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The Approaching Global Energy Crunch

And How Canada Should Meet It

Robert MacIntosh

In this issue...

Where do Canada's energy resources fit into the global outlook for energy? The escalation in the prices of oil and gas — beyond expecations — will force a vigorous response in the markets for fossil fuels and alternative energy sources.

The Study in Brief

The purpose of this *Commentary* is to consider where Canada's energy resources fit into the global outlook for energy and what this means for the nation and its public policies. If global prices for oil and gas continue to increase more than has generally been assumed — a central theme in this analysis — how does the market respond? How do investors in primary energy resources plan ahead to meet the growing risks? What impact will the market have on alternative sources of energy?

Although Canada is generally thought to be well endowed with primary energy resources, the long-term outlook is not so comfortable. Conventional oil and gas reserves are declining; their replacement requires heavy investment in higher-risk resources in the Alberta tar sands, the Mackenzie Delta, the Arctic and offshore. Global oil production is unlikely to meet rising global demand, with powerful growth in China being a major new factor. More attention will be given to imported liquid natural gas. Every option for developing new sources of energy will be expensive and time-consuming.

There are only a few large undeveloped hydroelectric power sites in Canada, and these are far from the major markets. Plans to eliminate thermal coal stations in Ontario, and political resistance to electricity generation from nuclear energy, represent serious challenges to the quest for viable alternatives. Governments will be pressed to demonstrate to consumers that they recognize and support the efforts of suppliers to raise the huge sums of capital required to ensure continued flows of electricity. Policymakers will have to avoid sheltering consumers from the reality of higher energy prices.

Alternative energy sources — wind, sun and hydrogen — will eventually make a contribution to the global supply of energy, though their current high cost makes them a relatively minor factor.

The Author of This Issue

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For the first time in decades, Canadians are worried about energy resources. Heating bills are rising and the price of natural gas has doubled in a relatively short time. Meanwhile, the cost of fuel for vehicles has climbed to levels last reached 20 years ago and monthly bills for electricity have become a painful reminder that energy is decidedly more expensive. Most striking of all was the electrical blackout of August 2003. With that, Canadians discovered that the cascading effects of the power failure quickly translated into a lack of fuel for cars and trucks, the closure of oil refineries and industries, the sudden shutdown of public transit, and a reliance on backup generators at hospitals. Although the impact on employment was short-lived, the implications of a longer power outage became obvious.

The public expects the government to ensure electricity supplies at stable prices and when the price of primary energy — mainly hydro — was relatively stable for long periods, the system worked reasonably well. However, the diversification of fuel sources and the rise of energy prices have introduced problems for capital investment in power generation. The lead time between the commitment to develop a new source of energy and its operation can be as long as 10 years. If prices climb in the interval, who is going to bear the risk? Can public utilities transfer some of it to market suppliers? Will suppliers undertake new ventures amid unpredictability? One of the key issues for decision makers is to close the gap between short-term market pricing and the long-term burden of investment risk.

This *Commentary* discusses where Canada's resources fit into the global outlook and what this means for the nation and its public policies. Global prices for oil and gas are likely to increase more than expected — a central theme in this analysis. That outlook raises the issue of what role the government has in trying to encourage consumers to adapt. The first task of market participants and policymakers is to recognize that global market forces are driving energy prices higher. The appropriate response will have to be a combination of policies. Governments will have to allow the market to perform its function of curbing demand, while encouraging supply and facilitating production and trade in energy resources. The private sector must find ways to make relatively large long-term investments that take into account a much greater degree of unpredictability and risk.

The high degree of uncertainty about the rate of increase in energy prices will require a greater use of indexation in the negotiation of long-term contracts to develop new sources of energy, whether domestic oil and gas fields, imports and exports, or newer forms of energy like wind and hydrogen. The long lead times and the high cost of new energy sources will force elected officials to steel themselves to make hard decisions, allowing market participants to transfer higher energy prices to users, rather than sheltering them. Apart from electric utilities,

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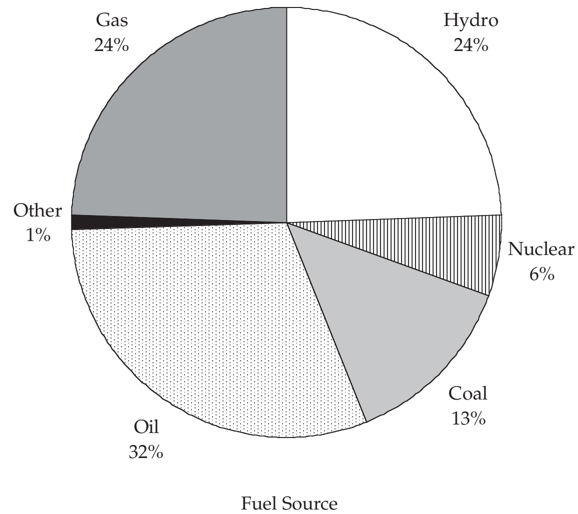
Figure 1: *Canadian Primary Energy Consumption by Source, 2001*



Source: EIA 2004. International Energy Outlook. "Other" includes natural gas liquids, methane and wind.

markets for energy supplies are largely in the private sector, and the relationship between short-term and long-term prices is determined by the interaction of many forces in the market place.

The various markets for primary energy — oil, gas, coal, hydro, nuclear and others — have all experienced inconsistent government intervention in the past 30 years, which has made long-term planning next to impossible. For example, California and Ontario have reversed themselves on privatization of power generation and offered mixed signals on pricing policy for electricity. The National Energy Program in the 1980s disrupted the oil industry in Alberta for years. Misguided intervention discourages investments which are urgently needed.

Investors in energy resources, including governments, must have clear ideas on what global market forces will do to prices, to the levels of risk, and to the prospects of meeting growth targets. This requires an overview of all the energy markets because they are closely interrelated. Canada's energy resources cannot be looked at in isolation.

Although Canada is generally assumed to be well endowed with primary energy resources, the long-term outlook is not reassuring. There are only a few large, undeveloped hydroelectric power sites, and they are far from the main population centres. Conventional oil and gas reserves are declining and their replacement requires heavy investment in higher-risk resources in the Alberta tar sands, the Mackenzie Delta and the offshore fields on the East Coast, as well as on the West Coast if opposition to testing and drilling in that area is overcome.

Most thermal coal is imported but it is currently on the priority list for elimination. Some observers argue that nuclear energy should be abandoned in spite of the strong business case for its expansion. Many are hopeful that new forms of renewable energy, such as wind power, solar power and fuel cells, will replace fossil fuels and nuclear power. While there are promising developments in newer forms of energy, it will be a long time before they replace large-scale conventional forms of energy. Figure 1 shows the distribution of primary energy sources in Canada in 2001.

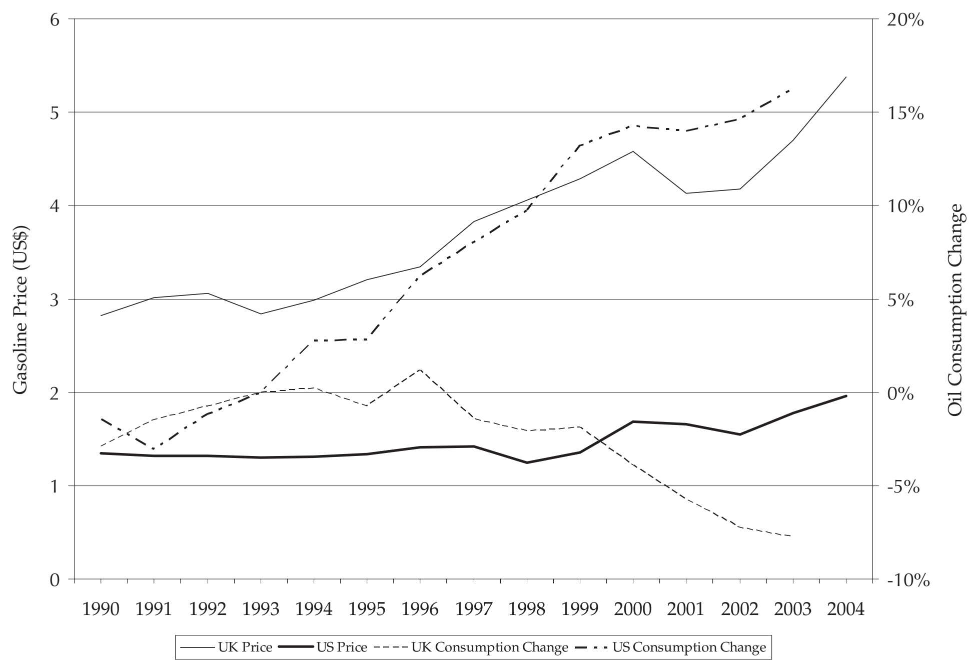
Canadian policymakers must closely examine their underlying assumptions about the availability and price of the various forms of primary energy. If coal is displaced and nuclear power minimized, there will inevitably be a much greater reliance on other fossil fuels. It is not clear that Canada will be able to meet its own requirements for oil and natural gas and still maintain its exports to the United States. The likelihood of an American energy shortfall is growing at the same time that China is sharply increasing its demand for oil, gas, and nuclear reactors. Among suppliers, Russia and some former Soviet republics are becoming important net exporters, somewhat offsetting the moderation in export growth from the OPEC countries, which will remain the main source of oil. All these factors impinge on Canada, and the key considerations include:

