a rapid decline (although remaining above the Canadian average), and relative stability into the 1990s. In the later 1990s, PI and PDI per capita in Alberta once again increased relative to the Canadian average.

We would note that, until the mid-2000s, Alberta's relatively lower individual income tax levels did not translate into a PDI standing that is noticeably higher than that for PI. (The absence of an Alberta sales tax would not be evident here.) While Alberta GDP, PI,

and PDI, compared to the Canadian average, show similar time trends, the relatively higher values for GDP are evident in Figure 13.5. This may reflect the higher capital intensity of the Alberta economy, so that depreciation and corporate profits are more important. But it may also reflect the importance of the petroleum industry. Consider, for example, the increased spread, after 1972, between the GDP and the personal income values. This began with the sharp rise in international oil prices as OPEC became more effective and stimulated price increases for substitute energy products such as natural gas. Even with the oil and natural gas price controls imposed by Canadian governments, the sales prices of oil and natural gas in Canada moved well above the levels of the 1950s and 1960s. Thus the 'value added' in petroleum production increased, raising per capita GDP. However, the increase in personal income (and PDI) was much less pronounced since (1) a significant part of the increased value of oil and gas went to governments in higher royalties and taxes and (2) much of the increased profit of the oil companies did not find its way into the hands of Alberta residents. That oil-price changes are still important is suggested by the decline in per capita values in the year 1998/9 and 2001/2, and the subsequent rise as international oil prices recovered, and as North American natural gas prices attained new highs.

Summary. At the end of the Second World War, Alberta and Saskatchewan held approximately the same number of people and appeared similar in economic structure, with agriculture the key industry. After the Leduc find of 1947, the economic development of the two provinces diverged, with Saskatchewan growing much slower than the Canadian average and Alberta much faster. We have not constructed a formal economic model of the Alberta economy, but it seems plausible that this difference stems from the growth of the petroleum industry in Alberta. In addition, periods of more rapid growth in Alberta and times of weaker economic performance also appear to be tied to changes in conditions in the oil industry, particularly movements in crude oil prices. Finally, this dependence on the petroleum industry seems to have led to a somewhat more unstable economy in Alberta. Figure 13.6 compares annual percentage changes in real GDP for Alberta and Canada from 1952 through 2011. The Alberta economy has tended to show wider swings in GDP than Canada as a whole, particularly in the 1972 to 1992 period and again after 2000. Further, the

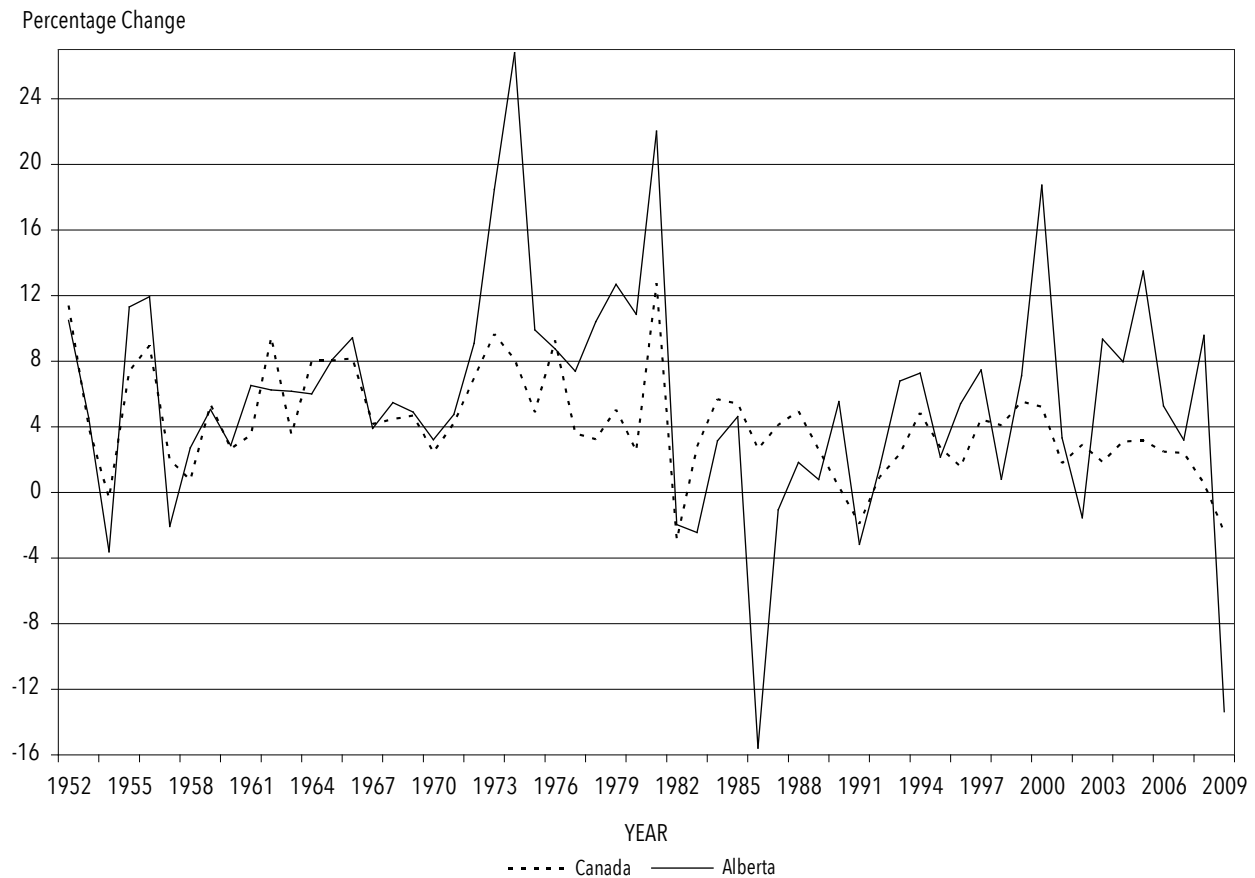


Figure 13.6 Canada and Alberta % Change in Real GDP, 1952–2009

widest swings are consistent with the interrelationship we have been suggesting in this section of a positive correlation between Alberta GDP and oil prices.

b. Other Analysts' Descriptions of the Alberta Economy

The depiction that we have provided of the Alberta economy and its relative strength compared to Saskatchewan and Canada as a whole in the years after 1947 is confirmed in other studies such as Hanson (1958), as described above, Coffey and Polèse (1987a), Lithwick (1977), and Mansell and Percy (1990).

The last of these studies argues that both Alberta and Saskatchewan exhibit much greater income instability than the Canadian average. Drawing on data from 1961 to 1985, Mansell and Percy (1990, p. 72) calculate an index of 'regional economic instability' (REI). They first established a time trend in the relevant series. They then calculated the sum of squared differences between actual values and the values shown by this time trend; squaring made sure that both positive and negative deviations from trend

were positive values and also assigned greater weight to larger deviations. Then the square root of this sum was divided by the average value for the series, to provide the REI. A higher value denotes greater instability. Values of the REI for Canada, Alberta, and Saskatchewan for three measures of economic activity are shown below.

	Canada	Alberta	Saskatchewan
GDP	169	2,672	1,000
Personal income	216	1,328	720
Per capita personal income	176	685	793

Both provinces exhibit much greater economic instability than Canada as a whole or any other province. (The NWT and Yukon showed even greater GDP instability.)

Mansell and Percy (1990, p. 21) also calculate annual employment 'location quotients' for Alberta relative to Canada for the years 1973 to 1987. A location

quotient is the share of employment in Alberta in an industrial sector relative to that share for Canada. We show values for three years.

	1973	1980	1987
Agriculture	2.45	1.65	1.81
Mining	2.63	3.24	3.66
Construction	1.18	1.65	1.10
Manufacturing	0.41	0.47	0.43
Transportation and Utilities	1.00	1.06	1.01
Trade	1.09	1.05	1.02
Finance	1.06	0.96	0.87
Services	1.03	0.96	1.05
Government	0.96	0.93	1.07

The regional significance of the resource industries and lesser significance of manufacturing is clear. Construction has been important, as might be expected given the capital intensity of the petroleum industry and Alberta's rapid growth.

In conclusion, assorted analysts have found that the Alberta economy grew rapidly after the Leduc find of 1947 and performed well in relationship to the rest of the country. Compared to Canada as a whole, the mining and agricultural sectors have played dominant roles. Generally speaking, per capita income was near or above the Canadian average, and Alberta's unemployment rate has normally been lower than average. However, the Alberta economy has been much more unstable than those of almost all other provinces.

We now turn to a more direct measure of the significance of the petroleum industry to the Alberta economy.

2. Petroleum's Contribution to GDP

The direct significance of different industries can be measured by looking at the 'value added' to GDP. As mentioned above, an industry's value added is the sum of wages, rent, interest, and (before-tax) profits paid. In essence, it is the value of an industry's production less its purchases of goods and services from other industries, and it can be used to measure the relative significance of different industries to the total economy. As noted above, when added up across all industries, it provides as measure of the total value of production in the economy. One complication is in determining exactly what properly constitutes an industry. For example, does the petroleum industry include only the crude-oil-producing industry, or does it also include pipelines, refineries, petrochemicals,

oilfield service companies, geological consulting firms, etc.? In this regard, the researcher is often constrained by the form in which statistics are collected.

We draw on the Alberta Provincial Accounts to show value-added shares of different industries for the years 1961 to 2001, and from CANSIM for 2002–2008, the last data available at the time of revision of this volume. Data are unavailable for years prior to 1961. A significant change in statistical methodology was applied to the statistics for years from 1971 on; definitions were changed again with the 2009 data. Accordingly, we utilize values for two separate time periods, 1961–71 and 1971–2008. The two are not strictly comparable, although at the level of aggregation we use they are broadly consistent with one another. The 'Mining' industry is almost entirely petroleum activities, and, in our data, has been expanded to include natural resource royalties (which are included in the "Finance" sector in the primary data sources). Coal is the other major mineral product produced in Alberta, partially for export, but also for electricity generation in the province. Bitumen and heavy oil upgrading, which are an important part of oil sands activities, are included in the mining sector. The provincial statistics include "Support activities for mining and oil and gas" in the mining sector.

However, as implied by open economy models, and discussed by Hanson in *Dynamic Decade*, the contribution of the petroleum industry is likely to go far beyond its direct contribution to provincial GDP. Mansell and Percy (1990, pp. 17–19) quote a government discussion paper that suggested that "in 1981, about half of the construction activity and one-quarter of the manufacturing activity in the province were related to oil and gas." Moreover, the industry purchases a variety of other services and is a major source of revenue to the provincial government. And, of course, the incomes generated by these activities directly tied to the petroleum industry help fuel the demand for assorted other household and business goods and services. It also appears that exports of petroleum-related goods and services have been of increasing importance.

Figures 13.7 and 13.8 include five broad industrial groups: mining; agriculture and forests; manufacturing; construction, transportation and utilities; and trade, finance, public administration and other services. The years 1961–71 are shown in Figure 13.7. In this period, the mining industry contributed between 10 and 15 per cent of Alberta GDP, with the share rising slightly to 1968, then falling off slightly. Overall, industry shares were relatively constant in this decade;

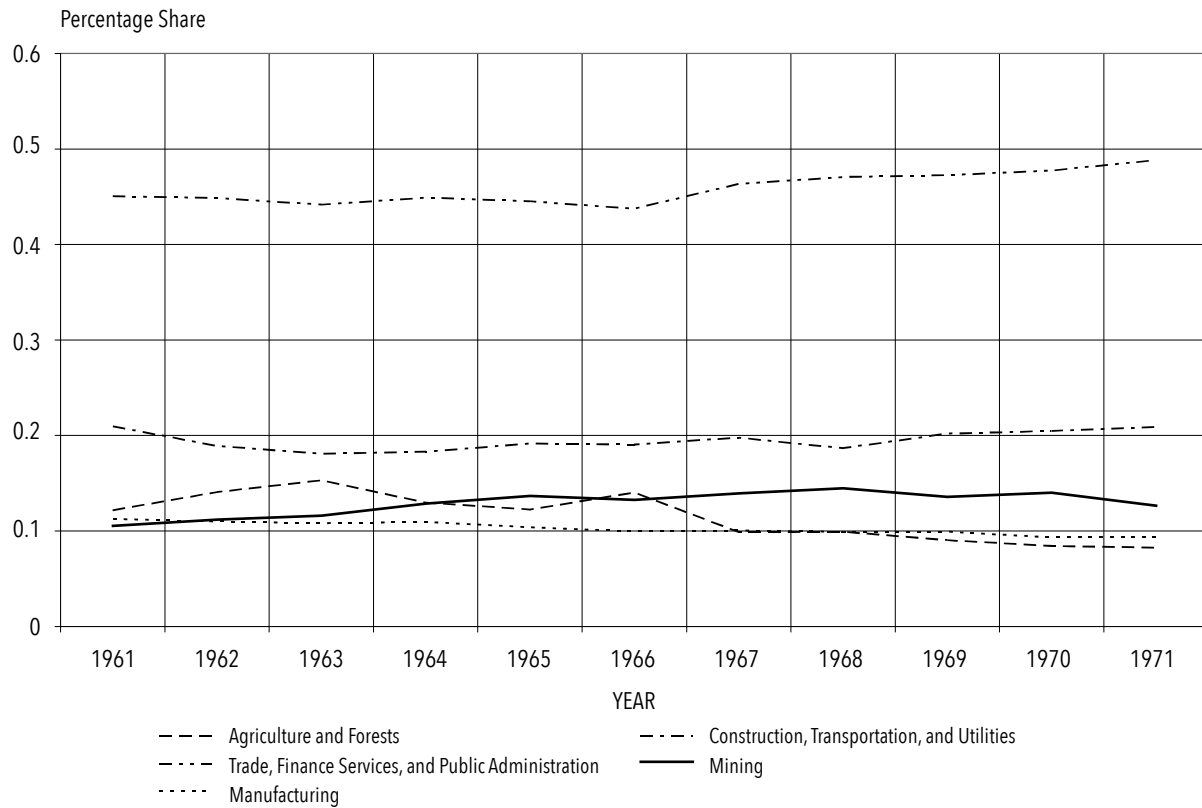


Figure 13.7 Industry Shares in Alberta GDP, 1961-1971

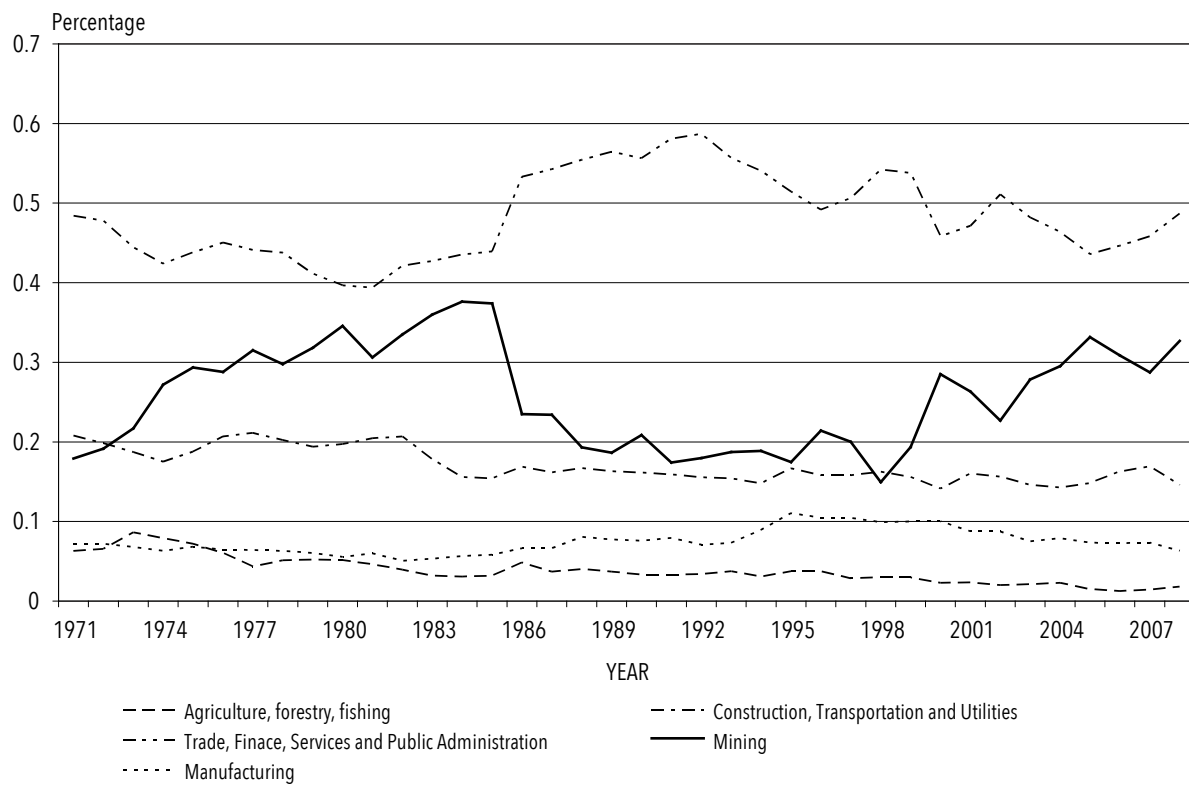


Figure 13.8 Alberta Industry Shares in GDP, 1971-2008

Source: Calculated from data in Alberta Department of Finance, ASIST Matrix 6106 and CANSIM II Table 3790026.

