# 2010 Natural Gas Market Review

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**Submitted to:**

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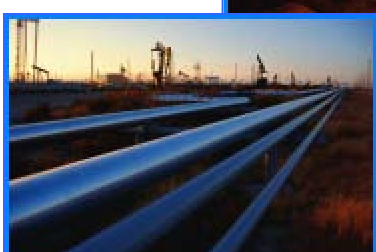

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# Glossary

| | |
|---|---|
| Bcf | Billion cubic feet. A measured volume of natural gas. |
| Bcfd | Billion cubic feet per day. A measured volume of natural gas. |
| Capacity | For electricity: The maximum amount of electricity a device can generate, use or transfer, usually expressed in megawatts. |
| | For natural gas pipelines: The maximum volume of natural gas a pipeline can transport within a given time period, usually expressed in billions of cubic feet per day (Bcfd). |
| CBM | Coal bed methane. A form of natural gas extracted from coal beds. |
| Combined Cycle | The production of electricity using combustion turbine and steam turbine generating units simultaneously. |
| Combustion Turbine | A rotary engine that extracts energy from the flow of combustion gases. |
| Conventional Natural Gas | Natural gas contained in high porosity geologic formations and produced by flow into standard well bores through conventional drilling techniques. |
| Energy Intensity | The amount of energy used per unit of measurable output or reference. |
| Hydraulic Fracture | Also referred to as “fracking”, a technique in which fluids are injected underground at pressure to create or expand fractures in underground formations, allowing natural gas to flow out of the formation. |
| GDP | Gross Domestic Product is measure of economic activity representing the market value of all goods and services within a specific time period. |
| GHG | Greenhouse Gas |
| Gross Output | Value of GDP plus consumption of intermediate products, services and materials. |
| GW/MW | Gigawatts/Megawatts, a measure of power, or energy conversion. |
| GWh/MWh | Gigawatt hours/Megawatt hours, a measure of energy. |
| IESO | Independent Electricity System Operator |
| LNG | Liquefied Natural Gas. Natural gas in its liquid form, typically after cooling processes reduces its volume by more than 600 times to accommodate efficient transport. |
| MMBtu | Millions of British Thermal Units; a measure of energy typically used for the pricing of natural gas. On average, natural gas |

| | |
|---|---|
| | contains 1030 Btu per cubic foot, so one MMBtu is equal to about 970 cubic feet. |
| MMcf | Million cubic feet; a measured volume of natural gas. |
| OPA | Ontario Power Authority |
| OPG | Ontario Power Generation |
| Reserves | The estimated remaining marketable quantities of fossil fuel and related substances recoverable from known accumulations. |
| Rig | A drilling rig is a machine that creates boreholes and/or shafts in the ground for the exploration and extraction of fossil fuel resources. |
| Shale Gas | A continuous and usually low-grade accumulation of natural gas contained in rocks such as shale. |
| Tcf | Trillion cubic feet; a measured volume of natural gas. |
| Unconventional Natural Gas | Natural gas contained in other geologic formations not considered conventional and produced using novel drilling and extraction techniques. Examples include CBM, tight gas, shale gas and gas hydrates. |