- A high and rising price of oil will encourage the search for conventional crude in the Arctic and at deep offshore sites;
- Further development of the oil sands in Alberta will become increasingly feasible as rising prices more than offset rising costs;
- Canada will have difficulty maintaining its oil and gas exports to the United States for the next few years, until substantially more production comes on stream from the oil sands and Mackenzie Delta gas fields;
- Proceeding with the Mackenzie Valley pipeline, subject to resolution of Aboriginal claims, will become more urgent with the declining supply of conventional gas;
- Negotiation of an economic route for an Alaskan pipeline to the lower 48 states will become a high priority as conventional gas reserves in the U.S. decline;
- Coastal facilities for the trans-shipment of Liquefied Natural Gas (LNG) to both Canadian and U.S. markets will receive a higher priority;
- Conservation policies for electricity and fuel consumption will attract increasing public support and enable governments to set goals;
- Contracts to supply natural gas and LNG for new electric power generation plants will require long-term agreements, indexed to global fuel prices, to attract the necessary investment by suppliers, and
- Rising prices for all forms of energy will reduce the quantities demanded at these higher prices. This will be the most effective form of conservation.

The Price Isn’t Right

Knowledgeable investors swiftly discern the influence of any change in the global supply of oil on the price, and their reactions move markets forcefully. In recent months, markets have reacted quickly as investors responded to several changes in OPEC’s announced intentions for its agreed ceiling on aggregate output. The mere declaration of a planned change in supply of 1 million barrels per day (bpd) on a global base of about 80 million bpd, is often enough to cause a sharp adjustment in the price of oil in world markets. However, over a longer time span, a significant rise in price produces little response in the supply in North America. In fact, conventional oil output in Canada and the U.S. is declining. Whether global supplies are rising is in doubt.

Figure 2: *Gasoline Prices and Crude Oil Consumption — United States and United Kingdom*



Source: EIA 2004 website. www. eia. doe.gov / Retail Motor Gasoline Prices, Selected Countries 1990-2001/ International Petroleum Consumption (Demand) Annual Data/ International Motor Price Gasoline Data 1996-2003.

In terms of demand, long-term projections are based largely on forecasts of economic growth, with little attention paid to price. Despite recent developments which have seen the world price of oil approach $50 per barrel, in June the U.S. Department of Energy confirmed its estimate that the price will rise from $22.68 per barrel in 2002 to $27 per barrel in 2025, in 2002 dollars. That would make the price of oil $23.37 in 2004, measured in 2002 U.S. dollars. (Unless otherwise stipulated, all prices are in U.S. dollars). On that basic price assumption, global oil exploration companies are misguided in their strenuous search for oil at the current price in 2004 dollars. Any success in finding oil would prove to be uneconomic.

In a longer perspective, $50 per barrel is not an unprecedentedly high price compared to the 1979-to-1985 period, when prices spiked to the range of $50-to-$100 per barrel, measured in 2004 dollars. From 1985 through the 1990s, the price was mostly in the $20-to-$35 range in 2004 dollars. In the last three years, the price has been rising. Will it fall back to 1990s levels? That seems highly unlikely. While global output of oil is near capacity, the demand for oil is suddenly burgeoning in China and South Asia. The prospect is for rising prices until they eventually affect consumer behaviour.

In the short run, a fuel price increase may not cause much change in consumer demand, which tends to be inelastic for a relatively brief period. But consumer behaviour changes significantly over time. If one contrasts the frugal use of electrical power in a Japanese home compared to one in North America, the difference is striking. Figure 2 provides a microcosm of the difference in consumer response to the price of gasoline in the United States and Britain from 1990 to 2003.

Table 1: *Two Forecasts of Global Energy Demand*

Period	IEA		EIA	
	Economic Growth	Energy Demand	Economic Growth	Energy Demand
	(compound annual growth, percent)			
1971-2000	3.3	2.1	–	–
2000-2030	3.0	1.7	–	–
1970-2001	–	–	3.1	1.9
2001-2025	–	–	3.1	1.9

Source: IEA 2003; EIA 2003 and 2004.

The Global Energy Outlook

Global forecasts — or, as they are often called, "scenarios" — of the demand for, and supply of, energy are usually based on a set of assumptions about rates of economic growth, as well as on calculations of past relationships between economic growth and demand for energy. Two official forecasts are widely used, both of which examine in depth the widely varying rates of growth in different countries and regions. These are the annual *World Energy Outlook,* published by the International Energy Agency (IEA 2003), and the annual *International Energy Outlook,* published by the Energy Information Agency (EIA 2003 and 2004) of the U.S. Department of Energy.

The IEA, which represents 26 of the 30 member countries of the Organisation for Economic Co-operation and Development (OECD), defines its "*Reference Scenario"* in terms of a set of assumptions about macroeconomic and demographic conditions as well as energy prices and supply costs. The economic growth assumptions are based on data from the OECD, the World Bank and the International Monetary Fund. The EIA builds its global outlook on a similar methodology, with moderately different assumptions about economic growth rates in the developed and less developed regions of the world. Table 1 sets out the comparison.

Both forecasts aim to show that economic growth largely determines the demand for energy. The IEA calculations suggest that over several decades, a 1-percent increase in gross domestic product (GDP) has been associated with a 0.64-percent increase in energy consumption. The comparable increase in the EIA analysis is 0.61 percent. In the developed industrial economies, energy intensity (the use of primary energy per unit of GDP) tends to decline for several reasons. For one thing, technological change brings greater efficiency in fuel consumption, in electricity generation and transmission, in reduced wastage at the extraction level, in home insulation, and in industrial production. For another, the shift from heavy industry to light, and from goods production to services, tends to reduce energy consumption.

As well, there are some limited efforts at conservation. Accordingly, the IEA anticipates a steady decline in global energy intensity to 2030, a decline which started about 1990. Although both the IEA and the EIA say they expect a more rapid rate of growth in the developing world than in the industrialized OECD countries, they appear to understate significantly the prospects for economic growth and for energy demand in the developing countries. For example, the U.S. analysis forecasts an economic growth rate of 6.2 percent for China in the 2000-to-2025 period, but only a 3.5 percent growth rate in energy consumption. This implies an intensity factor of 0.56 percent. However, in 2002, the GDP of China actually rose 8 percent and energy use increased by 7 percent-to-8 percent.

The IEA says that 1.6 billion people out of a world population of 6.2 billion have no electricity, and 2.4 billion rely on traditional biomass — wood, agricultural residues and dung, for their basic energy needs. Most of these people are no longer isolated from observing how people in the developed world live. Their wants and needs will be likely translated into a somewhat higher world demand for energy than the authorities are presently anticipating. A study which examined energy demand in relation to household income said:

> "When per capita GDP (on a purchasing power parity basis in 1997 U.S. dollars) reaches some $3,000 demand explodes as industrialization and personal mobility take off, $10,000 demand slows as the main spurt of industrialization is completed, $15,000 demand grows more slowly than income as services dominate economic growth…." (Shell International 2001).