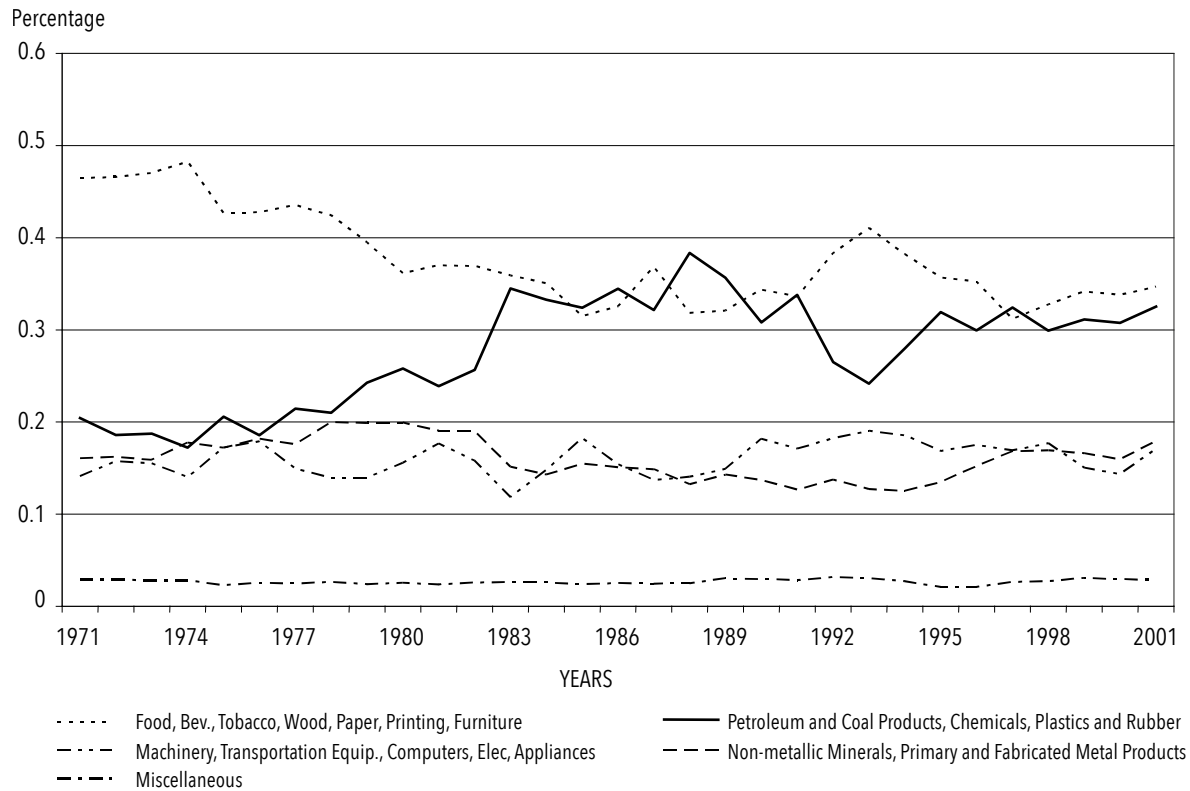


Figure 13.9 Shares in Alberta Manufacturing, 1971–2002

Source: Calculated from data in Alberta Department of Finance, ASIST Matrix 6106 and CANSIM II Table 3790026.

agriculture and forestry saw a reduced share, as, less dramatically, did manufacturing. Mining and services increased shares. A shift away from goods-producing industries towards services has been common for developed economies in the latter half of the twentieth century.

Figure 13.8 shows that more dramatic changes in the industrial structure of the Alberta economy occurred in the three decades following 1970. From 1971 to 1985, the share of mining in Alberta GDP rose from under 20 per cent to over 35 per cent. It will be recalled that this period saw large oil and natural gas price rises. (Figure 13.10, which will be discussed below, shows the relative changes in oil and natural gas production and real prices after 1969.) When international crude oil prices fell in 1985, the share of the mining industry in GDP also declined, to back below 20 per cent by 1988. From then, it varied up and down from a low of about 15 per cent in 1998 to just over 25 per cent in 2000, after which it rose again to over 30 per cent in 2005, before falling back somewhat then rising again in 2008. Oil and natural gas prices seem to be a major factor in these changes, with the

natural gas price hitting a high in the year 2005. The early 1980s bubble in the mining contribution to GDP includes the period of rapid growth in total Alberta GDP and per capita GDP discussed above. Obviously, a sharp rise in the mining share must be matched by declines in the shares of one or more other industrial group. This is seen to varying degrees in the 1971–85 shares for the other sectors, though only minimally so for manufacturing, and up to 1982 the construction, transportation, and utilities sector largely held its share. If the final years are compared to 1971, increased shares can be seen for mining, manufacturing, and the services group; the other primary industries and construction, transportation, and utilities show reduced shares of GDP.

The GDP shares for a broad aggregation of manufacturing industries for the years 1971 to 2001 are shown in Figure 13.9. (CANSIM data after 2002 included too many missing values, for confidentiality reasons, to be used.) One of these categories (petroleum and coal products, chemicals, plastics and rubber, which includes oil refining) is closely associated with the crude petroleum industry in the sense that these

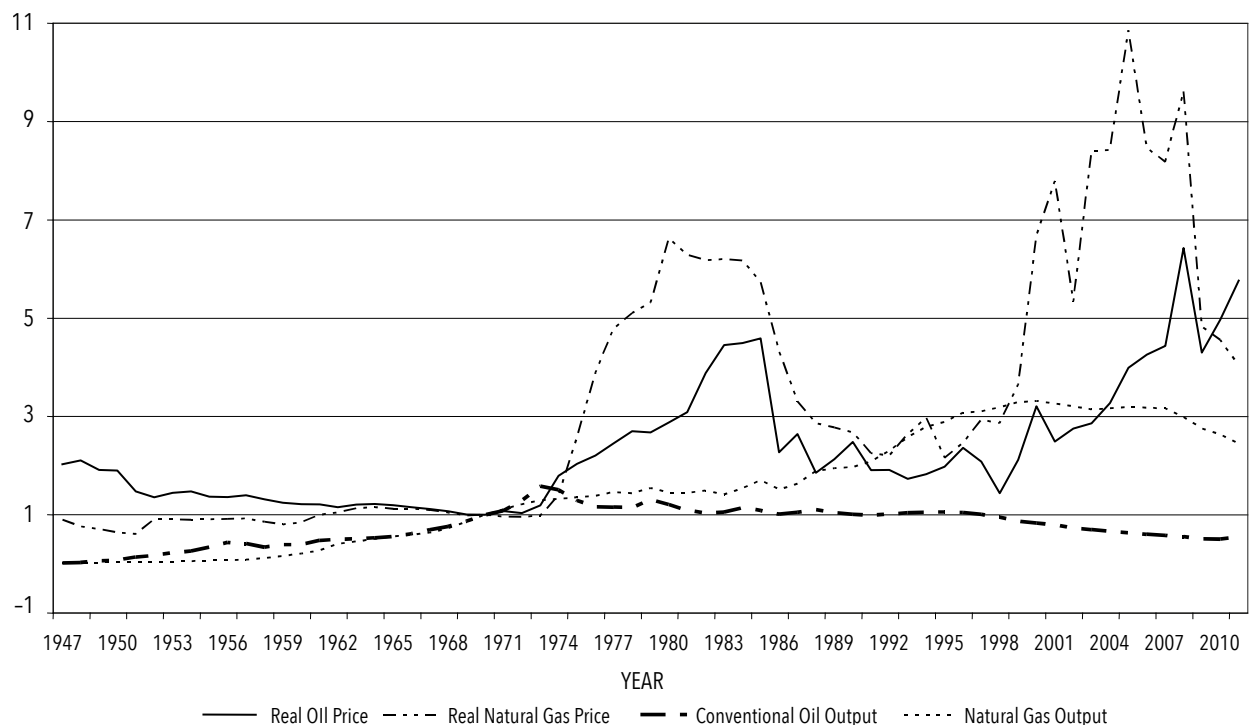


Figure 13.10 Indices of Real Oil and Gas Prices and Output, 1947–2011, 1970=1

manufacturing processes typically draw on oil or natural gas products as feedstock input (i.e., in addition to the need to buy energy to heat the manufacturing plant and provide process energy). From 1971 to 1988, the share of this group in Alberta manufacturing GDP increased dramatically, from just over 20 per cent to almost 40 per cent. The share of the agriculture and forestry-based manufacturing sector fell in a corresponding fashion, from over 45 per cent to about 32 per cent. This increase in the petroleum-based industries is similar to the increased share of the primary petroleum (mining) sector and reflects at least in part the increased value of petroleum in the marketplace. However, the peak for the petroleum products manufacturing sector (in 1988) comes after crude oil prices had fallen dramatically, and while the share of this sector did fall after 1988, and has shown significant variability, it maintained a value-added share in manufacturing that is some 50 per cent higher than its 1971 share. In 2009, the latest year for which data are available, petroleum-related manufacturing industries contributed 32 per cent to Alberta's manufacturing value added, while agricultural and forestry manufacturers contributed 28 per cent.

The significance of the petroleum industry to the services sector is difficult to determine with precision. Casual observation of the economy indicates that service providers to the Alberta petroleum industry have developed export markets, as well as meeting the needs of Alberta oil and gas producers. A 2001 government survey of the services sector (Alberta Departments of Economic Development and International and Intergovernmental Relations, July 2001) found that, in 1999, oil and gas services made up over 20 per cent of services sector revenue (for the seven key service sectors surveyed); this was second to construction services, which generated 61 per cent of the revenue. But the survey also found that for most non-oil-and-gas service providers (such as construction, computers, management consulting, and engineering), a part of the services provided were petroleum-related activities.

In summary, the petroleum industry obviously plays a major direct economic role in Alberta. In 1961, it was the least important of the five industry groups into which we separated Alberta GDP. (Mining, manufacturing, and agriculture and forestry were close in shares at that date.) By 2009, mining ranked

second, its share having risen from barely 10 per cent to almost 30 per cent.

As earlier tables in this book have demonstrated, both the volumes of production of conventional oil and natural gas and their real prices increased significantly since 1947. Figure 13.10 illustrates the importance of these changes since 1947, using 1970 as a base year. It can be seen that, prior to 1970, rising output of oil and gas was the dominating factor. After that, higher prices were of significant importance as was increasing natural gas production. (So, eventually, was rising oil sands output, which is not shown in Figure 13.10.) While both output and price could have generated higher value-added shares for the mining sector, the year-to-year variability in share suggests that price has played a particularly important role. In Alberta manufacturing, there has also been a shift over time towards a greater share for the sectors that utilize petroleum products as a material input for the good produced. The pipeline and construction industries obviously depend on the petroleum sector, and some manufacturers provide inputs to oil and gas production and transmission. Petroleum-related services also appear to have been increasing in value; in addition to meeting needs of the Alberta petroleum sector, some of these services providers engage in export sales, so are developing an existence independent of the Alberta petroleum industry. Unfortunately, published data on value added or revenue by industry is insufficiently detailed to allow precise estimation of the contribution of the petroleum industry to the Alberta economy as a supplier of inputs to other sectors and as a market for the output of other sectors.

We now turn to another measure of the relative size of the Alberta petroleum industry, its share in employment. Rather than giving extensive time series data, we utilize information from a recent year. (The contribution of the highly capital intensive petroleum industry to Alberta's total stock of capital is another measure of the significance of the industry, but not one about which we possess specific information.)

3. Petroleum's Contribution to Employment

Oil and natural gas production are capital-intensive activities, which do not require many direct workers. Of course, the total contribution of the petroleum industry to employment in Alberta is difficult to assess for the same reasons that its full contribution to GDP is hard to determine. (Which workers in other industries are employed only because they provide goods

or services to the petroleum industry or because they provide goods and services for the use of industries and households who reside here only because of the petroleum industry?)

In the broad historical context, Alberta, like other developed economies, has seen a decline in the importance of goods-producing industries, especially primary industries, relative to services. Thus, for example, the Alberta Bureau of Statistics (*Alberta Provincial Accounts*, 1973, p. 139) reported that the percentage of the employed labour force in agriculture, forestry, and fishing fell from 53 per cent in 1921 to 15 per cent in 1971, while service sector employment rose from 30 per cent to 60 per cent. This study lumped together mining, manufacturing, and construction, where the share rose from 16 per cent in 1921 to 25 per cent in 1971, rising markedly from a low of 13 per cent in 1941. More recently, in its *Facts on Alberta* of January 1994, the Industry Development Branch of the Department of Economic Development and Tourism (p. 8) showed 'fishing, forestry and mining' as providing 5.8 per cent of Alberta's employment (almost 90 per cent of this in mining, of which the petroleum industry provides most). The October 2010 issue of the same series (now from the Department Finance and Enterprise, p. 25), showed the employment share of "Energy" as 6.9 per cent. (Manufacturing's share fell from 7.6 per cent to 6.2 per cent over the same period.)

As these numbers make clear, the economic significance of the petroleum industry to the Alberta economy is not primarily through its direct employment.

4. Conclusion

In this section, we have set out broad features of the Alberta economy and the relative significance of the petroleum industry. The industry itself is highly capital-intensive, so that its direct contribution to provincial GDP is much larger than its contribution to employment. The value added by the petroleum industry has been a significant part of the Alberta economy, growing strongly after 1947, and especially during the period of historically high oil prices during the late 1970s and the early 1980s. The importance of the oil industry almost certainly is a major factor in explaining why, since 1947, growth of both population and real GDP in Alberta have been above the Canadian average, as has per capita GDP. The capital intensity of the industry and the high ex-Alberta

ownership and government-take of petroleum profits lead to per capita personal income in Alberta closer to the Canadian norm than per capita GDP; nevertheless, ever since the early 1970s, Alberta per capita personal income and personal disposable income have exceeded the Canadian average. Finally, it appears that the reliance of the Alberta economy on this single industry and the variability of oil and gas prices has led to greater instability in the Alberta economy than other provinces or Canada at large.

We now turn to five specific topics that relate to the role of the petroleum industry in Alberta: the degree of diversification of the Alberta economy (Section C); macroeconomic 'costs' of the NEP, and transfers from Alberta to the rest of Canada (Section D); the role of migration and price changes as economic 'equalizers' (Section E); impacts on Alberta government revenues and expenditures (Section F); and the significance of petroleum resource depletable-ity and the *Alberta Heritage Savings Trust Fund* (Section G). We provide broad overviews rather than detailed analysis.

C. Diversification

1. Introduction

It is often taken as obvious that a more diversified economy is preferable to a less diversified one. However, a proposition of this sort requires critical consideration. For example, that greater diversification is desirable is likely true only under some 'all else being equal' condition. For example, for any given size of the population, attainment of a more diversified economy at the expense of a sharp fall in the region's GDP would not be seen as a gain. Or, in an example of particular relevance to Alberta, a sharp rise in the value of the output in a major sector (e.g., rising oil prices from 1973 through the early 1980s) would lead to an increase in the contribution of that sector to the economy and, probably, a reduction in the industrial diversification of the economy; but it is hard to see this as necessarily undesirable.

One might suggest, as a tentative hypothesis, that a more diversified economy is preferable for any given level of GDP in the economy. The question now is "Why?" There seem to be two main answers, though they are often not made specific.

The first is that a more diversified economy is likely to prove to be more stable and resilient. (See, for example, Mansell and Percy, 1990, with regard to

Alberta.) This will hold true if the economic conditions in different industries are not highly correlated with one another, as when oil prices and wheat prices move largely in response to different factors. This argument for diversification would seem to be particularly strong when applied to regional economies from an export-base perspective. The diversification in this case relates to the exporting industries, where, for example, a collapse in the market for one export good will have a less drastic effect on the economy if the region has a number of other export goods for which market conditions remain strong. A secondary hypothesis might be that diversification is even more important for economies that depend heavily on non-renewable natural resources, which must, at some point, exhibit strong depletion effects.

A second possible argument for diversification is that a more diversified economy is likely to be more self-sufficient and hence less dependent in general on the vagaries of external market conditions. This argument is less convincing, as it confuses to some extent cause and effect and does not seem to focus on the most important variables in attaining a degree of self-sufficiency. Increased self-sufficiency hinges to a large extent on the economy attaining sufficient size that it can realize the economies of scale and agglomeration effects that make it efficient for producers of a wide variety of goods and services to produce for the local market rather than importing them. Thus it is not that diversification brings more self-sufficiency, but that, as a region grows large enough to attain more self-sufficiency, diversification follows.

It is important, then, to distinguish between diversification as a characteristic of an economy and increased diversification as a justification for public policy.

Thus, one could argue that greater diversification provides more economic stability for people in the economy but also that any government steps to raise the level of diversification are likely to prove either ineffective or more costly than is justified. Proponents of this line of argument would suggest that responsibility lies largely with individuals to protect themselves from the costs of instability (for example, by building up nest eggs in good times), with the government, perhaps, providing some economic 'built-in stabilizers' (e.g., unemployment insurance, food banks).

Others have argued that, since more economic diversification is desirable, governments should pursue an active 'industrial policy' designed to encourage the development of new industries. It is important to recognize that, in a country such as

Canada with a relatively mobile population, such policies, if successful, would almost inevitably lead to an increase in the size of the economy as well. In the Canadian context, this has led to speculation that the real purpose of such policies is not diversification but 'province-building' (Richards and Pratt, 1979; Pratt, 1984). This could reflect an interpretation of 'diversification' like the second of the two noted above, and/or the belief by regional politicians that a larger local economy is in their more selfish interests (for power, prestige, etc.).

Development of an 'industrial policy' is necessarily controversial since it involves the interplay amongst at least three questions.

1. *Who benefits?* In the real world of individual mobility, this is not a trivial question, as was noted above. At its most basic, the question is whether the policies should be aimed largely at those who are currently resident in the region (and their children and grandchildren, a 'generational' perspective) or at those who are currently and will in the future be residents of the region (a 'successor' perspective). From a 'generational' perspective, 'diversification' matters as a possible economic stabilization policy. As noted above, one way to attain this might be to extend the production life of the depletable resource over a longer time period, which might both keep the overall size of the economy smaller, and also reduce the concentration of GDP in the resource sector. In addition, there would be some advantages to mechanisms that transfer the rents from resource production into the hands of current resident households (e.g., through lower taxes or royalty trusts). On the other hand, from a 'successor' perspective, 'diversification' attained through the expansion of new industries could appear very attractive, generating income for more residents attracted to the region. Policies could involve using resource rents to help new industries get established and to provide additional public services available to newcomers as well as existing residents (which, if an improvement on public facilities in other provinces, could serve to attract immigrants).
2. *Given that a group has been defined, what are the policy objectives?* Here, it is common for economists to assume a 'public interest' perspective, with goals of efficiency and equity. However, readers will recall that economists have also

applied a 'public choice' viewpoint in which it is assumed that the policies will be those that politicians view as being in their own best interests, which may or may not correspond with the interest of the population at large.

3. If we assume that the objectives of public policy are such broad public interest goals as efficiency and equity, what specific policies should be adopted? While oversimplified, it is useful to suggest two general answers to this question. The first is that the appropriate 'industrial policy' is a largely passive, non-interventionist one. It is argued that attempts to force development of new industries almost always generate higher costs than benefits, and frequently involve permanent subsidization. Given the realities of a region's resources and location, and the increasingly globalized world economy, the best policy of the government is to ensure a flexible, well-functioning regional economy, with as neutral a tax system as possible; labour and business will then exploit the economic opportunities available to the advantage of the region and its residents. The second viewpoint argues for an interventionist 'industrial policy,' on the grounds that some corrections are needed in the existing system to attain the diversification/growth goals. A variety of 'failures' might be cited, including the following three: (1) the 'infant industry' argument, that a new industry requires government support until it attains sufficient size to realize the economies of scale and learning that allow it to compete in wider world markets; (2) the 'knowledge externality' argument, that governments have a responsibility to fund research and development and educational activities since they provide benefits that accrue to the economy at large; and (3) the 'agglomeration' argument, that the government should encourage economic growth to bring the economy to the size at which it can realize the widespread benefits of greater size and increased self-sufficiency. In addition, advocates of an interventionist approach often suggest that a non-interventionist policy frequently brings unacceptable 'equity' costs, for example by redistributing income away from workers towards owners of capital. Of course, these two policy approaches are the extremes; many analysts are willing to accept that some degree of active government policy is justified, but the question is how much.

We now turn to the specific issue of the petroleum industry and economic diversification in Alberta. Initially, we will discuss the degree of economic diversification of the economy. Then government diversification policies will be reviewed briefly.

2. The Extent of Economic Diversification in Alberta

The statistical information provided above allows some comments to be made on the question of diversification.