# Executive Summary

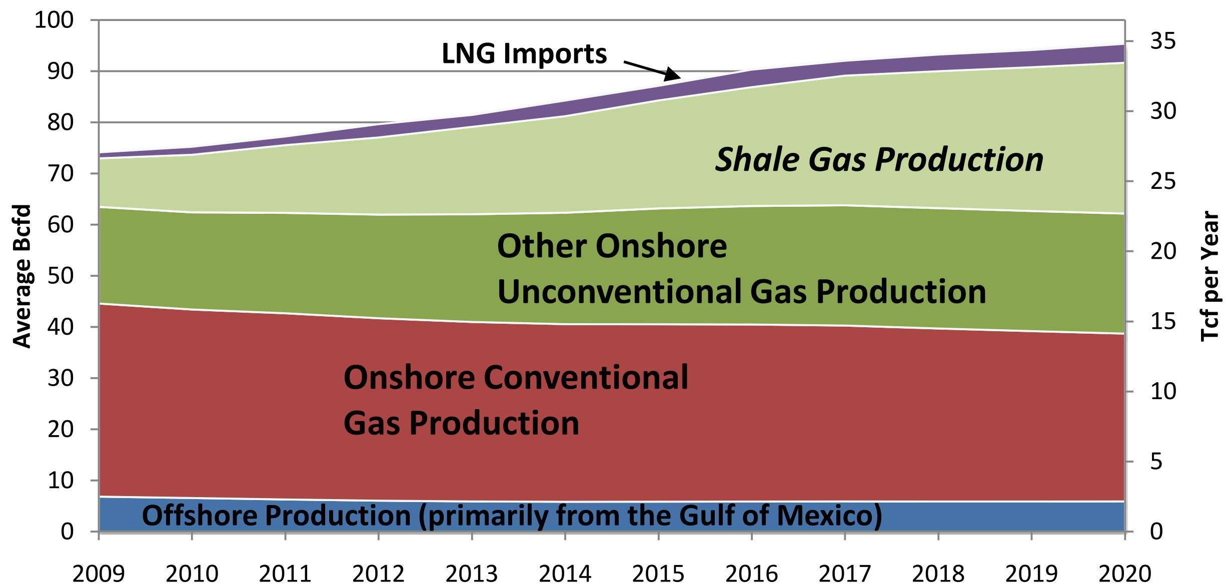
The Ontario Energy Board (OEB) is currently initiating a stakeholder process that will review and examine changes in the North American natural gas market to better understand the implications for Ontario's market. To begin the process, the OEB commissioned ICF International to prepare a review of the North American market. The report emphasizes the importance of the growth in unconventional gas supplies, expectations for gas demand growth, changes to gas pipelines and storage, the impacts of supply and demand changes on natural gas price, and how all these market changes may impact the Ontario gas market.

***The Changing Supply-Demand Balance***

The North American natural gas market underwent a fundamental shift in the last decade. Through the 2000s, as conventional production declined, demand increased, driven largely by the increasing use of natural gas for electricity generation. This tightening supply-demand balance caused natural gas prices to rise sharply. As gas prices rose, investments in gas exploration and production increased, particularly investments in unconventional gas resources like shale gas.

ICF estimates that the total North American natural gas resource base is over 3,700 trillion cubic feet (Tcf), enough to last over 100 years at current consumptions levels. Gas in shale formations makes up over 50 percent of the total resource base. The development of shale gas resources is a "game changer" for the North American natural gas market. Even though it is relatively new, shale gas has already become a significant component of total production, accounting for 13 percent of the total North American gas supply in 2009. By 2020, shale gas is projected to grow to over 30 Bcfd (10.8 Tcf per year) and account for over 30 percent of the total supply (Exhibit ES 1).