It is hard to avoid the conclusion that official projections are seriously underestimating the future demand for energy in the developing world.

The official Canadian forecast of energy demand (National Energy Board [NEB] 2003) is greatly at variance with those of the IEA and EIA. Although limited to Canada rather than global in scope, it produces a markedly different outlook for policymakers. This document offers two projections for energy demand in Canada, one called "Supply Push" and the other, "Techno-Vert".

> "The Supply Push scenario represents a world in which technology advances gradually and Canadians take limited action with respect to the environment. … The Techno-Vert scenario represents a world in which technology advances rapidly and Canadians take broad action with respect to the environment…." (NEB 2003).

The NEB forecasts the economic growth rate for 2000-to-2025 to be in the 2.2 percent-to-2.7 percent range, with the higher rate of growth being achieved in the Techno-Vert scenario. In other words, the greater the concentration on the environment, conservation and technology, the higher the growth rate of the economy. The contrast is evident in the NEB's two projections for the growth in energy consumption to 2025. In the Supply Push case, energy growth is 1.4 percent, compared to 1.7 percent in the IEA forecast and 1.9 percent in the EIA forecast. In the Techno-Vert outlook, however, the growth rate for energy consumption would be only 1.0 percent. The Techno-Vert estimate would be a very sharp departure from the linear relationship between economic growth and energy consumption for the 55-to-60 year period covered, looking both backward and forward in the world economy. Instead of a ratio of 0.64 of energy growth to economic growth, the green ratio would be 0.37 percent. That is the reason that the federal government

Table 2: *Distribution of Global Demand for Primary Energy*

Energy Source	2000	2030
	(%)	
Oil	38	37
Coal	26	24
Natural Gas	26	28
Nuclear	7	5
Hydro	3	2
All others	2	4

Notes: The EIA (2004) has recently raised its demand estimate for oil to 39 percent by 2025. Columns may not sum to 100 because of rounding.

Source: IEA 2003.

perceives the Kyoto Protocol to be a positive achievement; its green scenario would imply a quantum leap in energy efficiency compared to those perceived by the IEA and the EIA.

The Supply Side of Primary Energy: Oil

Oil comes first as a primary source of energy, as shown in Table 2. I consider each of the other primary sources — natural gas, coal, hydro and nuclear — before turning to the newer forms, such as wind, sun and hydrogen.

Most surveys of global oil resources suggest that they are quite adequate to meet global requirements for the next 25-to-30 years. This *Commentary* argues that the price forecasts overstate the availability of reserves and understate global demand. The following quotations from the IEA suggest a rather comfortable scenario for world oil supplies to 2030:

> The world's energy resources are adequate to meet the projected growth in energy demand. Oil resources are ample but more reserves will need to be identified in order to meet rising oil demand to 2030. Fossil fuels will remain the primary source of energy, meeting more than 90 percent of the increase in demand. International oil trade is set to grow considerably…. Net international trade rises from 32 mb/d (millions of barrels per day) in 2000 to 66 mb/d in 2030." (IEA 2003).

These observations make no allowance for the political risks in the Middle East, the region that will remain the main source of oil. They also seriously underestimate the impact on world demand from the rapidly expanding Chinese economy and other developing countries. This leads to a substantial underestimate of oil and gas prices. The IEA expects the price of imported crude oil to fall in the first decade of the century, then rise gradually to $29 per barrel in 2030, compared to $28 per barrel in 2000. The IEA emphasizes that there will be even

Table 3: *Regional Distribution of Proven Oil Reserves, Dec. 31, 2002*

Region	Reserves	Share of World
	(billion barrels)	*(%)*
North America	49.9	4.8
South & Central America	98.6	9.4
Europe and Eurasia	97.5	9.3
Middle East	685.6	65.4
Africa	77.4	7.4
Asia Pacific	38.7	3.7
TOTAL WORLD	1047.7	100.0

Source: BP. 2003. Derived from data in *Oil and Gas Journal*.

Notes: Reserves of shale oil and oil sands not included. IEA provides reserves data only to Jan. 1, 1996. The IEA global total for 1996 is 959 billion barrels. BP 2004 data include oil sands, which alters percentages.

more price volatility than in the past, but in the longer run it sees only a modest rate of increase in the price of internationally traded oil.[1]

The EIA shares the views of the IEA on the price outlook. It sets out a comparison of world oil prices projected by seven analysts, as well as its own and those of the IEA. Comparisons are clouded by the use of different definitions of oil and different base dates. However, the projected price increase from 2005 to 2025, measured in constant 2001 dollars, is identical at 28.6 percent for the EIA and the IEA. The other six forecasts quoted by the EIA all fall within a range of zero percent-to-40 percent growth in the next 25 years. In the months or years since these forecasts were made, the price of oil has been significantly higher than these projections. The question arises as to whether short-term factors such as the Iraq war explain this, or whether the projections are missing something. What is missing is any attempt to assess the global political situation and its impact on energy prices.

Canadian forecasters specialize in flat-line price projections. The NEB assumes a U.S. dollar price (in constant dollars) of $22 from 2001 to 2025 (NEB 2003), slightly lower than the flat-line figure of $22.48 used by Natural Resources Canada.

OPEC's Role

The difficulty in forecasting prices arises from the geographic distribution of conventional oil reserves. Table 3 shows the regional distribution. As much as 65.4 percent of the world's oil reserves are in the Middle East. Adding the five members of OPEC that are not in that region, the concentration of resources in OPEC[2] hands is 78.2 percent. All five are countries with a risk of political instability — Algeria, Libya, Nigeria, Indonesia and Venezuela. In fact, political instability in

1 The IEA publishes its estimates of global energy data in even-numbered years. It is possible that its estimates for 2003 and 2004 could change significantly for some countries. The IEA, in effect, eliminates political factors by stating: "The Reference Scenario does not include possible, potential or even likely future policy initiatives".

2 OPEC has 11 members, six in the Middle East (Iran, Iraq, Kuwait, Qatar, Saudi Arabia and the United Arab Emirates) and five others (Algeria, Indonesia, Libya, Nigeria and Venezuela).

Table 4: *Crude Oil Production in Selected Regions, 2003*

	Production	Share of World
	(mpd)	(%)
Canada	3.0	3.8
United States	7.5	9.2
Saudi Arabia	9.8	12.8
Iran	3.9	5.1
Iraq	1.3	1.8
Former Soviet Union (FSU)	8.5	11.4
China	3.4	4.6
Middle East Total	22.6	29.6
OPEC Total	30.4	39.6

Source: BP 2004. Includes oil sands.

Venezuela and Nigeria had a marked effect on world oil markets in 2002/2003. In early 2004, Indonesia was actually a net importer. Russia and the former Soviet republics account for a further 7 percent of world supplies.

The high concentration of proven oil reserves in the OPEC countries raises a number of policy issues. One is whether OPEC will be able and willing to supply global markets with sufficient output to meet global demand. Says the EIA: "It is generally acknowledged that OPEC members with large proven reserves and relatively low costs for expansion of production capacity can accommodate sizable increases in petroleum demand" (EIA 2004).[3]

This may be true for Saudi Arabia, Iran and Iraq, but the issue is whether OPEC will choose to accommodate global demand. Table 4 sets out the regional distribution of oil output in 2003. OPEC accounts for 39.6 percent of total output, and the Middle East, 29.6 percent.

The production numbers are very different from the reserve numbers. But in many parts of the world, production has peaked and is likely to decline. In North America, output is declining. Mexico could expand, but is hampered by its constitution which prevents foreign direct investment in energy (Hufbauer and Schott 2004). South America, Africa and the Far East could not offset any significant reduction in OPEC output. Most of the Middle East suppliers, other than Saudi Arabia, are close to their production capacity. I look at the cases of Russia and China subsequently.

A close examination of OPEC indicates that it will sustain its dominant position. In the 10 years to 2002, production in the Middle East grew at 0.07 percent per annum. The growth rate in OPEC as a whole was 1 percent per annum. This amounts to 3.3 million bpd over the decade. If continued for 28 more years, and if all the OPEC output went to the United States, then the expected level of U.S. demand could be met without relying on non-OPEC sources. This calculation is an unrealistic hypothesis, intended only to demonstrate the order of size of future U.S. requirements. What are the prospects of OPEC increasing its output to the

3 In early 2004, some experts began raising doubts about the validity of Saudi Arabian reserves.

industrialized OECD countries at a consistent rate for the next three decades? The short answer is: not very high.