First, the expansion of the petroleum industry in Alberta after 1947 provided diversification of the economy away from agriculture, which did not occur to the same extent in Saskatchewan. However, as shown above, Mansell and Percy (1990) argue that the Alberta economy, from 1961 to 1985, was the most unstable provincial economy.

Second, the rise in oil and natural gas prices starting in the early 1970s might be interpreted to have reduced the diversification of the Alberta economy because the petroleum sector increased its relative significance. However, we argued above the impact of an increase in the price of an important industry's output is probably better seen as increasing the gross production of the economy (GDP) than as reducing the economic diversification of the region, unless the high prices lead to a continued expansion of that particular industry at the expense of other sectors (as in the 'Dutch Adjustment'). The value-added data for Alberta industries does not suggest that this occurred in Alberta. However, it is likely that instability in petroleum prices has been a significant factor in the instability in the Alberta economy noted by Mansell and Percy. Their measure of instability (the size of deviations from a trend line) would obviously be very sensitive to the sharp rise in value for many economic measures in the decade from 1973 and the fall and flatness for the next decade (as seen in the GDP and GDP per capita lines in Figures 13.3 and 13.5). Recall, also, that Figure 13.6 shows greater percentage variability in Alberta real GDP than Canadian, even after 1993.

Third, following the crude oil price collapse of 1985, there seems to have been a rise in the share of the manufacturing sector in the Alberta economy. That sector does appear to show greater diversification recently than at the start of the 1960s, largely as a result of a decreased share for the agriculture/forestry-based goods and a rise in petroleum-based products. (See Figure 13.9.)

However, the aggregated industrial statistics we have presented may hide the actual level of diversification. Thus, for example, the energy sector includes

conventional crude oil, non-conventional oil, natural gas, and coal. While there does appear to be a positive correlation between the prices of these energy products, the correlation is not perfect, as we pointed out in Chapter Twelve, when comparing crude oil and natural gas prices. In addition, each energy product exhibits its own unique production characteristics; for example, depletion effects could differ between conventional oil and natural gas, and the production linkages for non-conventional oil differ significantly from those for conventional petroleum. Thus it is possible that the increased relative shares of natural gas and non-conventional oil (relative to crude oil) starting in the 1970s provided increased stability to the Alberta economy even while the energy sector continued to be a major production sector. In another example, Norrie and Percy (1981) note that Alberta's agricultural sector is much more diversified than those of the other two Prairie provinces.

On the other hand, if the rising share of manufacturing comes largely in the form of increased processing of petroleum products, it may not provide as much economic diversification as it appears because these manufacturing industries may be subject to the same instabilities (due to price changes or depletion effects or the like) as the crude petroleum industry.

Thus, more detailed modelling is needed to address in a meaningful way the impact of the petroleum industry on the functioning of the Alberta economy. We will note, briefly, four such approaches, although not all specifically address economic diversification.

First, as mentioned above, Richards and Pratt (1979) and Pratt (1984) see Alberta's economic development in the 1970s as following a model in which (Pratt, 1984, p. 194)

... the powers and resources of an interventionist 'positive' government are being employed to defend the province-building interests of an ascendant class of indigenous businessmen, urban professionals, and state administrators. The objectives of this nascent class are to strengthen its control over the Alberta economy, to reduce Alberta's dependence on outside economic and political forces, and to diversify the provincial economy before oil and natural gas reserves are exhausted.

Obviously, this approach sees economic development largely in terms of class interests. It also draws heavily on a 'staples theory' perspective, wherein market

economies tend to separate into strong diversified centralized economies and undiversified, resource-based hinterland economies. Only through strong government policies can the hinterland economy (hampered by its distance from the centre's large markets and corporate decision-making processes) hope to attain some economic independence. Pratt sees the Lougheed government's policies in the 1970s and early 1980s as involving a three-pronged process of (1) wresting control over the petroleum industry away from the federal government after Ottawa's strongly interventionist policies began in 1973; (2) increasing economic rents on Alberta-produced petroleum, and gathering a higher share of these rents for use by the provincial government; and (3) encouraging the development of new industries in Alberta, particularly the petrochemical industry. Presumably the intent is that Alberta's locational advantage in terms of accessibility of petrochemical feedstocks (e.g., ethane) offset its locational disadvantage in terms of long distances from major consuming markets. We will not review Alberta's policies regarding petrochemicals, but there have been suggestions that the policy is likely to require continuing subsidies, either direct or indirect (e.g., by prohibiting the free sale of potential feedstocks in export markets, thereby reserving their use in Alberta at lower prices to petrochemical plants).

Within Pratt's political economy approach, there seems to be some doubt about whether a single hinterland region can effectively offset the inherent locational problems of a capitalist market economy. However, the activist government policies are seen as reflecting "the anxieties and aspirations of a dependent business community and an ascendant urban middle class, neither of which seek the elimination of the market economy – merely promotion within it" (Pratt, 1984, p. 220). Diversification, then, will require an activist approach to support the larger domestic economy. Most economists have been unconvinced about the inevitability of the centre-periphery economy dichotomy, arguing that the development of new industries and the growth of a larger domestic market may occur, allowing a greater degree of local autonomy and self-reliance.

Assessment of the extent of economic diversification of the Alberta economy, as has been seen, is often approached in the context of comparisons with other regional economies. In the Canadian context, this raises a number of issues that have been discussed in the context of regional economic disparities; that is, a second avenue of research suggests that the degree of economic diversification may be one of the factors

that contribute to regional economic differences. An economic approach to Canadian regional development can be found in two reports from the Economic Council of Canada, *Living Together* (1977) and *Western Transition* (1984), and in research undertaken for the Royal Commission on the Economic Union and Development Practices for Canada, the Macdonald Commission, which reported in the late 1980s. Mansell and Copithorne (in Norrie, Simeon, and Krasnick, 1986), in work for the Royal Commission, provide an overview of economists' thinking about Canadian regional economic disparities. They note that economists have not reached agreement on the explanations for differences in the economic performance of different provinces but that a number of factors are commonly implicated, some related to differences in economic structure and others to differences in the process of economic adjustment. They also remark that disparities in output per capita exceed disparities in per capita disposable income, presumably reflecting a variety of stabilization and equalization programs. They also note that regional mobility of labour and capital has played a role in keeping regional differences from widening. Differences in five aspects of an economy are argued to be most significant in explaining regional income differences: "Capital intensity, labour quality, scale and technology, participation rates and unemployment rates" (Mansell and Copithorne, 1986, p. 31). Presumably similar factors, including the nature of the key industries, relate to the stability of regional income. They note that studies designed to decompose the contribution of various actors to per capita income suggest that differences in the capital intensity of different industries (higher capital intensity yielding a higher capital-to-labour ratio) and in the quality of the labour force are major factors affecting regional income differences. Thus, Alberta's relatively high per capita output reflects, in part, a well-educated labour force and the high capital intensity of the petroleum and agricultural industries.

A third line of research involves the neo-classical modelling efforts of Copithorne (1979, looking at regional economic differences in Canada) and Mansell (1975, and 1981, looking at both migration and the functioning of the Alberta economy; also Mansell and Wright, 1981, and Mansell and Percy, 1990). Copithorne's research suggested that disparities in natural resources are not the main basis of Canadian interregional economic differences, although the functioning of specific resource industries like forestry in British Columbia and the Newfoundland open-access

fishery do have lasting structural effects. Rather, his model places emphasis on the mobility of capital and labour and the degree of flexibility in labour and capital markets, with greater rigidity in factor adjustments associated with lower income. Mansell (1975) and Mansell and Wright (1981) also found that Alberta benefited from a greater degree of labour mobility than in some other parts of Canada.

Mansell and Percy (1990, pp. 35ff.) report simulations of the Alberta economy using a large econometric model. Within this model, investment spending is found to have been a major driving force (and an increasingly important force) behind the growth of the economy. This is entirely consistent with petroleum-resource booms in the late 1940s and the mid-1970s. In the 1980s, starting in 1982, an economic slowdown is explained by a fall in petroleum investment (argued to be occasioned by the National Energy Program), as well as by high interest rates and a large net financial transfer out of Alberta to the federal government. Throughout, migration into (or out of) Alberta is responsive to relative income differences between Alberta and the rest of Canada.

Mansell and Percy argue that this model places less importance on purely structural aspects of various industries and more emphasis on inappropriate government policies. From a Keynesian perspective, an economy in which investment spending forms a significant part of aggregate demand may be particularly prone to instability. Presumably, in Alberta, the high role for investment reflects both the capital intensity of key industries and the fact that the province has exhibited periods of higher than average growth. (The Keynesian 'accelerator/multiplier' model exhibits just such instability. Investment stimulates economic growth, through a multiplier effect on the economy; this growth in turn attracts increased investment, which accelerates the income growth. However, if any factor stops the growth in investment, then the growth in income tends to stop, and investment falls, which reduces aggregate demand and reduces income, leading to a further drop in investment, and so on.)

A fourth line of research on the Alberta economy, using general equilibrium models, was undertaken for the Economic Council of Canada by Norrie and Percy (1981, 1982, 1983). A general equilibrium approach is designed to capture the wide-ranging effects of changing sectoral growth rates or of specific economic policies, by explicitly looking at the interconnections amongst various sectors of the Canadian

and provincial economies. (Much of their work posits a 'Western Economy,' based, for example in the 1982 paper, on Alberta and Saskatchewan. We shall discuss the results as applicable to Alberta.) Norrie and Percy (1981) found that, while Alberta expanded relatively faster than Central Canada through the 1970s, largely due to rising resource prices, there was little evidence of significant structural change in the Canadian economy; for example, little diversification was seen in Alberta. Growth through labour migration did have some effects, including some labour shortages in Alberta, and price effects in markets for non-traded commodities (such as housing, with weaker prices in regions losing labour, and higher prices in regions like Alberta gaining labour).

There is no evidence that Alberta's expansion came at the expense of central Canada. In fact, some 'Dutch Adjustment' effects are evident, in which skilled labour shortages in Alberta make expansion of manufacturing and service industries there less appealing, and imports from Central Canada more appealing. The 1982 paper focuses explicitly on the utilization of resource rents by the provincial government. It finds that if the province uses the revenue to provide additional goods and services to residents, as opposed to passing the rents through in the form of lower taxes, the net benefits to residents on average are reduced, but the provincial economy grows in size and certain local residents (e.g., property owners) experience a net gain. This is a 'province-building' strategy, and it has greater impact if there are regional agglomeration effects.

In conclusion, while the Alberta economy has clearly grown faster than the Canadian economy since 1947, and appears somewhat wealthier but also somewhat less stable, there is little consensus as of yet on the exact nature of the underlying growth processes and whether the economy has become more diversified in the process. Part of the problem is in the difficulty in defining 'diversification'; partly it is in devising an adequate measure of diversity for any specific definition of that term.

Conceptually, the petroleum industry would affect the larger Alberta economy in three major ways: (1) through an increase in the level of petroleum production and associated investment; (2) through an increase in the real price of petroleum; and (3) through increases in productivity. To some extent, all three factors have operated since 1947. Figure 13.10 provided some information on the relative importance

of the first two factors, showing the relative changes since 1947 in oil and natural gas output as compared to real prices.

- The period from 1947 through to the early 1970s was driven largely by the rising production, as can be seen in the tables in Chapter Six for oil and Chapter Twelve for natural gas. In this stage, the petroleum industry initially provided diversification away from the heavy reliance on agriculture but left Alberta largely dependent on these two industries.
- From 1973 to 1982, rising energy prices were the key factor, as shown in Figure 13.10. The essential economic effects of higher prices for oil and natural gas are relatively straightforward, although the precise impact depends on how the increased values are utilized. Initially, there is a significant inflow of funds into the province (due to what most economists would call an improvement in Alberta's 'terms-of-trade,' as petroleum prices rise relative to the prices of other goods and services). The higher prices and incomes induce greater spending on goods and services generally and petroleum production in particular. This, in turn, increases imports into the region and drives up local prices, including prices of the skilled labour and other inputs used in the petroleum industry. Longer-run effects begin to operate, including a rise in the inflow of labour and capital into the region, which helps to alleviate the local inflationary pressures. However, rising costs of local inputs also decrease the attractiveness of production for many goods and services. In effect, the resources utilized to produce more of the increasingly valuable petroleum come from two sources: in-migration and resources transferred from other production in the region. The latter effect is a manifestation of the 'Dutch Adjustment' and implies an increased economic reliance on the petroleum industry or a reduction in economic diversification.
- International oil prices fell after 1982, and natural gas prices followed, as seen in Figure 13.10. While petroleum and agriculture have continued to be the mainstay of the Alberta economy, many observers have expressed the feeling that by the turn of the century Alberta had become somewhat more economically diversified, at least in the sense of having attained a relatively large, robust, and growing economy. The sharp fluctuations in

international oil prices in the late 1990s and early 2000s seemed to have a somewhat smaller effect than similar real price changes had in the 1970s and 1980s. In 2003, the Toronto Dominion Bank (TD Bank, 2003) issued a report labelling the Calgary–Edmonton corridor one of Canada's four high-growth areas (along with Toronto, Montreal, and Vancouver), describing it as "the only Canadian urban setting to amass a U.S.-level of wealth while preserving a Canadian-style quality of life" (p. 1). They note the high reliance upon the oil and gas sector but suggest that some economic diversification has taken place (p. 9):

Oil and gas mining production and exploration activity remains the single largest industry in Alberta, at 19 per cent of GDP, followed by finance, insurance and real estate (16 per cent), manufacturing (10 per cent), and construction (8 per cent). However, the past few decades have seen some notable shifts across the sectors in terms of relative importance to the provincial economy. The real GDP shares of oil and gas and public services (including health care and education) have both slipped by 4–5 percentage points since the mid-1980s. In contrast, several industries – such as forestry, chemicals and machinery and equipment, residential construction, transportation services and wholesale trade – have registered above-average growth and rising shares of provincial output. Finally, professional, scientific and technical services and communication services have witnessed among the largest jumps in relative importance over the past two decades, spurred in part by the surge in industrial and consumer demand for information-technologies.

Thus, by the start of the twenty-first century, the Alberta economy appeared to have become more resilient and somewhat less dependent upon the direct activities of the petroleum industry than it had been over the previous five decades.

In addition, as was remarked in Chapter Seven, there have also been changes due to the contraction of conventional oil production and the expansion of non-conventional oil activities. The mining/upgrading approach to the oil sands involves more regionally

concentrated (in northeast Alberta) production activities and different labour skills and equipment than conventional oil drilling and lifting. Further, while oil sands and heavy oil output expansion may help to maintain government revenue as conventional oil and gas production declines, the reliance upon profit-sensitive rules for government take may increase the instability of this revenue flow.

3. Alberta Government Policies

The Alberta provincial government has long seen diversification of the provincial economy as important. Following the election of the Progressive Conservatives in 1971, replacing Social Credit, which had been in power since 1935, the government has usually been characterized as pursuing a relatively activist diversification policy, as captured by the term ‘province-building.’ A key component of this policy was the active encouragement of processing industries using petroleum, especially natural gas; petrochemicals were the main example and were guaranteed access to ethane under favourable conditions.

After the mid-1980s, the official policy has shifted to a more passive diversification policy, generally captured in the phrase the “Alberta Advantage.” Mansell (1997) and Emery (2006) provide useful reviews of Alberta’s diversification policies. They argue that the ‘active’ policy pursued by the Lougheed and Getty governments through the 1970s and 1980s was not successful and involved losses of over \$2 billion in government funds. The 1991 discussion paper *Toward 2000 Together* set out a variety of options but signals this shift quite clearly: “the Alberta Government is committed to building a competitive business environment which encourages private sector growth and strengthens the role of market forces in the Alberta and Canadian economies” (Alberta, 1991, p. 4). While the discussion paper was supposed to allow Albertans to discuss various development strategies, the government’s preferred approach seemed to have been decided already. In the same year, the Alberta Department of Economic Development and Trade, in an overview of the Alberta economy entitled “Alberta Industry and Resources,” under the heading “Alberta’s economic strategy,” said:

Alberta sees the role of Government as one of providing support to, but following the lead of, the private sector. This role serves Alberta well in a rapidly changing and competitive world, where decisions taken by individual

entrepreneurs ultimately select the “winners and losers.” Once business has established the direction, government policy can support and enhance its competitiveness and encourage further development.

The government has seen the “Alberta Advantage” largely in terms of measures to free up markets (including those for labour), removing regulatory barriers to business activity (partly through fewer, but also through transparent and stable, regulations), the provision of general infrastructure, which can be utilized by any business, and a regime of low income taxes (both personal and corporate). The Toronto Dominion Bank’s 2003 study of the Calgary–Edmonton corridor listed three factors as of particular importance to the corridor’s economic strength (pp. 9–14): ‘low costs’ (particularly a low-tax environment); ‘a young and diverse population’ (including high skill levels); and ‘world-class infrastructure’ (including transportation, internet communications, and educational facilities). All three are dependent on provincial government policies, but policies of a ‘general’ nature, rather than activist policies that try to direct economic diversification into specific industries.

Of course, this policy has not been without its critics. Thus, for example, the TD Bank study notes that the reason for the young and skilled Alberta labour force lies largely in the qualities of in-migrants to the province. One of their main suggestions is that the Alberta government should be doing more for education, training, and investment in research and development. A second concern of some observers is the extent to which economic development in Alberta hinges on the ready accessibility of relatively low-cost natural gas. This is obviously important for the petrochemical industry but also for enhanced oil recovery projects for conventional oil and for oil sands production; it also underpins the hopes of some that Alberta might play a lead role in the development of a ‘hydrogen economy.’ The concern is whether a free market environment will allow Alberta to maintain abundant relatively low-cost natural gas supplies as North American gas markets become more integrated and as existing low-cost Alberta gas pools are drained. (Also see Bradley and Watkins, 2003.) To support the more diversified economic structure of the province, while allowing continued growth, may require a somewhat more activist policy than has been seen recently.

We now turn to very brief discussions of several other issues related to the role of the petroleum industry in the Alberta economy.

D. The Macroeconomic Costs of the National Energy Program and Net Provincial Transfers to the Rest of Canada

In Chapter Nine, we discussed the ‘overt’ regulation of the petroleum industry in the years 1973–85. This period generally involved joint agreements between the federal government (‘Ottawa’) and the Alberta provincial government (‘Alberta,’ and other provincial governments). However, the initial regulations were introduced unilaterally by Ottawa, first in 1973, and then again in October 1980 in the National Energy Program (NEP). It will be recalled that amongst the regulations were policies to hold the price of Canadian-produced oil below world levels, to restrict exports of oil and natural gas, and to transfer a greater share of the industry’s economic rent to Ottawa. It has been argued that these policies had detrimental effects on Alberta. Mansell and Percy (1990) note two: (1) inducing an economic downturn, and (2) ensuring that federal fiscal policy was consistently deflationary in Alberta, even during periods of recession when fiscal stimulation would be desirable.