**Exhibit ES 1: Projected U.S. and Canadian Gas Supplies by Type, 2009-2020**



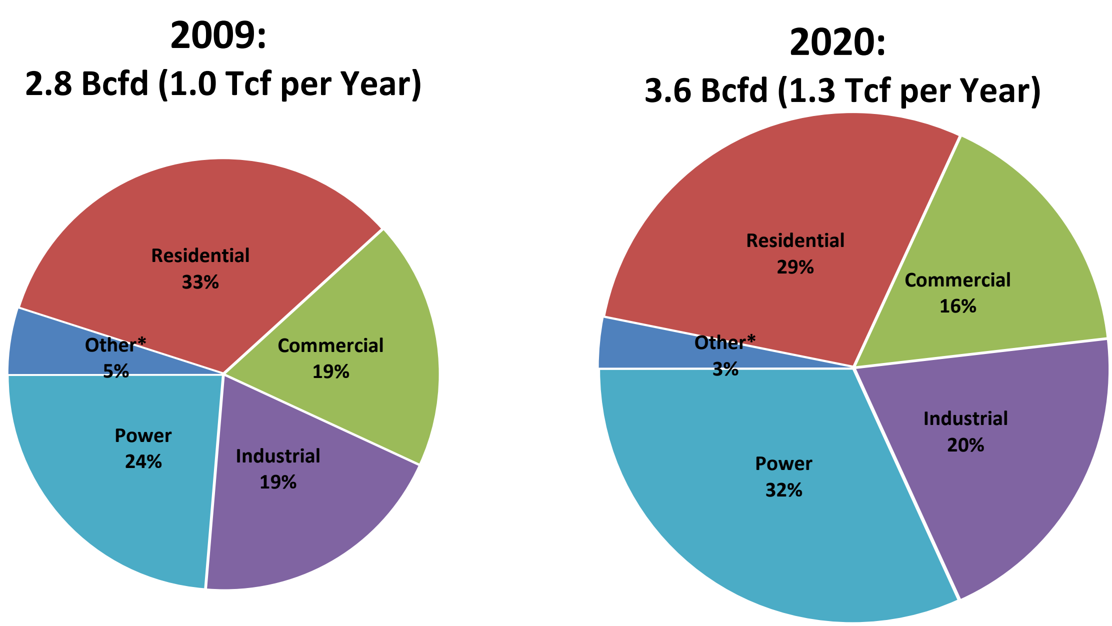

Source: ICF

***The Shifting Demand Profile***

With relatively modest growth expected in the residential, commercial, and industrial sectors, gas demand for electricity generation is expected to continue as the leading source of gas demand growth, both for North America as a whole and for the Ontario market. By 2020, total North American gas demand is projected to increase by 30 percent to 94 Bcfd (34.3 Tcf per year), and two-thirds of that incremental increase is expected to come from growth in the power sector.

In the Ontario market, the policy initiative to remove over 6,000 MW of coal-fired capacity from the electricity generation sector is expected to be a major driver of gas consumption growth. ICF projects that a substantial amount of new gas-fired generation will be needed to offset coal losses, support increased development of intermittent renewable resources, and support the refurbishment or replacement of aging nuclear assets. By 2020, the power sector is projected to increase to nearly one-third Ontario's total gas demand (Exhibit ES 2).