In March 2000, OPEC decided to set a target range for its exports of $22-to-$28 per barrel.[4] To achieve this target, OPEC adjusts its aggregate output quota from time to time. There have been several changes in the past three years, mainly to adjust for the decline in output from Venezuela and Iraq. But in September 2003, OPEC made the unexpected decision to reduce the quota by 900,000 bpd, or about 3.6 percent (Economist 2003). This action followed OPEC's upward revision in July of its own forecast of world demand, as well as the many delays in the restoration of output by Iraq. Moreover, the price of oil was above the $28 target ceiling when the reduced quota was imposed.

In December 2003, the Saudi oil minister declared that because the U.S. dollar had depreciated 35 percent in three years, OPEC would set its target range in dollars at the currency's 2000 value. That raised the current target to $35 from $28. In February 2004, OPEC agreed to cut production by another 400,000 bpd. Although energy analysts estimated that OPEC's target output was being exceeded by perhaps 1.5 million bpd, the lack of clarity surrounding OPEC's intentions and the growing concern about terrorist threats to the supply from Saudi Arabia led to a sharp climb in the price of oil to nearly $50 a barrel by late August 2004. In May 2004, Saudi Arabia pressed OPEC to raise the quota by 1.5 million bpd, and Riyadh agreed to provide half of the increase.

It is noteworthy that most OPEC members are currently producing at capacity and that apart from Iraq, only Saudi Arabia is in a position to increase output significantly in the short run. With its large reserves, Iran could increase production in the long run, though that would require a major capital investment. As for Iraq, its current output is about 1.3 million bpd (BP 2004), compared to its peak output of 2.6 million bpd in 2000. Internal consumption will absorb 0.5 million bpd, so that the current increase of Iraqi exports is perhaps 0.8 million bpd or half the September reduction in the OPEC quota. Iraq could again be a major supplier if it gains political stability and sufficient capital investment in the next decade.

The Russia Factor

It seems likely that the United States is seeking to diversify its access to offshore oil from sources other than OPEC — an obvious strategy. But a major new factor is that both China and Japan are developing large-scale plans to move Russian oil and gas to the Far East, deflecting a significant flow of primary energy away from Europe and North America.

Russian output was 8 million bpd in 1992, and fell to 6.1 million bpd in 1996. By 2003 it had recovered to 8.5 million bpd, and there are indications that Russia will prove to have relatively large undiscovered reserves. The IEA reported its

4 World pricing systems are summarized on EIA 2003b website. The OPEC price basket is similar to the EIA's Imported Refiners' Acquisition Cost (IRAC). Note that crude oil data used here exclude natural gas liquids (NGLs), which account for 3-4 million bpd in many published reports. In 2003 global demand was 75.1 million bpd, and in 2004 it is forecast to increase by about 1.7 million bpd.

proven reserves in 2002 at 60 billion barrels. The former republics with substantial reserves are Azerbaijan, with seven billion, and Kazakhstan, with nine billion (BP 2003). There is not the same degree of reliability in these figures as in those of more developed countries. Still, the potential is so great that several major OECD oil companies are swiftly forming alliances for exploration in the former republics.

British Petroleum has substantially raised its estimate of the area's oil reserves, and is developing plans to export natural gas to China and South Korea. Royal Dutch/Shell is working on plans to develop a Siberian oil site at Salym in partnership with a Russian company (Whalen and Cummins, 2003). Both ExxonMobil and Chevron Texaco are seeking alliances with the Russian majors Yukos and Sibneft. Pipelines from the Caspian Sea area to the Black Sea and the Mediterranean are intended to give Russia and the former Soviet republics much greater export capacity.

The forthcoming surge of investment in the region by western oil companies is almost overshadowed by the surge of investment in Russian pipelines to serve China and Japan.

Yukos has already signed long-term agreements to deliver oil to Daqing in China. Another 4,000-kilometre pipeline from Siberia will terminate at a port on the Pacific. Japan is so anxious to obtain the 1 million bpd content of this pipeline that it will advance up to $5 billion to build it (Fackler, 2003).

The China Factor

The immense expansion of the Chinese economy is the principal factor which will render invalid the official projections of the world's energy analysts. According to the EIA (2004), oil production in China will be 3.4 million bpd in 2025, the same as in 2002. The EIA estimates that Chinese consumption will grow 3.3 percent per year from the base of 5.9 million bpd in 2003 (by early 2004 it was already up to 6.2 million bpd). This will bring China's consumption to 13.9 million bpd in 2030. Imports will rise to 10.5 million bpd in 2030 from 2.2 million bpd in 2002. By comparison, U.S. consumption and imports of oil would be just about twice as large as China's by 2030 (EIA 2003a) The International Energy Agency assumes a growth rate in world oil demand of 1.6 percent per annum to 2030, and a much faster 3.0 percent rate for China. It projects Chinese demand at 10 percent of the world total by 2030 or 12 million bpd.

Neither of these projections seems realistic, even in the context of the economic assumptions used. The international agency assumes a growth rate of 4.8 percent per annum for China's GDP to 2030, while the U.S. agency assumes 6.1 percent to 2025. Under these assumptions, then, the demand for oil would have to be far greater than both official forecasts, unless there is a significant decrease in the intensity of energy use. What is the likelihood of that happening in China?

A far more likely outcome is that the opposite pattern will develop. In 2002, China's GDP increased about 8 percent, while energy consumption rose 7 percent-to-8 percent, a very high rate of intensity. General Motors estimates that automobile sales in 2003 reached 4.4 million units, an increase of 29 percent from 2002 (Mukherjee, Anindya 2003). In 2000, there were 12 vehicles per 1,000 people in China compared to 700 per head in the U.S. and Canada. Electric power genera-

Table 5: *Canada and China: Comparative Size of Population and Crude Oil Use, 2003*

	China	Canada	China / Canada
	level	*level*	*ratio*
Population (million)	1,300	32	41.0
Crude oil reserves (billion barrels)	18.3	6.9	2.9
Oil Consumption (million bpd)	5.4	2.0	2.7
Oil Production (million bpd)	3.4	2.9	1.2

Source: IEA 2003. Excludes oil sands.

tion capacity is about 315,000 megawatts, expected to grow to 500,000 MW by 2010. These forecasts indicate that the comfortable projections of the IEA and the EIA regarding the adequacy of known oil reserves in the world are questionable.

Table 5 illustrates the contrast between Canada and China when assessing the outlook for energy demand 25 or 30 years in the future. Although it is conceivable — even probable — that the intensity of oil demand will decline in Canada as the economy matures and conservation occurs, the intensity of energy consumption in all forms is almost certain to rise in China. Aggregate world demand will reflect this pattern, even if conservation measures take hold in the developed countries.

U.S. Import Dependence

According to the EIA, the growth rate of U.S. oil demand will be 1.5 percent per annum from 2001 to 2025. If this same growth rate is used for the 28 years from 2002 to 2030, the U.S. will need 29.9 million bpd in 2030, an increase of 10.2 million bpd. Table 6 shows that in 2003, the United States consumed 20.1 million bpd, and produced 7.5 million bpd. Net imports were 12.3 million bpd, of which 1.1 million bpd, or 9 percent, came from Canada

Even with the growing output of the Alberta tar sands, it is doubtful that Canada can sustain the level of its crude oil exports to the United States. At the current rate of net exports to the U.S., Canada would account for 10 percent of total U.S. imports of 20.1 million bpd by 2030. The U.S. will become increasingly dependent on OPEC, especially on the Middle East, and also on Russia and the former Soviet republics.

Proven reserves of conventional oil are falling in both the United States and Canada, and recently there has been growing concern that reserves are overstated. Table 7 shows proven reserves in the two countries. These do not include the Alberta oil sands, which I examine next.

