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Towards North American Energy Security: Removing Barriers to Oil Industry Development

by Gerry Angevine

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Contents

Foreword

This paper is the first in a series of papers being undertaken by the Fraser Institute in the course of developing a Continental Energy Strategy. As noted in *A Vision for a Continental Energy Strategy*, published by the Fraser Institute in 2008, the fundamental objective of this strategy is to ensure that the applicable policy and institutional frameworks are conducive to as rapid a development of North America's energy resources as possible in light of market conditions, legitimate environmental concerns, and global investment opportunities (Klein and Tobin, 2008). The goal of accelerated development of the continent's energy resources is predicated on the economic benefits that it can bring in terms of expanded employment, improvements in living standards, and security of energy supply. In order to achieve this objective, non-market barriers to private investment must be identified and removed.

Executive summary

This paper focuses on crude (i.e., non-refined) oil, which is an important element of North America's overall energy mix and involves a range of exploration, development, production, and transportation activities which, together, represent a significant component of the continental economy. This will be followed by papers pertaining to the natural gas and electric power sectors which will also identify barriers to investment and put forward recommendations to facilitate investment in the development of production and transportation facilities.

North America's proven crude oil reserves, including the Alberta oil sands, represent only about 15% of the world's reserves.[1] However, if unproven (probable and possible) crude oil resources in US oil shale formations and in the offshore areas of Canada, the United States, and Mexico are considered, the continent's crude oil supply potential is more substantial. Requirements for oil fuels are also partially being met by the production of products such as ethanol from plant sources. The potential to produce oil fuels from the continent's coal supplies on a commercial basis is also emerging.

Of the three North American countries, Canada is the only net exporter of crude oil. Canada's oil exports have been increasing, despite declining production from conventional oil fields, because of the growth in production from the oil sands. In stark contrast, the United States is heavily dependent on imports of crude oil. Canada is now the major single-country supplier of oil to the US, though the majority of US oil imports come from OPEC and other countries overseas, which means that the US economy is vulnerable to supply disruptions. Until recently Mexico was a net oil exporter but, in spite of having considerable undeveloped crude oil resources in the Gulf of Mexico, the country has become a small net crude oil importer. Mexico's inability to increase its crude oil production reflects its inability to attract foreign investment because the country's constitution vests ownership of any hydrocarbons that are discovered in Petroleos Mexicanos (PEMEX), the state-owned oil company.

Review of prospects for growth in crude oil production and demand in the three countries suggests that Mexico's dependence on imports could increase somewhat in the period to 2030. The most recent long-term forecast for the United States by the Energy information Administration (2010) suggests that the United States' depend-

1 Proven reserves are those oil resources which are deemed recoverable under current and expected economic conditions and technologies.

ence on imported crude oil could stabilize rather than increase, but this rather optimistic view is dependent on a number of assumptions such as expanded offshore crude oil production and commercialization of crude oil production from oil shale. Canada, on the other hand, has the potential to grow its capacity to export crude oil on account of continued oil sands development.

Growth of North American crude oil production will require considerable investment in small pipelines that are needed to gather supplies for transportation over long distances by the major oil pipelines. Additional long-distance pipeline transportation capacity will be needed to deliver bitumen from the Alberta oil sands to port facilities on the West Coast and to market points in the United States, including the important Houston area market.

The analysis presented in this paper indicates that North America as a whole will not only remain heavily dependent on imported crude oil supplies but could become even more so. This suggests that growth in North American crude oil production beyond the volumes included in the forecasts examined here would be readily absorbed in the continental market, provided that the incremental production is competitive with overseas supplies. Clearly, there is an opportunity for firms on this continent to increase crude oil production which would trigger employment, labor, income, and general economic benefits. However, for this to occur, barriers to investment in crude oil production and transportation facilities must first be removed.

Barriers to investment in expansion of the continent's crude oil production capacity include, in some cases (for example, Canada's Northwest Territories, California, and Colorado) royalties on oil production that are not competitive with other jurisdictions in the continent and overseas, such as Texas and Australia. Barriers also include royalty schemes that fail to recognize the higher costs involved in deep drilling, whether on or offshore. They also include uncertainty as to how environmental policies in relation to air emissions, and land and water contamination, will unfold, and the impact that the changes will have on costs; moratoria on offshore exploratory drilling for crude oil; and obstacles to the mobility of skilled labor, especially across international boundaries, but also within Canada. Finally, there is the aforementioned constraint that the Mexican constitution imposes on multinational oil companies that seek to participate in the exploration and development of that country's crude oil resources.

Investment in projects to expand the capacity to transport crude oil from new and expanded North American supply sources to markets is often impeded by unnecessarily long, complex, and costly regulatory processes and procedures as well as by protracted disputes with native groups with regard to project siting.

This study recommends that policy makers at the appropriate national, state, and provincial levels move to reduce barriers to investment in North American crude oil and transportation facilities by:

- Ensuring that crude oil production royalties are competitive with other jurisdictions;
- Reflecting the higher cost of producing oil from deepwater offshore and non-conventional sources in the royalties or, preferably, reforming the taxation of petroleum production such that net revenues are subject to a flat tax, as outlined in a recent Fraser Institute paper (Clemens, 2008);
- Removing environmental policy uncertainty hanging over oil sands development, especially in relation to greenhouse gas emission constraints;
- Removing uncertainty in relation to environmental policies affecting conventional oil production, as with the conventional heavy crude oil and regulations pertaining to offshore areas;
- Removing moratoria on offshore exploration and development if it is determined that the environmental risks can be adequately mitigated;
- Streamlining regulatory processes for obtaining energy pipeline construction permits;
- Adopting standard, consistent procedures for resolving native land claims;
- Adopting further measures to improve labor mobility; and
- Finally, seeking innovative means to overcome the constraint that the Mexican Constitution, by vesting ownership of all hydrocarbons that are discovered there in state-owned Petroleos Mexicanos (PEMEX), imposes on exploration and development of that country's crude oil resources. This constraint is very severe since it precludes other petroleum exploration and development companies from direct investment and therefore essentially limits their involvement to that of subcontractors.

These recommendations will comprise part of the overall continental energy strategy that is being developed through this project.

About the Continental Energy Strategy initiative

As noted in the Institute's 2008 *Vision for a Continental Energy Strategy*, the proposed strategy will comprise a set of policy recommendations that are designed to ensure that North America's energy resources are developed as efficiently as possible given market requirements, science-based environmental concerns, and international competition (Klein and Tobin, 2008).

The primary objective of the energy strategy initiative is to ensure that the citizens of Mexico, the United States, and Canada are able to realize the maximum possible economic and social benefits from development of the continent's energy resource endowment through free and open markets, including free energy trade with the rest of the world. Increased availability of energy supplies from North American sources resulting from investment decisions made under free market conditions would increase the range of options available to consumers for meeting their energy requirements. More broadly, increased development and production of the continent's energy resources would bolster the security of energy supply by, for example, increasing crude oil and refined petroleum product supply options. Certainly, accelerated investment in the development of Canada's energy resources that takes advantage of export opportunities holds considerable promise as it would trigger increased employment and income and contribute to improvements in the quality of life of all Canadians.

Market forces will determine the most efficient allocation of North America's energy resources. For this reason, development of a continental energy strategy does not involve identifying energy investment, production, and trade targets. Rather, the focus is on ensuring that government policies pertaining to energy resource investment, development, consumption, and trade are stable, fair, and appropriate. Government must avoid intervening in energy investment decisions because the allocation of resources is best left to those who are motivated by market forces, have an in-depth knowledge of the technologies involved, and are prepared to take risks based on their understanding of how energy requirements are likely to change.

Public policy settings and institutional arrangements need to be conducive (by fostering conditions which allow free markets to function effectively) to investment in the expansion of the continent's energy supply capacity. In relation to a particular energy commodity, such as crude oil, this strategy requires identifying both barriers to such investment and prospective policy improvements, including the streamlining of regulatory procedures and processes. Policy frameworks must also support energy market competition and innovation, and allow investors freedom of choice to determine production locations and to define the scope of their businesses in accordance with market conditions.

Introduction

This paper focuses on crude (i.e., non-refined) oil because of its importance in the North American energy mix and economy. Not only is the oil industry an important component of economic activity in North America[2], but crude oil is the largest source of primary energy on the continent, accounting for 41% of the continent's total primary energy demand in 2006.[3] This compares with coal's 20% share of total energy use, natural gas's 20% share, and nuclear power's 8% share (International Energy Agency, 2009). A portion of the share of energy that crude oil currently provides is projected to be replaced by renewable energy sources and biofuels by 2030. However, crude oil's projected 35% share as of that year will still be much greater than those of coal, natural gas, and nuclear energy, which the International Energy Agency's *World Energy Outlook* Reference Case suggests will remain at or close to their current levels (International Energy Agency, 2009).

If the capacity to produce and transport crude oil were increased from current levels by lowering investment barriers (such as the cost of regulatory compliance in relation to new projects by employing more efficient regulatory approval procedures), this would give rise to ancillary, indirect and induced, economic benefits, both during facility construction and the ensuing operations, in addition to the direct employment, labor income, and GDP impacts.[4] For this reason, the paper identifies inefficient government constraints that prevent companies in the oil industry from responding to changes to market conditions by, for example, ramping up the capacity to produce oil

2 By way of example, in 2007 the oil industry (excluding natural gas activity, but including oil refining and refined petroleum product distribution, for which separate data were not available for segmentation purposes) accounted for approximately 4.9% of GDP in the United States, 4.3% of US labor income and, with 6.5 million jobs, 3.7% of total US employment. (These estimates were derived by the author from recent studies by PriceWaterhouseCoopers and IHS Global Insight for the American Petroleum Institute and America's Natural Gas Alliance, respectively (PriceWaterhouseCoopers, 2009; IHS Global Insight, 2009).

3 Primary energy is energy that exists in natural form; it includes coal, natural gas, and crude oil. Primary energy demand is demand for energy that, at the point of consumption, has not been transformed into another form of energy such as electricity.

4 Indirect employment, labor income, and GDP effects are those that arise when an increase in spending on goods and services by an industry causes that industry's suppliers to increase spending on labor and materials. Induced effects are triggered when workers employed as a consequence of the direct and indirect effects use portions of their incomes to purchase goods and services. While entrepreneurs cannot be expected to consider macroeconomic impacts such as these when making investment decisions, they are, nevertheless, important aspects of economic and energy policy analysis.

from North American sources. The paper then recommends policy changes to remove, or at least lower, such barriers.

Because policy recommendations pertaining to crude oil investment, production, and transportation will form an essential and important component of the continental energy strategy, it is important that any such initiatives in these areas align with the principles and goals outlined in the *Vision for a Continental Energy Strategy*. In particular, policy recommendations must recognize the importance of free and open trade in crude oil and petroleum products, both internally and across international and intra-continental borders. The recommendations must also indicate the value of limiting government involvement in the oil markets to ensure that the tax, regulatory climate, and business environment conditions are fair and competitive with those in other jurisdictions.[5] Policy changes may also be necessary to help to ensure that infrastructure required to develop facilities to produce and transport crude oil, as identified by market signals, is adequate and that the labor markets from which project construction workers will be drawn are flexible and competitive.

In order to provide a backdrop for the recommendations that are presented, an overview of North America's crude oil and oil sands bitumen endowment and of the continental crude oil supply and demand situation and outlook is provided at the outset. Second, constraints on the capacity of the crude oil transportation system to meet the requirements of increased oil production from Canada's oil sands are discussed.

This is followed by examination of the uncertainties and risks that constrain development of additional oil production and transportation facilities and constitute barriers to such investment. This sets the stage for the final section of the paper which lays out a number of oil policy initiatives fully consistent with the goals and objectives of a continental energy strategy.

5 Enumeration of the performance of government regulators in approving major project proposals in the North American oil industry, and the extent to which they have constrained development, are beyond the scope of this paper. There have been cases, such as the application to construct the Mackenzie Valley gas pipeline and related gathering system, where the regulatory process has clearly been far too time-consuming and costly. Essentially, policy makers will need to ensure that regulation of transportation facilities is as efficient and as light-handed as possible in order that resource development is not constrained by regulatory processes and procedures that unnecessarily delay construction of new crude oil and refined product pipelines.

Oil resources and reserves

This section examines the extent of North America's crude oil resources and reserves. In conjunction with the discussion of current production rates that follows, it provides some indication of North America's ability to meet its crude oil requirements from its own oil resource endowment. To help readers understand the terms used later in this paper, this section begins with an explanation of a number of concepts related to oil resources and reserves. Unless otherwise indicated, these explanations are taken from a National Energy Board crude oil assessment paper (National Energy Board, 2005).

Explanation of key terms

Ultimate potential resource is an estimate of all the crude oil resources that may become recoverable or marketable, in light of geological prospects and anticipated technology.

Resources in place is the gross volume of crude oil estimated to be initially contained in a reservoir, before any volume has been produced and without regard for the extent to which such volumes will be recovered.

Recoverable resources refers to the portion of the ultimate crude oil resource potential that is recoverable under expected economic and technical conditions.

Proven (or proved) reserves, according to the National Energy Board, are those crude oil resources that are recoverable with current technology and under present and anticipated economic conditions, specifically demonstrated by drilling, testing, or production. The US Energy Information Administration's definition is similar, but not identical: proven reserves are the estimated quantities of crude oil that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions (Energy Information Administration, 2010c).

Probable reserves are the crude oil volumes that, on the basis of geologic evidence that supports projections from proved reserves, can reasonably be expected to exist and be recoverable under existing economic and operating conditions (Energy Information Administration, 2010c).

According to the National Energy Board, *established reserves* are the sum of proven reserves and half of probable reserves.

Possible reserves are the crude oil resources that geological and engineering data suggest are less likely to be recoverable than probable reserves (PEMEX, 2009)

Initial established reserves are established reserves prior to deduction of any production.

Remaining reserves (or remaining established reserves) are initial reserves less cumulative production as at a given time.

Overview of crude oil resources in North America

While much of the continent's "conventional" crude oil resources (i.e., oil producible via conventional well-drilling and pumping technologies) have already been produced, development of so-called "unconventional" supplies is becoming more important. Unconventional sources include heavy oil or bitumen found in oil sands and a form of oil known as kerogen, which is found in oil shale. In Canada, oil sands bitumen is a major unconventional source of crude oil. Development of Canada's capacity to produce bitumen has been substantially ramped up over the past decade and strong growth is expected through 2030 (National Energy Board, 2007).

Table 1 shows proven crude oil reserves for Canada, the United States, and Mexico, as well as the totals for the continent and the world at the end of 2009 (BP, 2010). The data relate only to conventional crude oil sources, with the exception of Canada's proven reserves of crude oil in the Alberta oil sands.[6] As the following discussion indicates, if portions of undiscovered oil resources and resources already discovered but unproven were included, North America's reserves would appear more robust. For example, the proven reserves data summarized in table 1 exclude unproven resources in the deepwater outer continental shelf. The data also exclude reportedly huge volumes of oil locked in shale deposits in the United States (discussed below) because production is not feasible.

Table 1 indicates that Canada holds about 12.6% of the world's proven crude oil and oil sands bitumen reserves, while Mexico and the United States hold only 0.8% and 2.0%, respectively. In North America, Canada accounts for about 82% of proven oil reserves, while the United States and Mexico account for 13% and 5%, respectively.

6 Canada's oil sands are the only source of unconventional crude oil resources in North America that have proven reserves.