It is apparent that the federal overt petroleum policies did not consistently depress Alberta GDP, since the economy showed strong growth during the years immediately after 1973. However, growth would have been expected to be even faster had oil prices in Canada risen at the same rate as world prices, rather than at the slower controlled rate. After 1981, Alberta’s real GDP did decline. Mansell and Percy discuss this period (pp. 30–41) and, as mentioned above, report simulation results of an econometric model of the Alberta economy that finds that “the NEP was the key factor in initiating the downturn, and its negative effects were compounded by the accompanying high interest rates” (p. 37). As Figure 13.3 showed, Alberta GDP remained flat right through to 1993, long after deregulation in 1985. This suggests, as others had argued, that the key factor in the poor economic performance was less the NEP than plunging international oil prices, though the major price decline did not come until 1985. Mansell and Percy suggest that the NEP provoked a recession in Alberta but find that it would likely have occurred after 1985 anyway due to the lower petroleum prices. The NEP, presumably, made the downturn longer than it would otherwise have been, though they find that the adjustments the economy began to make after 1981 helped somewhat in the adjustments to lower prices after 1985.

Mansell and Percy (1990, Appendix A, drawn from Mansell and Schlenker, 1988) show Canadian

“Net Federal Fiscal Balances” by year from 1961 to 1985. The Net Federal Fiscal Balance (NFFB) is federal government revenues collected in a region less federal expenditures in that region. This is based on government budget numbers from the Canadian economic accounts with several adjustments. The most significant relates to the oil-pricing policy from 1973 to 1985, in which it is assumed that without Ottawa’s policies, Canadian petroleum prices would have followed world prices; the price controls are therefore seen as a federal government tax and transfer scheme, which ‘taxed’ oil producers on the difference between world and Canadian prices and transferred the difference to Canadian energy consumers. In Canada (with the organizational activities of the federal government concentrated in Ottawa-Hull and a commitment to the Equalization program, which transfers funds from ‘have’ to ‘have-not’ provinces), one would expect that different provinces exhibit different NFFBs. In the 1960s, four provinces ran positive NFFBs (revenues collected exceeded expenditures) while the other six provinces and the two territories had negative NFFBs.

From a macro perspective, a positive NFFB is contractionary, and a negative NFFB is expansionary. The four ‘have’ provinces in the 1960s – those with a positive NFFB – in this regard were Quebec, Ontario, Alberta, and British Columbia, with the first two generally showing the largest NFFBs. However, in 1971, the Quebec NFFB turned negative, as did those of B.C. and Ontario in 1977; from 1977 to 1985, only Alberta had a positive NFFB. Alberta NFFB from 1961 to 1973 is reported to vary between 1 and 8 per cent of ‘Market Income,’ but from 1974 to 1982 the values ranged from 19 to 52 per cent. (By 1985, the value was back down to 8 per cent, although, as mentioned, Alberta was still the only province with a positive NFFB.) Clearly, the petroleum price controls played a major role in the size of the NFFB. Apart from the rising political resentments of Ottawa seen in Alberta in the 1970s, Mansell and Percy (1990, p. 39) note that the net federal surpluses in Alberta “produced a strong fiscal drag on the provincial economy”; this was particularly true in the 1981–85 NEP period, but “in the absence of a continued rapid escalation in energy prices and energy investment, the exceedingly large federal fiscal surpluses with Alberta as early as the mid-1970s began to exert substantial deflationary effects on the provincial economy.”

Mansell et al. (2005) provide revised and updated NFFB calculations, concluding that “for the period from 1961 to 2002 Alberta made a net fiscal contribution of \$244 billion, compared to \$315 billion for

Ontario and \$54 billion for B.C.” (p. 2). (Values are in 2004 dollars.) Almost 70 per cent of the Alberta contribution was credited to the 1970s and 1980s, which includes the period when Canadian petroleum prices were regulated, with oil prices held below the international level. Over the entire period, the relative contribution from Alberta is shown as significantly more than would be justified by Alberta’s ‘have’ status; however, in the 1990s, when oil prices were no longer fixed below the world price, this discrepancy is not apparent.

In conclusion, from Alberta’s perspective, the overt regulation period imposed, not only the efficiency costs discussed in Chapter Nine, but also significant macroeconomic stabilization costs.

E. Economic Equalizers: Migration and Input Price Changes

Oil and natural gas are highly prized natural resources, seen by many as a route to wealth and power. As discussed above, they served as the prime engine for growth in the Alberta economy after 1947. To understand the full economic impact of the crude petroleum industry, it is necessary to apply a broad framework. The economic models we refer to in this section generally draw on a long-term, general equilibrium perspective that emphasizes that increased wealth as a result of the exploitation of petroleum calls into play dynamic reactions that modify the initial wealth-creating effects. In an increasingly ‘globalized’ world, these effects operate at the international level, but they are particularly potent in a regional economy such as Alberta, housed in Canada’s developed market economy, where labour and capital are highly mobile.

The short-term and long-term effects on Alberta of a rise in the real value of petroleum were suggested above. The immediate effect is a rise in the economic rent earned on the sale of petroleum. Some of this leaves the region in the form of higher payments to non-resident resource owners; this may occur directly as dividend payments or indirectly as an increase in the value of the assets held (e.g., the price of common shares in companies). However, some of the increased value remains in the region as returns to resident owners of the petroleum and as rent collected by the provincial government. If the local economy is operating close to full employment, the immediate increase in local incomes must be translated into higher expenditures on goods and services produced outside the region (that is, imports) or savings (e.g., money

held in bank accounts, in banks based in Toronto) and may also be accompanied by local inflation.

The longer-term adjustments are stimulated by two main factors:

First, the increased value of petroleum encourages investment in the oil industry. If the economy is close to full capacity, the oil industry must attract productive inputs from other sources, which is accomplished by increasing the price paid for the input. That is, the wages of the labour needed by the industry will rise, as will the price of specialized inputs such as drilling rigs, steel pipe, etc. These higher prices draw the required inputs to the petroleum industry from three sources: (1) imports from outside the region, including in-migration of workers; (2) the freeing-up of local inputs due to reduced production of other goods and services in the region as a result of the higher costs of hiring labour and purchasing inputs; and (3) absorption of any unemployed local resources, labour, or otherwise. It is often suggested that these effects can be understood somewhat better by dividing the goods and services produced by the economy into two broad classes, the tradable (like petroleum, agricultural goods, steel pipe, lumber, etc, which move easily between regions) and the non-tradable (like land and some personal services, which do not move easily). For tradable goods and services produced by the local economy, the main factor operating is that an increase in production costs reduces production locally because exports fall and/or imports increase (the ‘Dutch Adjustment’ effect). For non-tradables, the major effect is that an increase in cost reduces the domestic demand for the product.

Second, the way in which the provincial government elects to utilize its share of the increased economic rent from petroleum will affect the nature of the adjustment. The discussion of economic diversification, above, suggested two alternative approaches, although the provincial government is likely to use a mix of both. In an ‘active’ diversification policy, the government uses its higher revenue to offer support for certain non-petroleum industries in order to maintain their competitiveness. This is typically done to reduce the decline in the non-petroleum tradable good production, and benefits, especially, the producers of those goods; it also shifts some of the adjustment for higher petroleum production onto the other long-term adjustment mechanisms. (These mechanisms include the non-tradable goods and services sector, larger imports of other goods and services,

and more in-migration; as discussed above, the latter process is why this use of the higher government revenue is often called a 'province-building' strategy). Alternatively, the government may transfer the funds to local residents, generally through some combination of lower taxes and more public services. These benefit current residents, but also make the region a more appealing place to live, therefore attracting more immigrants.

If there were a one-time rise in petroleum prices, economists suggest that one would expect these long-term adjustments to continue until a new equilibrium is reached. Consider, for example, the in-migration of labour. The primary motivation is an increase in real wages in the region, which will be enhanced by government programs to offer lower tax rates or a higher level of public services than can be found elsewhere in the country. As more workers enter the labour market in the province, the real wage will tend to fall, reducing the incentive to move to the province. The precise path to lower real wages is complicated. New migrants bring their own demands for housing, food, and other goods and services, which puts upward pressure on local prices. The tendency of an increased labour force to put downward pressure on wages – due to diminishing marginal productivity of adding more workers – hinges on inflows of additional capital resources. An equilibrium would be established (the incentive to migrate ceases) where, at the margin, the benefits to a worker of moving into the province (e.g., higher wages, lower taxes, more public services) are just equal to the costs of moving (e.g., dislocation costs of leaving an existing home; higher living costs in the new location; congestion costs in the rapidly growing new location).

We do not explore these factors in any great detail for Alberta but will offer some evidence on two elements. (We must note that the simple graphs we offer, illustrating the relationship between several variables, do not offer the assurance provided by multivariate statistical analysis.)

First, consider population change in the region. Recorded changes in population and migration seem consistent with the theoretical picture we have just drawn. (In the Canadian context, with a particular emphasis on Alberta, Mansell, 1975, and Schweitzer, 1982, are revealing.) One aspect of the model is the supposition that an expansion of the petroleum industry (from either the 'supply' side, through new discoveries, or the 'demand' side through higher prices) stimulates economic expansion, which draws in new

people. Figure 13.11 is a visual presentation of the relationship over time between percentage changes in Alberta real GDP and population. The correlation is not perfect, and GDP exhibits much more variability. A part of population change is 'natural,' reflecting the age structure of the resident population, and is relatively independent of GDP changes. Figure 13.11 does not show a clear relation between real GDP growth and population change, apart from the fact that positive growth in production is associated with a rising population; that the percentage change in GDP is generally higher than the percentage change in population reflects, among other factors, increasing productivity of the economy over time. The high rates of increase in GDP after 1973 did see relatively high, and rising, rates of increase in population. And the recession and slowdown of economic growth beginning in 1982 also saw population growth fall.

Net migration data, capturing the actual inflows and outflows of individuals, are only available for years from 1972 on. Figure 13.12, which uses these data, hints at a positive correlation between changes in GDP and migration into Alberta.

Figure 13.13 shows Alberta population changes since 1947 in relation to Alberta per capita GDP relative to the Canadian average. The discussion above suggests that this may be a better measure of one of the main factors that motivates migration, an improvement in the economic return an individual can expect by moving into this region. While the two time series do not exhibit a one-to-one relation, the connection looks somewhat closer than that of Figure 13.11. In particular, there are periods in the 1950s and 1970s in which an increase in Alberta's per capita GDP relative to Canada saw increases in the population growth rate; and the levelling off, and subsequent decline, in Alberta's relative GDP starting in the early 1980s also saw the population growth fall sharply. These broad measures, in other words, are consistent with the economic model we have been describing of the relationships between the petroleum industry and the Alberta economy.

A second characteristic of this model is the suggestion that the impacts of rapid growth in Alberta, occasioned by expansion of the real value of petroleum production, may be particularly pronounced in the prices of non-tradable goods and services. Reflection suggests that the concept of 'non-tradable' is as much conceptual as real, since many immobile goods and services have mobile components. Thus, while land does not move, many of the things that give value to real estate are tradable (e.g., buildings and other

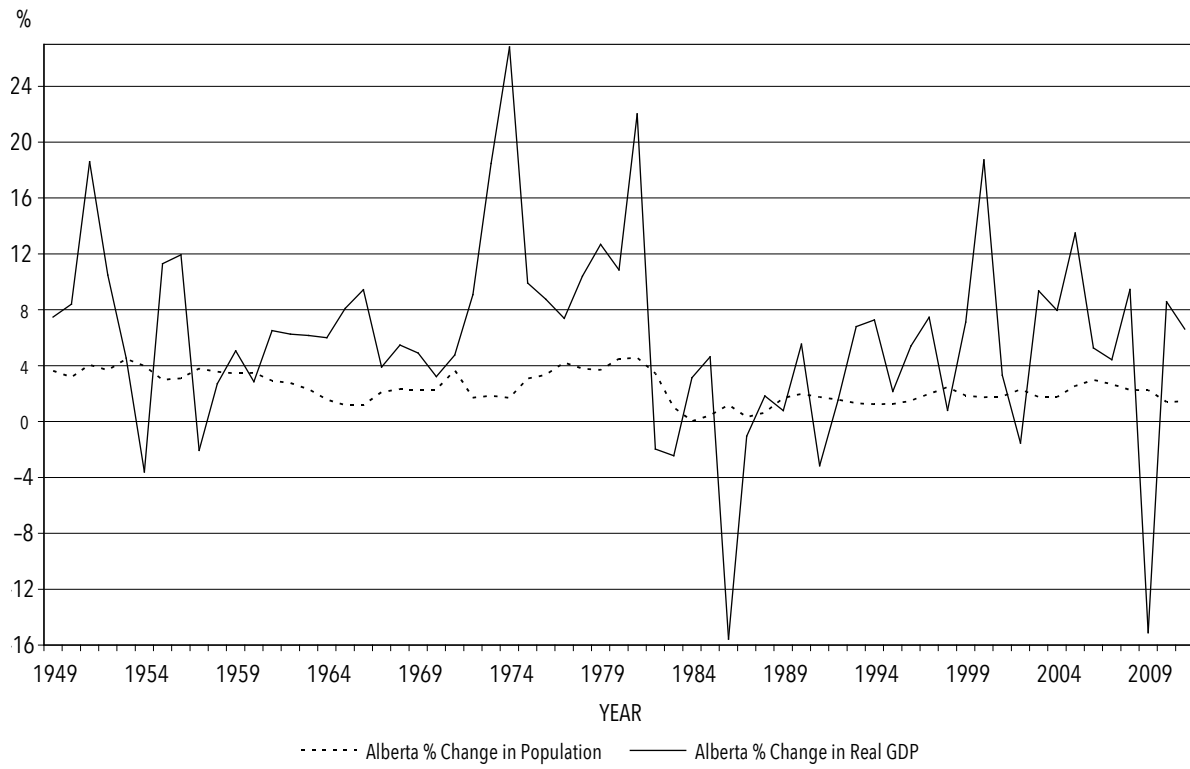


Figure 13.11 Alberta % Changes in Population and Real GDP, 1949-2011

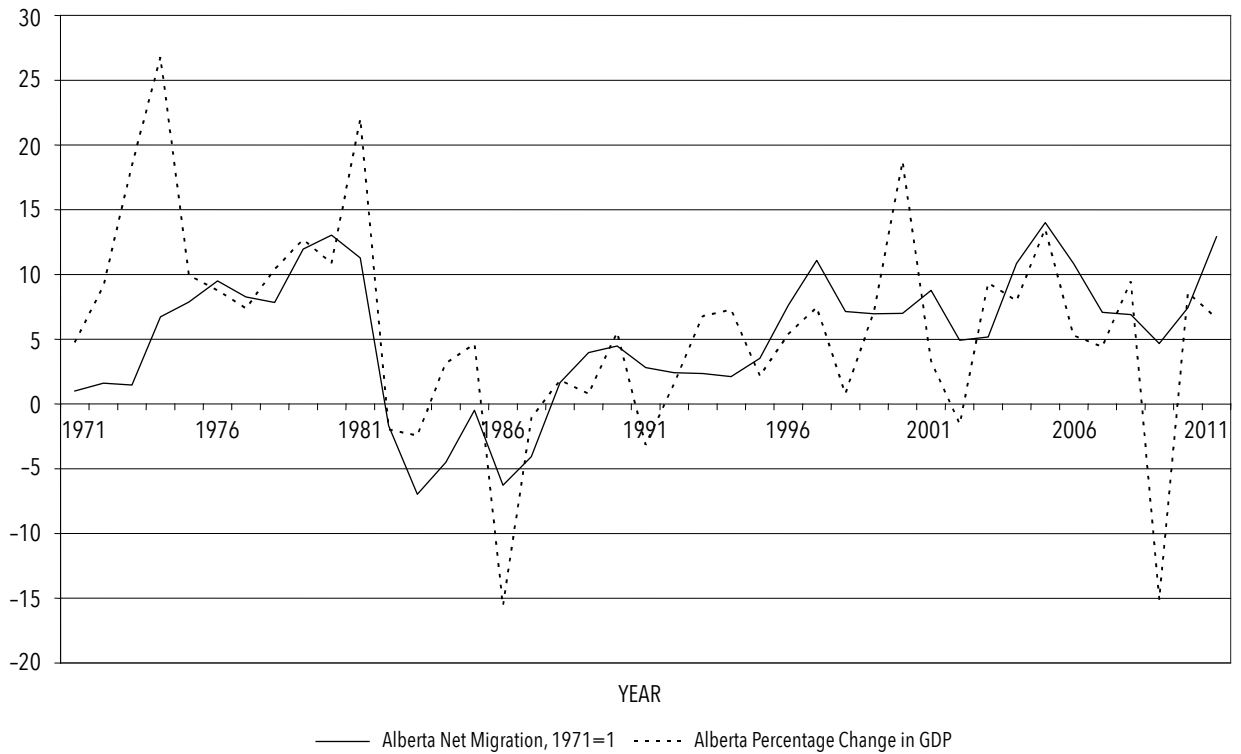


Figure 13.12 GDP Change and Net Migration, 1971-2011

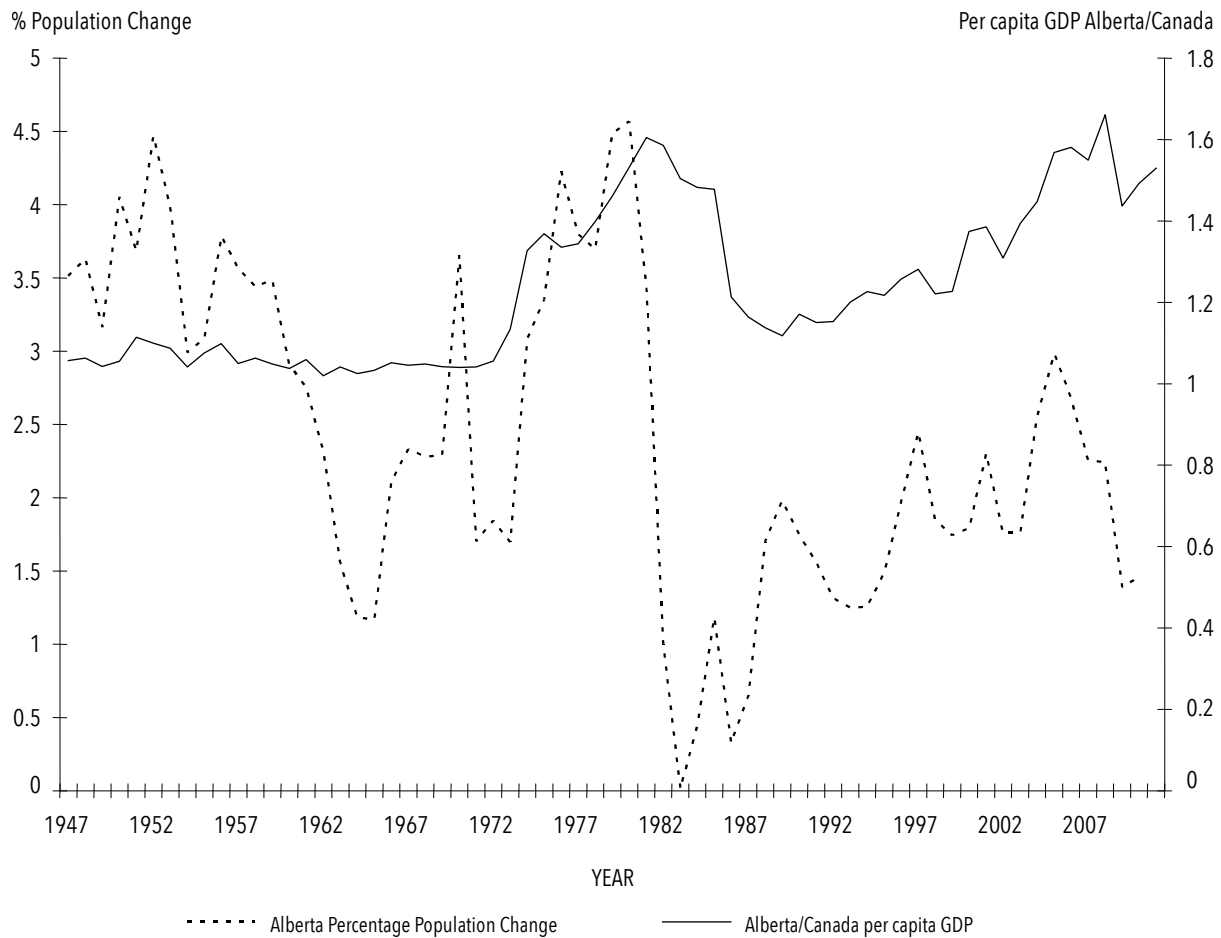


Figure 13.13 Alberta Population Change and per capita GDP, 1947-2011

capital improvements). Similarly, many social and community services are strongly location-dependent, and so not readily tradable across distances, but also draw upon labour and materials that are mobile. In this context, the main non-tradable may be intangibles, such as a sense of belonging and supportive social interaction, which may become scarcer in an environment of rapid growth. On the other hand, recent research, by Richard Florida (2005) suggests that a region's economic vitality is closely connected to its social and cultural diversity, which are likely to increase as the region grows and attracts a greater variety of individuals. One of the readily accessible possible measures of trends in the value of non-tradable goods and services is real estate values. Here the comparison with Saskatchewan may be revealing. In 1947, house prices in Calgary and Edmonton were not much different from those in Regina and Saskatoon. After that, average house prices rose somewhat

faster in Alberta than in Saskatchewan, especially after 1973. For April 2004, the Canadian Real Estate Association web site reported the following average housing prices: Regina, \$110,593; Saskatoon, \$135,550; Edmonton, \$178,777; and Calgary, \$220,245. The average for the two Alberta cities was over 60 per cent higher than for the two cities from Saskatchewan. (It is not clear whether these values control adequately for differences in the characteristics of houses. It should also be said that, at that time, average housing prices in Victoria, Vancouver, and Toronto were much higher than in Calgary. By the time of final revision, in April 2013, the gap between the Alberta and Saskatchewan cities had narrowed to 29 per cent, reflecting in part the rapid economic growth in Saskatchewan after 2008.)