Also shown for 2002 are the percentage of world reserves and the ratio of reserves to production per year (R/P ratio). The R/P ratio shows the remaining life of reserves at Dec. 31, 2002, assuming production continues at the level of 2002 and that reserves do not change. However, as noted, reserves have been slowly declining in both the U.S. and Canada for some time, despite the tendency of world oil prices to rise. The hard truth is that conventional oil reserves are becoming harder to find even with improved technology (Goodstein 2004). The explo-

Table 6: *Production, Consumption & Trade of Crude Oil, Canada and the United States, 2003*

	Production	Consumption	Imports	Exports
		(million barrels per day)		
United States	7.45	20.07	12.25	0.92
Canada	2.99	2.15	1.13	2.01

Source: BP 2004. Includes oil sands and shale oil, as well as natural gas liquids. Oil sands exports in this Table differ from Table 7. Discrepancies are accounted for by stock changes and unavoidable disparities in the definition and measurement of data. Exports and imports are analyzed in more detail in Bradley and Watkins. Data for 1991/2001 appear to differ moderately from BP data.

Table 7: *Proven Reserves of Crude Oil, U.S. and Canada, 1982–2002*

	Rerserves (billion barrels)		Share of World (%)		Reserves/Production (ratio)	
	U.S.	Canada	U.S.	Canada	U.S.	Canada
1982	35.1	8.3	–	–	–	–
1992	32.1	7.5	–	–	–	–
2002	30.4	6.9	2.9	0.7	10.8	9.0

Source: BP 2003. Includes estimates of natural gas liquids but not oil sands.

ration is reaching out to deep offshore sites, which are somewhat more expensive to explore —and to operate when a search is successful. Recently, the drilling results off Nova Scotia have been disappointing.

Canada's Storied Oil Sands

The underestimation of the rise of oil prices and overestimation of global oil supplies over the next three decades will enhance the economic viability of Alberta oil sands production.

It is only in the last two years that the oil sands have gained attention in calculations of the world's crude oil reserves. In part, that reflects their relatively modest contribution to global supplies so far, as well as the perception that crude extraction from the oil sands is a far more costly process than the lifting of conventional reserves in the Middle East. Canada's oil reserves rocketed to 180 billion barrels in 2003 from 7 billion barrels in 2002. This makes them second only to Saudi Arabia's 259 billion barrels.[5] How is this possible? "[D]ramatic reductions in development and production costs have brought oil sands into the range of economic viability" (EIA 2003a). Table 8 sets out four estimates of the Alberta oil

5 EIA data are derived from the *Oil and Gas Journal*. The projections are those of the Alberta Energy and Utilities Board (AEUB), the official regulator. The AEUB has published its methodology, which appears to be accepted by the EIA, the IEA and the NEB.

Table 8: *Canadian Oil Sands. Recoverable Reserves and Production*

	Recoverable Reserves 2002/03			Production 2001/02		
	In situ	**Mining**	**Total**	**In situ**	**Mining**	**Total**
		(billion barrels)			*(000 barrels per day)*	
EIA	–	–	173	300	400	700
NEB	241	61	302	–	–	–
IEA	–	–	–	350	300	650
AEUB	142	33	175	295	530	829

Notes: EIA 2004 for 2003, total reserves of 179 billion, less 6 billion conventional; NEB 2003 data for 2002 are in cubic metres converted to barrels at 6.289 barrels per cubic metre, rounded, as NEB numbers do not add; IEA 2003, for 2002 production; AEUB 2003 for 2002 in barrels converted from cubic metres.

sands recoverable reserves. These are far less than what is called "original bitumen in place."[6]

Even so, current and proposed production numbers are relatively small in relation to recoverable reserves — a fraction of 1 percent — so that a closer consensus on total recoverable reserves is not relevant for policymakers in this decade.

What is relevant are the projections of output from the oil sands in the next 10-to-20 years. The EIA projects 2.2 million-to-2.5 million bpd by 2025, depending on petroleum prices and technology. The IEA projects 1.2 million bpd in 2010 and 3.2 million bpd in 2030. These forecasts appear low because actual output in 2002 was already 829,000 barrels per day. The AEUB projects output of 2,634,000 bpd in 2012. Much of this growth will offset the projected decline in Alberta's conventional oil production. After meeting the province's internal requirements, the volume of crude oil available for export to the rest of Canada and the United States could be less than 1 million bpd by 2012. Obviously the impressive size of the reserve numbers is somewhat misleading when translated into the expected output based on present plans and technology. With China's growth surpassing 1 million bpd every year, the addition of that amount from the oil sands eight years out is modest in global terms.

However, a number of new oil sands projects would add considerably to this number. Because of the marked shift in price assumptions for oil and gas used in this paper, the policy implication is that governments should hasten the environmental review process and the resolution of political issues so that the oil sands industry can develop them.

There are a host of unknowns in projections of oil sands output, of which the most critical is the world price of oil and the future costs of production. If the prevalent Canadian assumption on prices is valid, then oil sands development will

6 The AEUB estimates that the oil sands have 1,631 billion barrels of oil, of which only 11 percent, or 175 billion, are recoverable. The NEB, using data adopted from the AEUB, puts "resources" at 2,500 billion barrels, of which 315 are recoverable. The EIA estimates 1,700 billion barrels of bitumen, of which 15 percent, or 255 billion, are recoverable. See also NEB 2000 and AEUB 2003.

be very constrained. At the current price of oil, however, there is a wide profit margin in relation to estimated total operating costs of C$16-to-C$26 per barrel.[7]

The foreign exchange rate is also a factor. Under current conditions, some of the existing oil sands plants are moderately profitable. However, the concurrent construction of several new or expanded facilities has placed enormous strains on the supply of skilled labour and materials. In some cases, costs have exceeded expectations by 50 percent or even 100 percent, changing the risk/reward calculation significantly.

Many other difficult factors remain in the future development of the oil sands. The severe climate causes equipment breakdown, seriously impairing productivity. The extraction and processing of oil sands consumes relatively large amounts of energy, absorbing the available supply of natural gas. Some of the natural gas fields have been shut down by the AEUB because of their impact on some oil sands plants.

Canadian adherence to the Kyoto Protocol could also affect productivity. The combination of risks and unknowns is translated into a higher cost of capital in an industry which already requires relatively large amounts of capital. On the other hand, if the assumed world price of oil turns out to be considerably higher than is currently projected — one of the key contentions of this paper — then the economics of oil sands production will justify further large investments.

Natural Gas

Natural gas is not generally considered to be part of a global market like oil because of transport problems. There is a world price of oil, adjusted for quality and location. There is not a global price for natural gas, but many regional prices. Currently, Canada and the United States share a regional market. Over time this might change because the pressure of demand will make LNG increasingly price competitive in global markets. In this section, I examine the Canada-United States regional relationship.

The Canada-U.S. Market for Natural Gas

In a regional context, Canada plays a significant role in the North American market as a large producer for the domestic market and as an exporter to the United States. Table 9 shows Canada-United States trade in natural gas in 2003.

The gap between U.S. production and consumption of gas is much smaller than is the case with oil. Canada fills almost the entire shortfall of about 3,500 billion cubic feet per annum. Several factors contribute to this, among them: the gas is available from Canada's Western Sedimentary Basin; it can easily access the U.S. by pipeline; the price is relatively low in U.S. dollars, and its importation meets the growing U.S. concern about security. However, as in the case of oil, reserves

7 In Canadian dollars, total costs per barrel consist of production costs of $8-to-$12, capital costs $5-to-$9, upgrading and cleaning costs $3-to-$5. Pipeline transport costs are $2-to-$3. These are estimates of the EIA, but there have been some serious capital cost overruns acknowledged in 2004.

Table 9: *Production, Consumption and Trade in Natural Gas, Canada and the United States, 2003*

	Canada	United States	World
		billion cubic feet per annum	
Production	6,374	19,406	92,472
Consumption	3,087	22,241	91,500
Imports	276	3,482	16,064
Exports	3,482	594	16,064

Source: BP .2004. Cubic metres converted to cubic feet. Numbers do not reconcile due to inventory changes and timing of contracts. U.S. imports gas from Mexico by pipeline and 229 bcf of LNG from rest of world.