Table 1: Proven Reserves of Crude Oil

Region	Proven reserves (in billions of barrels)	Share of North American and world oil reserves	
		North America (%)	World (%)
Canada	176.8	81.5	12.6
Mexico	11.7	5.4	0.8
United States	28.4	13.1	2.0
North America	216.9	100.0	15.4
World	1,404.1	not applicable	100.0

Sources: BP *Statistical Review of World Energy 2010*;. National Energy Board, 2009a, *Reference Case* appendix table A3.1

United States

As table 1 shows, the United States has proven crude oil reserves of 28.4 billion barrels. By comparison, domestic oil field production in 2009 was 5.3 million barrels per day, or about 1.9 billion barrels per year (Energy Information Administration, 2010d). However, the United States' long-term oil supply potential is likely to be substantially greater than the proven reserves data suggest, mainly because none of the oil resources found in US shale deposits are represented in table 1.[7]

Oil shale is composed of rock and kerogen, an organic material with a high hydrogen-to-carbon ratio, which can be transformed into high quality oil. The United States is reported to have about 626 billion barrels of oil that could be produced from shale formations. About half of this oil is located near the common borders of Wyoming, Utah, and Colorado. It is found close to the surface, generally in outcroppings and not deeper than 1,000 meters below the surface (National Petroleum Council, 2007).

Kerogen must be separated from the host rock and is converted into oil through a combination of high pressure and temperature, either in a large container vessel or before the shale is mined (National Petroleum Council, 2007). To date, very little oil has been produced from US oil shale because of the high production cost. The most common production technology has involved surface mining of the shale, followed by processing at temperatures in the vicinity of 500° C. This requires special facilities, an energy source to raise the temperature, and the disposal of large quantities of rock. An

7 Unlike Canada, the United States does not have crude oil resources in oil sands deposits.

alternative, lower-cost approach currently under investigation involves heating the shale while it is in the ground but to a temperature lower than 500° C. Considerable research will be required to find a commercially viable way to produce oil from kerogen. Until a technological breakthrough occurs which substantially improves the economics of doing so, we are unlikely to see any significant production of oil from shale.

A second reason why the proven oil reserve data presented in table 1 underestimate the US oil supply potential is that they do not reflect the potential for oil production from the outer continental shelf. The Minerals Management Service of the US Department of the Interior estimates that yet-to-be discovered offshore oil fields in the outer continental shelf likely contain some 86 billion barrels of oil, in addition to known reserves of nearly 14 billion barrels (Minerals Management Service, 2006). Together, known offshore reserves and undiscovered resources total approximately 100 billion barrels.[8]

The oil resource potential of the US outer continental shelf and the resources contained in shale formations in a few of the Rocky Mountain states suggest that total US oil resources likely exceed 100 billion barrels. This is equivalent to about 50 times the current annual rate of US domestic crude oil production.

Canada

Canada holds 176.8 billion barrels of proven or remaining established crude oil and bitumen reserves (table 1). This represents about 150 years of supply at the current rate of production (BP Statistical Review of World Energy, 2010). Almost 98% of Canada's crude oil reserves indicated in table 1 are unconventional and are composed mainly of bitumen found in Alberta's Athabasca, Peace River, and Cold Lake oil sands deposits (National Energy Board, 2009; Energy Resources Conservation Board, 2010a). The remaining 2% of Canadian oil reserves consists of conventional reserves in the Western Canada Sedimentary Basin (WCSB), including the Yukon and Northwest Territories mainland, Ontario, and the Newfoundland and Labrador Grand Banks. About three-quarters of the conventional reserves are in the WCSB where annual production

8 A little more than half of the potential oil supply from undiscovered fields in the US outer continental shelf—approximately 45 billion barrels—is believed to be in the US portion of the Gulf of Mexico where known reserves of 7 billion barrels have been located. The second largest yet-to-be developed oil resource concentration is estimated to be located off Alaska's shores, where about 27 billion barrels of oil are thought to exist in addition to known reserves of about 30 million barrels. By way of comparison, the outer continental Pacific and Atlantic shelves combined are estimated to contain about 13 billion barrels of undiscovered oil reserves (Minerals Management Service, 2006).

generally exceeds reserve additions and there has been a downward trend in the remaining oil reserves. The rest of Canada's conventional reserves are found mostly in the Newfoundland and Labrador Grand Banks offshore region (National Energy Board, 2009).

The oil sands are composed of crude bitumen and the rock material with which it is found, along with any heavy oil that may be present. Bitumen was first produced from the oil sands on a commercial basis in the late 1960s. Over the past decade, technological improvements and higher oil prices have resulted in accelerated development of new and expanded bitumen production facilities. Where the oil sands deposits are near the surface, they are mined and then processed to extract the bitumen. Otherwise, the bitumen is produced *in situ* (on site) by injecting steam into the reservoir to induce the bitumen to flow to the surface. Once produced, the bitumen is mixed with diluents, such as pentanes plus,[9] that enable it to be sent through pipelines to refineries. Alternatively, the bitumen is first upgraded to synthetic crude oil and then transported to refineries.

According to Alberta's Energy Resources Conservation Board (ERCB), 6.9 billion barrels of bitumen have been produced from the oil sands to date, including about 0.54 billion barrels in 2009 (ERCB, 2010a). The Board estimates that 169.9 billion barrels of established reserves of bitumen remain in Alberta (ERCB, 2010a).[10] This estimate is approximately one-tenth of the estimated volume of bitumen currently in place—1.7 trillion barrels.[11]

Canada's crude oil reserves are most likely greater than indicated in table 1. As more oil sands projects are developed and more information becomes available, the ERCB's ongoing review and exploration processes are likely to result in increases in estimated in-place bitumen volumes. And with technological developments that lower production costs, a larger portion of the bitumen considered to be in place will likely come to be considered as established reserves. Further, the data in table 1 do not include the potential oil sands bitumen deposits now being identified in Saskatchewan.[12]

Canada's offshore Atlantic, Pacific, and Beaufort Sea frontier areas also hold large quantities of recoverable oil. Oil reserves and resources in the vicinity of 1.8 bil-

9 According to the National Energy Board, pentanes plus is a mixture of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate, or crude oil (National Energy Board, 2009).

10 In its 2009 *Reference Case*, the National Energy Board reported 172.9 billion barrels of remaining oil sands reserves as of the end of 2006.

11 For an analysis of the Alberta oil sands as an economic resource, see Atkins and MacFayden, 2008.

12 Bitumen deposits in Saskatchewan are in the early stages of delineation and no official resource estimates are available yet.

Table 2: Canada's Offshore Crude Oil Reserves and Resources (in billions of barrels)

	Resources in place	Reserves and recoverable resources
Newfoundland and Labrador	NA*	1.8**
BC Queen Charlotte Basin	9.8	2.5
Mackenzie Delta/Beaufort Sea	n/a	1.0

*No recent publicly available estimates were found.
**Total remaining oil reserves and resources. According to the National Energy Board's *2009 Reference Case,* only 912 million barrels, or about half of the indicated volume, fall into the "remaining established reserves" category.
Sources: British Columbia Ministry of Energy, Mines and Petroleum Resources, 2002; National Energy Board, 1998; Canada-Newfoundland and Labrador Offshore Petroleum Board, 2010a; and the National Energy Board 2009a, appendix table A3.1.

lion barrels remain in the Newfoundland and Labrador Grand Banks (table 2), where oil is currently being produced from the Hibernia, Whiterose, and Terra Nova fields (Canada-Newfoundland and Labrador Offshore Petroleum Board, 2010a).[13]

A 2002 report commissioned by the province of British Columbia indicates that there are likely about 9.8 billion barrels of oil in the Queen Charlotte Basin between the Queen Charlotte Islands and Vancouver Island, of which 2.5 billion barrels could be recoverable (British Columbia, Ministry of Energy, Mines and Petroleum Resources, 2002). However, the resources in this area are not being further explored or developed because of federal and provincial moratoria on drilling and resistance from local First Nations to the development of an offshore petroleum industry until their claims and concerns have been addressed.

Some crude oil has been discovered in the Mackenzie Delta/Beaufort Sea area in Canada's north. A 1998 report by the National Energy Board estimated the amount of

13 These resources consist of approximately 900 million barrels of remaining reserves in the Hibernia, Whiterose, and Terra Nova fields, and about 900 million barrels in other Grand Banks locations. The Canada-Newfoundland and Labrador Offshore Petroleum Board defines "resources" as volumes of oil, expressed at 50% probability, that have been assessed as being technically recoverable but not delineated and which have unknown economic viability. This differs from the "recoverable resource" concept used by the National Energy Board, which assesses volumes in place for both technological and economic factors. Application of the 50% factor may have been done to provide an approximate estimate of the size of the recoverable resource.

recoverable oil there to be 1.0 billion barrels (National Energy Board, 1998).[14] More exploration is required to further delineate the potential oil production there and in the arctic islands.

Given the prospects for oil sands bitumen production in northwest Saskatchewan and the potential of offshore and northern oil reserves yet to be discovered, along with the likelihood that technological developments will allow a greater portion of Alberta's oil sands bitumen resources to be identified as "proven reserves," Canada's oil reserves are undoubtedly greater than the volume of "proven reserves" indicated in table 1. Unfortunately, no estimate of Canada's overall potential crude oil resources is currently available.

Mexico

According to the *BP 2010 Statistical Review of World Energy*, Mexico's proven crude oil reserves totaled 11.7 billion barrels at the end of 2009 (table 1). This compares with a report by state-owned Petroleos Mexicanos (PEMEX) that Mexico had proven crude oil reserves of 10.4 billion barrels as well as "probable" reserves of 10.4 billion barrels, bringing the total of proven and probable reserves (so-called "2P" reserves) to 20.8 billion barrels, as of January 1, 2009. In addition, PEMEX identified 10.1 billion barrels of "possible" reserves (PEMEX, 2009).[15]

As table 3 shows, 31% of Mexico's proven crude oil reserves are onshore, while 69% are located offshore. Fifty-three percent of total proven *and* probable reserves are offshore.

The table indicates the dominance of the offshore fields in the composition of Mexico's proven crude oil reserves and, especially, the importance of the Cantarell and Ku-Maloob-Zaap fields in the northeast marine region. Together, those two fields constitute almost 60% of Mexico's total proven reserves.

Of probable reserves of 10.4 billion barrels, the northern onshore Aceite Terciario del Golfo field is by far the largest with 53% of the total. The offshore Cantarell and Ku-Maloob-Zaap fields combined account for more that a quarter of total probable reserves.

Although 3.4 billion barrels of crude oil were discovered in Mexico from 2004 to 2008, Mexico's total oil reserves declined over that same period because the additions

14 The most recent National Energy Board tally of Canada's oil resources (Table A3.1 in the 2009 *Reference Case*) does not recognize any remaining established reserves in the Mackenzie Delta/Beaufort Sea area or the arctic islands region.

15 Proven, probable, and possible reserves are defined at the beginning of this paper.

Table 3: Mexican Crude Oil Reserves as of January 1, 2009 (in billions of barrels)

	Proven	Probable	Total
Northeast Offshore			
Cantarell	2.96	1.22	4.18
Ku-Maloob-Zaap	2.96	1.63	4.59
Southwest Offshore			
Abkatun-Pol-Chuc	0.56	0.34	0.9
Litoral de Tabasco	0.61	0.64	1.25
Total Offshore	7.09	3.83	10.92
Northern Onshore			
Aceite Terciario del Golfo	0.50	5.51	6.01
Poza Rica-Altamira	0.31	0.33	0.64
Veracruz	0.01	0.00	0.01
Southern Onshore			
Bellota-Jujo	0.93	0.14	1.07
Cinco Presidentes	0.19	0.09	0.28
Macuspana	0.04	0.04	0.08
Muspac	0.10	0.11	0.21
Samaria-Luna	1.22	0.32	1.54
Total Onshore	3.30	6.54	9.84
Total	10.39	10.37	20.76

Source: PEMEX, 2009.

resulting from exploration were more than offset by production. Based on geological information about areas in the US Gulf of Mexico offshore that lie close to the Mexico-US boundary, it is widely believed that significant crude oil reserves remain to be discovered in the Mexican northeast offshore area.

Production

As figure 1 illustrates, according to the *BP 2010 Statistical Review of Energy*, North American crude oil production, including natural gas liquids and oil sands bitumen, was slightly less in 2009 than 11 years earlier.[16] US production declined by 0.83 million barrels a day, or about 10%, from 1998 to 2009. Continental production would have been even lower in 2009 were it not for an increase of approximately 836,000 barrels per day of Alberta bitumen production.

A shift in the composition of continental oil supply has occurred since 1998. The US share of total production has dropped 2.8 percentage points, from 56.5% in 1998, while Canada's share has risen about 5.2 percentage points, from 18.8%. Mexico's share decreased slightly during the period, as will be discussed below, because of a significant decline in production in one of its major oil fields. The respective shares of 2009 production were: US, 53.7%; Canada, 24.0%; and Mexico, 22.3%.

United States

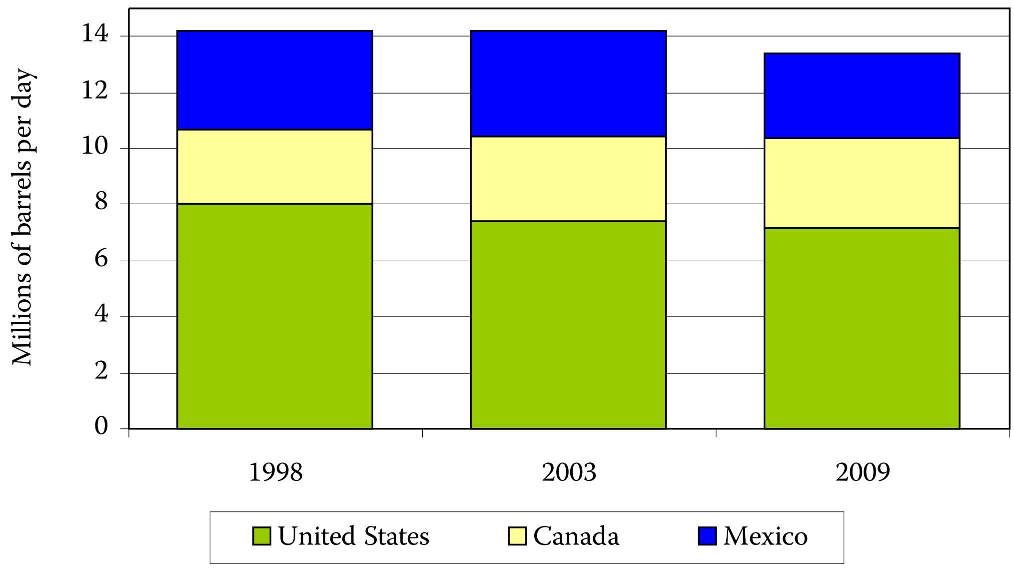
Looking ahead to 2030, the US Energy Information Administration's (EIA) 2010 *Annual Energy Outlook* Reference Case projection anticipates that offshore crude oil production will begin to ramp up as the result of recent discoveries in the Gulf of Mexico (Energy Information Administration, 2010a).[17] Expiration of the Congressional moratoria pertaining to the Eastern Gulf of Mexico and Pacific regions of the outer continental shelf is also expected to make a difference. Total offshore production of crude oil (excluding Alaska) is anticipated to reach 2.2 million barrels per day by 2030 compared with only 1.3 million barrels per day in 2008 (Energy Information Administration, 2010a, table 113).

The Energy Information Administration is projecting onshore crude oil production in the lower 48 states to increase from 3.0 million barrels per day in 2008 to 3.4 million barrels per day in 2030 (Energy Information Administration, 2010a). That US

16 Natural gas liquids are included where they are extracted separately. Most such liquids are produced in association with crude oil.