In conclusion, the development of the petroleum industry in Alberta led to economic growth in the province. It is hardly surprising that rapid expansion

of the volume of oil and natural gas produced during the two decades from 1947 brought an increase as well in the population of the province to support higher activity. However, this occurred even after 1973 when the main reason for the GDP growth was not increases in the volume of petroleum produced but higher real prices for crude oil and natural gas. There were strong forces in place that ensured that the higher values of petroleum did not simply translate into higher average incomes in the province. Two of these equalizing forces were immigration into Alberta and inflation in local prices, especially for goods not easily traded.

F. Government Revenues and Expenditures

As earlier chapters demonstrated, the petroleum industry has proven to be the major source of revenue to the provincial government, providing in some years close to 50 per cent of the total annual government expenditures. This has raised several important policy issues, some of which we have touched on in other parts of this chapter.

How should the petroleum revenues be allocated across various possible uses? Earlier, we spoke of the basic distinction between using the funds to support various industries in the hope of gaining economic diversification and using money in a more general way to benefit citizens of the province. Examples include the provision of a greater level of government-produced goods and services (education, health, roads, parks, etc.) and reducing taxes. In the 1990s, one of the priorities of the Alberta provincial government became reducing the provincial debt; this would reduce future debt interest costs and therefore allow higher government spending or lower taxes in the future. Another possibility was for the government to save the money; this was the purpose of the Alberta Heritage Trust Saving Fund, which will be discussed in the next, and last, section of this chapter.

How does the fact that conventional petroleum is an exhaustible natural resource affect the government's utilization of petroleum revenues? (We would remind the reader that the notion of petroleum as an exhaustible resource is not as straightforward as many assume, since we do not know for certain the total amount of petroleum physically available in a region, and the amount that will ultimately be produced is constrained not so much by the physical availability as by economics and technology.) As mentioned in the section above dealing with economic diversification, this concern about depletion of petroleum was one

of the reasons that diversification of the provincial economy was assumed to be desirable. The issue at hand can be expressed in somewhat different terms. The government revenue derived from petroleum can be seen as current income received by depleting the petroleum asset. This raises the question of how much of the income should be used up on current consumption and how much of it should be saved to 'replace' (in an economic sense) the depleting petroleum. We will return to this question in the next section.

Since the provincial government's petroleum revenues are unstable, how can the government accommodate this instability in its public finances? The instability in revenues reflects, in part, the variability of bonus bids, which fluctuate with the anticipated profitability of the mineral rights for sale in that year. It also mirrors the instability in oil and gas prices, which has been evident since 1972; conventional oil and natural gas are assessed royalties based directly on the price of the product, and the net profits of oil sands output, on which oil sands and bitumen royalties are based, depend heavily on the oil price as well. Table 11.2 in Chapter Eleven clearly shows the fluctuations in the revenue the Alberta government has derived from the petroleum industry. Bonus bids, for example, over the fiscal years from 1979/80 through 2011/12 varied from over \$3.5 billion (2005/6) to as low as \$167 million (1992/3). The 2002 Alberta Financial Management Commission of July 2002 reported that (p. 23): "Since 1981/82, annual non-renewable resource revenues have ranged from a low of \$1.9 billion to a high of \$10.6 billion.... As a share of the province's total annual revenues over the past ten years, resource revenues have varied from a low of 14% of total revenues (in 1998/99) to a high of 41% of total revenues (in 2000/01)."

Fluctuating receipts by the government from the oil industry pose obvious difficulties for the budget process. (For detailed discussion with respect to Alberta, see the papers in Bruce et al., 1997; also Emery, 2006, and Emery and Kneebone, 2009.) Part of the difficulty is in forecasting future revenues and expenditures in order to engage in the responsible determination of expenditure and tax programs. Possible 'irrationalities' in the public decision-making process may exacerbate the problem. Thus, decision-makers may be prone to an 'optimism' bias, in which favourable conditions, such as unusually high petroleum revenues, are expected to continue. Lobbying efforts by special interest groups for new expenditures may be particularly successful in years in which petroleum revenues are unusually high but

would generate continuing expenditure commitments. Some public policy analysts have suggested that governments tend to exhibit a 'spending bias,' since the larger the government, the greater the power and prestige of the legislators and bureaucrats. Larger revenues in a particular year, even if not expected to continue, may draw forth increased spending, simply because the money is there. This tendency may be greater just prior to an election!

Instability in petroleum revenues became an even more pressing issue after the Alberta government adopted a balanced budget requirement in the early 1990s. (This commitment is currently housed in the 2009 *Fiscal Responsibility Act* (RSA 15-1, Section 2. The 2013/14 provincial budget proposed a new *Fiscal Management Act* which had not been passed at the time of final editing of this book.) We will not engage in a detailed assessment of the wisdom of such a policy. In brief, the proponents argued that it provided protection against the tendencies of the government to be more willing to increase expenditures than to control expenses and/or increase taxes, thereby leading to perpetual annual deficits. Opponents suggested that the government was giving up its responsibilities for fiscal stabilization policy. Requiring a balanced budget would be countercyclical, since the government would have to reduce its expenditures or raise taxes when economic conditions were bad and the economy needed stimulation. The government was also said to be sacrificing flexibility in its operations and failing to recognize that borrowing is an entirely fair and reasonable way to finance capital investments; since the services of the capital accrue over time, so should payments for capital assets.

In part, a government can attempt to manage fluctuating petroleum revenues through careful longer-term forecasting, rather than basing programs solely on current revenue flows. However, much of the instability in oil and gas prices is impossible to forecast with any degree of accuracy. The key would thus seem to lie in basing the fiscal program on reasonable expectations of average petroleum values over a number of years and introducing some offsetting flexibility in other parts of the revenue or expenditure stream. Since government revenue is generally collected under relatively fixed regulations and virtually all tax sources are subject to their own variability, the required flexibility is more likely to come from the expenditure side of the government's operations. In Alberta, three main avenues of expenditure flexibility have been proposed. One is to make greater use of the Alberta Heritage Savings Trust Fund for revenue

stabilization purposes. (See the next section.) The second, which has played a major role, is to use the government's commitment to debt reduction as the major avenue for responding to fluctuating provincial revenues; given various other program-spending commitments, the debt could be paid down more or less rapidly depending on the vagaries of government revenues. By March 2005, the provincial debt (with no allowance for the Heritage Fund assets of over \$11 billion) had been reduced to about \$3.5 billion, from some \$23 billion in 1993. In that year, the government set up a Debt Retirement Account to pay off the remaining debt as it matured; the final payment was made on March 1, 2013. However, the March 2013/14 budget included new borrowing; this budget established a formal distinction between a balanced operating budget and a capital budget, which might rely on borrowing with a clear schedule of repayment.

In the 2003 Alberta provincial budget, a third way of handling instability in petroleum revenues was adopted. This followed the July 2002 report, *Moving from Good to Great*, of the Alberta Financial Management Commission, under the Chairmanship of David Tuer. The commission had been formed in March 2002 with "a broad mandate to explore the province's finances and recommend possible improvements" (p. 14). The 2002 Commission was the second such commission.

The previous commission had reported in 1993, in response to persistent provincial government deficits. This set in motion a major re-evaluation of the Alberta government's fiscal policy, which included a variety of new accounting/accountability measures. The changes also tied into the new policy approach mentioned earlier, which came to be labelled the "Alberta Advantage"; it legislated balanced budgets, lower taxes, debt repayment, and reduced government spending. We are concerned only with the parts of this program that relate to resource revenues. The main provisions related to unstable provincial revenues included the adoption of a three-year budget-planning period, conservative revenue forecasting, and the requirement to set aside, in each budget, an 'economic cushion' of 3.5 per cent of the projected budget revenue. Such a cushion would provide some protection against unexpected revenue shortfalls, as well as leaving a source of funds for unexpectedly high expenditures and emergencies. (For general discussions of the provincial budgeting process, see Bruce et al., 1997, and Kneebone and McKenzie, 1999.)

The Tuer Commission on Alberta Financial Management noted (p. 21) that "the province, like all

other natural resource owners had consistently had difficulty accurately forecasting resource revenues. Between 1993 and 2001, the government underestimated resource revenues by a total of close to \$12 billion, or an average of almost \$1.5 billion a year.” (A significant part of this, some \$4 billion, came in the 2000–2001 fiscal year.) Underestimation may partly reflect a deliberate ‘defensive’ budget policy of conservative forecasting, but it seems fair to argue that persistent *underestimation* of resource revenues cannot be solely due to *instability* in the revenues. Moreover, persistent errors must either make government budgeting less than optimally efficient or suit some other political purpose. (The Tuer Commission notes [p. 21] the perception among some Albertans that it served to rationalize lower spending on a variety of social programs.)

The Tuer Commission made an extensive set of recommendations, which relied heavily on changes in the role of the Heritage Trust Savings Fund and which will be reviewed in the next section. One significant change, consistent with the Commission’s suggestions, was implemented in the 2003/4 provincial budget. A total of \$3.5 billion of non-renewable resource revenue was to enter into the province’s general revenue. Any revenue above \$3.5 billion would go into a new ‘Sustainability Fund,’ to be drawn on in later years if resource revenues fell below \$3.5 billion. The Sustainability Fund would be allowed to build up to a size of \$2.5 billion, after which potential additional contributions might be diverted to a number of specific uses such as debt repayment or disaster relief (but not to general government operating expenses). This measure clearly addressed very directly the problem of unstable resource revenues. In its budgets after 2003, the government increased the amount of non-renewable resource revenue that would go into the operating budget above the \$3.5 billion ceiling.

In subsequent years, despite transfers for disaster relief and to other capital funds, the Sustainability Fund grew in size, reaching almost \$7.7 billion by September 2007, as a third provincial commission was looking at the government’s finances. (By this year, the amount of non-renewable resource revenue applied to general government expenses had risen to \$5.3 billion, with the excess going to the Sustainability Fund or other capital funds or capital projects. In 2008, non-renewable resource revenue in excess of about \$6.6 billion would go to the Sustainability Fund.) *Preserving Prosperity: Challenging Alberta to Save* was the title of the December 2007 report from the Alberta Financial Investment and Planning Advisory

Commission (under the chairmanship of Jack Mintz). The Mintz Commission recommended maintenance of the Sustainability Fund but with a cap of \$3.5 billion (in real dollars), which it judged large enough to meet its stabilization objectives; the excess capital in the fund should be transferred to the Heritage Fund (Alberta Financial Investment and Planning Advisory Commission, p. 41). The Commission argued that the objectives of the Sustainability Fund were too broad and undefined, including, as well as provincial government budget stabilization, vague goals related to natural gas price subsidization for Albertans, and meeting the costs of disasters and settlement of aboriginal land claims; the Commission recommended that such subsidiary objectives be dropped.

As of the time of final revision to this chapter (spring 2013) these recommendations had not been acted on. The Sustainability Fund stood at \$2.7 billion at the end of the 2012/13 fiscal year; it had been drawn on in the years 2008–13 to offset government deficits. (In 2009, the ‘Capital Account,’ also established in 2003, had been rolled into the Sustainability Fund.) In its 2013/14 budget, the government forecast that by March 2014, the value of the sustainability fund would be less than \$700 million but would increase again after that in the form of a new ‘Contingency Account’ with a maximum value of \$5 billion.

G. The Heritage Fund and Preserving the Income from Depleting Capital Assets

As this chapter has implied, the petroleum industry makes two quite different contributions to an economy. First, production requires factors of production (labour, capital, supplies, and management skills). Second, a resource like petroleum generates economic rent, a surplus of revenue above production costs, which can be used to the benefit of people in the region. These two contributions raise rather different economic issues, which the local government must somehow reconcile.

With respect to the first issue, production of petroleum normally involves economic growth, with both an expansion in population and in real per capita incomes in the region. The rate of expansion is determined in large part by factors outside the control of the regional government (demand for oil and natural gas, world prices, technological changes). However, as discussed in various chapters in this book, domestic government policies also affect the levels of industry activity and production. There is often pressure to

think that 'more is better': a larger provincial economy has more influence at the national level; growth allows realization of agglomeration effects and economies of scale, which bring lower costs and greater self-reliance; growth brings a more vibrant and diverse community; growth is necessary to maintain the demand (especially the investment demand) needed to sustain full employment. Against this, however, one must balance the costs of growth, such as personal adjustment costs, congestion effects, higher local inflation, and environmental degradation. Finding an optimal balance is a chimera, especially since a number of the benefits and costs are difficult to measure accurately and because many of the forces affecting the level of petroleum industry activity are outside the control of the provincial government. In the Alberta context, the rate of development of the industry has been affected by such 'market forces.'

The second issue involves an array of factors. One is the efficiency with which the provincial government collects economic rent. The main focus of provincial government policy has been on devising rent-collection mechanisms that transfer a significant share of economic rent to the government while having minimal impact on the behaviour of the petroleum industry. A second component of this issue is that of the 'use' to which economic rents might be put. As discussed in this chapter, this is not transparent, most fundamentally because it is not entirely clear who the beneficiaries of the economic rent should be. At its most extreme, we suggested that one might take a 'descendants' view (the prime beneficiaries should be the 'initial' residents, e.g., Albertans as of 1947 and their families), or a 'successors' view (the prime beneficiaries should be whomever happens to reside in the province). From a political perspective, the reality probably reflects a combination of the two: at any point in time, the government is largely concerned with the interests of current residents (a descendants perspective), but as time passes the population of the province changes, so the government's constituency changes (a successors perspective). However, the absence of any pronounced policies to control the level of petroleum production to one that could be handled largely by the current population implies that policies have been largely 'successor'-based. We would argue that the 'successor' view is the more desirable one in a world in which resources must be flexible to exploit the most efficient economic opportunities and when one values the ability of individuals to make choices freely (including the choice of where to live). As we suggested earlier in this book, at the theoretical

level, one of the strongest arguments for a more 'descendant'-based perspective is for a region heavily dependent upon exhaustible resource production, where a clear rising-then-falling life cycle of production is anticipated and there are minimal prospects for other types of economic activity; in this case, policies might favour current residents (and their descendants) rather than others who would be expected to migrate in for a while and then depart again.

Some analysts have suggested that one might provide a better framework for consideration of these complex and controversial issues if petroleum were explicitly seen as a regional asset, as part of the region's wealth. Higher wealth allows higher consumption, but it is not desirable to consume all the wealth in a single year. There are clear analogies to the prevailing neoclassical economic model of an individual's consumption. An individual's life style is predicated on prevailing income (from all sources) and the yet-to-be-realized return on various assets the individual owns or will own. A 'rational' individual would base consumption, not on the maximum possible expenditures in the current period (attainable by liquidating all assets now), but on a life-time consumption-savings plan. If the individual focussed solely on his/her own self, this would mean that assets are liquidated gradually over time, until they disappear when the individual dies. This simple model is not strictly accurate, partly because many individuals have 'self-control' problems that lead them to consume more in the present period than is optimal. In addition, we would not expect people to run their assets down to exactly zero at their deaths. For one thing, at the time of death, there is invariably some probability that the individual might have lived longer, so some assets would still be maintained. More importantly, most individuals also exhibit a 'bequest motivation,' to pass assets on to their heirs. If an individual gives just as much weight to his family and other heirs as to his own wants, then the individual would be inclined to maintain his wealth relatively constant, even at death. This situation is similar to that of a government concerned with the well-being of its citizens through the indefinite future.

This conceptual approach suggests that, as petroleum is produced, the 'income' could be used for current consumption purposes, but the 'principal' or asset value should be saved. In this manner, depletable oil and gas will be transformed into other lasting assets that yield a return over time. (Habib, 2009, provides an interesting perspective on the ethical dimensions of spreading natural resource values across generations.)

There are numerous problems in actually implementing such a policy. To begin with, since the petroleum resource base is not known with accuracy, and since oil and gas prices are constantly changing, the 'true' value of the petroleum asset can never really be known. One might take the 'user cost' of petroleum production as an approximation of the asset value. (See Chapter Four. The user cost is the present value of the future profits given up by lifting a unit of petroleum today, instead of leaving it in the ground, and is therefore a measure of the reduction in the value of the resource due to current production.) However, the user cost cannot be easily measured. There is also the difficulty in building up an alternative capital stock, which could take many forms: industrial diversification in the region; infrastructure in the region; human capital (training, health, and education) in the region; private saving by residents of the region; investments, either direct or indirect, outside the region. Presumably funds should be allocated in such a way that the (risk-adjusted) marginal rate of return is equal in all such uses. This is no easy task!