Table 10: *Proven Reserves of Natural Gas, 1983-2003, Canada, United States and the World*

	1983	1993	2003
		(trillion cubic feet)	
Canada	92.17	78.75	58.7
United States	198.12	160.68	184.8
World	3272.97	4982.2	6204.9

Source: BBP 2004; p.20. Converted from cubic metres.

have been declining in both countries over two decades. Table 10 presents the data. There has been a sharp decline in Canadian reserves, and U.S. reserves are only three times as large as those of Canada.

Their combined reserves are relatively modest in a global context, representing 0.9 percent and 3.0 percent, respectively, of world totals. The United States currently consumes about 24 percent of world output, and its demand for gas is certain to increase. Nearly all the electric plants built since 1998 are designed to be fired by natural gas, in spite of the fact that the price of gas has risen in recent years. The EIA projects U.S. consumption of 34.9 trillion cubic feet (tcf) per year in 2025, over 10 tcf higher than now, assuming a growth rate of 1.8 percent per year. The U.S. National Petroleum Council forecasts a slow decline in the supply of gas from conventional sources to 2025, but a rise in production from oil shale in the Rockies, from Mexican Gulf deep water and from Alaska.

Coal bed methane (CBM) accounted for 10 percent of total U.S. natural gas reserves in 2002, a rising proportion in the last 15 years, but its growth rate is slowing. The IEA estimates that there are only 2 tcf of coal-bed methane in the western Canadian prairies and foothills, about equal to one year’s decline in natural gas reserves. The Alberta Energy and Utilities Board says that “estimates of CBM reserves do not yet have a high enough level of accuracy to warrant their publication at this time” (AEUB, 2003). There are also serious environmental problems in CBM production and the conflict with agriculture is acute.

Including these resources which are on the geographic frontier or at the margin of economic feasibility, U.S. production would be around 24 tcf per annum in

2025, compared with 19.3 tcf in 2002 (EIA 2004); this is consistent with the EIA's projection of 7.3 tcf of imports in 2025. About 2.5 tcf of this would be coming from Canada, 4.7 tcf from LNG imports and none from Mexico.

These calculations by the EIA imply a reduction of about 30 percent in Canadian natural gas exports to the U.S. 22 years from now. If Canadian domestic needs were to increase to 4 tcf per year, Canadian gas production would have to be about 7 tcf in 2025, slightly above today's production level. With conventional reserves declining at 2 tcf per year, there is clearly an urgent need to bring on gas from the Mackenzie Delta and also from Alaska.

However, there are several obstacles. For one thing, the U.S. plan to pipe gas from Alaska is fraught with political and economic problems and Congress is deeply divided on exploiting resources on the Alaskan shelf. As well, Alaska insists on an uneconomic route southbound across the state and some business leaders and politicians want to shelter gas producers from high risks by providing subsidies or a guaranteed minimum price. Not only that, the capital investment is likely to be $15 billion or more, even for the more economic route via the Mackenzie Valley.

Canada, too, faces risks and unpredictability. Still, one of the biggest hurdles facing Arctic development seems to have been overcome with the breakthrough agreement between a consortium of major oil companies and the Aboriginal Pipeline Group in June 2003.

The co-operative atmosphere was entirely different from that surrounding the negotiations over the Mackenzie Valley pipeline 25 years ago. However, economic challenges remain. A total of C$1 billion will have to be spent on exploration, to be followed by C$5 billion for construction in the 2006-to-2009 period. The extreme climate and the persistent shortage of skilled labour present further difficulties. At the same time, the price of northern natural gas has to be competitive with alternative sources of gas and oil for the next 30 years. However, this should not be an obstacle because global prices for oil and gas will be trending upwards. Hence, policy should encourage northern development.

Conservation measures could alter these projections. The U.S. National Petroleum Council qualifies its forecast of North American supply in 2025 by about 6 tcf, or 18 percent, if what it calls efficiency gains take effect. It defines efficiency gains as decreased electric power intensity, increased efficiency in gas-fired power generation, and "efficiency gains in commercial and residential consumption".

While U.S. authorities are somewhat optimistic about the prospects for meeting about 75 percent of North America's natural gas requirements from U.S. and Canadian sources, the NEB is more cautious: "The size of Canada's natural gas resource base continues to be a significant uncertainty, especially for the frontier regions and unconventional gas"(NEB 2003).

Even if the natural gas resources in the North come on stream in as little as five years, there will still be a large gap between North American production and consumption. Together, both countries will have to look to the global market.

The Global Market for Natural Gas

An energy policy that is based on generating electricity from natural gas will have to grapple with the issue of the feasibility of importing natural gas to supplement domestic resources in North America. In global terms, there is plenty of gas. The question is whether suppliers can arrange for its safe transportation at a competitive price.

Global reserves of natural gas were just 6 percent less than global oil reserves at Dec. 31, 2002.[8] Reserves are more broadly distributed in the world than oil reserves, and gas is more widely produced and consumed. The OPEC nations do not have the same degree of oligopolistic power in natural gas as they do in oil. There are a number of smaller non-OPEC countries which could feed natural gas into the world market, if capital investment needs were met.

About 24 percent of total gas consumption in 2003 was traded internationally. Natural gas can be transported by pipeline or, when converted into LNG, by tanker. There is an extensive network of pipelines in North America, a network linking Russia to Eastern and Western Europe, and 129 LNG carriers (IEA 2003). In Europe, gas moves from Norway to Britain and Poland, from Russia to Germany and Italy, and from Algeria to Spain. Japan is by far the largest importer in the world of LNG, and with some of its nuclear power plants shut down, will remain so. China has relatively small proven reserves of gas; it will import gas from Indonesia and Australia to displace coal-fired plants in Shanghai and elsewhere. The global picture is one of rapidly expanding trade. The EIA forecasts world consumption to rise at 2.8 percent per year until 2025, to 176 tcf from 90. This will require a relatively large capital expenditure on infrastructure (Yergin and Stoppard 2003).

Natural gas must be cooled to minus 260 degrees Fahrenheit to convert it to liquid for transport in specialized tankers, then reconverted at the port of entry. About half of the 5.4 tcf of LNG which trades internationally is imported by Japan in this way. LNG facilities are not only costly but somewhat of a safety risk. The gas is highly flammable and would represent a hazard in a populated area. There are only four operating port facilities in the United States and none in Canada. A major challenge for industry and government will be to construct trans-shipment ports which are secure from terrorist attack.[9]

LNG is considered costly, although not only has the gap between the price of natural gas and LNG narrowed, the price at Henry Hub, Louisiana, now exceeds the LNG price in Japan.[10] In the past year, the price of natural gas has averaged around $5.50, so that LNG appears to be competitive in the North American market.

The most likely source of LNG imports is Russia, with its huge reserves. It could provide a stable supply to the U.S., enabling it to avoid the instability in the

8 One barrel of oil is equivalent to 5,610 cubic feet of natural gas. British Petroleum estimates that global natural gas reserves were 6,204.9 tcf in 2003, which translates into 1,106 billion barrels of oil, about 5.5 percent more than global reserves of oil at Dec. 31, 2003 (BP 2004).

9 El Paso Corp. has abandoned a project in the Gulf of Mexico due to concern over terrorism. A project for an LNG terminal on the coast of Maine has been rejected by the local community. A proposal for an LNG terminal near Quebec City is meeting opposition, as is a similar proposal for Saint John, N.B.

10 Prices of LNG are published by BP 2004 and IEA 2003. The IEA reports the cost of European imports by pipeline at $3.90 per British Thermal Units, (BTUs) compared to $4.70 for Japanese imports. Conveniently, 1,000 cubic feet of natural gas (1 mcf) is equal to 991,130 BTUs, so that the price in mcf and BTUs is almost identical.

Middle East. However, there are many other potential suppliers, such as Trinidad and Australia.

Wherever the source, it is unlikely that long-term contracts will be feasible at the going spot price for LNG. The notion that ocean carriers will be re-directed from one destination to another because the spot price has shifted (as suggested by Yergin) is fanciful. The capital investment by both seller and buyer will be so great that infrastructure will not attract financing unless there are irrevocable take-or-pay contracts covering the period required to amortize the investment, or unless prices are indexed in contracts. These principles will apply to most energy contracts that seek to guarantee the delivery of a stable supply of power or fuel to consumers.