17 The projection of crude oil production in the Gulf was made before the BP Deepwater Horizon oil leak began near the end of April 2010. Government review of permitting and safety requirements as a result of the BP accident could slow exploration and development, and therefore growth of production, from what the EIA projected—at least for several years.

Figure 1: North American Crude Oil Production



Source: *BP Statistical Review of World Energy 2010*.
Includes oil from oil sands and natural gas liquids.

onshore oil production is able to more than hold its own is mainly the result of greater application of enhanced oil recovery methods. These generally involve injecting carbon dioxide or chemicals into a crude oil reservoir in order to increase the flow of oil to the surface.

Total US crude oil production is anticipated to increase from 5.2 million barrels per day in 2009 to 6.2 million barrels per day by 2030 in spite of a decline of 60,000 barrels per day in Alaskan production (Energy Information Administration, 2010a).[18] This would require average annual growth of total (both on- and offshore) oil production in the lower 48 states of 1.0%.

The Energy Information Administration is also assuming that technological advances will lead to significant and growing amounts of production of liquid fuels from sources other than crude oil.[19] For example, commercial production of oil from

18 Indicated total US 2009 crude oil production is less than the amount illustrated in figure 1 by approximately 1.9 million barrels a day. The difference is because the data underlying figure 1 include natural gas liquids, whereas the EIA's crude oil definition does not. Unfortunately, the source data for figure 1 did not include separate information for crude oil production alone for the 3 countries.

19 The EIA refers to the combined production of refined petroleum products from crude oil and liquid fuels from sources other than crude oil as "oil liquids."

coal-to-oil conversion is assumed to commence by 2012, and production of oil from oil shale in the early 2020s. Including oil production from corn and other crops, sources other than crude oil are expected to represent a larger portion of total US oil liquids supply by 2030.

The Energy Information Administration's 2009 *Annual Energy Outlook* report underscored the fact that higher than projected world oil prices could lead to greater investment and therefore greater crude oil production growth than indicated (Energy Information Administration, 2009a). On the other hand, lower prices would result in less investment in oil exploration and production development, and make it more likely that the US would increasingly have to rely on oil imports from overseas, contrary to the objective of reducing dependence on imported supplies touted by the present and previous US administrations as important for energy security reasons.

Canada

The National Energy Board projects Canadian crude oil production to grow at an average annual rate of about 2.8% from 2008 to 2020, climbing to 3.8 million barrels per day from 2.7 million barrels per day in 2008 (National Energy Board, 2009).

The decline in production from mature wells in the Western Canada Sedimentary Basin (WCSB), including the southern portion of the Northwest Territories, is expected to continue. However, this drop is limited to about 3% annually because of growth in production from the Bakken oil play in Saskatchewan, continued success of the Weyburn and Midale CO_2 injection projects (where CO_2 is injected to stimulate the flow of oil), and assumed production from new, enhanced oil recovery projects using CO_2 as the result of carbon capture and storage and CO_2 pipeline initiatives (National Energy Board, 2009).

East Coast offshore

Canadian offshore oil production is currently limited to Newfoundland's Hibernia, Terra Nova, and White Rose fields. During the first 4 months of 2010, total production from these fields averaged 292,000 barrels of crude oil per day compared with about 428,000 barrels per day when production peaked in May 2007 (Canada-Newfoundland Offshore Petroleum Board, 2010b). The National Energy Board's most recent projections indicate that production from the Grand Banks will continue to decline (National Energy Board, 2009). However, an agreement reached by the government of Newfoundland and Labrador with petroleum exploration and development companies in the summer of 2008 is expected to lead to development of oil production from the Hebron offshore field's estimated 700 million barrels of oil reserves, with production commencing by 2017. In addition, Newfoundland and Labrador has reached an agreement with producers to develop production from a field adjacent to Hibernia reportedly containing some 220 million barrels of oil (Newfoundland and Labrador, 2009). The addition of production from fields close to Hibernia and Hebron will slow the decline in offshore Newfoundland production.

Alberta's oil sands

The main bright spot in Canada's oil production continues to be the Alberta oil sands. Although escalating capital costs, the financial crisis, and a drop in oil price expectations led to the postponement of construction of numerous projects during the second half of 2008, construction of projects already in progress continued (International Energy Agency, 2009; Energy Resources Conservation Board, 2010a). As a result, some additional productive capacity was added in 2009, and more is being added. The reduction in labor and materials costs, restoration of confidence in the financial sector, and the widespread expectation that the price of oil will, on average, be sufficient to ensure the viability of new bitumen production and upgrading facilities, is expected to entice a number of cautious investors to proceed with their construction plans in the near future. One indication that this is occurring is that ExxonMobil Inc. and Imperial Oil are moving forward with the first phase of their Kearl Lake project (Energy Resources Conservation Board, 2010).

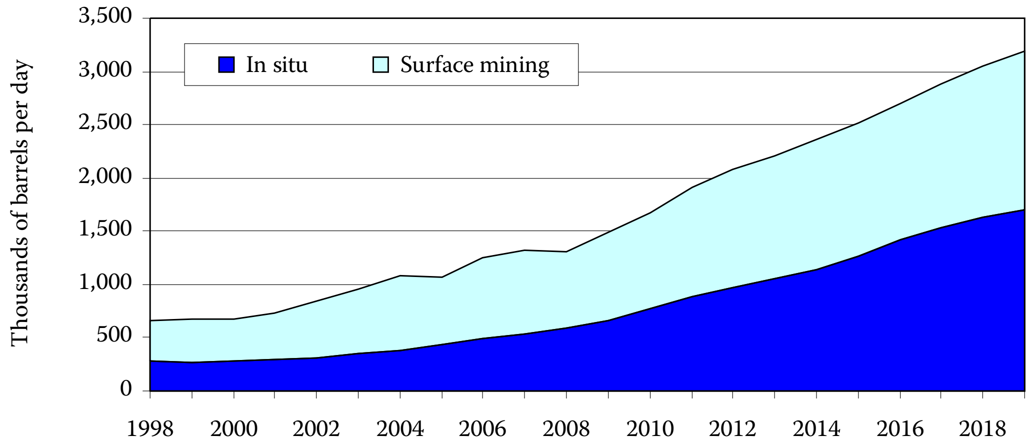
As indicated in table 4 and illustrated in figure 2, Alberta's Energy Resources Conservation Board estimates that annual production of bitumen from the Alberta oil sands will more than double from 2009 to 2019, reaching 3.2 million barrels per day, or approximately 1.17 billion barrels per year, by the end of the period (Energy Resources Conservation Board, 2010a). Bitumen output from *in situ* operations is projected to grow more rapidly than output production from surface mining operations. This is because the total cost of the production facilities is less in the case of a typical *in situ* operation than for an integrated mining and upgrading project. Also, the lion's share

Table 4: Alberta Bitumen Production Forecast (in thousands of barrels per day)

	2009	2019	Increase
In situ	665	1,704	1,039
Surface mining	827	1,488	661
Total	1,492	3,192	1,700

Source: Energy Resources Conservation Board, 2010a.

Figure 2: Alberta Bitumen Production, 1999-2019



Source: Energy Resources Conservation Board, 2010a.

of the bitumen production opportunities is located in areas where the bitumen is too far below the surface for surface mining to be feasible.

Environmental impact concerns could result in slower growth of bitumen production than projected by the ERCB, but these are being addressed by the provincial government and the industry. For example, because bitumen production and upgrading have been identified as a major source of greenhouse gas emissions, means to lower the costs of carbon capture and storage are being developed through field tests initiated by the Alberta government (Alberta Department of Energy, 2008). Another fear, that of limited supplies of water, is being addressed through efforts to increase the extent to which water used in bitumen production is recycled. Worries that the tailing ponds used in bitumen mining operations contain wastes from bitumen removal and processing operations are being addressed with new requirements that the fluid tailings be reduced and the deposits made suitable for reclamation. These obligations are leading to improved technologies, including a process proposed by Suncor Energy and conditionally approved by the ERCB in June 2010 (ERCB, 2010b).

Promising new technologies are addressing another concern, the amount of natural gas being used as the main energy source in bitumen production. One new technique involves the combustion of ashphaltenes, or bitumen residues, from the production process to generate steam. Another involves *in situ* bitumen combustion, which enables the bitumen to flow from the sand in which it is embedded.

West Coast offshore

Federal and British Columbia policy and native land claim issues are preventing the resumption of exploration in the Queen Charlotte Basin and other promising areas off the shores of the West Coast (Angevine and Hrytzak-Lieffers, 2007). While the federal and BC governments have each at times expressed interest in reopening the area to exploration, both claims to the resources by various First Nations groups, and environmental protection procedures, must first be resolved and agreed upon. Also, in the wake of the massive BP Deepwater Horizon oil leak in the US Gulf of Mexico in the spring of 2010, Canada's environment minister Jim Prentice has been quoted as saying that exploration on the West Coast cannot commence until reasons for the leak are understood, and appropriate environmental protection measures are developed (Pynn, 2010).

Mexico

According to the US Energy Information Administration, Mexico is likely to experience a sharp drop in conventional crude oil production from 2008 to 2030, to 2.08 million barrels a day from 3.19 million barrels a day (Energy Information Administration, 2010a, table 21).[20] This is mainly attributable to the continued decline in production from the country's most important oil field, Cantarell. In 2004, 61% of Mexico's total crude oil output was produced from the Cantarell offshore field, which then held 26% of the country's total proven crude oil reserves (Energy Information Administration, 2007: 33). It is unlikely that Mexico's other large oil fields, such as Ku-Maloob-Zaap and Bellota-Jujo, will be able to increase total crude production sufficiently before 2020 to more than offset the impact of the decline in production from the Cantarell field. In large part, this reflects the inability of state-owned PEMEX to finance sufficient offshore development due to the extent of the government's reliance on the company as a major source of revenue.

Mexican crude oil production is indicated in the most recent EIA projections to increase slightly from 2020 to 2030 (Energy Information Administration, 2010a, table 21). However, this assumes that the policy adjustments made by the Mexican government in response to declining production will be effective and adequate to increase production.

20 This figure includes natural gas liquids.

Uncertainties and risks in the continental oil production outlook

North American oil liquids production in 2008 and projections for 2015, 2020, and 2030 are provided in table 5.[21]

Table 5 indicates that North American oil liquids production is anticipated to increase from 14.2 million barrels per day in 2008 to 19.0 million barrels per day in 2030. The estimated 4.8 million barrels per day or 34% increase implies an annual average growth rate of 1.3% during the 22-year period.[22]

Table 5: North American Oil Liquids Production, 2008 to 2030 (in millions of barrels per day)

	2008	2015	2020	2030
United States	8.3	10.0	10.7	11.5
Canada	2.7	3.2	3.8	5.4
Mexico	3.2	2.1	1.8	2.1
North America	14.2	15.3	16.3	19.0

Source: Energy Information Administration, 2010a, table 21 for the US and Mexico; National Energy Board, 2009a, figure 5-1, with Fraser Institute extrapolations beyond 2020 for Canada.
Note: Because the 2009 National Energy Board projections only go out as far as 2020, estimates for 2030 and intervening years were extrapolated. The 2030 production estimate, for example, was obtained by applying the implied annual average rate of growth from 2015 to 2020 in the Board's projection to its production estimate for 2020.

21 As noted earlier, oil liquids comprise conventional crude oil, bitumen from oil sands, oil from biomass, oil produced from oil shale kerogen, oil from gas-to-liquid and coal-to-liquid processes, and natural gas liquids.

22 If the forecasts provided in table 5 and later in this report had been produced with single-equation predictors developed from regression analysis, an indication of the likely ranges within which future values could be expected to fall relative to the point forecasts would have been available from "standard error" values from the regression statistics. However, because the forecasts for Canadian, US, and Mexican oil production and oil liquids consumption were developed from complex sub-sections of large model structures such as the US National Energy Modeling System, and the authors of the referenced forecasts did not provide information about the historical forecast accuracy of the models, error ranges for the forecast point estimate values are unknown. Even if standard error information were available, statistics based on historical data relationships are unable to project catastrophic events such as the massive oil leak in the US Gulf of Mexico and the ramifications of such events for oil production and consumption.

The projections of oil liquids production and consumption for the United States and Mexico that are presented in this paper are taken from the US Energy Information Administration's *Annual Energy Outlook 2010* Reference Case. The Canadian forecasts are from the National Energy Board's *2009 Reference Case Scenario: Canadian Energy Demand and Supply to 2020* (Energy Information Administration, 2010a; National Energy Board, 2009.)

In the Energy Information Administration's Reference Case, real US GDP is assumed to grow at an annual average rate of 2.4% from 2008 through 2035. The world oil price (defined as the average price of light, low-sulfur crude oil delivered at Cushing, Oklahoma, in 2008 dollars) is assumed to rise from a low of US$70/barrel (bbl) in 2010 to US$95/bbl in 2015, and US$108/bbl in 2020, and then increase at a slower rate, reaching US$124/bbl in 2030. The prices of natural gas, coal, and other energy commodities, such as electricity, are determined by the modeling system employed by the Energy Information Administration and are, therefore, a function of economic growth, the world oil price, and a number of detailed assumptions related to hydrocarbon supply technologies and other matters.[23] In the Reference Case the real price of natural gas increases from US$4.50/MMBtu in 2010, to US$6.27/MMBtu in 2015, to US$6.64/MMBtu in 2020, and reaches US$8.05/MMbtu in 2030. The real price of coal is essentially unchanged from 2010 to 2020, but drops by nearly 7% from then until 2030.

The National Energy Board's *2009 Reference Case* assumes that Canadian real GDP will grow at an average annual rate of 2.1% from 2011 to 2020 following a decline of 2.6% in 2009 and a 2.6% recovery during 2010. In real 2008 dollar terms, the price of West Texas Intermediate crude oil is assumed to average US$50/bbl in 2009, but then to increase with the recovering global economy, reaching US$90/bbl by 2020. The real price of natural gas is assumed to increase from US$6.70/MMBtu in 2011 to US$7.50/MMbtu in 2020. Coal prices are assumed to remain approximately constant in real terms during the period to 2020 relative to their 2007 levels. No incremental carbon price is assumed.

The projections suggest that the respective shares of North American liquids production will change somewhat from 2008 to 2030. Canada's share would increase from 19% to about 28% as the result of increased bitumen production from the oil sands. The nearly 3 percentage point increase in the US share, to 60%, is mainly attributable to the expected increase in biofuels production. The drop in Mexico's share from 22.5% to 10.5% reflects the US Energy information Administration's view, as already noted, that Mexican crude oil production will suffer as a consequence of Mex-

23 A full, 195-page presentation of the detailed assumptions underlying the Energy Information Administration's *Annual Energy Outlook 2010* Reference Case and alternative scenarios is available (Energy Information Administration, 2010c).

ico's inability to attract sufficient investment and expertise to develop its offshore resources.

For each country, the projections used here are based on a unique set of assumptions. For this reason, the implied North American oil supply outlook must be regarded as but one of many possible scenarios. Risks and uncertainties associated with these and other long-term oil supply forecasts suggest that whatever projections policymakers consider to represent the "most likely," or "reference case," or "base case" scenarios (which in practical terms effectively all mean the same thing), they must exercise considerable judgment when deciding how the markets for crude oil and refined products are likely to evolve and what, if any, policy changes may be are required to improve market efficiency. The most important areas of uncertainty and risk with regard to the continental crude oil supply outlook appear to be as follows:

Impacts of environmental policy changes on investment in new oil production facilities

Continued uncertainty at the state, provincial, and federal levels with regard to the volume of mandated reductions in emissions of carbon dioxide and other greenhouse gases, and when new regulations will become effective, is making it difficult for potential investors in conventional oil production, bitumen production and upgrading, and transportation facilities to make decisions. This is especially the case in situations where carbon emissions per unit of output are greatest, as with oil sands bitumen production, because emissions abatement requirements will increase capital and operating costs.