The literature in 'political economy' also touches on this issue. In particular, there may be a lack of long-term perspective and financial responsibility on the part of governments with a particular interest in shorter-term (electoral) popularity. Politicians may find it hard to resist the temptation to spend unexpectedly large revenue inflows immediately, although prudence would suggest restraint and retaining some revenues for future times when the inflow of funds is reduced. A savings plan might reduce these temptations to spend more when revenues surge.

It is clear that the uses to which Alberta has put its petroleum revenues have aspects of both current consumption and saving, but one particular use ties directly to investment. In 1976, the province created the Alberta Heritage Savings Trust Fund, which was designed with four objectives in mind (Alberta Financial Management Commission [Tuer Commission], 2002, p. 27):

- To function as a savings account that would offset declining resource revenue in the future;
- To provide additional leveraging opportunities for the government, reducing the province's future debt load;
- To improve quality of life for Albertans; and
- To facilitate stability in the economy by providing a fund that could help diversify the economic activity of the province.

Alberta was not the only petroleum-producing region to create such a fund. Davis et al. (2001), with the International Monetary Fund, have studied some such funds, although not Alberta's. They suggest that governments have set up the funds for two somewhat different purposes: savings funds and stabilization funds. The Heritage Fund is an example of the former. (The Stabilization Fund that Alberta created in 2003, discussed above, is an example of the latter.) Davis et al. are not strongly impressed by the conceptual arguments for establishing these funds. They view them as necessary primarily to offset the faulty decision-making of governments who otherwise would fail to handle natural-resource revenues correctly; but if governments would make bad decisions without these funds, they must surely expect that governments, who have sovereign power, would also utilize the funds badly! Davis et al. admit that some countries have made good use of natural-resource funds. Both Norway and Alaska are often seen as examples. In Alaska, for instance, the government has ensured that the fund receives petroleum revenues on an established basis, regulations regarding investment of the funds are carefully set out, part of receipts are reinvested in the fund to maintain its real value in the face of inflation, and the main use of the remaining return on the fund is rebates to Alaska citizens rather than to the state government (Anderson, 2002). Warrack and Keddie (2000) compare the Alaska and Alberta funds.

The Alberta Heritage Fund commenced operations in fiscal year 1976/77, with a contribution from petroleum revenues of \$2.1 billion. Thirty per cent of the province's non-renewable resource revenues were to go into the fund. (These values are drawn from p. 13 in the Alberta Heritage Trust Fund 2003 *Annual Report*. A 1980 special issue of *Canadian Public Policy* investigated the Heritage Fund. See Collins, 1980.) Contributions out of petroleum resource payments to the Alberta government continued, at lower levels, for another decade; in the early 1980s, the government reduced the share of resource revenues going into the fund to 15 per cent. A final contribution of \$216 million was made in 1986/87. With falling oil prices in 1986, the government decided that all petroleum revenues would go into general government revenues. In all, in this first decade, a total of just over \$12 billion built up in the Heritage Fund. Beginning in mid-1982, the government withdrew, into general government revenues, virtually all the net income earned by the fund. (Until that date, earnings were retained, increasing the value of the fund.) This meant

that, from 1984 and for over two decades, the size of the fund was stable at about \$12 billion. Only in 2005 did the province begin to contribute to the fund once again. (In that year, the government also contributed a special \$1 billion to the fund in an 'Access to the Future' account meant to finance advanced education investments.) The 2002/3, 2007/8, and 2008/9 fiscal years were the only ones in which the fund earned a negative return, as did most North American investment funds. As of December 31, 2012, the value of the fund was \$16.4 billion, down from its peak of about \$17 billion in spring 2008.

The general investment objectives of the fund have changed over its life, consistent with the change noted above in Alberta's industrial policy. Initially, a prime purpose of the fund was to aid actively in the economic diversification of the Alberta economy. This could be done by direct funding of key infrastructure projects in the province and by giving priority to loans to Alberta entrepreneurs for promising projects. The latter mandate probably reflected a presumption that Canadian capital markets focussed on central Canada and discriminated unfairly against projects in the periphery. From 1976 through 1995, the fund spent a total of \$3.5 billion on direct capital investments. From its inception, the Heritage Fund maintained a general investment portfolio with a broad mix of investments, including loans to other provinces. (In the politically charged regulatory environment of the late 1970s and early 1980s, when the federal government constrained Alberta's oil and gas prices, and Alberta was arguing for higher prices, such loans may have been one way of persuading other provinces that their interests were allied to some extent with Alberta's. Mumey and Ostermann, 1990, and Smith, 1991, provide assessments of the investment strategies of the Heritage Fund.)

As we discussed above, Alberta government policy changed in the 1990s from an active diversification strategy to a more neutral emphasis on the 'Alberta Advantage.' Consistent with this, a revision of the *Alberta Heritage Savings Trust Fund Act* became effective at the start of 1997. Under this act, the objective of the Heritage Fund is "to provide prudent stewardship of the savings from Alberta's non-renewable resources by providing the greatest financial returns on those savings for current and future generations of Albertans." This clearly establishes the fund's role as an investment fund, rather than an economic diversification fund.

The government's strong commitment to the Heritage Fund was in the period of high oil and gas

prices from the late 1970s through to the mid-1980s. For the next two decades, its value was pretty well constant in nominal dollars, so its real value fell. (In contrast, the Alaska Fund is designed to reinvest part of its earnings, in order to retain its real value, before any payouts are made to Alaska citizens.) During its establishment period, the government appears to have felt that an activist policy was needed to help preserve the 'asset' value of Alberta's petroleum. In part, this reflected the perceived necessity of a government-led, and active, diversification policy. It may have also reflected some mistrust in more neutral investment and savings procedures. For example, the government is always under political pressure to spend public funds on current projects, and a commitment to spin some revenue off to a special fund may reduce this. It has also been argued that private decision-makers may be excessively myopic and save less of any income gains than is socially desirable, so a government 'forced savings' plan like the Heritage Fund is preferable to transferring the money to the private sector.

The more passive role for the Heritage Fund after 1995 cannot be taken as evidence that the government has lost interest in an objective of maintaining capital assets in the province as petroleum resources are run down. In fact, the government argues that the 'Alberta Advantage' is designed to make Alberta unusually attractive for new private-sector investment. Instead, the policy change with respect to the Heritage Fund reflects a change in policy: a much greater trust in the efficiency of relatively unregulated markets and a greater disbelief in the necessity for government programs to offset inefficiencies or inequities in market outcomes. From this perspective, the surprising fact is not that the government has chosen to treat the Heritage Fund in a relatively passive manner, letting its value decline through the effects of inflation. It is that the fund has been retained at all: for example, running down the fund over a period of years would permit even lower tax rates and could have been employed for debt reduction, increasing the 'Alberta Advantage.' Maintenance of the fund during this period seems to be due less to a commitment to the principles of such a fund and more to the fact that numerous opinion polls demonstrated that a majority of Albertans want to see the Heritage Fund maintained.

In April 2002, the government released *The Savings Question: A Discussion Paper*, which suggested that most analysts see a desirable role for a special government savings plan when non-renewable resources are a major source of government revenue.

A number of possible uses of the savings that were mentioned included more activist project funding and more passive debt repayment and tax reduction possibilities. None of these were specifically endorsed.

The July 2002 *Report of the Alberta Financial Management (Tuer) Commission* recommended (p. 51):

1. The Alberta Heritage Savings Trust Fund should be retained, strengthened, allowed to grow, and renamed the “Alberta Heritage Fund” with four new purposes:
 - To stabilize the impact of volatile resource revenues on the province’s budget;
 - To manage the orderly pay down of existing debt as it comes due;
 - To address the backlog of deferred capital projects in the short term; and
 - To serve as transition to the time when resource revenues decline and as an integral part of the province’s strategy for achieving a sustainable economic vision for the future.
2. To provide stable and predictable funding, the Commission recommends that all non-renewable resource revenues should go into the renewed Alberta Heritage Fund on an annual basis. All year end surpluses should also go into the Heritage Fund. A fixed and sustainable amount of resource revenues should be drawn out each year to support the government’s budget.

With respect to the part of resource revenues that would be drawn into the general government budget each year, the Commission recommended that: “This fixed amount should be set at a conservative and sustainable level. We recommend the lesser of \$3.5 billion (the historical average over the past 20 years excluding the spike in revenues in 2000–2001) or the average of resource revenues for the previous three years.” We would note that if several exceptionally good years occurred close together (like 2000–2001 and 2002–2003 or 2005–2008), there could be a significant difference between these two approaches. The Commission expected (p. 53) that the Heritage Fund might, under this policy, more than double its current value by the year 2025. These recommendations would, as the Commission notes, mean a complete change in the role of the Heritage Fund, which would become a key player in the province’s finances, and

the mechanism through which all petroleum revenues received by the government are managed. The government did not adopt these recommendations, and the Alberta Heritage Trust Savings Fund continued to operate as it had over the past fifteen years, as a relatively passive investment fund with a fixed size of about \$12 billion.

Beginning in the 2005/2006 fiscal year, the province began (under the *Alberta Heritage Savings Trust Fund Act*) to reinvest a portion of the fund’s annual earnings (or transferred funds from the Sustainability Fund) to offset annual inflation (*Alberta Heritage Savings Trust Fund*, 2008, p. 319). (From 1996 on, there had been some partial compensation for inflation.) In addition, in the years 2006/7 and 2007/8, the provincial government made additional transfers into the fund as petroleum revenues substantially exceeded forecast amounts due to higher than anticipated prices.

The role of the Heritage Trust Savings Fund was a major concern of the Mintz Commission in its December 2007 report. The Commission noted that if one compared the change in the provincial government’s net financial position with its resource revenues, just over 30 per cent of resource revenues had been saved on average each year from 1994 to 2007 (*Alberta Financial Investment and Planning Commission*, 2007, pp. 26–27). Much of this saving came in the form of reductions to the province’s debt, with relatively little coming in the form of the increases in the size of the Heritage Fund after 2004. The Commission suggested that the province was saving too little and doing so in an unsatisfactory ‘*ad hoc*’ manner (p. 31). The report, in a ‘province-building’ framework, argued (p. 3) that government saving was important:

The government’s financial investment and planning policies are extremely important to the long-term stability and growth of the Alberta economy. To put it in clear terms, Alberta’s non-renewable resources should provide significant benefits not just to Albertans today, but also for our children and grandchildren. When Alberta sells its resources, it has given up wealth that can either be spent today or saved for the future. When our stock of non-renewable resources dwindles, Alberta’s economy will need to rely only on its people – not its natural resources – to create wealth. The government itself will have to rely on investment income from the financial

assets that it has accumulated and taxes paid by future Albertans to fund essential public services needed by a growing and aging population. Alberta should not look like a ghost town in the next century when the resources are depleted. Instead, Albertans want to have a dynamic economy attracting people from around the world to enjoy Alberta's advantages long after the resources are used up. For those reasons, our Commission is proposing a new approach to savings. The approach is designed to simplify the current approach, to make savings a clear and deliberate objective with tangible targets, to provide the necessary fiscal discipline, and to encourage proper stewardship of Alberta's savings to maximize the benefits to Albertans. It is intended to capture Albertans' interest and attention, to renew their commitment to savings, and to hold the government accountable.

The Commission examined Alberta's long-run fiscal position and recommended that the provincial government undertake an active and large savings program, preferring this to an approach that paid 'dividends' to Alberta citizens and let them decide how much to save individually. (Reduced taxes to 'give away' any government revenue surpluses would be equivalent to such a dividend.) The Mintz Commission (agreeing with the Tuer Commission) recommended that the 'Alberta Heritage Savings Trust Fund' be replaced by a reconstituted 'Alberta Heritage Fund.' The Heritage Fund would incorporate most existing government savings programs and would be increased in size annually, to a total of \$100 billion by the year 2030. (As discussed above, the Commission recommended continuation of the Stabilization Fund, but with a ceiling size of \$3.5 billion, indexed for inflation, solely for the purpose of stabilizing the government budget as fluctuating revenues might require. A 'Heritage Capital Fund' would also exist separately.) To attain this target, the Commission recommended that the government commit to set aside a fixed proportion of revenues each year for the Heritage Fund (pp. 33–34), to contribute at least 75 per cent of any budget surpluses (after topping up the Sustainability Fund, if needed) to the Heritage Fund (p. 40) and to draw on only 4.5 per cent of the value of the Heritage Fund each year for the government's budget (p. 37).

As of April 2013, the government had not acted on these recommendations but the 2013/14 budget incorporated several proposals with respect to the

Heritage Fund. Firstly, starting in fiscal 2014/15, a higher share of the fund's earnings would be retained and reinvested, with 100 per cent of earnings retained by the 2016/17 fiscal year. Secondly, again commencing with fiscal year 2014/15, regular contributions to the fund would be made out of non-renewable resource revenues; the amount of investment would start at 5 per cent of the government's resource revenues up to \$10 billion in revenue, then 25 per cent of the next \$5 billion and 50 per cent of any resource revenues over \$15 billion.

4. Conclusion

The economic development of the Alberta economy since 1947 is intimately tied to the development of the petroleum industry. Many economists see this connection from an 'export base' or 'staples' point of view. The external demands for petroleum products are an essential force driving the process of economic growth, while the form that growth takes is affected by the backward and forward linkages of the petroleum industry. The petroleum industry can be seen as affecting the local economy through three mechanisms, which operate jointly: changes in the volume of production; changes in the real value of the products; and increased productivity. The precise dependence of the economy on a specific industry is difficult to measure. Other export industries may have initially developed based on the demands of an export-base industry, and the viability of industries producing largely for the local market may hinge on the growth in demand stimulated by the export-base industry.

Starting in 1947, for the next two decades or so, the levels of petroleum output (crude oil and natural gas) increased dramatically, while prices were relatively stable. This attracted new productive inputs to the economy and reduced Alberta's dependence on agriculture. Gross production in Alberta grew more rapidly than the Canadian average, as did employment and the population. Per capita income also rose, but, over much of the period to the early 1970s, remained quite close to the Canadian average. Alberta depended heavily upon two export industries, petroleum and agriculture.

Beginning in the early 1970s, the real prices of oil and natural gas began to rise dramatically, spurring increased economic growth through to the early 1980s. The higher real value of petroleum increased the relative share of the petroleum industry in the Alberta

economy (which some saw as reduced economic diversification); migration into Alberta increased, and the prices of local goods and services were put under upward pressure; even with the in-migration, per capita Alberta incomes rose above the Canadian average. However, oil prices began to soften in the world market after 1981 and then fell dramatically, ushering a period of relative income stagnation in Alberta. Unemployment rose, population growth slowed, and Alberta GDP per capita fell close to the Canadian average. The relative contribution of the petroleum industry to the Alberta economy fell.

Starting in 1993, Alberta population and GDP, in total and per capita relative to the Canadian average, began to increase once again, although still fluctuating as the prices of oil and natural gas changed. There is a feeling that the dependence of the economy on the petroleum industry has lessened somewhat, reflecting such factors as new export industries, import substitution, and agglomeration effects. There has been increased production by sectors of the economy other than the petroleum industry, including manufacturing and a variety of services, such as information technologies and petroleum service companies that sell to customers outside the province. In addition, as the population has grown from barely 800,000 in 1947 to almost 3.9 million by 2013, agglomeration effects and economies of scale have been easier to realize, allowing more varied industrial production for both domestic and export customers.

At the level of economic policy, the desirability of economic diversification has been a persistent focus of attention. On the whole, the process of economic

growth has been what naturally occurred in response to market forces. Especially in the later 1970s and early 1980s, the provincial government used some of the resources it gained from the high prices of crude oil and natural gas to actively encourage expansion of new industries, concentrating on those like petrochemicals that further processed crude petroleum. Beginning in the later 1980s, and up to the present, the government's approach has been more neutral, emphasizing lower taxes and the high quality local infrastructure. As mentioned in the previous paragraph, most analysts think that the economy has gained a greater degree of diversification and stability over the past decade. It is important to note that the Alberta economy is still highly dependent on oil and gas prices. And high oil prices are essential to the growing oil sands and heavy oil industry, which provide an increasing share of Alberta's liquid hydrocarbons as conventional production declines. Indeed, by 2002 oil sands output exceeded that from conventional sources. Higher natural gas prices also bring higher government revenues, but some analysts have expressed concern that continued economic growth (especially in industries like petrochemicals and oil sands, which use energy-intensive production processes) may prove difficult if natural gas prices become too high. Accessibility to natural gas may prove an important issue in the future although the fall in prices after 2008 has alleviated immediate concerns.

The petroleum industry has been the key factor underlying the economic development of the Alberta economy for the past four decades. It will continue to do so for the foreseeable future.

CHAPTER FOURTEEN

Lessons from the Alberta Experience

Readers' Guide: In the final chapter, we briefly explore the relevance of Alberta's experience with petroleum to other jurisdictions. This chapter does not involve any empirical comparisons between Alberta and the rest of the world but does offer thoughts on the treatment of the petroleum industry. In addition, it makes some final assessment of the general effectiveness of government regulation of the Alberta petroleum industry.

1. Introduction

Even in this shrinking, increasingly integrated world, the petroleum industry stands out for the scope and breadth of its regional interconnections. In part, this reflects the uneven geographical distribution of the underlying natural resource. The geological realities of the distribution of oil and natural gas in nature bear little relationship to the concentrations of population and economic power that drive energy consumption. As a result, many regions or sub-regions of the world find themselves in a position similar to that of Alberta, rich in petroleum with limited domestic requirements. How is this valuable resource to be developed so as to provide maximum benefit to the region? The purpose of this brief concluding chapter is to examine the Alberta experience with an eye to the possible lessons it might offer to other parts of the world. We do not attempt an empirical comparison of developments in Alberta with those elsewhere. Rather we draw upon the experience, problems, and regulations in Alberta,

as discussed in previous chapters of this book, in order to offer suggestions that we feel could be usefully pondered by decision-makers elsewhere in the world. Because this discussion is based on the previous chapters, no references are cited in this chapter. The discussion and suggestions are divided into three broad categories: factors related to the 'physical' realities of petroleum; factors related to the operation of petroleum markets; and factors related to economic rents.

The petroleum industry within a region does not arise in a pristine historical and institutional environment. Hence, several specific characteristics of the Alberta situation need review. First, Alberta is fortunate in being a modern economy, part of the developed western world. Thus the birth of Alberta's oil and natural gas industry occurred within an established and stable political and legal environment. Alberta was ready to participate immediately in the development of petroleum. Industry and government could draw upon a well-educated local population, established business firms, and a responsible and well-trained civil service. Not all petroleum-bearing regions are so fortunate; in war-torn regions such as Sudan or Angola, or in countries such as those of the former Soviet Union undergoing fundamental economic and political transformation, a multitude of problems must be resolved before decision-makers can even begin to consider most of the issues that were important for Alberta.