Why Coal Is King

The global market for thermal coal will have relatively little to do with Canada's energy policies in the future. Substantial imports of U.S. coal to Ontario will be phased out if the province proceeds with its decision to shut down its seven coal-fired plants beginning in 2007.[11]

Whether this policy is executed as planned depends on the speed with which alternative sources come into production. There are minor imports of thermal coal to Nova Scotia and New Brunswick, and minor exports from British Columbia. Alberta and Saskatchewan, however, have relatively large and accessible coal resources, which are the primary source of energy for 66 percent of electricity in Alberta and 54 percent in Saskatchewan. Rather than phase out coal, private and public companies in those two provinces are concentrating on reducing pollutants using improved technology now in operation in Europe and the United States.

Coal supplied 24 percent of the world's primary energy in 2001 (EIA 2004), and is expected to still supply 24 percent in 2030. The IEA forecasts a growth rate in world coal production of 1.4 percent per year for the next three decades. Even its forecast for North America shows a steady increase in output, at 0.6 percent per year — with over 95 percent of this in the U.S. China and the rest of Asia are dominant suppliers and consumers in the present coal market, and will be even more so in the future (Table 13).

World reserves of coal are large enough to maintain the current rate of consumption for over two centuries. British Petroleum estimates that world reserves are 984 billion metric tonnes, of which 465 billion are thermal coal (BP 2004). Thermal coal powers generators and 90 percent of the growth in the world's coal production to 2030 will be for that purpose. The projected world production of 3,606 mtoe of coal in 2030 places it third among the sources of primary energy. For power generation alone, coal will still rank first in 2030 (Table 14).

Even in the United States and Canada, the IEA reckons that coal will still be the most important source of energy for power generation. In 2000, the U.S. and Canada together obtained almost 49 percent of their power generation from coal. By 2030, the IEA forecasts that the two countries together will still derive almost

11 But the NEB's scenarios to 2025 provide for the construction of new coal-fired plants in Ontario.

Table 13: *Primary Supply of Coal in 2000 and 2030*

	2000	2030
	(mtoe)	
North America	579	685
China	659	1278
Other Asia	281	655
World	2355	3606

Source: IEA 2003.

Table 14: *Projected Energy Consumption by Source, 2030*

	Oil Equivalent	Share of total
	(million tonnes)	(%)
Coal (for electricity generation)	2656	41
Oil	311	5
Gas	2032	31
Nuclear	703	11
Hydro	366	6
Other Renewables	466	7

Source: IEA 2003.

42 percent of power generation from coal, but this forecast does not take account of Ontario's plans to phase it out. The EIA projects growth in U.S. demand to 2025 at 1.3 percent per year.

The sustained U.S. dependence on coal causes a problem for Canadian policymakers. Air pollution — smog and acid rain — come mainly from nitrogen oxides and sulphur dioxide, although there are other contributors such as mercury. The coal plants in Ontario contribute about 15 percent of domestic nitrogen oxide emissions, and 24 percent of domestic sulphur dioxide emissions. About 55 percent of the pollutants in Canadian air originate in the United States, while 45 percent are domestic. Thus, 15 percent of 45 percent, or 7 percent of nitrogen oxide emissions in Ontario are from the Ontario coal plants and 11 percent (25 percent of 45 percent) from sulphur dioxides. Shutting down the coal plants to reduce air pollution will not accomplish the stated goal. Canadian policymakers should reconsider the tradeoff between the cost of replacing the coal-fired plants entirely and the cost of modernizing the existing plants.

Hydro Power

Hydro accounts for 3 percent of the global supply of primary energy, and the IEA expects it to decline to 2 percent by 2030. Most of the feasible sites for backing up water behind huge dams have been exploited in the developed world. There are still some relatively large sites in the developing world, but the challenge to using them is the displacement of millions of people along the world's major rivers. This did not stop the development of the Three Gorges Dam on China's Yangtze River.

The Chinese government weighed the upheaval of about one million citizens against the ultimate power output of 18,200 megawatts, and chose to proceed.[12]

For the most part, hydroelectric power does not enter into world trade because it is limited by the location of the dam sites and the transmission distance to markets. The export market from Canada to the United States is an exception to the rule. In 2002, Hydro Quebec sold over $3 billion of hydro power to New England and New York. (Hydro Quebec 2003a). In 2003, sales fell to $1.35 billion, or 12 percent of total revenue (Annual Report 2003). Whether this will continue depends on domestic requirements in Quebec, which have first call on capacity. This export market was made possible by leading-edge technology that enabled Hydro Quebec to transmit large volumes of power from remote sites.[13]

In its current five-year plan, Hydro Quebec lists a number of sites which it plans to develop. Having settled on its own medium-term and longer term requirements, Hydro Quebec might agree to export power to Ontario from its undeveloped sites. In that case, policymakers would have to write long-term contracts, probably indexed to energy prices, which would shift the burden of risk to the buyer. Short-term contracts, based on spot prices for peak load requirements of the consumer, would not interest a supplier who wants to build a multi-billion-dollar dam. If the seller were to commit to a stable supply (unless disrupted by severe weather conditions), a contract would probably include some shared responsibility for the financing.

Manitoba and British Columbia also export power to the United States. British Columbia has a substantial market in California and the northwest states. Incremental growth of exports to the United States does not appear to pose policy problems. In the case of Manitoba, the Nelson River is 3,400 kilometres from Toronto. To reach the populous Ontario market, Manitoba exports would have to be fed into the grid in Minnesota.

The Nuclear Power Puzzle

Recently, nuclear power became the fourth most important source of primary energy, after the three big fossil fuels. But its acceptability as a source of energy has been declining in many countries, including Canada. Still, recent developments indicate that Canadian policymakers should carefully weigh any recommendations to eliminate nuclear power. The rising cost of fossil fuels and the fact that nuclear technology is improving in safety and efficiency are the main reasons for preserving nuclear power as an option.[14]

Certainly, nuclear generation is a branch of the industry that is fraught with problems that go beyond the production of power. There is the issue of nuclear

12 This output is equivalent to the production from 25 nuclear power reactors of the Candu size near Shanghai.

13 The direct-current lines are 735 kilovolts feeding directly to the U.S. utilities, where they are transformed to alternating current, and not part of the northeast power grid.

14. On March 18, 2004, the Ontario Power Generation Review Committee submitted its report to the Minister of Energy of Ontario. Its basic recommendation is to pursue nuclear development, partly by proceeding with the refurbishment of a second Pickering A reactor, and partly through forming public-private partnerships to build nuclear reactors employing the improved technology now considered available.

weapons proliferation, as well as widespread concern that safety standards have been slack, with too many incidents of sloppy management. There are also unresolved problems of waste disposal as well as the inability of the nuclear power industry to provide regulators with credible evidence that their capital costs and plans for life expectancy are actually realized.

As a result, there is a sharp division of opinion on the global outlook for nuclear energy. The IEA foresees a decline in its share of power generation to 9 percent in 2030 from 17 percent in 2000. Some countries in Western Europe, including Sweden, Germany, Italy, Austria and Belgium, are planning to phase out nuclear power by 2020. At the other extreme, France has 58 nuclear power stations which account for over 75 percent of its electricity production. Finland has just committed to a French nuclear reactor at a cost of $3.72 billion. Britain is downsizing nuclear power to 9 percent in 2025 from about 20 percent of current power production. The United States still has 104 nuclear reactors, though there have been no new orders since the Three-Mile Island near-disaster in 1979. The existing plants produce about 20 percent more electricity than 25 years ago as a result of improved safety and efficiency.

Both the IEA and the EIA forecast strong growth in nuclear power in the Far East. Japan, China, Korea, Taiwan and India are all building reactors. Japan shut down 19 of its nuclear power plants in 2003 because of concern about their safety, though it plans to restore them and build more plants.[15] China, which had only three nuclear plants in 2001 is planning a rapid expansion, using technology from several countries to speed the development of its domestic capacity. Its first two plants were of French design, but in 2003 it commissioned two advanced Candu-6 reactors near Shanghai with a total capacity of 1,456 MW (EIA 2004). These were built by an international consortium at a cost of $3.9 billion, completed within budget and ahead of schedule (Ross 2002). In contrast to the previous generation of heavy-water reactors, the new, mostly light-water design of the Candu-6 generation, called the ACR-700, appears to be significantly cheaper, safer and easier to manage.