Expansion plans at existing facilities will also be affected by emissions reductions requirements since the cost of mitigating emissions will impinge upon the operators' ability to add to capacity. For this reason, it is important that facility owners be informed of changes in environmental requirements, including details of the institutional arrangements, as far in advance as possible. For example, if a carbon emissions cap-and-trade system is to be implemented, investors will need to know how initial allowances will be distributed, whether credits will be available for actions already taken, and the extent to which credits purchased from other stakeholders may be used.

Similarly, if policymakers are contemplating taxing petroleum products according to carbon emissions, or introducing low-carbon fuel standards, it is important that such policy changes be defined as soon as possible. Continued uncertainty will prevent potential investors in oil supply production facilities from determining how market conditions are likely to change and whether the plans they have made are viable.

Impact of environmental concerns on the development of offshore production

Much of the increase in US crude oil production in the Energy Information Administration's *2010 Annual Energy Outlook* comes from a 72% increase in oil production from the lower 48 offshore regions—from 1.27 million barrels per day in 2008, to 2.19 million barrels per day in 2030. This assumption may be unrealistic since, as the Administration itself points out, "after 2010 … discoveries are smaller, and capital expenditures rise, as development moves into deeper waters" (Energy Information Administration, 2009a: 79). Further, the projection was partly based on the assumption that the Bush administration's lifting of congressional moratoria on oil exploration and production in 2008 on the Atlantic Outer Continental Shelf, in 2014 on the Pacific Gulf of Mexico Shelf, and in 2025 on the Eastern Gulf of Mexico Shelf, would allow production to increase in these zones. However, the extent to which activity in the Outer Continental Shelf can increase is subject to approval by the secretary of the interior. Continued opposition to the development of offshore production and failure by the government to approve requested development plans would slow the pace of development from that assumed in the *Annual Energy Outlook* Reference Case.

The announcement by President Obama on March 31, 2010, supporting the opening of offshore drilling along the Atlantic Coast from Delaware to Florida, in areas off the North Coast of Alaska, and in the eastern part of the Gulf of Mexico might have been expected to attract additional upstream investment in exploration and development and contribute to growth in offshore production (Obama, 2010a). However, the disastrous British Petroleum oil leak that began on April 20, 2010, with an explosion on an offshore oil rig in the US Gulf of Mexico will make it more difficult for future US offshore oil exploration and production projects to gain approval. Moreover, as already indicated by the governors of Florida and California, any expansion of their states' offshore zones that have been available for exploration is likely to be out of the question for some time to come. The Energy Information Administration's projected increase in oil production from US offshore areas is, therefore, very likely at risk.

Uncertainty regarding future oil prices

Investors rely heavily on the price of crude oil as they decide whether or not to invest in petroleum exploration and development, and as they decide how much oil to produce. Whether oil supply forecasts are developed by analysts or derived using models of one form or another, the assumed future crude oil prices are an important element in the forecast of oil supply. For this reason, the US Energy Information Administration, the

National Energy Board, and other organizations engaged in forecasting crude oil production frequently generate forecasts using both high and low price scenarios. These alternative scenarios help frame the range within which oil production is likely to vary depending on crude oil prices. In reality of course, oil prices are determined by the interaction of decisions taken by crude oil producers and petroleum product consumers.

Speculative assumptions surrounding the commercialization of new technologies

The US Energy Information Administration is predicting that conventional and non-conventional US oil liquids production will increase by 3.1 million barrels per day, or approximately 37%, from 2008 to 2030. Officials anticipate that only about half of that increase will come from greater conventional onshore and offshore crude oil production. They assume that the remainder will come mainly from non-conventional sources, especially biomass, but also including the production of oil from shale formations and coal-to-liquids conversion.

There is no basis for the indicated emergence of commercially viable oil liquids production from coal-to-liquids conversion processes as early as 2011 or 2012 and the accelerated growth of oil liquids production from that source that is assumed to follow. The Administration simply assumes that the necessary technological improvements will occur and that the price of oil will be sufficient to trigger the required investment, in spite of the fact that such a carbon-intensive process will likely face considerable additional costs because of constraints on allowable greenhouse gas emissions.

Similarly, the assumption that the production of oil from oil shale will be commercially feasible by 2023, and will increase rapidly thereafter, is sheer conjecture. The Energy Information Administration simply assumes that "research and development efforts [will] provide the necessary technology improvements to yield commercial quantities of liquids from oil shale production that, over time, can be further increased in scale" (Energy information Administration, 2009a, page 80). The indicated commencement of significant commercial production of oil liquids from biomass-to-liquids, coal-to-liquids conversion, and oil shale, although possible, must be regarded as highly speculative.

Increased Canadian oil production arising from CO_2 injection

The July 2009 National Energy Board forecast of Canadian crude oil production assumes that anticipated government policy restrictions on greenhouse gas emissions will result in the development and application of carbon capture and storage (CCS) technologies which, together with the construction of CO_2 pipelines leading to oil reservoirs suitable for enhanced production through CO_2 injection, will lead to incremental oil production. But there is no assurance that such pipelines will be built to the extent assumed by the board and, even if they are, that oil producers will be willing to purchase and use CO_2 for injection purposes to the degree assumed, or that the assumed increase in production from CO_2 injection can be achieved. In short, much of the 100 million barrels of incremental oil production assumed to be forthcoming from CCS promotion and CO_2 pipeline construction may not be achievable, at least in the assumed time frame.

Uncertainty regarding development of Canadian oil sands production

Cutbacks in investment in oil sands production capacity began to be announced in early 2008 because of sharply lower price and revenue expectations, financing constraints, and escalating capital costs. According to the International Energy Agency, oil sands bitumen production and upgrading projects with a combined total capacity of 1.7 million barrels a day and costing around US$150 billion were suspended or cancelled (International Energy Agency, 2009: 147).

The US Energy Information Administration's 2010 *Annual Energy Outlook* predicts that Canadian bitumen production will increase from 1.5 million barrels per day in 2008 to 4.6 million barrels a day by 2030 (Energy Information Administration, 2010a, table 21.) This does not appear to be far-fetched given the opinion from Alberta's Energy Resources Conservation Board that bitumen output will reach 3.2 million barrels a day by 2019 (ERCB, 2010a). However, the speed and extent of the drop in expected investment in oil sands ventures underscores the sensitivity of big-ticket projects to fluctuations in the estimated costs. Although the global credit crisis appears to have eased, uncertainty about the impact of expected new provincial and federal environmental regulations pertaining to greenhouse gas emissions and other aspects of oil sands operations (e.g., water usage and waste disposal) will cause some potential investors to proceed cautiously. Essentially, it is difficult to predict with much accuracy the rate at which oil sands activities will expand.

Uncertainty regarding the outlook for Mexican oil production

There also is considerable uncertainty regarding the outlook for Mexican oil production growth. The US Energy Information Administration's 2010 *Annual Energy Outlook* Reference Case indicates that Mexican production is likely to decline until the early 2020s, primarily because of falling output from the major Cantarell offshore field, but also eventually from the Ku-Maloob-Zaap offshore field, and producing oil fields in the Chicontepec Basin northeast of Mexico City, with recovery predicated on an assumed eventual change in policy to allow participation in offshore exploration and development by foreign companies.

The projection of Mexican crude oil production contained in the International Energy Agency's 2008 *World Energy Outlook* is similar to that from the Energy Information Administration, but has production bottoming out sooner (in 2015) because of increased production from the Ku-Maloob-Zaap and Chicontepec fields (International Energy Agency World, 2008: 270). Crude oil output is then predicted to gradually recover to more than 3 million barrels per day during the 2020s. This result is dependent, however, on the development of onshore reserves and on output from new offshore discoveries that are unlikely to be made during the indicated time unless exploration is accelerated.

According to the Mexican energy secretary, the country's crude oil production will stabilize during 2010 and then begin to improve. In an appearance before the Mexican Senate in January 2009, Secretary Georgina Kessel said, "beginning in 2011 a gradual increase in production will begin until we reach levels near or slightly superior to 3 million barrels a day" (Kessel, 2009). The secretary's remarks are apparently based on optimism that the October 2008 reforms will offer sufficient encouragement to large foreign companies for them to become involved in oil exploration and development in Mexico for the first time in many years. However, since foreign companies will only be able to operate under contracts with PEMEX and cannot own and thereby have commercial control of the petroleum that they discover, they are unlikely to shift their attention from other opportunities. For this reason, the Mexican government's hoped-for turn-around in oil production is unlikely to be realized.

Conclusion

Due to underlying uncertainties, the Energy Information Administration's oil production projections summarized in table 5 are at risk. The projections are particularly vulnerable because of the speculative nature of certain factors, especially commercialization of coal-to-liquids and kerogen-from-shale production stemming from assumed technological breakthroughs. Also, the impact of environmental policy changes and concerns will undoubtedly result in hesitation and delays in investment in the development of oil production facilities, both on- and offshore, and slow the pace of development of Alberta's oil sands. Further, stiffer regulatory requirements as a consequence of the BP Deepwater Horizon oil leak in the US Gulf of Mexico will slow US offshore oil exploration and development and constrain growth in production from offshore wells. In addition, unless there is a more fundamental shift in Mexican policy regarding foreign investment in upstream exploration and development, it is doubtful that the drop in Mexican oil production because of the declining production rates in the Cantarell field and other mature fields can be turned around.

In Western Canada, at least, forecasters have occasionally failed to fully anticipate additions to conventional oil reserves. However, the likelihood of this occurring now is much less than it was 20 or 30 years ago because of the extent of exploration that has already occurred and the maturity of many producing fields. The current risk, it seems, is the reverse: that conventional Canadian and US oil production will fall short of the projections for many of the reasons discussed in this section.

North American crude oil production appears much more likely to fall short of the projections examined here than exceed them unless development is buoyed by stronger than anticipated oil prices and/or unnecessary barriers to investment in new or expanded production and transportation facilities are removed.

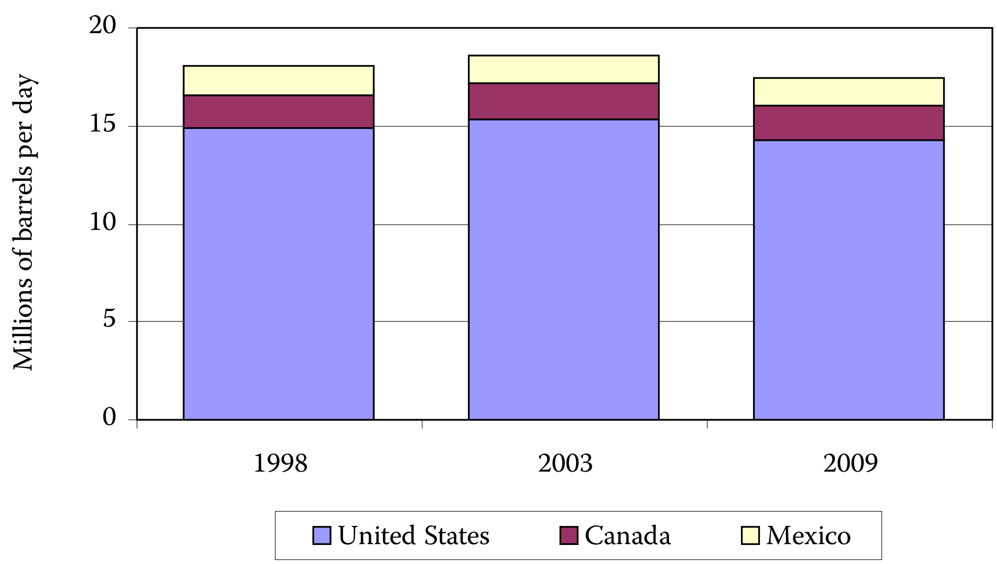
Demand

North American consumption of crude oil, as measured by refinery throughput, decreased slightly (by 0.3 percentage points) from 1998 to 2009 (figure 3). Average daily crude oil demand in North America was 17.4 million barrels in 2009. US refineries consumed 82% of the total, followed by Canada at 10%, and Mexico at 8%.

Table 6 summarizes the long-term outlook for oil liquids consumption in the US and Mexico contained in the US Energy Information Administration's 2010 *Annual Energy Outlook*, as well as projections for Canadian oil liquids consumption derived from the National Energy Board's *2009 Reference Case.* [24]

According to the National Energy Board *2009 Reference Case* projection to 2020, and as projected by the author to 2030, Canadian consumption of refined petroleum products, about half of which is diesel fuel and gasoline, will increase by about 0.6 mil-

Figure 3: North American Crude Oil Demand (Refinery Throughput)



Source: *BP Statistical Review of World Energy 2010.*

24 Oil liquids at the point of consumption consist of oil products produced by oil refineries, such as gasoline, diesel fuel, and heating and fuel oils, as well as bio-fuels, such as ethanol, that are used in gasoline blends.

Table 6: North American Oil Liquids Consumption, 2008-2030 (in millions of barrels per day)

	2008	2015	2020	2030
United States	19.9	20.7	21.1	22.1
Canada	2.1	2.4	2.5	2.7
Mexico	1.6	1.7	1.8	2.0
North America	23.6	24.8	25.4	26.8

Sources: Energy Information Administration, 2010a, table 21 for the US and Mexico; National Energy Board, 2009a, appendix table A2.1; and Fraser Institute extrapolations.
Note: The National Energy Board Canadian oil consumption data were converted from energy units to volume units using the assumption that 37.8 gigajoules of refined petroleum product are equivalent to 1 cubic metre. Because the NEB's 2009 projections went only to 2020, the 2030 volume was extrapolated by applying the implied growth rate in the Board's numbers during the 2015 to 2020 period to their 2020 estimate.

lion barrels per day from 2008 to 2030, when the consumption rate will reach approximately 2.7 million barrels a day (National Energy Board, 2009, table A2.1). From 2008 to 2030 the gain in consumption is estimated to be in the order of 29%. Most of the growth in refined petroleum product consumption will occur in the transportation and industrial sectors.

In comparison, US oil liquids consumption is projected to increase by about 11% from 2008 to 2030, largely as the result of increases in the demand for diesel fuel and bio-fuels, such as ethanol. US gasoline consumption is projected to decline along with industrial fuel oil consumption and fuel oil use for electricity generation. In Mexico, oil consumption is projected to increase by about 21% from 2008 to 2030, mainly because of growth in the demand for gasoline; fuel oil requirements for electric power generation are anticipated to decline.

These and other publicly available projections of oil liquids demand, including those contained in the International Energy Agency's *World Energy Outlook*, are subject to a number of uncertainties and risks, including the following:

Oil and petroleum product prices

The price of crude oil is a primary determinant of refined petroleum prices. Therefore, unrealistically high or low oil price assumptions generally result in crude oil and oil product demand projections that are either too low or high, respectively.

In the Energy Information Administration's 2010 *Annual Energy Outlook* Reference Case, the average crude oil wellhead price in the lower 48 states is predicted to reach $69.85 per barrel in 2010 (in 2008 US dollars) and then rise to $90.84 per barrel in 2015, $102.00 per barrel in 2020, and $114.75 per barrel in 2030. As indicated by the high and low price sensitivity cases described in the 2010 *Outlook*, higher or lower oil price assumptions lead to quite different projections of oil demand.