Second, special problems are created by Alberta's status as part of a federated political system, where the province of Alberta shares jurisdiction with the federal government in Ottawa. Some parts of the world do not have this set of problems to consider (e.g., Qatar),

and in others the division of powers are quite different than in Canada, so the responses to interjurisdictional conflicts may also have to be different.

Third, the conventional petroleum industry in Alberta is smaller than that in a number of other parts of the world, small enough that we have generally been satisfied to treat Alberta as a price-taker in the oil market. Thus the issue of the best way to exercise market power, which has been of vital concern to countries belonging to OPEC, has not attracted much attention in Alberta.

Fourth, the majority, although not all, of the petroleum 'in the ground' in Alberta has been under the ownership of the provincial government (the 'Crown'); this has been true in much of the world, but not everywhere at all times. With initial government ownership of petroleum rights, the interactions of the government with the private-sector petroleum industry are in its role as 'landowner,' as well as the governing representative of the people.

2. Factors Related to Physical Aspects of Petroleum

Oil and natural gas typically lie in segregated deposits (pools or reservoirs), invisible from the surface, deep within the earth. Pools differ, not only in the volumes of hydrocarbons held, but in the chemical make-up of the hydrocarbons present and the characteristics of reservoir rock and reservoir pressure. In addition, petroleum is a depletable natural resource in the sense that oil and natural gas do not naturally regenerate themselves within anything like the human time span, nor are they recyclable, like aluminum, after use. It is accepted that socially optimal development of petroleum calls for a government regulatory framework that recognizes the unique characteristics of the resource. Many of the desirable regulations relate to the environmental impact of the industry and have not been dealt with in this book; this includes such regulations as those regarding the disposal of water produced in conjunction with petroleum, the flaring of natural gas, safety in drilling, sealing of abandoned wells, the environmental impacts of fossil fuel use, etc. We would note that Alberta seems to have a good reputation in many of these areas, especially those related to petroleum engineering, and that many of the regulations have been overseen by the Alberta Energy Resources Conservation Board (ERCB), which is also responsible for a number of the programs that

we have discussed in this book. In this section, we will discuss three main issues related to the 'physical' nature of petroleum: uncertainties about reservoir existence and location; the reservoir as a single pressure system; and the meaning of 'depletability' of the natural resource.

A. Uncertainty and Exploration

Estimates may be made at any time of the size of the petroleum resource base within a region, but such estimates, especially in the early days of exploration in a region, are subject to a very wide margin of error. From an analytical perspective, little has been done in economics to integrate five essential components of a theoretical model of petroleum exploration: the extremely wide range of possibilities for the resource base; the precise nature of a social welfare function in such an uncertain setting; the open access nature of the exploration process (where investors may be motivated to undertake rent-destroying early exploration to capture mineral rights); the 'option value' of delaying exploration (waiting until others explore, or exploring more slowly, is likely to reduce the geological uncertainty the investor faces, allowing more profitable investment later); and the joint product nature of exploration (today's exploration activity generates knowledge of significance to both oil and natural gas discoveries, now and into future time periods). To suggest, as has been common in many theoretical models of exhaustible resources, that the key social issue is that of defining the 'optimal depletion path' for the resource, seems to be putting the policy cart in front of the information horse. Rather, we would suggest that one of the key policy issues in a newly developing petroleum region has been to find an efficient way of generating new knowledge in face of the extreme uncertainty involved.

From the early days of industry activity in Alberta, the government elected to address this through a combination of competitive private exploration and careful mineral rights issuance. We think that there is much to be recommended for such an approach, that efficiency arguments favour a reliance on private industry. Since most of the mineral rights are owned by the Crown, it would have been feasible to undertake exploration through a single government-owned 'national' (i.e., provincial) petroleum company. However, it is doubtful that a single company would have been as efficient in generating knowledge within the very uncertain geological environment

that characterizes the petroleum industry. Allowing exploration to be undertaken by competing private firms allows for maximum testing of varying geological opinions, something that is likely to be hard for a single company, regardless of its interest in the 'public welfare.' In addition, experience in other parts of the world suggests that it is often difficult for a public petroleum company to generate the level of exploration investment it desires since the government often uses its ownership to appropriate a large share of any 'excess' funds in the company. Possible disadvantages of a reliance on the private sector for all exploration activities must, however, be acknowledged. The main one is the possibility that a large portion of mineral rights will be transferred to private companies with relatively little return to the government. If access to mineral rights is relatively low-cost, or if risk-averse companies are willing to pay little up front for access, or if petroleum discoveries *ex post* (after the fact) turn out to be exceptionally large, or if there is a lack of sufficient competition, the government will find that the majority of the economic rents accrue to the private sector.

Alberta handled this problem in several ways. Issuing mineral rights through competitive bonus bids, in a setting in which a large number of firms were active, ensured that a significant portion of anticipated (*ex ante*) rents would go to the government. Including rental and royalty provisions in the mineral rights meant that the government would share in ongoing rents from successful exploration. Drilling requirements helped to ensure that companies would not sit on land indefinitely and that geological knowledge would be generated. Dissemination of this knowledge was aided by the requirement that companies lodge well core samples with the ERCB, with the samples made public after a period of time (usually one year). Finally, checkerboard relinquishment provisions ensured that, as exploration determined which lands were of most value, the government retained an interest (for later sale) in the regions found to be of highest value. An argument might be made for one additional activity in the early stages of the petroleum industry in a region: given the very high initial uncertainty, the government might undertake, at its expense, an initial exploratory well-drilling program with the results made public knowledge. However, for many countries this would require considerable public expenditure from a relatively poor government (before any revenue flows from petroleum taxation occur). Alberta did not undertake such government drilling; it did, however,

allow companies only a short period of time (typically one year) in which the results of their drilling could be retained privately.

It is desirable, from the beginning of petroleum industry activities in a region, to establish policies that are stable, efficient, and equitable and allow important geological knowledge to be generated quickly and made public. Alberta met these standards well.

B. The Reservoir as a 'Natural' Unit

Petroleum production is a deliberate economic act, but it must follow nature's constraints. Private petroleum producers will, of course, be aware of the limitations nature imposes, but this need not ensure that their production practices (investment, output levels, and production techniques) will be socially optimal. Hence governments may be motivated to regulate aspects of petroleum production practices. Many of these regulations relate to producers' uses of 'environmental amenities,' the capabilities of land, air, and water, which are not priced and sold in economic markets and hence are overutilized by profit-oriented companies. As has been mentioned, this book does not deal with such environmental aspects of Alberta petroleum production.

A typical conventional petroleum reservoir is a connected volume of porous rock (bounded by impermeable rock) holding hydrocarbons and water under pressure higher than surface pressure. Production of crude oil and natural gas draws upon the pressure differential between the reservoir and surface. In physical terms, the reservoir is a 'natural' unit of production, and it is sometimes useful to see production as the 'production' of reservoir pressure changes. Depending on the reservoir itself and the number, type, and location of wells, their output rates, and the location and volume of fluids (natural gas, water, CO₂, etc.) injected back into the reservoir, the time path of pressure in the reservoir (and the output of oil and natural gas) will vary. Since oil companies are interested in maximizing the present value of the profits received from the reservoir, one would expect that they would be vitally interested in the responsible management of reservoir pressure. However, they may not develop reservoirs in a socially efficient manner.

Within North America, the most obvious reason for this derived from the sharing of reservoirs by companies and the incentives of the 'rule of capture,' which said that the ownership of oil and gas went to the party that lifted them to the surface. Companies

and land owners were often not willing to go to the expenses of time, money, and effort involved in negotiating and monitoring a joint agreement to 'unitize' the reservoir and lift from it as single producer. Instead, there was an incentive to produce competitively to capture petroleum before neighbouring companies could do so. This meant rapid declines in reservoir pressure and output, a smaller reservoir recovery factor, large numbers of wells with high expenses, and a reluctance to invest in pressure maintenance or enhancement. The economically preferred solution would be a compulsory unitization program. Alberta did not adopt this solution, although in certain circumstances (where obvious damage to reservoirs took place) the provincial regulatory board could order it. Instead, Alberta drew on U.S. regulations, with a mix of well-spacing rules (limiting the number of wells that could be drilled), maximum output rates (to avoid undue pressure decline), and 'market-demand prorationing' for crude oil, which limited output to the level that the market was willing to accept (at prevailing prices). Market-demand prorationing was not introduced for natural gas reservoirs. Here the excesses of the rule of capture in Alberta were reduced by the prevalence of long-term contracts that slowed the rate of reservoir depletion.

However, market-demand prorationing brought its own inefficiencies. By controlling output, it blunted the operation of market forces, an impact that was felt at the North American level since the program operated in many of the most important producing regions (especially Texas). It also increased oil production costs by prorating controlled output across all producers, therefore restricting production of low-cost oil in order to make room for higher-cost oil. Finally, regulations often induced producers to drill incremental wells to gain higher output quotas even when existing wells were capable of lifting more; successive revisions of prorationing meant that this incentive was pretty well eliminated in Alberta by the mid-1960s. Market-demand prorationing became gradually less significant in Alberta from the mid-1970s and was entirely removed in the later 1980s. Well-spacing and maximum rate regulation continued, and the advantages of unit operations were now well known to companies, so the excesses of the rule of capture have been blunted to a considerable extent.

In many parts of the world, the rule of capture is not operative, if only because single companies frequently control entire reservoirs. In many of these countries, a different type of insecurity of ownership of oil reservoirs may induce companies to exploit the

oil excessively rapidly. This is the case if there is a fixed life of the mineral rights, with oil reservoirs reverting back to the government at the end of the agreement; companies then have no incentive to consider the impact of today's pressure decline on output past the end date of the contract. From the viewpoint of economic efficiency, the most direct way to address this problem would be to allow continuation of the mineral rights until the producer decides to abandon the reservoir, as has been the case in Alberta. Should governments be unwilling to do so (perhaps because it is regarded as politically impossible), then a 'conservation' regime of well-spacing and maximum output rate limitations might be well advised. Here, the Alberta experience might prove instructive, particularly the decision to rely heavily upon a quasi-judicial regulatory board with a highly qualified technical staff and open procedures.

It has been suggested (for instance by some apologists for OPEC) that the petroleum industry always requires market-demand-prorationing regulations for 'conservation' reasons to limit an inducement to excessively rapid production. This argument does not acknowledge the fact that market-demand prorationing arose out of the specific setting of a North American industry in which the rule of capture held in common law and mineral rights holdings covered very small surface areas. In Alberta, in contrast to the continental U.S., where private ownership of initial mineral rights was common, the majority of Alberta's mineral rights are Crown-held, but the government typically issued production leases for relatively small areas. These conditions simply do not hold in much of the world. For most economists, therefore, there is no obvious justification for prorationing as a 'standard' petroleum policy; rather, it appears that those desiring high oil prices are attempting to find a justification for their exercise of market power.

C. The Significance of Depletability

Conservation of petroleum use is another possible reason to limit current production, and is normally justified by reference to the limited resource base for conventional petroleum. It has been suggested that, unless action is taken soon, resource limitations will translate into catastrophic future shortages, although many analysts are quite vague about exactly what the nature of this crisis will be.

Readers of this volume will know that the authors are not sympathetic to this line of argument. There

is great misunderstanding about the 'exhaustible' nature of petroleum resources since it is primarily an economic phenomenon, not a physical one. That is, we will 'run out' of crude oil or natural gas when they become too high in cost, relative to market value, to continue with production. In economic terms, as the world turns to more and more costly petroleum, relatively less energy-intensive activities and alternative energy sources will become more attractive, reducing the consumption of petroleum. There is a strong presumption amongst most economists that market forces will, if allowed, handle this transition relatively smoothly, particularly since producers and consumers have a strong incentive to anticipate such an outcome and begin to take action prior to significant price increases. If this is correct, the transition to other energy forms will be relatively smooth and will have resulted from the 'economic' (not physical) exhaustion of our petroleum resources. Not everyone accepts this argument since many feel that economic markets fail to understand the fundamentally limited nature of the underlying resource base. OPEC representatives have often justified their production restraint by a presumed need to conserve scarce resources. However, economists have tended to view this rationale with a high degree of scepticism, since it is clearly in OPEC's immediate interest to force oil prices to high levels.

It is of interest that, in the case of Alberta, there has been a persistent tendency for the relevant government agencies to underestimate future petroleum production and reserves. This is not surprising and is common in studies of other regions as well since forecasts of petroleum availability are necessarily based on current knowledge and future geological plays, economic conditions, and production technologies are impossible to forecast with accuracy. Many studies attempt to make allowance for these uncertainties, but there seems to be a persistent tendency to underestimate their effect on future reserves additions. There is obviously no guarantee that past underestimation of future petroleum producibility will continue through the indefinite future. However, the historical evidence suggests that economists who argue that economic markets adequately recognize the depletable nature of petroleum are more justified in their argument than those who fear sudden and catastrophic exhaustion.

Those who argue in favour of restricting current petroleum production to generate higher supplies for a future energy supply crisis must recognize the complexity of such a policy. Clearly the approach rejects the idea that petroleum is a product like other products that one is willing to trade in economic markets.

The key question is why this is the case. As suggested, it normally reflects a belief that current market forces fail to reflect the future value of petroleum. It also implies that government regulators are better able to determine this future value. (Given the wide range of oil prices over the past fifty years, it seems disingenuous to simply say that the socially optimal value is always higher than observed prices.) The Canadian experience suggests that this faith in regulators may be misplaced: official estimates of future oil and gas prices have been notoriously inaccurate. (So, we should note, have been most private forecasts!)

Prohibition or limitation of exports is often recommended as a way to preserve resource supplies, as was done by Canada from 1973 to 1985. This generates contradictions. After all, the argument is that we are all using the resource stock too quickly, not simply that foreigners are using too much. By itself, restricting exports forces greater supply onto the domestic market, lowers the domestic price, and encourages greater consumption of petroleum at home. Thus we ourselves are using up the natural resource more quickly. It also requires the expense of an effective regulatory program to ensure that domestic petroleum does not leak into the higher-priced foreign market. There is also the contradiction that we usually expect to be able to import, at prevailing international prices, the resources that we ourselves do not possess in abundant quantities. Why should we expect this to continue while our country cuts back petroleum sales to other nations? It is also curious to note that export limitations may appear to generate precisely the outcome that was feared. Reserves additions will be inhibited, but this is not because markets have underestimated the availability of petroleum resources but because lower prices make reserves additions less profitable. Lower domestic prices, as a result of export limits, also induce earlier abandonment of reservoirs, reducing the recovery ratio, and inhibit technological innovations that increase the recoverability of petroleum.

If concerns about resource availability are legitimate, this would suggest that the appropriate policy is to force domestic prices higher to inhibit resource use. Exports would disappear, as domestic supply would be priced out of the international market, and consumption at home would fall. The easiest way to do this would be through a tax on oil that would raise prices to consumers and reduce prices for producers. However, the difficult part of such a policy is determining exactly when and how the future dire scarcities of petroleum will occur and how, at that

time, incremental petroleum will be made available to domestic users. As noted, the essence of this argument is that markets fail to recognize the exhaustible nature of petroleum and that at some future date a massive energy crisis is going to occur in the world. Presumably, at that time, this nation would prohibit exports and increase petroleum production; petroleum prices would move below world prices and domestic petroleum users would benefit. Economies elsewhere would suffer from energy shortages, but this country would be protected, at least to some extent. There are, of course, ethical and political implications. Could we justify reserving petroleum use for ourselves alone when people in other parts of the world are going short? Would other powers allow us to withhold supplies of petroleum?

But our main objection to this line of argument is that we view the entire scenario as unlikely and betraying a failure to appreciate the essentially economic nature of resource limitations and the ability of economic markets to signal resource scarcity and induce compensatory actions. Our inclination is to see the essential problem as one of risk (and insurance) rather than resource exhaustibility. Since perfect foresight is impossible, it may be that petroleum resource scarcity will occur faster and more dramatically than is generally expected. It might be judged desirable to have some 'insurance' in the event of this outcome; the insurance could take the form of current subsidization of alternative energy forms and energy conservation, that is, of those activities that will play a prominent role in any smooth adjustment to petroleum depletion. It might take the form of 'strategic petroleum reserves' (SPRs), that is government-owned reserves set aside for later use as needed. This differs significantly from intervention with petroleum sales to retain scarce petroleum assets for domestic use.

3. Factors Related to Petroleum Markets

The discussion in the previous section illustrated a commonly expressed concern: that petroleum markets fail to function in an appropriate manner so that governments are justified in interfering with prices or trade flows. Experience in Canada and Alberta has illustrated many possibilities in this regard. Thus, both Alberta and Canada imposed domestic requirement limitations on natural gas exports; oil imports into Canada were limited from 1962 through 1972,

allowing domestic oil to sell at prices in excess of the international level; oil and natural gas export sales were limited from 1973 to 1985, and domestic prices were fixed at levels below those in external markets. We have generally been critical of such policies on the ground that they impose economic efficiency costs on the economy, without clear offsetting gains. Thus, for example, setting prices above the prevailing market level stimulates production of petroleum that costs more than the price of imports and penalizes domestic consumers. Holding prices below the prevailing market level means that higher utilization of oil is stimulated in uses that have a lower value than the amount that foreign buyers are willing to pay for that petroleum, and domestic production is inhibited. The obvious question is whether some additional factor justifies these efficiency losses.

In addition to the arguments related to resource exhaustibility discussed above, several other possible reasons for interfering in the operation of petroleum markets will be briefly discussed, including: second-best considerations; providing a fairer distribution of the benefits and costs of petroleum; generating improved macroeconomic stability and adjustment; and encouraging regional development.

A. Second-Best Considerations

The efficiency advantages that economists see accruing from competitive free markets can be guaranteed, economic theory tells us, only if they are part of an entire system of 'complete and perfect' markets. If the market for one product is effectively competitive, but other associated markets are not, we move from our 'perfect ('first-best') world to a 'second-best' world, and we do live in a second-best world. This does not necessarily mean that we should interfere with the operation of markets, but it may mean that there are efficiency gains that could be attained from such interference. Thus, for instance, we argued in Chapter Nine that the Alberta oil industry was tied in the 1960s to the large U.S. oil market where oil prices were maintained above international levels by the joint operation of state-run market-demand prorationing regulations and the federal oil import quota program. The Canadian National Oil Policy divided the Canadian oil market at the Ottawa River valley, allowing the western part to access the U.S. market at prices above the international level. This benefited western Canadian oil producers at the expense of oil consumers and might normally have been expected to give

an efficiency loss. However, if account is taken of the incremental oil export earnings, due to U.S. oil regulations, then the policy generated net gains to Canada.

However, the world oil market currently shows few if any similar examples since pretty well all major participants now operate in the market in a free manner. It is possible that other second-best situations exist, but each of these requires a clear demonstration that there is a gain to be made from interference with petroleum prices or trade flows. We would also suggest that the most plausible of these market failures (such as the failure to adequately 'price' environmental amenities) are more likely to be addressed by tax/subsidy schemes that operate through the market rather than by direct interference in petroleum markets.