The global impact of nuclear power on Canada will be determined by the record of the new reactors in terms of timely construction, economic maintenance and safety. Because of the growing recognition that the price and availability of natural gas may discourage its use to fuel the generation of electricity, nuclear power may once again be perceived as a viable alternative to fossil fuels. The immediate challenge for energy policymakers will be to assess the option of commissioning new reactors — preferably at unpopulated locations — against the uncertain costs and timing of rebuilding old ones.

Canada will also have a role in the global nuclear power industry as a supplier of uranium and new-generation nuclear reactors.

Wind, Sun and Hydrogen

Necessity is the mother of invention, and the global energy situation is an ideal place to observe the phenomenon. Global demand for energy will outstrip the

15 Seven reactors had been restored by March 2004.

supply, with 85 percent of the world's population aspiring to the living standards of the other 15 percent. Human ingenuity is already demonstrating that alternative solutions will be found by harnessing the wind and the sun, and overcoming the critical electricity storage problem through fuel-cell technology. But translating technological triumphs into real-world economics is not simple. Green Power is mostly subsidized, and the challenge will be to bring it to commercial feasibility. With the rising price of fossil fuels, the commercial gap is already narrowing.

There are serious financial obstacles in the path of wind power, however. Canadian policymakers should study the various innovative proposals already employed in other jurisdictions to promote wind technology, as well as other renewable energy sources such as solar power and biomass. Many jurisdictions, notably Scotland and some U.S. states, are forcing the issue by requiring electric power generators to produce or buy in the market as much as 10 percent of their output from renewable resources, of which wind is the most prominent. Ontario is seeking 1,350 megawatts (MW) of renewable energy — about 5 percent of total capacity — by 2007.

Wind power is currently most developed in Germany, Spain and Denmark. Western Europe has about 20,000 MW of operating capacity feeding into the grid. In the case of Denmark, 2,500 MW were already installed by 2001, and the target is 5,000 MW. The government is contemplating the withdrawal of subsidies for wind power. Denmark has some special advantages: lowland coastal sites that do not attract environmental opposition (as is the case in Nantucket Sound); a strong and constant wind, and a short distance to the main market, keeping transmission costs low.

In Canada, most provinces have pilot projects for wind turbines. Saskatchewan has a 150 MW wind project that cost C$250 million or C$1.67 million per MW. In Ontario, there are seven relatively large wind turbines, one at Pickering, one on the Toronto waterfront, and five that are operated by Huron Wind, a green subsidiary of Ontario Power Generation (OPG) and Bruce Power. The total wind capacity in Ontario is about 11.5 MW but there is not sufficient data available to measure the cost.

Most land-based systems experience 50 percent-to-60 percent downtime because of lack of sufficient wind and suitable sites are often far from markets. The capital investment required is still high compared to the alternatives. There are some benchmarks of capital costs per MW of capacity that do not cover operating costs or transmission costs:

- TransAlta Corp. has two wind farm sites in Alberta, with a combined cost of C$195 million, and capacity of 143 MW, for an average cost of C$1.37 million per MW.
- TransAlta invested C$490 million in a Sarnia, Ontario, co-generation gas plant, which joined the grid in 2002 with a capacity of 575 MW. The cost was C$0.85 million per MW and the site is relatively close to the market (TransAlta, 2003).
- OPG sold 488 MW of hydro power to the private sector in 2002. At C$342 million, the market value of the hydro power sold was C$0.70 million per MW.

Capturing energy from the sun through photovoltaic cells is an established technology. Millions of Japanese homes have solar panels on their roofs, mainly to heat water. Similar applications are found world-wide. But the large-scale production of solar power (and wind power) to displace fossil fuels will depend on solving the problem of storing energy. Fortunately, a technological solution exists through the manufacture of hydrogen. Most hydrogen is currently obtained from natural gas, although other fossil fuels can be the primary energy source.

About 4 percent of hydrogen is produced by electrolysis, which splits water into hydrogen and oxygen, leaving no carbon emissions. The difficulty with electrolysis is the relatively high cost of the electricity required, which makes this method of producing hydrogen about four times the cost from natural gas, which itself is a process several times costlier than using fossil fuels. A major challenge is to harness large amounts of solar energy (and other forms of energy, such as nuclear) to provide the electricity for large-scale electrolysis projects. The creation of hydrogen fuel cells in great quantity would ease the problem of storing electricity and transporting it from equatorial deserts to major markets.

The distribution of generating capacity into relatively small units would moderate the growing complexity and interdependence of the electricity transmission grid. Although much attention has been paid to fuel cell technology for motor vehicles, policymakers should consider the merits of fostering small, stand-alone generators to back up vital facilities such as hospitals and central communication systems. Such generators could feed into the grid, but in the case of a blackout, could be dedicated to specific critical functions. The real possibility of chronic power outages, with their deleterious effect on public health and safety, suggests that further government assistance for fuel cell research should be a priority. The cost of generating power from fuel cells by electrolysis is still 10-to-12 times higher than from conventional sources, and the potential benefits from improved technology vary.

Conclusion

Global forces will increasingly influence Canada's energy policies. Currently, the most pervasive influence is the world price of oil. This *Commentary* argues that official forecasts of the global price of oil overestimate the prospects for increased production and underestimate the political and economic risks of delivering output to world markets. These misleading forecasts seriously underestimate the future price of oil and natural gas (as current events demonstrate) and the cascading effects of their prices on other energy sources.

The priority for those dealing with Canadian energy policy is to reconsider their underlying assumptions about the real price of oil and gas. There will have to be a greater emphasis on promoting oil sands development and offshore oil exploration. Government policies to facilitate the job of the private sector in the exploration for natural gas in the Mackenzie Valley and the Arctic, and the financing of pipelines, should also be a high priority.

Reserves of proven conventional oil and gas are declining in both Canada and the United States. North America faces the prospect of declining domestic production until new resources can be found and developed in the North, in offshore deepwater sites, or in unconventional forms, such as oil shale and coal-bed methane. There is certain to be a hiatus of five years or more until this happens and policymakers must focus on this period. In particular, the public should not be sheltered from the full impact of rising prices in the market, which is the effective route for curbing demand.

The contribution of oil sands development to the North American supply of oil will be important, though modest. Relatively large capital expenditures and production costs will add perhaps two million bpd to the present 900,000 in a span of six years. In the context of global production of 80 million bpd, and U.S. imports of 12 million bpd or more, the oil sands will make a limited contribution. Policymakers will have to address the options in closing the gap between growing demand and future supply from offshore. This will involve developing facilities for importing LNG from Russia, Qatar or elsewhere. Governments should facilitate the private sector in finding suitable sites which are relatively secure, both for Canadian imports and as a staging point for U.S. imports.

The implications of a declining Canadian capacity to export oil and gas to the United States are serious for the Canadian balance of payments and for the Canadian dollar. This is a major reason to press forward with oil sands and northern gas development.

Governments should strive to broaden inter-provincial trade in hydroelectric power. For the longer run — perhaps in a decade — government support of fuel cell research for electric power generation should remain.

A major policy issue that has to be addressed is the postponement of premature decisions to phase out coal and reduce dependence on nuclear power before alternative sources of energy are in place. Those who are concerned about the effect of coal-fired power on public health should contemplate the more serious effects on public health of a blackout.

Although there is a widespread inclination to de-emphasize nuclear power, the business case for its reinstatement as a source of new electricity generation has recently been made forcefully by the Manley Committee in Ontario. Weighing the choice between investing further capital in old nuclear reactors or embracing a new generation of reactors which are cheaper, more efficient and safer, is a process which is already occupying government authorities. Conservation will be accomplished most effectively by allowing market prices to guide behaviour. In Ontario, the target of reducing electricity consumption by 5 percent by 2007 is probably achievable.

But the sure way that demand will respond to the growing pressure on supply is through prices. This was demonstrated earlier in this paper in the contrast between the profligate use of gasoline in the United States, compared with Britain. While there will be strong consumer resistance to rising energy prices, in time consumer behaviour will adapt to reality. Canadians in their cold climate have a splendid opportunity to prove the case.

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