In its "2009 Reference Case Scenario," the National Energy Board assumed that the price of West Texas Intermediate crude oil would average about $70 per barrel in 2010 (in constant 2008 US dollars) and rise to about $90 per barrel by 2020 (National Energy Board, 2009).[25] As with the Energy Information Administration's projections for the US, the board's high and low price sensitivity cases underscore the sensitivity of Canadian oil product demand to the price of crude oil.

Even though the demand for transportation fuels such as gasoline is not very sensitive to price changes, not knowing what the crude oil price—and therefore petroleum product prices—will be in the future increases the challenge of predicting fuel consumption (Hughes, Kittel, and Sperling, 2008). In turn, this affects the ability to forecast crude oil demand.

Economic growth

Another key determinant of crude oil and refined petroleum product demand is the rate of economic growth. In its *Annual Energy Outlook 2010* Reference Case, the US Energy Information Administration assumes that US annual economic growth, as measured by changes in the real Gross Domestic Product, will average 2.4% from 2007 to 2030. This is based on the assumption that labor force growth will average 0.64% per year and that annual productivity gains will average 2%. During the same period, Mexican real GDP is assumed to grow at an average annual rate of 3.3% (Energy Information Administration 2010b). In the National Energy Board's "2009 Reference Case Scenario," Canadian real GDP is assumed to grow by 2.1% per year from 2008 to 2020 (National Energy Board, 2009).

Comparison of total non-renewable energy expenditures in the Energy Information Administration's high and low US economic growth sensitivity cases from the 2010 *Annual Energy Outlook*, with 3.0 and 1.8% average GDP growth respectively, indicates that total US energy expenditures differ by about $600 billion (in constant 2008 dollars) between the two cases in 2030. With stronger economic

25 The price of West Texas Intermediate (WTI) crude oil is widely used as a reference point in the determination of the prices of other US and Canadian crude oils. Although not the same as the average US lower 48 wellhead price of crude oil, movements in the latter closely correspond to movements in the WTI price.

growth, oil product demand in the residential, commercial, and industrial sectors would therefore be greater than in the reference case. It is difficult enough forecasting crude oil demand when no one can foresee how the prices of oil and oil products will perform. Uncertainty about the strength or weakness of economic growth compounds that difficulty.

Political risk and uncertainty

Petroleum demand forecasts are also at risk because of unforeseen political developments. Expropriation or nationalization of petroleum industry assets in a major oil-producing country, for example, can cause sudden swings in both current and expected crude oil prices. In turn, any jump in crude oil prices very quickly affects refined petroleum product prices and consumption levels around the globe.

Technological improvements

Other things being equal, technological change will improve the efficiency of oil product consumption and slow the growth of oil demand. Similarly, technological improvements and breakthroughs will determine how rapidly substitutes for fuels derived from oil are developed and produced on a commercial scale. Electric vehicles, fuel cells, and hydrogen-powered vehicles are ready examples of emerging opportunities to reduce dependence on diesel fuel and gasoline. Not knowing how such technologies are likely to unfold, and the speed at which they will be introduced on a commercial scale and be adopted by consumers, contributes to the difficulty of predicting how the demand for oil and products derived from oil will evolve.

Requirements for electricity generation

Another element of uncertainty in the North American oil demand outlook is the extent to which diesel and other fuel oils will be required for electricity generation. In 2006, 1.6% of total US electricity generation was sourced from the combustion of oil, the same share as in Canada. In Mexico, the oil-fired share of total 2006 electricity generation was considerably greater, at 24.8% (Energy Information Administration, 2009b, figure 5.4 for US and Mexico; National Energy Board 2009, appendix table 5.4 for Canada).

The US Energy Information Administration's 2009 *International Energy Outlook* assumes that the oil-fuel shares of electricity generation in the US and Mexico will

Table 7: Electricity Generated from Oil Liquids (in millions of megawatthours)

	US	Canada	Mexico
2006	64.3	9.3	58.5
2020	n/a	7.5	n/a
2030	60.3	n/a	49.0

Note: n/a = not available
Source: Energy Information Administration, 2009b, tables 53 and 54; National Energy Board, 2009a, appendix table 5.4.

fall to 1.2% and 11.2%, respectively, by 2030 (Energy Information Administration, 2009b, figure 54). The July 2009 National Energy Board projections show the oil-fired share of total generation in Canada dropping to 1.1% by 2020 from an estimated 1.4% in 2008 (National Energy Board 2009, appendix table 5.4).

Table 7 summarizes the extent to which the reliance on oil combustion for electricity generation is expected to fall in all three countries.[26]

The reduction in reliance on oil combustion for electricity generation in the United States is mainly based on assumed increases in the use of coal and renewable energy sources. In Canada, increased reliance on natural gas and on wind generation, biomass solar power, and other renewable sources, is anticipated to help reduce the dependence on oil for power generation. In Mexico, the expected drop in oil requirements for power generation assumes that a 230% increase in electricity demand will be met almost entirely by additional natural gas fired generation capacity.

In general, much of the projected reduction in reliance on oil products for power generation is being driven by government incentives to increase the use of renewable energy sources, such as wind and solar. Another factor is that the prices of natural gas and crude oil have largely been decoupled because of changes in market fundamentals (e.g., a greatly improved natural gas supply picture in North America because of improved, less costly technology for extracting gas from shale and tight sand formations) with the result that natural gas will be a less costly fuel source than oil. For these reasons, it is likely that the demand for fuel oils for power generation will decline in all three countries during the next two decades. However, the inability to predict with

26 The demand for fuel oils for power generation implied by the numbers table 7 may be estimated by assuming that 1 barrel of fuel oil is required to generate 1.64 megawatt hours of electricity (Energy Information Administration Energy Kids, Energy Calculators (n.d.)).

much precision both the extent and timing of reductions in fuel oil and diesel fuel requirements for power generation adds another element of risk to projecting crude oil demand.

Environmental policy changes

Forecasting the demand for crude oil and oil products is subject to further risk because of the environmental policy changes that are being touted to reduce greenhouse gas emissions that are purported to be contributing to climate change. The imposition of carbon taxes and low carbon fuel standards, for example, will affect the volume and type of petroleum products that are consumed. Not only are the full extent and timing of such proposed market interventions unknown, but little historical experience and data are available to guide forecasters charged with assessing the impacts of policy shifts of these kinds on oil demand.

Conclusion

Given the uncertainties outlined above, any projection of crude oil or oil product consumption must be viewed as but one in a range of many possible outcomes. In the Reference Case projections examined above, it is not possible to conclude whether growth in the demand for oil is over- or understated, and to what extent; there are simply too many variables involved.

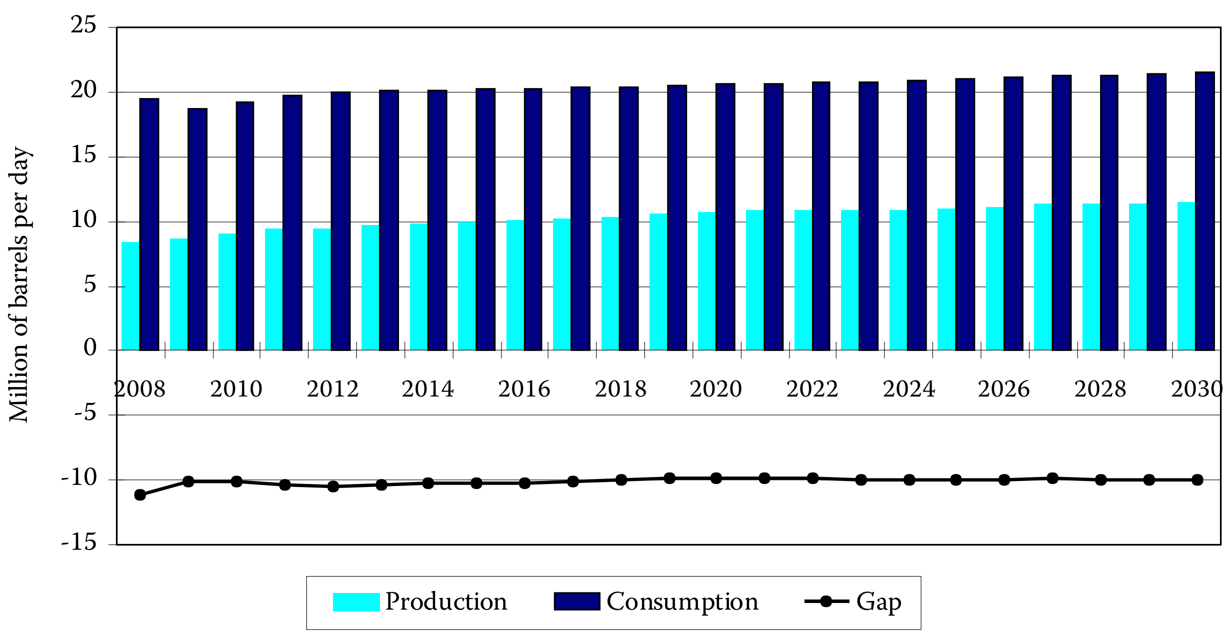
Considering the picture for both crude oil consumption and production that is painted by the reference cases, and the risks associated with those projections, it appears that the continent will remain heavily dependent on imported oil supplies—and could become even more so. This suggests that growth in North American crude oil production beyond the forecast volumes would be readily absorbed in the continental market provided that the incremental production is able to compete with supplies from overseas.

Country and continental oil production and consumption relationships

The figures that follow illustrate the relationship between domestic oil liquids production and consumption in each of the three countries to 2030, as indicated by the US Energy Information Administration's 2010 *Annual Energy Outlook* Reference Case for the US and Mexico, and the National Energy Board's *2009 Reference Case Scenario* for Canada (extrapolated to 2030).

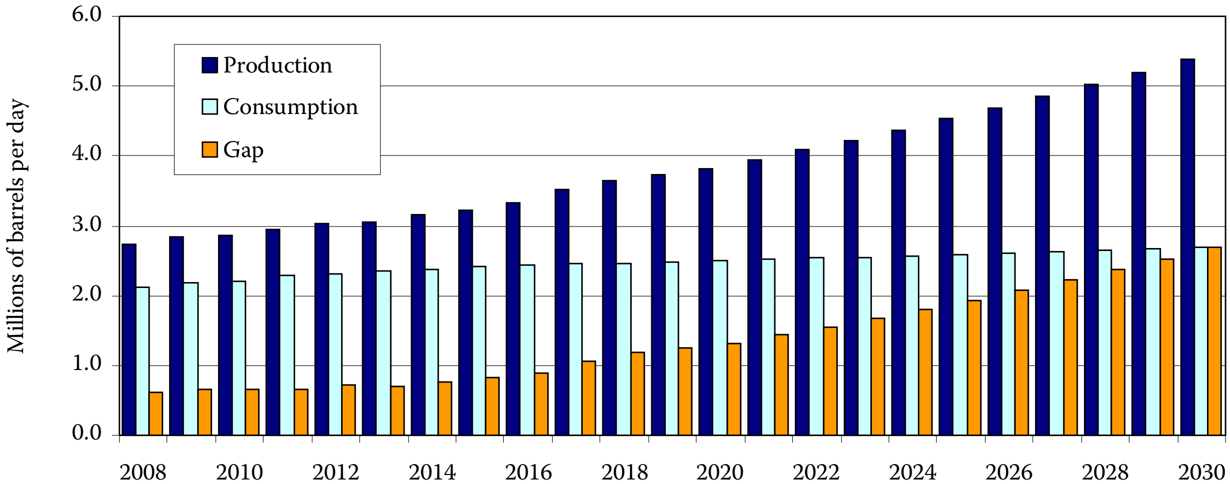
The Energy Information Administration's production and consumption projections suggest that US oil consumption will continue to exceed domestic production by a wide margin. As figure 4 illustrates, the shortfall, or gap, in domestic production relative to requirements could stabilize over the next 20 years. However, if the assumed contributions to supply from the offshore, the increased onshore oil production

Figure 4: US Oil Liquids Production & Consumption, 2008-2030



Source: Energy Information Administration 2010a, table 21.

Figure 5: Canadian Oil Liquids Production and Consumption, 2008-2030

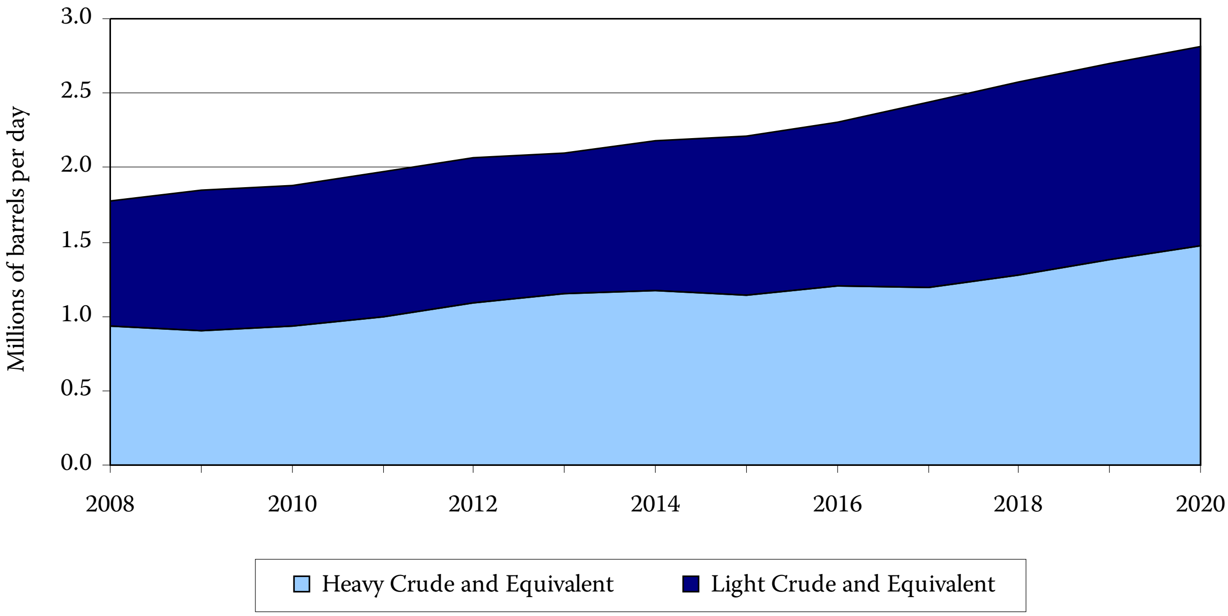


Source: National Energy Board, 2009a, figure 5-1, table A2.1; Fraser Institute extrapolations from 2020 onwards.

resulting from the application of enhanced recovery technologies, and the growth in the production of fuels from plant material do not materialize, the US will have considerable difficulty preventing its dependence on imported supplies from increasing. President Obama clearly sees oil supply as an important issue. He has committed to reducing the extent of America's reliance on imported oil for energy security reasons (Obama, 2010b). Prolonged disruption in the delivery of oil supplies from abroad could be disastrous for the US economy. There is additional reason to be concerned if investment that would grow the capacity to produce more crude oil from domestic sources, thereby reducing foreign dependence, is constrained by regulatory or other barriers.