B. Fairness

Petroleum price changes impact differently on different individuals in the economy. Oil price rises, for instance, hurt oil users but benefit owners of private oil companies, petroleum industry input suppliers, and governments in oil-producing regions. One of the main reasons that the Canadian federal government fixed oil prices below international levels from 1973 to 1985 was to ensure that the benefits of the increasingly valuable oil was spread across all Canadians, rather than concentrated in the western producing regions, with most other Canadians feeling mainly the higher prices. However, the justification for the policy was less a desire to shelter oil users than it was a reflection of the difficulty in deciding in a federal system what is a fair interregional distribution of the gains (to an oil-exporting economy) from higher oil prices. Moreover, the policy of holding oil prices down had the effects of encouraging more use of oil, discouraging production of oil, and necessitating an increasingly convoluted set of regulations limiting and taxing exports to ensure that foreign consumers did not benefit from the low Canadian prices.

It should be noted that the Canadian evidence does not offer much support for the argument that rising petroleum prices are highly regressive in their impact. Petroleum takes a relatively low proportion of people's income and does not take a much higher share for the poor than the rich. Should such income-distribution effects be of concern, the more appropriate policy would be to combine an effective rent-collection program (see below) with modest tax reform; that is, extra government revenue from the increased profits on higher-priced petroleum could be

used to lower personal tax rates on the poor or provide social programs that benefit the less-well-off.

It is tempting for oil-exporting countries to set domestic prices low to ensure that citizens benefit from 'their' petroleum, and many governments have found that such programs become very difficult to remove once in place. Our view, however, is that the argument of the previous paragraph holds for most nations. In fact, in very poor nations, income distribution is often more unequal than in Canada, and the very poorest use little petroleum so benefit very little from low oil prices. Moreover, many of these countries have relatively inefficient public administration systems, so the ability to control illicit trade in subsidized oil is weak. We suspect that it would be more effective to help the poor by exporting more petroleum at higher world prices and using the government revenue gained on programs aimed directly at the poor. In other words, unfairness of the distribution of income is a general societal problem, not best tackled by subsidization of the prices of individual goods or services.

C. Macroeconomic Stability

Rapid changes in petroleum prices, especially, it seems, rapid *rises*, impose adjustment costs on an economy, particularly an oil-importing economy. Many, but not all, economic analysts assign rising world oil prices a significant role in the 'stagflation' starting in the mid-1970s. (Stagflation is the combination of a sluggish economy, or recession, with high inflation.) One of the justifications for the Canadian oil and natural gas price freezes of 1973 was that Canada, as a net oil exporter, could use this policy to reduce macroeconomic adjustment problems. If the oil price rises were temporary, as some expected in 1973, Canada could wait out the blip in prices, and if they were permanent, Canada could make the required adjustments more gradually. However, subsequent economic analysis has cast doubt on this argument. For example, two of the major oil-importing nations (West Germany and Japan) weathered the oil price rises of the 1970s very well. Not all large petroleum price rises seem to have generated strongly stagflationary effects, and some models have suggested that the problem is not so much higher oil prices as the macroeconomic policy response to the higher prices. Further, simulations with several Canadian macroeconomic models did not find much difference in levels of such key economic indicators as the

unemployment rate and the Consumers Price Index between cases with immediately higher oil prices and those with more slowly staged price increases. Thus our conclusion is that the macroeconomic benefits from holding petroleum prices below market levels are not likely to offset the efficiency losses of such a policy.

D. Regional Development

A final justification for interfering in the operation of free market forces in oil and natural gas markets is that such a policy might generate regional economic gains by encouraging resource-using industries to establish in the region; that is, export limitations and/or regulated lower prices could generate higher economic growth. It is not an easy argument to assess. This is particularly true if the focus of analysis is on individuals and appropriate attention is given to our personal mobility: the government of Alberta might see a clear benefit in having a petrochemical plant located in the province, but an individual worker may be less concerned about whether the plant is located in Edmonton or Vancouver.

There is also the question of whether the policy instrument (e.g., lower prices that benefit all users) is appropriate to the objective (to support a specific industrial user who otherwise would not locate here). More specialized subsidies might cost less and would be more transparent than intervention in the operation of the petroleum market. Also, policy-makers must recognize that it is difficult for governments to know exactly which new industries to encourage. Presumably this is made easier if there is a temporary factor inhibiting an industry from moving into the area; short-term subsidies then can be designed to last until the new industry establishes itself. For example, if the industry outside the region is dominated by oligopolists not willing to build in the region, despite the ready resource availability, then temporary government support for a new company might be reasonable while it breaks into the market. Or, if the problem is the lack of skilled local labour, temporary encouragement of the new industry could be attractive while the requisite training occurs.

We find little reason to suppose that a policy of holding down petroleum prices or prohibiting profitable exports is justifiable as a way to support regional economic development, given the known inefficiencies of such a policy and the possibility of introducing more finely tuned measures that specifically address the problems inhibiting development.

4. Factors Related to the Sharing of Economic Rent

Issues of taxation are inevitably controversial. Petroleum taxes might be imposed in order to change behaviour in petroleum markets; an example would be a 'carbon tax' designed to reduce utilization of petroleum in order to reduce carbon dioxide emissions. However, the most significant reason for governments to assess charges on the petroleum industry is to capture for the public purse a high proportion of the economic rent generated by the production of oil and natural gas. Economic rent is attractive as a revenue source for governments since it is excess to necessary production costs, so it can, in theory, be taken without inhibiting production. The government incentive to capture economic rent is particularly pronounced where the mineral resources are initially publicly owned. In a region such as Alberta, there are two main sources of this economic rent. First, petroleum reservoirs vary greatly in quality. In a well-functioning market, price must be high enough to cover the costs of the highest-cost supply necessary to meet demand, so higher 'quality' petroleum (in the sense of more productive lower-cost supplies) will earn profits in excess of costs. Second, because oil is seen as a non-renewable resource, most oil and natural gas will command an excess of price above production cost reflecting this general scarcity factor. (In economic theory, this premium is called a user cost, as discussed in Chapter Four.) A third source of profits on petroleum is the deliberate exercise of market power, as has been done by OPEC in the crude oil market. For a region such as Alberta, which takes the price of oil as given by the world market, this means that more oil is commercially viable and oil profits (economic rents) are higher.

Governments typically claim a right to a significant portion of these petroleum rents, often because the underlying natural resource that generates the rents is seen as the property of the people of the region. In the Alberta context, this perception has legal standing because, in over 80 per cent of the area of the province underlain by sedimentary rocks, the petroleum rights are held and issued by the provincial government. Beyond this, economic rent is an appealing source for government revenue from an 'ability to pay' principle of taxation since it represents a surplus of revenues above the essential expenditures to produce the resource. This often leads to the recommendation that governments should 'maximize' their share of economic rents. We have suggested the more

modest objective of governments attaining a 'high' share of the rents. Partly this is because it is impossible to define an actual rent-collection scheme that touches only (and 100% of) the rent. At a more abstract level, it seems unlikely to us that there is a clearly defined absolutely 'pure' economic rent (i.e., revenue in excess of necessary production costs) that plays no role whatsoever in encouraging efficient, cost-minimizing production. A 'perfectly effective' government rent-collection scheme, which left no rent in the hands of private companies, would leave little incentive to keep costs to a minimum except on the highest-cost projects, particularly if benefits to the private owner could be disguised as 'costs.'

The task of gathering economic rents for the government is very much complicated by the great uncertainties associated with petroleum industry activities. In our earlier discussion, we framed this in terms of the difference between *ex ante* (expected) and *ex post* (actual) economic rents. It can also be seen in terms of the risk-sharing. Thus, for example, a government might be effective in capturing 100 per cent of anticipated rents, leaving all the risk with the private sector. However, unless the government is highly risk-averse, this would not be seen as desirable. Many have argued that private investors are more risk-averse than governments, implying that the value they place on anticipated economic rents may be less than the value the government places on them. Governments, then, would wish to collect much of their share in the form of ongoing payments as rents actually accrue. It is also noteworthy that early estimates of ultimate recoverable reserves for the world's main petroleum-producing regions have been shown to be conservative; hence estimates of anticipated economic rents when a region is under initial exploration typically fall below actual earned rents. Finally, there are advantages (in terms of economic planning and self-discipline) in a government spreading its petroleum revenues relatively evenly over time. For reasons such as these, governments have generally focussed on gaining a high share of actual rents rather than expected rents.

To capture a share of rents in an economically efficient manner, the methods of raising revenue should, ideally, be neutral with respect to industry activity. Specifically, it would be desirable that the methods of rent-extraction should not: (1) discourage investment in exploration or development; (2) induce earlier abandonment of reservoirs; or (3) change the time path of petroleum production. It has been suggested that this could be accomplished by a 'resource rent tax,' that is a tax upon profits earned (including an

allowance for the required return on capital as a cost of doing business). However, the practical implementation of such a tax is difficult. Allowance for exploration costs for individual projects is almost inevitably somewhat arbitrary, and an emphasis on earned profits often entails the notion that the government would not receive any payments until after full 'payout' of costs has occurred. In the 1990s, Alberta introduced a 'generic' tax for oil sands and heavy oil projects that was explicitly based upon an accounting definition of profits, although a minimum *ad valorem* royalty provision was also included. This was largely motivated by the high cost of this oil, with the associated vulnerability to low oil prices.

However, for conventional petroleum industry activities, Alberta has long utilized a mix of rent-collection mechanisms, including competitive bonus bids, royalties, land rentals, and a corporate income tax (applied to all companies, with regulations largely set by the federal government in Ottawa, but with Alberta receiving a portion of the revenue). A royalty has been the traditional method for North American land owners to obtain a share of oil revenues, so was an obvious instrument to use as the government of Alberta issued Crown mineral rights. This is an example of how private landowner leasing arrangements may have affected Crown mineral rights provisions. A major disadvantage of a traditional royalty (based on the gross revenue from oil) is that it fails to distinguish between lower- and higher-cost oil; thus, if set at a level high enough to earn significant revenue, it inhibits oil production. The government of Alberta introduced a variation on traditional flat-rate royalties by setting the royalty rate higher for higher-output wells, which were presumed to have lower per unit costs of production. Under reasonably competitive conditions (there have been many private companies active in the province), the bonus bid can be expected to capture a significant portion of expected rents after companies make allowance for the rentals, royalties, and income tax that they expect to pay.

This approach seemed to work well until the rapid rise in world oil prices (and North American natural gas prices) starting in the early 1970s, when two problems became apparent. First, actual profits on petroleum surged far beyond what anyone had expected, and, under existing royalty regulations, the largest share of the profit increase went to the private sector. Secondly, as economic rents surged, the issue of the appropriate division of rents, particularly between the provincial and federal governments, became red hot. This was particularly critical because the main

rent-collection devices that were used by Alberta (competitive bonus bids and royalties) were deductible as costs for the main rent-collection tool of Ottawa (the corporate income tax); Ottawa feared that Alberta would pre-emptively gather all the rent increases before it had a chance to generate more revenue itself.

This complex situation led to a period of political and regulatory instability from 1973 to 1985, characterized by increasingly complex government regulation. Alberta moved to raise royalty rates substantially by making the royalty rate a positive function of the price of petroleum; since higher royalties are a disincentive to production, the government retained the sliding-scale rate based on output. (For example, the royalty rate on oil fell towards zero as output from a well fell to nil.) It also set lower royalty rates on new production which required new investment. Ottawa moved to fix petroleum prices below world levels, to make royalties and bonus bids non-deductible for the (federal) corporate income tax, and, starting with the National Energy Program in 1980, introduced several exclusively federal taxes. (These federal taxes, and price controls, were removed with deregulation in 1985/6.)

Alberta's experience in rent collection offers useful lessons to other jurisdictions. First, it is important in federal government systems that the various levels of government work cooperatively to determine fair rent shares. Second, there is much to be said for Alberta's use of a number of rent-collection mechanisms so that the governments can give weight to a number of different objectives: ensuring a flow of income across time (i.e., with royalties and income taxes); differentiating among heterogeneous projects (i.e., with competitive bonus bids and sliding-scale royalties); and allowing the government a suitable share in risky, fluctuating rents (i.e., with royalties and income taxes that vary with earnings). Third, by electing to use gross royalties and land rentals that are not directly tied to profits earned, Alberta has found it necessary to introduce rather complicated measures, such as sliding-scale royalties and a number of incentive schemes, so as not to unduly inhibit investment in new, higher-cost projects. Rent-collection instruments more directly attuned to private company profits (such as have been used for oil sands ventures) might be somewhat less complex administratively. On the other hand, it is somewhat harder than might be thought to set up a well-balanced and effective profit tax on petroleum because (except for projects such as those in the oil sands) it is not possible to define separate projects clearly (since exploration costs, in particular, are

of a joint-product nature, rather than tied to any one project), and it is very difficult to set up regulations that are equitable across different types of companies (e.g., established companies with existing cash flow from which this year's costs can be deducted as compared to new companies with no or low cash flow who must carry current expenditures forward until they have sufficient cash flow to claim them).

On balance, the Alberta petroleum rent-collection scheme in place after the mid-1980s for conventional petroleum seemed to strike a good balance among the objectives of gathering a high share of rent, ensuring some stability in revenue flow to the government, sharing risk with the private sector, and providing stable and relatively low-cost administration. The main difficulties have been in designing a system that is sensitive to sudden increases in profitability due to surges in world oil prices, as had been seen in 1973 and 1980 and occurred again in 2005–2008, and one that minimizes the disincentive effects of *ad valorem* royalties.

5. Conclusion

Alberta has been most fortunate in its petroleum endowments, with extensive conventional oil and natural gas resources plus large volumes of the less-conventional, higher-cost resources (e.g., oil sands and coal bed methane), which are expected to play an increasing role in the future. These resources have spurred rapid economic growth in Alberta and have been the key input in making it the wealthiest of Canadian provinces. The role of government (both the province of Alberta and the federal government in Ottawa) in generating benefits from the petroleum industry has been controversial. The Alberta experience certainly offers a wealth of experience in different types of government programs. Our view is that certain forms of government regulation have been very effective in the Alberta case, others less so.

In Alberta, governments have been effective in establishing a relatively stable and well-defined system of property rights, which encourages risk-taking and long-term planning on the part of petroleum producers. To help offset the negative effects of specific market failures in the operation of petroleum reservoirs, the Alberta government established an independent and powerful regulatory board (now known as the ERCB, the Energy and Resources Conservation Board), which has a well-earned

international reputation for careful and honest regulation with respect to the technical aspects of oil and gas production. This board has powers related to many environmental matters (gas flaring, safe drilling and well operation, control of well blowouts, well abandonment, and closures), which are an inevitable part of the physical process of exploring for and lifting petroleum. In addition, it has managed the day-to-day problems associated with the insecurity of property rights over petroleum in the ground generated by the 'rule of capture.'

However, in more recent years the ERCB has been subject to criticism with respect to the fairness and effectiveness of its hearings and judgments with regard to broader health and environmental issues and whether it is giving appropriate attention to the 'public interest.' The decision, in 2012, to transfer many of the board's regulatory powers to a new energy regulator may, in part, reflect these concerns. In this study, we have not considered such important environmental issues as pollution and global warming.

The government of Alberta has also been quite successful in its rent-collection regulations. It has succeeded in establishing regulations that ensure a relatively high proportion of economic rent, both expected rents and unexpected rent changes, accrues to the government, without significantly inhibiting petroleum production.

However, it took an extended period of time for a regulatory regime to be established in Alberta that recognized two key factors. One was largely political, establishing a stable and efficient regulatory framework within the context of a federal state, when both the provincial government and the federal government might reasonably exercise some claim on the benefits from the petroleum resource. As might be expected, these disputes came to a head in the 1970s when world oil prices soared and the value of Alberta's oil and natural gas resources increased dramatically. The eventual resolution, in the mid-1980s (which was undoubtedly aided by falling world oil prices), essentially recognized the primacy of the province and the acceptance of market forces in determining the values of oil and natural gas. The controversial policies of the period from 1973 through 1985 had led to changes that somewhat increased the rent-collection efficiency of the corporate income tax (accruing largely to the federal government).

A second important factor was devising a regulatory regime that recognized the inevitable uncertainties and risks attendant to the petroleum industry. This included, not just the geological risks

of exploration and reservoir performance, but also the economic (and political) uncertainties of the operation of global energy markets. This is very important for rent-sharing; if governments are to capture a large share of the actual rents that accrue, the rent-collection mechanisms must be flexible to changing geological and economic circumstances. A variety of mechanisms have been used, including competitive bonus bids, relinquishment provisions on mineral rights tracts, and royalties that are sensitive to output levels and prices.

It took some time for Canadian governments to agree to adapt to the variability of international energy markets, rather than imposing regulations to 'protect' either Canadian oil producers or consumers from the impacts of uncertain and variable prices. Since the mid-1980s, and with the free trade agreements with the United States and, later, the United States and Mexico, Canada seems willing to allow market forces to establish prices for both oil and natural gas. Previous experiments with price and trade regulations had made it evident that governments were no more successful than the private sector in forecasting future prices, so temporary 'bridging' policies to allow gradual adjustment to price changes were not possible. Policies to control prices interfered with desirable consumption and production adjustments; holding prices below the international level, for instance, encouraged more oil use and inhibited consumption, therefore raising the possibility of increased dependence on expensive imported oil. It was also apparent that the regulations would likely become very complicated. For example, if international oil prices changed frequently, then so must various regulations; holding domestic prices down required limitation on exports of petroleum and/or export taxes; the level of taxes would have to recognize quality differences, etc.

Thus there was an extended period in Alberta in which a distrust of the operation of petroleum markets led to considerable controversy and to experimentation with regulatory programs that entailed real economic inefficiencies. Since the mid-1980s, there has been a willingness to accept the operation of petroleum markets. This is well-justified from an economic point of view. But a part of this desirability stems from the existence by then of a stable and relatively effective regime for sharing economic rents and controlling many of the production externalities generated by the activities of an industry operating in a physical world. In this respect, Alberta can serve as a good example for the rest of the world.

NOTES AND REFERENCES

Notes

1. Over the years government departments and agencies responsible for regulations and statistics concerning the petroleum industry have undergone name changes. For example, the Alberta Energy Resources Conservation Board has been variously known as the Turner Valley Conservation Board; Petroleum and Natural Gas Conservation Board; Oil and Gas Conservation Board; Energy Resources Conservation Board (twice!); and Energy and Utilities Board. Departmental responsibility in Alberta has been undertaken by Lands and Mines; Mines and Minerals; Energy and Natural Resources; and Energy. Federally, we have seen the Department of Natural Resources; of Energy Mines and Resources; of Energy; and of Energy and Natural Resources. In this book, and in the References, we normally use the title at the time at which the document referred to was issued. The main exception is with ongoing publications from the main provincial regulatory agency, which are usually sourced here as published by the ERCB (Energy Resource Conservation Board).
2. Government publications typically come from the issuing source, so publisher data (location and name) are not included. Government publications listings (for government departments or agencies) begin with the name of the government (e.g., 'Alberta' or 'Canada'). Reports from important Commissions commonly referred to under the name of the Head of the Commission are usually listed both under the appropriate government and also under the name of the Head.
3. This reference list includes all documents referred to in the text of the book. Statistical sources used for Tables and Figures are referenced in the Table or Figure.

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