Figure 5 illustrates the anticipated oil liquids domestic production and consumption relationship for Canada. Even with consumption of oil liquids expected to continue to increase until 2030, because of the growing production of bitumen from the oil sands the excess supply of oil liquids available for export is anticipated to grow remarkably during the forecast period, rising from an average of .62 million barrels per day, to nearly 2.7 million barrels a day. Most of this exportable surplus is anticipated to be consumed in the US lower 48 states, although some crude oil, bitumen, and synthetic crude oil and blends may be exported to Asian Pacific countries such as South Korea and China. The possibility of future oil shipments to Asia is underscored by the fact that Japanese, South Korean, and Chinese interests have invested in Alberta oil

Figure 6: Canadian Crude Oil Exports



Source: National Energy Board, *2009 Reference Case*.

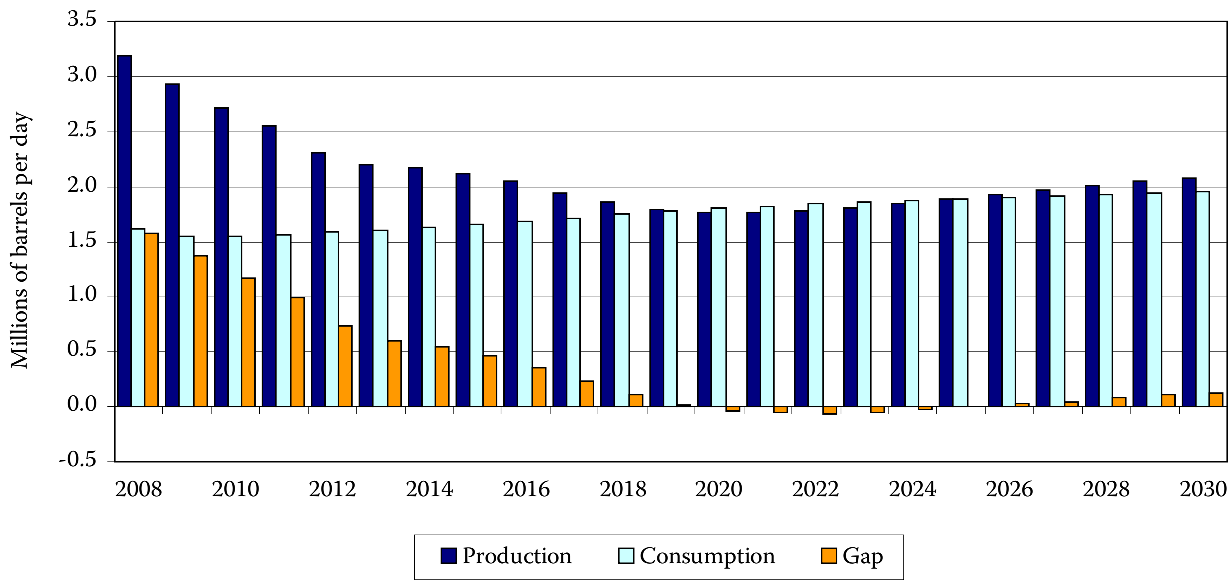
sands projects. Whether or not potential exports grow to this extent will mainly be determined by the pace at which the capacity to produce bitumen from Alberta's oil sands is expanded.[27]

Because the shortfall, or gap, illustrated in figure 5 is calculated by simply deducting estimated oil consumption from total production, and ignores the fact that Canada imports crude oil to supply some refineries (and refined petroleum products when it is economical to do so), it is indicative of net rather than gross oil exports. The National Energy Board's *2009 Reference Case* projects very little growth in refinery crude oil imports from the 2008 rate of approximately 1.4 million barrels per day.[28] Moreover, product imports are unlikely to exhibit much growth given the National Energy Board's outlook for oil product consumption. With imports exhibiting only very minimal growth, gross exports and net exports will likely increase by about the same extent. Gross exports are expected to grow more or less in step with the increase

27 Assuming that export capacity is not constrained by the capacity to transport bitumen or bitumen/synthetic crude oil blends via pipeline to US markets or port facilities.

28 Data for 2009 were not available when the National Energy Board was preparing its *2009 Reference Case*.

Figure 7: Mexican Oil Liquids Production and Consumption, 2008-2030



Source: Energy Information Administration, 2010a, table 21.

in Canadian oil production, which will be led, as discussed earlier, by increasing bitumen production from the oil sands.

Figure 6 illustrates the projections of Canadian crude oil exports provided in the National Energy Board's *2009 Reference Case*. The "light" oil component includes synthetic crude oils derived from bitumen, which is why total exports of light crude oil are able to continue to grow in spite of declining light oil production from conventional sources. Similarly, production of heavy crude oil and equivalents is expected to increase because of growth in bitumen production from the oil sands. During the final five years of the National Energy Board's projection, total Canadian crude oil exports are anticipated to increase at an annual average growth rate of approximately 5%. If the estimated export volume of 2.8 million barrels per day (MMB/d) in 2020 is extrapolated at that rate, the estimated volume in 2030 is 4.6 MMB/d, or 2.5 times the 2008 volume. This is an indication of the increasing role which Canadian crude oil exports are likely to play in the future, especially bitumen from the oil sands and synthetic crude oils developed from bitumen.

Figure 7 illustrates that Mexico is at risk of becoming a net importer of crude oil by 2020, if not before, as the result of the continuing decline in its oil production. Given the anticipated growth in oil demand arising from the transportation sector's increasing need for fuel, it will be difficult for the country to maintain its position as a net oil exporter beyond 2020. The EIA's long-term forecast assumes that a shift in pol-

Table 8: US Crude Oil and Refined Product Imports (in millions of barrels per day)

	2008	2015	2020	2030
Canada	2.35	2.47	2.56	2.83
Mexico	1.28	1.15	1.07	0.89
OPEC— Persian Gulf	2.40	1.72	1.46	1.74
OPEC—Other	3.32	3.21	3.09	2.90
All other	2.86	2.42	2.46	2.59
Total	12.21	10.97	10.64	10.95

Sources: Energy Information Administration, *Annual Energy Outlook 2010*, Supplemental table 127.

icy will attract the foreign investment needed to boost exploration and development of crude oil resources in the Mexican portion of the Gulf of Mexico and prevent the country from becoming a net oil importer. That this will in fact occur is doubtful.

Table 8 summarizes the outlook for US imports of crude oil plus refined and unfinished or partially refined petroleum products from Canada, Mexico, OPEC–Persian Gulf, OPEC–Other, and all other countries, as projected in the US Energy Administration's 2010 *Annual Energy Outlook*.

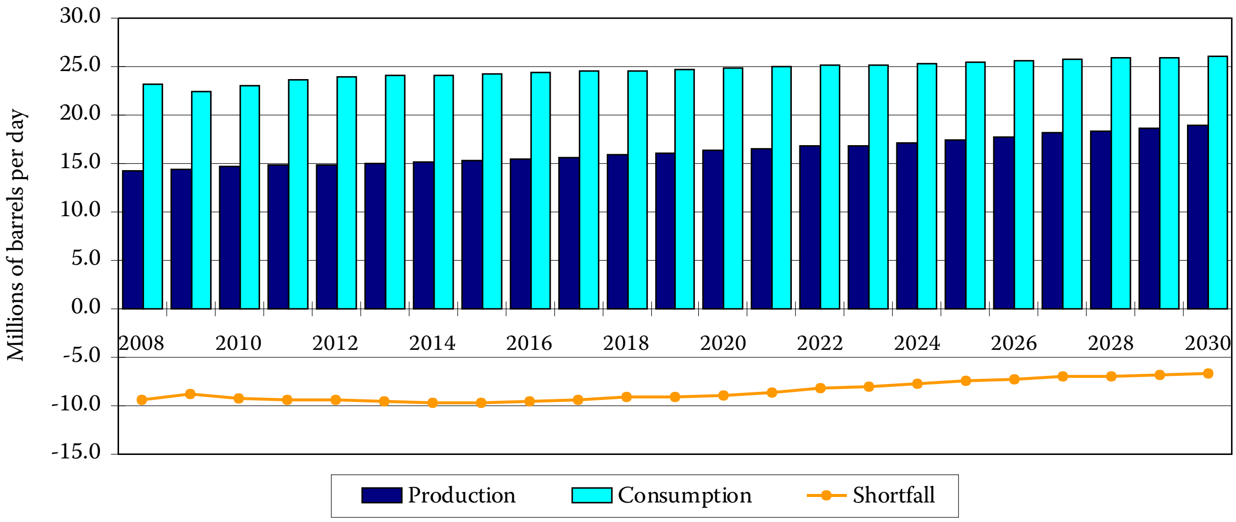
As table 8 indicates, a major reduction in the extent of US dependency on crude oil and refined product imports is not expected to occur during the forecast period. Rather, US imports are projected to remain fairly stable following a reduction of about 10% from 2008 to 2015.

Canada and Mexico will continue to meet a fairly large portion of US crude oil and oil product import requirements. Nevertheless, the US will continue to be heavily dependent on oil supplies from outside North America.

Mexico will not be able to increase oil shipments to the US because of its weakening position as a producer and the need to meet domestic demand.

Canada is expected to become an ever larger supplier of oil requirements to the US. The rather modest growth in US oil imports from Canada indicated in table 8 does not appear to be consistent with the strong increase in Alberta oil sands bitumen production that the National Energy Board forecasts to 2020, and the author's extrapolations beyond that date. Canada is already the largest single-country supplier of oil and oil products to the US, and has the potential to increase its share considerably. The Canadian share of US oil and product imports, now about 20%, will likely surpass 30% by 2030 (Energy Information Administration, 2010e). Increased US reliance on crude

Figure 8: North American Oil Liquids Production and Consumption, 2008-2030



Source: Energy Information Administration, 2010a, table 21; National Energy Board, 2009b, figure 5-1, table A2.1; and Fraser Institute extrapolations of the National Energy Board 2009 forecast from 2020 onwards.

oil from Canada would improve US oil supply security and also generate employment and income benefits in Canada.

Figure 8 illustrates that, taken together, the US Energy Information Administration's 2010 *Annual Energy Outlook* Reference Case projections for Mexico and the United States, and the National Energy Board's *2009 Reference Case Scenario* projections for Canada indicate that North America will continue to be a significant importer of oil liquids during the forecast period. However, the degree of dependence on supplies from overseas may begin to subside after 2016 as increased production of bitumen from Canada's oil sands begins to make a greater contribution to the continental oil supply picture.

Expansion of the continental crude oil pipeline and storage system

Canada exported 291,900 cubic metres (1.8 million barrels) of crude oil per day in 2009, including bitumen blended with much lighter hydrocarbons (referred in the industry as "diluents") such as pentanes plus, upgraded bitumen (referred to as synthetic crude oil), and bitumen-synthetic crude oil blends. All but 2,400 cubic metres (15,000 barrels) of crude oil per day (0.8%) were shipped to markets in the United States. Except for crude oil exported from the East Coast, and a relatively small quantity of oil shipped to California from British Columbia in tankers, all of the oil exported to the US was transported from Canada through pipelines (National Energy Board, 2010).

Sixty-four percent of the exports to the US were pipelined to PADD (petroleum administration for defense district) II which, as indicated by figure 9, embraces the Midwest and includes such metropolitan areas as Chicago, Detroit, and Minneapolis.[29]

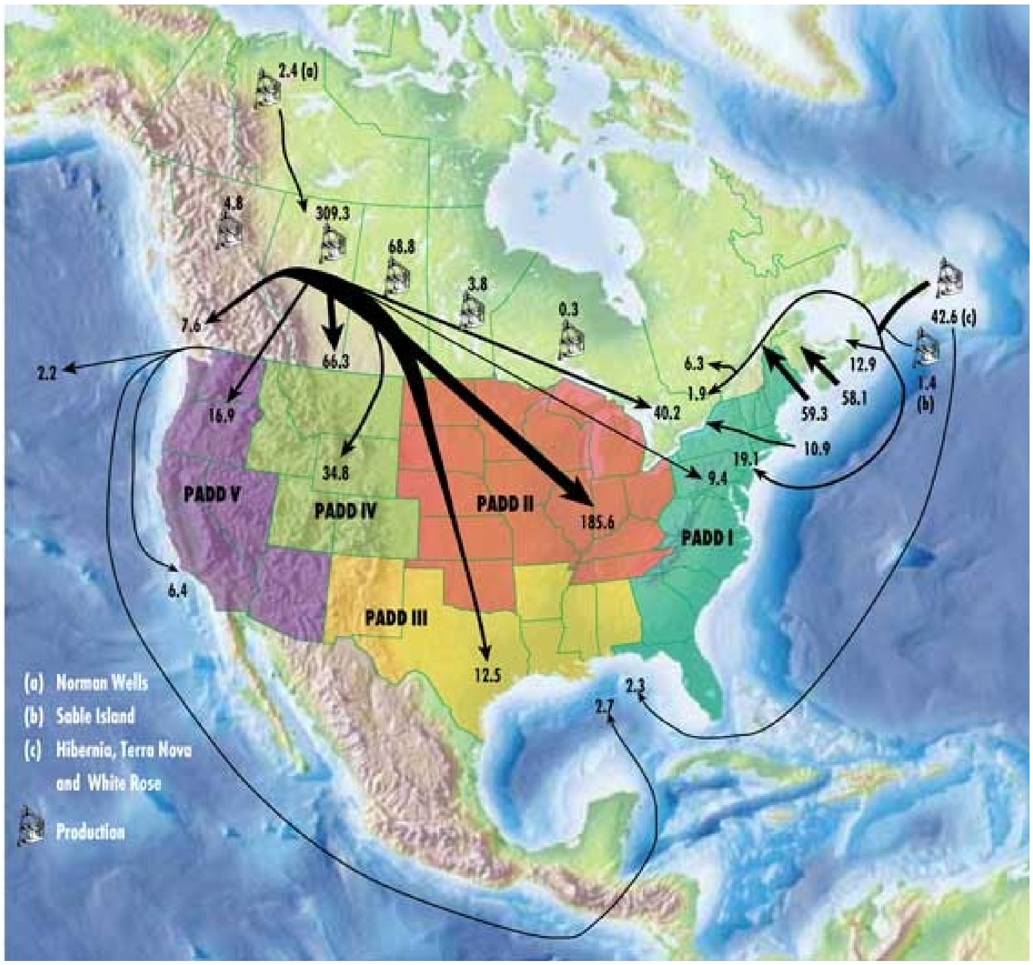
About 12% of Canadian crude oil, bitumen, and synthetic crude oil exports to the US were shipped to the PADD IV group of states, of which Colorado is the most populated. Crude oil exports from the East Coast and western Canada to destinations in PADD I (which includes New England and the Atlantic states) constituted 10% of Canadian crude oil shipments to the US. Eight percent of Canada's oil exports to the US were shipped to California and other locations on the US West Coast; only 6% were shipped to PADD III.

The pipeline system that facilitates the export of crude oil from Canada to the United States, and shipments within the two countries, is illustrated in figure 10.

As noted earlier, Canadian crude oil production from conventional sources is declining because production rates are dropping in many maturing oil fields in western Canada. However, this decline does not mean that sufficient capacity will be available in the oil pipeline transportation system to accommodate increased volumes of bitumen and bitumen/synthetic crude oil blends from the oil sands. The production of oil from the oil sands is more than offsetting the decline in conventional oil production. In fact, with the main oil export pipelines (Enbridge, Express/Platte, and TransMountain) operating at or close to capacity during 2008, oil exports were con-

29 The PADDs are geographic aggregations of the 50 US states and the District of Columbia into five districts, with PADD I further split into three sub-districts.

Figure 9: Crude Oil Supply and Disposition, 2009 (in thousands of cubic metres per day)



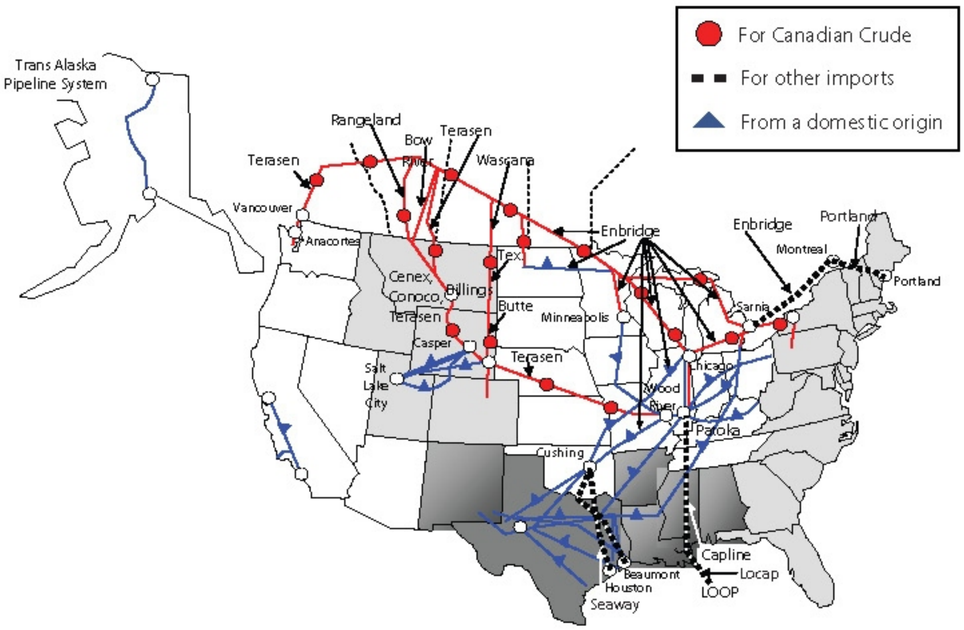
Source: National Energy Board, 2010, fig. 4.6.

strained at times during the year, and the allocation of quotas (apportionment) was required on occasion (National Energy Board, 2009b).[30]

Because of the anticipated growth in Canadian oil production from continued oil sands development, the National Energy Board, which is responsible for approving the construction of crude oil pipelines that cross provincial boundaries and the Can-

30 Bitumen and synthetic crude oil exports from Canada's oil sands averaged 106,700 cubic metres (6.7 million barrels) per day in 2008 and comprised almost 38% of total Canadian oil exports to the US. Only 700 barrels per day of bitumen and synthetic crude oil (SCO) were exported to overseas markets.

Figure 10: Selected Crude Oil Trunkline Systems Serving the United States



Source: Allegro Energy Group, 2001. Updated to 2008. Used with permission.

ada-US border, has received a number of applications from pipeline and oil companies in recent years either to expand existing pipeline capacity, or to build new pipelines. Enbridge Inc. and TransCanada Pipelines Limited, for example, have been endeavoring to add capacity to ship crude oil, bitumen, and SCO from Alberta to markets in the United States.[31]

North America's crude oil pipeline transportation system—comprising local gathering facilities, major transportation pipelines, and refinery-delivery offshoots—is poised for considerable and very significant expansion through the coming decade and beyond. Oil pipeline projects recently completed, approved, under construction, and proposed include the following:

31 Approval must be sought from the US State Department to build pipelines in the US for the purpose of importing oil or gas. Expansions and new pipeline construction on the US side of the border also require approvals from the responsible federal and state government agencies.

- Expansion of the capacity of Kinder Morgan's TransMountain Pipeline, which runs from Edmonton to Vancouver via the Anchor Loop Expansion project, was completed in October 2008. The expansion increased the system's capacity by 40,000 bpd (barrels per day) to about 300,000 bpd (Kinder Morgan Inc., 2010).
- The Enbridge Line 4 Extension, completed during the first half of 2009 connecting the Hardisty, Alberta, oil pipeline hub to Edmonton, strengthened the capacity to ship synthetic and heavy crudes from new and expanded oil sands projects to US refining markets. The project involved construction of 85 miles of 36-inch diameter pipe, terminal connections at Edmonton, and three pump stations. The extension matches the 880,000 bpd capacity of Line 4 east of Hardisty (Enbridge, 2008a).
- As a result of Enbridge's "Southern Access Expansion" project, oil pipeline capacity from Superior, Wisconsin, to Flanagan, just west of Chicago, has been increased by 400,000 bpd. The expansion, which commenced service in 2009, included the construction of 454 miles of 42-inch pipeline between Superior and Flanagan. Enbridge is planning to extend the system from its Flanagan terminal south to the petroleum transportation hub at Patoka, Illinois (Enbridge, 2010a).
- The Enbridge Alberta Clipper Expansion project is a 36-inch, 1,000-mile pipeline from Hardisty, Alberta, to Superior, Wisconsin. The initial capacity to deliver crude oil from Alberta to the US at Superior will be 450,000 bpd, but there will be allowance for expansions to increase capacity up to 800,000 bpd. Together with the Southern Access project, Alberta Clipper will ultimately enable delivery of an incremental 1.2 million bpd of Alberta oil to eastern Canadian markets and US refineries throughout the Midwest, the mid-continent, and the US Gulf Coast (Enbridge, 2008b). This pipeline expansion project was mechanically complete as of April 1, 2010, but it will take several months to fill the line. Service is expected to commence early in the fall of 2010 (Enbridge, 2010b).
- The Enbridge Southern Lights pipeline will transport light hydrocarbons from US refineries in the Chicago area to Edmonton, where they can be used as diluent in pipeline transportation of bitumen to the US and other markets. The US $2.2 billion project has five components. Part I saw the construction of 44 miles of new pipeline from Manhattan, Ill. to Streator, Illinois. Part II involved construction of new pipeline from Streator to Superior, Wis. Part III involves constructing a new pipeline from Cromer, Manitoba, to Clearbrook, Minn. in order to maintain delivery capabilities after the reversal and conversion of the existing Line 13 crude oil pipeline, which will then be used to transport diluent from Clearbrook, Minn. to Edmonton (Part IV). Part V comprises 188 miles of pipeline to carry diluent from Superior, Wis., to Clearbrook, Minn. The Superior to Edmonton diluent pipeline will have a capacity of 180,000 bpd when it begins service following reversal of Line 13 in the latter half of 2010. The project com-

plements the Clipper project by allowing diluents that are shipped to the US with bitumen blends to be recycled (Enbridge, 2010c).

- If approved, the Enbridge dual pipeline Northern Gateway $5.5 billion project would allow shipment of crude oil from Bruderheim near Edmonton to a new marine terminal to be built at Kitimat, British Columbia, and the importation of condensate for use as diluent to facilitate transportation of bitumen via pipeline. The 36-inch oil line would be 1,172 kilometres long and have a capacity of about 525,000 bpd. The 20-inch pipeline that would transport condensate east from Kitimat to Edmonton along the same route as the oil pipeline would have capacity of 193,000 bpd. The oil transported to Kitimat would be exported to markets in Asia and the US via tanker. Enbridge filed an application with the National Energy Board on May 27, 2010, to begin construction of the Northern Gateway project. With timely approval, the company anticipates that construction could begin in 2013, allowing the facilities to start operating in 2016 (Enbridge Northern Gateway Pipelines, 2010).

- TransCanada Pipeline's Keystone Pipeline Project will deliver crude oil from Hardisty, Alberta, to Houston, Texas. The first phase, a 1,851-mile, 435,000 bpd pipeline from Hardisty to Steele City, Nebraska, and on to Wood River, and Patoka, Illinois, has been constructed and oil is now flowing to Illinois. The second phase, a 298-mile extension from Steele City to Cushing, Oklahoma, is currently being constructed and is expected to be in service in early 2011. When that extension is completed, the system will reach a 590,000 bpd capacity.

  The third phase, connecting Cushing to Nederland, Texas, is the first part of what has been labeled the Keystone Gulf Coast Expansion (Keystone XL). TransCanada is currently awaiting approval from US regulators on this phase. The anticipated in-service date is the fourth quarter of 2011.[32]

- TransCanada plans to increase the initial 590,000 bpd capacity to deliver Alberta crude oil to Texas to approximately 1.1 million bpd in a fourth phase. This phase would involve building a new 1,179-mile pipeline from Hardisty to Steele City, Nebraska, and a 47-mile pipeline from Liberty County, Texas, to the Houston area. As the initial phase of Keystone XL, this final phase is awaiting approval from US regulators. It is expected to begin operating in early 2013. When completed, the Keystone pipeline system will link an increasing and reliable supply of Canadian crude

32 Environmentalists who consider bitumen from Alberta oil sands as "unclean," and a number of members of the US Congress who apparently believe that to be true, are attempting to block expansion of the Keystone pipeline from Oklahoma to Texas (Reuters, 2010). This prompted the premier of Alberta to appeal to Americans in a letter to the *Washington Post* on July 2, 2010, to consider what is being done to lessen the environmental impacts of oil sands production and the benefits that access to Alberta bitumen represents for the security of oil supply (Stelmach, 2010).

oil from the oil sands to growing US energy markets, including Texas oil refineries (TransCanada, 2010).

- In 2007, Enbridge Inc. and ExxonMobil Pipeline Company proposed a "Texas Access" pipeline to transport crude oil from ExxonMobil Pipeline's Patoka, Illinois, crude oil terminal to refineries in the Houston area of Texas. The 768-mile 400,000 bpd pipeline would facilitate the shipment of crude oil from the Alberta oil sands and from the upper US Midwest to the US Gulf Coast PADD I market area. The pipeline was to have been built by 2012, but it now appears that it may not be constructed and in service until 2014. Meanwhile, Enbridge has opted to move crude oil via pipeline from Alberta to Montreal, from there to Portland, Maine, through reversal of flow on the Portland to Montreal pipeline, and then by tanker to destinations in the US Gulf of Mexico (Reuters, 2008).

The above is a brief summary of major oil pipeline construction recently completed, underway, or proposed that will transport growing production of Canadian bitumen and SCO from the oil sands to markets in the US and elsewhere. The gathering system in Alberta's oil sands producing area will also need to be expanded. For example, additional capacity will be needed to connect production from the Exxon Kearl Lake project, the Husky Energy/BP PLC Sunrise project, and other new bitumen production developments in the Fort McMurray region to take-away capacity in the Edmonton/Hardisty area.

As oil sands production facilities continue to be developed, a stream of applications for oil pipeline extensions or expansions and new pipeline construction projects will be filed with regulators in Canada and the United States. New gathering and transportation capacity will also be required to transport crude oil to the US mainland from the Gulf Coast and other US offshore locations as new production developments there become active. Similarly, pipeline system upgrades and expansions will be required in various onshore regions of the US as oil production increases. For example, Enbridge Pipelines (North Dakota) LLC recently upgraded pumping station capacity to allow an additional 51,600 bpd of crude oil to be transported from the Williston Basin in North Dakota and Montana to the Enbridge Clearbrook, Minnesota, metering facility. From there, oil refineries throughout the Midwest and beyond are accessible through connections with the Enbridge Lakehead System and Minnesota Pipeline (Enbridge, 2010d). Protracted and unnecessary regulatory approval processes and procedures that delay the construction of essential transportation facilities could also delay investment in new oil production facilities.

Barriers to oil sector development

The outlook for continuing North American dependence on imported sources of crude oil suggests that some of the supplies coming from overseas could be replaced by indigenous, North American supplies, if market conditions warrant. The continent has an abundance of yet undeveloped conventional oil resources in the northern frontier; onshore, with plays such as the Bakken field in Saskatchewan and North Dakota; and in offshore regions such as the Queen Charlotte Basin, the Gulf of Mexico (on both sides of the US-Mexican border), and the Outer Continental Shelf. Further, there are huge unconventional sources of supply yet to be tapped in the Alberta oil sands.

Unfortunately, a number of regulatory and taxation barriers are discouraging investment in the North American oil sector and making it difficult for projects here to compete with development opportunities in other parts of the world. These include:

Uncompetitive royalty regimes

The tax structures facing the oil and gas industry in North America, including royalties and production taxes, need to be competitive with those elsewhere so that jurisdictions in Canada, the United States, and Mexico are not at a competitive disadvantage in the global market.

In general, the oil and gas royalty regimes in place in Canada and the United States are competitive with those in other countries. However, some provinces and states appear to tax oil and gas production to an extent that makes them less desirable for petroleum industry investment than other places in North America and overseas. This is reflected in the relatively poor scores that Alberta, California, Colorado, Newfoundland and Labrador, New Mexico, New York, and the Northwest Territories achieved relative to most other Canadian and US jurisdictions—and many countries—with respect to their fiscal terms (royalties and production taxes) in the 2010 Fraser Institute *Global Petroleum Survey* (Angevine and Cervantes, 2010).[33] In this recent survey, according to this measure, Manitoba, Saskatchewan, Texas, Wyoming, Oklahoma, Australia, and New Zealand, were seen to be more attractive locations for investment than many other other jurisdictions, including Alberta.

In the 2009 edition of the Fraser Institute *Global Petroleum Survey*, respondents indicated that Alberta posed the greatest barriers to investment in petroleum explora-

33 Mexico was excluded from the survey because only the state-owned petroleum company, PEMEX, is allowed to explore for and develop oil and gas resources there.

tion and development due to its royalties of all the Canadian provinces and US states that were evaluated (Angevine and Cervantes, 2009). This result reflected the provincial government's decision to impose higher royalties as of January 1, 2009, under Alberta's New Royalty Framework. The decision caused some companies to allocate larger shares of their exploration budgets to other provinces and countries. Evidence of the Alberta petroleum industry's lack of competiveness due to the province's imposition of higher royalties than other jurisdictions, especially British Columbia and Saskatchewan, and US states such as Texas, was also provided in a study by Jack Mintz and Duanjie Chen of the University of Calgary School of Public Policy (Mintz and Chen, 2010).

On March 11, 2010, the Alberta government announced that effective January 1, 2011, oil and natural gas production royalties (excluding those applicable to the production of bitumen from oil sands), will be reduced to levels similar to those in force prior to 2009 (Alberta Energy, 2010a). The provincial government apparently came to understand that petroleum exploration and development is sensitive to the shares of oil and gas production that, as owner of the resources, it claims through royalties. The announcement largely explains Alberta's improved performance in the 2010 *Global Petroleum Survey* (Angevine and Cervantes, 2010).

Royalty regimes that fail to recognize the higher costs of unconventional supplies

Royalty and production tax regimes that fail to take into account the higher costs of oil development and production from unconventional and offshore resources relative to conventional, onshore sources of supply are another barrier to investment that can cause would-be investors to look elsewhere. For example, there are greater costs associated with exploration in the Outer Continental Shelf because of distance from the shore and depth; in the far north because of the climactic conditions and distances involved; and in the production of oil from oil shale because of the high pressure and temperature required. Jurisdictions that have taxation structures that fail to recognize this will see investment inhibited. Consequently, both the pace and magnitude of exploration and development in such jurisdictions will suffer.

A recent Fraser Institute study recommended a flat business tax regime (Clemens, 2008). A net revenue "royalty" based on that approach would tax revenue from the sale of crude oil and natural gas, minus the cost of all inputs, including wages, salaries, and equipment, and thus recognize the higher costs involved in developing and operating expensive projects. In the absence of comprehensive tax reform along these lines, royalty regimes ought to be calibrated to take costs into account. One notable exception is the Alberta royalty on oil sands bitumen production, which is based on net revenue and, therefore, does recognize production costs.

Alberta has introduced special incentives that lower royalties in the case of unconventional gas (i.e., gas from shale formations and coalbed methane) production and in the case of deep or horizontal oil and gas wells—all situations where the cost of production can be higher than with normal conventional oil or gas production (Alberta Department of Energy, 2010b). However, recognition that special adjustments are necessary simply underscores the fact that the present royalty regime is poorly designed. Further, that there are no definite time frames attached to such incentives introduces an element of uncertainty.[34] Rather than special incentives, a crude oil production tax system is needed that recognizes higher costs as an inherent part of its design, as, for example, a flat tax.

Uncertainty in environmental policies related to oil sands and heavy oil production

The cost of compliance with policies aimed at reducing CO_2 and other greenhouse gas emissions, which many believe are contributing to global warming, is of particular concern to existing and potential Alberta oil sands producers and investors, as well as heavy oil producers in Western Canada, California, and other locations. Oil sands and heavy oil projects involve greater carbon emissions per unit of production than conventional light and medium oil production. The cost of reducing carbon and other greenhouse gas emissions in bitumen production and bitumen and heavy oil upgrading processes by deploying more efficient combustion technologies and carbon capture and storage applications is therefore potentially much greater with these activities than with light or medium crude oil production. Until federal, state, and provincial policies are clearly defined, it is impossible for potential investors to determine how much it will cost to comply with anticipated new regulations. Continued uncertainty may cause potential Canadian and US investors to shift their focus to petroleum development opportunities overseas.

34 From time to time in other Canadian and US jurisdictions, special petroleum drilling incentives have been introduced to encourage the industry to tackle projects with high exploration and development costs. Ready examples are a US tax credit for unconventional gas drilling and a reduction in royalties in the case of deep Outer Continental Shelf exploration drilling (Caldwell, 2001). Royalty adjustments to attract investment where the costs of petroleum development are greater than usual are not an issue in Mexico where, under the constitution, only the state may own, develop, and produce discovered oil and gas resources.

Regulatory uncertainty concerning conventional and offshore oil and gas exploration and production

Another barrier to investment is uncertainty concerning environmental regulations other than those pertaining to greenhouse gas emissions (discussed above) as with offshore exploration and production. For example, results from questions in the Fraser Institute 2010 *Global Petroleum Survey* indicate that that some survey respondents were discouraged from investing in the US Pacific and Atlantic offshore regions because of uncertainty about possible changes in environmental regulations and zoning with respect to marine conservation areas. They didn't indicate as much concern with uncertainty about the future course of environmental regulations in the US Gulf of Mexico Offshore region. However, the survey was undertaken before the BP Deepwater Horizon disaster; uncertainty about environmental regulations pertaining to the US part of the Gulf is likely much greater today.

Moratoria on offshore exploration and development

Moratoria on offshore exploration (as, for example, in the Queen Charlotte Basin off British Columbia's mainland), are another investment obstacle that is inhibiting the growth of North America's oil production. This obstacle is particularly frustrating to would-be investors because there appears to be no environmental reason for holding back exploration on the West Coast. A scientific task force appointed by British Columbia Premier Campbell in 2002 following an in-depth review concluded that, with appropriate safeguards and assessments of any proposals brought forward, the moratoria on hydrocarbon exploration and development off British Columbia's shores could be ended responsibly (British Columbia Ministry of Energy Mines and Petroleum Resources, 2002). Further, the accords between the federal government and Nova Scotia and Newfoundland and Labrador appear to effectively address environmental concerns over offshore exploration and production in the Atlantic region. This raises the question as to why similar agreements cannot be worked out for the Pacific offshore.[35]

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35 Unfortunately, the failure of automatic flow shut-off controls to activate when the rig at the BP Deepwater Horizon site in the US Gulf of Mexico exploded in April 2010, causing hundreds of thousands of barrels of crude oil to leak into the Gulf with untold environmental damage, will make it more difficult to sway those who argue that risks to the environment from offshore drilling cannot be adequately controlled. As noted earlier, Canada's environment minister has signaled that the West Coast moratorium will not be lifted until the lessons from the BP disaster are understood (Pynn, 2010). On the other hand, the Canada-Newfoundland and Labrador Offshore Petroleum Board has announced that it is proceeding with plans for further exploration off Newfoundland's shores (Canada-Newfoundland and Labrador Offshore Petroleum Board, 2010c).

Regulatory delays in pipeline approval processes

When the National Energy Board finally reaches a decision on the Mackenzie Gas Project application, more than 6 years will have passed since Imperial Oil Resources Ventures Ltd. and a group of co-venturers filed their application for a construction permit in October 2004. Although this is an exceptional case, it nevertheless serves to illustrate just how lengthy and costly the regulatory process can be.

Without the necessary oil and gas transportation infrastructure, investors who have spent millions of dollars exploring for natural gas in the far north with the belief that the Mackenzie gas pipeline and gathering system would soon be built are faced with mounting financing costs. Needless to say, further investment in exploration and production in the region is stymied for the foreseeable future because of the uncertainty.

Pipeline construction delays, which prevent incremental oil or natural gas supplies from getting to market, can affect consumers by increasing the local cost of natural gas or oil products. Moreover, delays in pipeline construction can markedly increase the capital cost of a pipeline because of wage and price inflation during the delay period.[36] In turn, this leads to higher transportation costs, since pipeline tariffs are based on the cost of service, including depreciation and interest.

The National Energy Board has self-imposed timelines for releasing decisions following the completion of public hearings. However, they serve only as guidelines and are not hard and fast rules that must be followed. Moreover, there are no such standards with respect to the time span from when an application is received until the public hearing on the application commences, or time limits on the completion of hearings per se.

Much of what the National Energy Board Act requires the board to do is unnecessary. For example, in a pipeline application evaluation, the board must assess the availability of the commodity in question to the pipeline, the existence of a market for the commodity, and the economic feasibility of the pipeline (National Energy Board Act, s. 52). Such determinations are better left to the project proponents and the experts who have been retained. Indeed, officers of private companies have a fiduciary responsibility to evaluate the economics of a major new pipeline project well before an application to construct the project is filed. At the very least, private financing would be hard to come by for any project that doesn't fulfill basic feasibility criteria.

36 According to evidence filed with the National Energy Board by the project proponents, it appears that the capital cost of the Mackenzie Gas Project has at least doubled since the application was filed with the board in 2004 (Imperial Oil Resources Ventures Ltd., 2007). If the project is built, a significant part its increased price tag will be as a consequence of inflation in the costs of wages and materials during the protracted regulatory process.

Native land claims

Uncertainty over land claims, or demands for project equity participation by aboriginal groups without any investment being required, can have even worse consequences for pipeline and other energy project developments and consumers than delays in the regulatory process. These occur if, for example, the uncertainty results in a project being deferred indefinitely. Alone, the delays arising from the time spent to reach a settlement will add to the capital cost of the project and increase the transportation toll or tariff. The actual cost of the settlement will further inflate the cost.

Labor availability

Prior to the 2008-2009 recession, the capital costs of new oil sands production facilities and upgraders had been escalating. This was partly because an insufficient supply of skilled workers was slowing construction and putting pressure on construction costs. This problem has largely disappeared because of the effect of the economic slowdown on the job market, but labor market pressures could stifle future development unless barriers to the flow of workers across and into Canada are reduced.

The mobility of Canadian workers has been improved by a number of bilateral agreements that have been signed since 2006, including the Trade, Investment, and Labour Mobility Agreement (TILMA) between Alberta and British Columbia that provide for mutual recognition of provinces' skilled trade certifications.[37] Further, in January 2009, the Canadian government and all of the provinces and territories agreed to amend the labor mobility chapter of the Agreement on Internal Trade (AIT). The adjustments will go a long way towards guaranteeing that the credentials of a skilled worker from a given province or territory are recognized without "significant material or non-material" re-certification requirements in any of the other provinces (Industry Canada, 2010). However, these agreements do not address constraints on the mobility of workers between Canada, the United States, and Mexico.

Also, neither the TILMA nor the AIT address aspects of Canada's employment insurance program that reduce the incentive for workers to move from areas of chronically high unemployment to regions of the country where labor demand is stronger. In this regard, a recent Fraser Institute study suggests that shorter benefit periods and lower levels of financial support would provide more incentive for unemployed workers in areas of high unemployment to seek work in areas of the country with more full-time employment opportunities (Angevine and Thomson, 2008).

37 Effective July 1, 2010, the TILMA agreement between Alberta and British Columbia was extended to include Saskatchewan. Details of the agreement that apply to professionals and tradespeople are available online (New West Partnership Trade Agreement, 2010).

Political constraints on upstream investment

Some countries have laws and regulations that forbid foreign investors from sharing in the risks and rewards from the discovery, development, and production of oil and gas. In cases where sufficient domestic capital and expertise are not available, those rules lead to slower production growth than would be the case if foreign investment were welcomed. This is the case in Mexico, which nationalized the petroleum industry in 1938, causing foreign-owned oil companies to leave the country.

In 2008, the Mexican government introduced a number of reforms to the Mexico petroleum law in an attempt to increase petroleum exploration. The changes allow PEMEX to contract with domestic and foreign drilling companies to explore for and produce oil, and to relate the contractual obligations to performance, including productivity. Unfortunately, allowing PEMEX to negotiate incentive arrangements with subcontractors falls far short of introducing a truly free market in this area (Mueller, Thomas, et al., 2008). This is mainly because ownership of any hydrocarbons that are discovered through exploration is reserved for the state (i.e., PEMEX).[38]

38 The situation is much different in Canada and the United States, where foreign companies (including state-owned enterprises) may explore for, own, produce, and market oil and gas resources subject to state, provincial, and national laws.

Policy recommendations

In order to lower barriers to investment in the development of the continent's extensive oil resource base, policy changes are necessary. In addition to the employment and income benefits from such investment, the resulting increase in production would bring domestic demand and production into closer balance. This would improve continental energy security by reducing the vulnerability of the oil supply to disruptions in shipments from the Middle East and elsewhere.

The main objectives, therefore, must be to eliminate non-market barriers to production development, and pipeline and storage facility construction in the three countries, and to remove barriers to intra-continental and global crude oil trade.

In general, the policy structure needs to become more market-oriented to ensure that North America does not impose unnecessary barriers to investment in crude oil production and transportation facilities compared with other industries and with oil industry investment opportunities overseas.

Specific policy recommendations include the following:

1. *Ensure that oil production royalties are competitive with other provinces, states, and countries.*
   Canadian and US national, state, and provincial governments must ensure that the crude oil production royalties over which they have jurisdiction are competitive, not just within Canada and the US, but also in comparison with jurisdictions worldwide with which they must compete for oil industry investment.

2. *Reflect in royalty regimes the higher cost of producing oil from deepwater offshore and non-conventional sources.*
   Governments must be aware of the cost differences between conventional onshore oil production on the one hand, and production in the outer continental shelf and from non-conventional sources of supply (such as bitumen from oil sands and oil from kerogen contained in oil shale) on the other. In light of the substantial cost differences for exploration and production development, including in some cases the cost of essential research, policymakers need either to move to the flat tax methodology referred to earlier, or, as a minimum, to reduce royalties to reflect market realities.

3. *Remove uncertainty hanging over oil sands environmental policy.*
   The provincial and federal governments need to ensure that any new environmental regulations that affect oil sands bitumen production and upgrading are finalized as soon as possible to remove the cloud of uncertainty that has been hanging over the industry regarding the potential costs of compliance.

4. *Remove uncertainty regarding environmental policies that affect conventional oil production.*
   Federal, state, and provincial governments need to remove uncertainty over possible environmental policy changes related to atmospheric emissions that would affect conventional crude oil production. This is especially important in the case of heavy crude oil, because measures to curb greenhouse gas emissions will impose considerable costs and will influence investment decisions. In addition, uncertainties over possible changes to environmental policies surrounding offshore oil exploration and production development need to be removed.

5. *Remove the moratoria on offshore exploration and development.*
   Moratoria on petroleum exploration and production in offshore areas such as the Queen Charlotte Basin and the US Pacific Offshore should be lifted once the authorities are satisfied, having studied the cause of the BP Deepwater Horizon crude oil leak in the US Gulf of Mexico, that the environmental risks can be mitigated.[39] With the lifting of the moratoria, new areas for potential discoveries will be opened and additional indigenous oil supplies can be tapped.

6. *Streamline regulatory processes for obtaining energy pipeline construction permits.*
   Additional pipeline capacity will be needed to transport a substantially increased volume of bitumen and synthetic crude oil from Alberta to markets in the United States and to ports on Canada's West Coast. Delays in putting the new pipeline and storage infrastructure in place will prove costly, so the regulatory processes and procedures that must be followed to obtain construction permits need to be overhauled.

   To ensure a more rapid response to pipeline construction applications in Canada, more is needed than simply tightening the National Energy Board's self-imposed service standards. The National Energy Board Act needs to be revamped. Government involvement in the construction permitting process should be confined to non-commercial aspects such as safety, the environmental impacts, and other matters of public importance.

7. *Adopt standard, consistent procedures for resolving native land claims.*
   A standard, consistent approach for settling native land claims issues expeditiously, fairly, and appropriately needs to be developed by the state, provincial, and federal governments. Such an approach will prevent these issues from delaying project construction and will avoid the case where the ultimate users of the commodities are saddled with inappropriate transportation costs.

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39 The BP Horizon incident illustrates that more diligence is required to prevent costly offshore oil leaks and spills from occurring. Industry and government will need to ensure that stringent safeguards are in place.

8. *Adopt measures to improve labor mobility.*
   An extension of the labor mobility clause in the North American Free Trade Agreement that applies to professionals to the skilled trades would improve skilled worker mobility among Canada, the United States, and Mexico.[40] Armed with an offer from a Canadian employer satisfied with their credentials, skilled tradespeople from Mexico and the United States could obtain a work permit for Canada, provided they complied with public health, safety, and national security requirements. The process would be similar to that governing the flow of workers between New Zealand and Australia under the Trans-Tasman Mutual Recognition Arrangement. This agreement allows people registered in a particular occupation in New Zealand to apply for and obtain registration (and thereby recognition) in one of the Australian states or territories, or vice versa (Council of Australian Governments, 2010).[41]

   Canada, the United States, and Mexico should also explore the possibility of securing bilateral labor mobility arrangements with other countries, similar to the arrangement in place between Australia and New Zealand.

   Within Canada, governments must re-examine aspects of the employment insurance program that allow unemployed seasonal and other workers in regions with chronically high unemployment rates to collect benefits for extended periods. The employment insurance program should have as one of its goals the improvement of worker mobility from one region to another.

9. *Reduce barriers to Mexican oil production growth*
   In Mexico, heavy taxation and constitutional restrictions on foreign direct investment severely limit the ability of PEMEX to invest in technology and resource exploration (Energy Information Administration, 2007: 32-35). Opening investment to foreign companies would significantly boost Mexican oil exploration and production development and help prevent Mexico from becoming dependent on oil imports for some years to come. In addition to the difficulty PEMEX faces in securing the necessary capital to fund further very expensive exploration and development of deep, offshore wells, if must somehow also find the necessary expertise to do so (Centre for Strategic and International Studies, 2008). Involving the major multinational companies would assist PEMEX to accomplish this, given the companies' collective pools of experienced oilfield workers.

40 NAFTA would not have to be renegotiated to accomplish this; the change could be implemented with a collateral or "side" agreement.

41 An alternative to an agreement under NAFTA would be a separate agreement patterned after the Trans-Tasman Mutual Recognition Arrangement.

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