**Exhibit ES 2: Ontario Natural Gas Demand by Sector, 2009 and 2020**



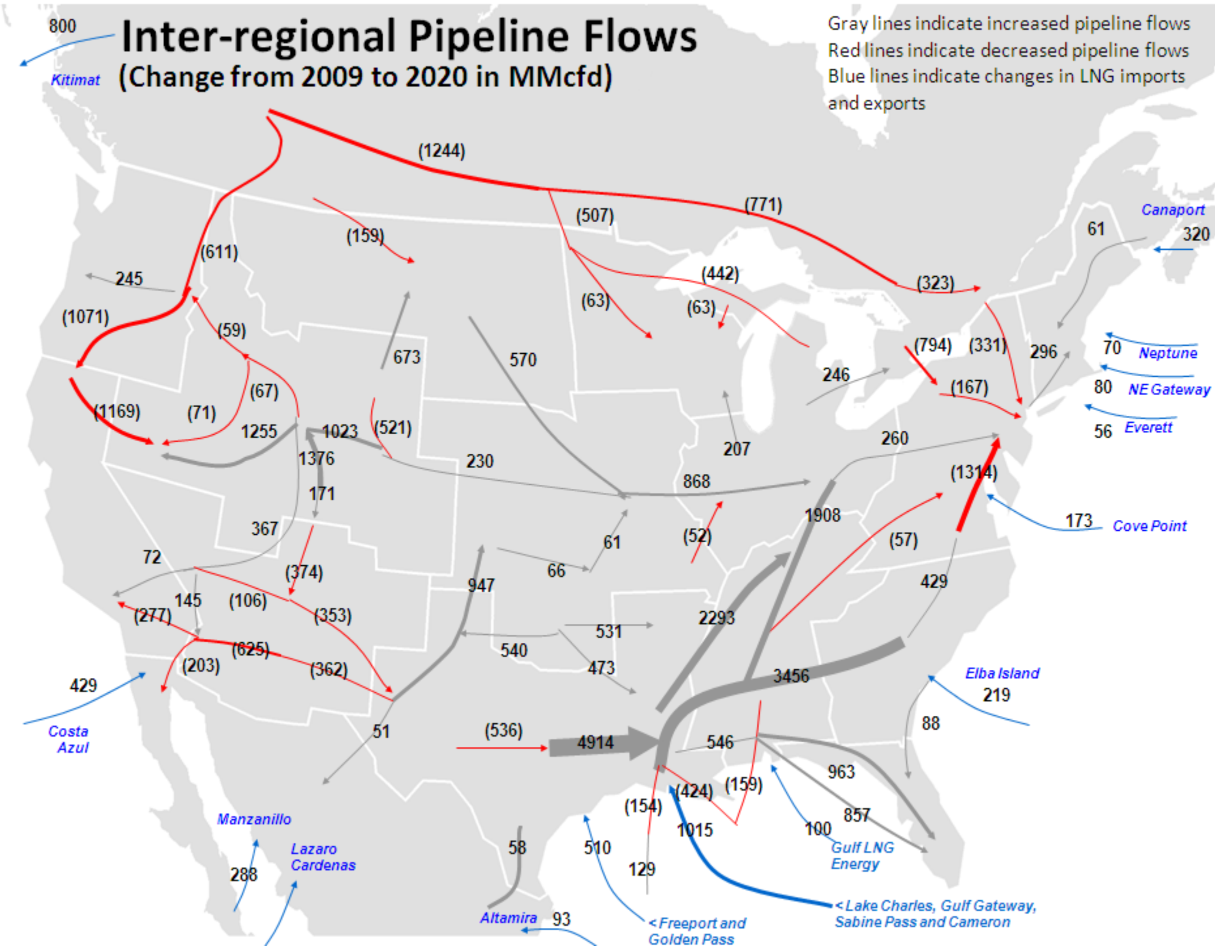

* Other includes Pipeline Fuel and Lease and Plant gas use

Source: ICF

***Change in Supply and Demand, Yield Changes in Inter-regional Pipeline Flows***

As gas production continues to shift to unconventional supply resources and regional gas demands change, inter-regional flows on pipelines are also projected to change (Exhibit ES 3). Traditional supply sources like the Gulf of Mexico Offshore and conventional production in Western Canada are projected to decline, which decreases flows from these areas. In the U.S., new gas pipelines have been built to carry newly developed supplies from the Rockies and mid-continent shale plays to downstream markets both east and west. The growth of gas production from the Marcellus Shale, which stretches across West Virginia, Pennsylvania, and New York, is expected to displace some pipeline flows from Canada and the Gulf Coast into the Northeast U.S.

**Exhibit ES 3: Projected Changes in Inter-regional Pipeline Flows, 2009 to 2020**




Source: ICF

***Ontario's Future Gas Supplies***

Changes in Ontario's gas supplies are projected to generally reflect the overall changes in North American gas production (Exhibit ES 4). While Western Canada is expected to remain the largest single supply source for Ontario through 2020, both the absolute volume and share of total supply are projected to continue to decline. Conventional production in the Western Canadian Sedimentary Basin (WCSB) has been declining for some time, while at the same time gas demand in Alberta from oil sands projects has been increasing. This has resulted in less gas moving eastward on the TransCanada Pipeline (TCPL). The trends in WCSB conventional gas production and oil sands gas consumption are projected to continue, further reducing the flows on TCPL in the future.

As the flow from Western Canada declines and Ontario's demand for natural gas increases, it will need supplies from other sources. Shale gas is expected to play a critical role in providing new gas supplies to both replace declining conventional production and support demand growth. By 2020, shale gas is projected to account for nearly 30 percent of Ontario's total gas supply. While production from the Marcellus Shale is not projected to be a major direct source of supply for Ontario, it does play a critical role in the overall supply outlook. Much of the gas that currently flows on TCPL is destined for the Northeast U.S. Gas production in the Marcellus

Shale displaces the need for exports to the Northeast U.S. Therefore, even if the flows on TCPL decrease over time, more of the gas that does flow can stay in Ontario rather than being exported to U.S. markets. Also, increasing Marcellus Shale production is projected to create some flow of gas back from Niagara, New York, into Ontario in the spring and fall when Northeast U.S. gas demand is low. While the net annual flow of gas is still expected to be toward New York, the seasonal flow of gas from Marcellus helps to fill natural gas storage at Dawn, which is critical to meeting Ontario's peak winter demand.

**Exhibit ES 4: Ontario's Projected Gas Supplies by Source, 2009 to 2020**

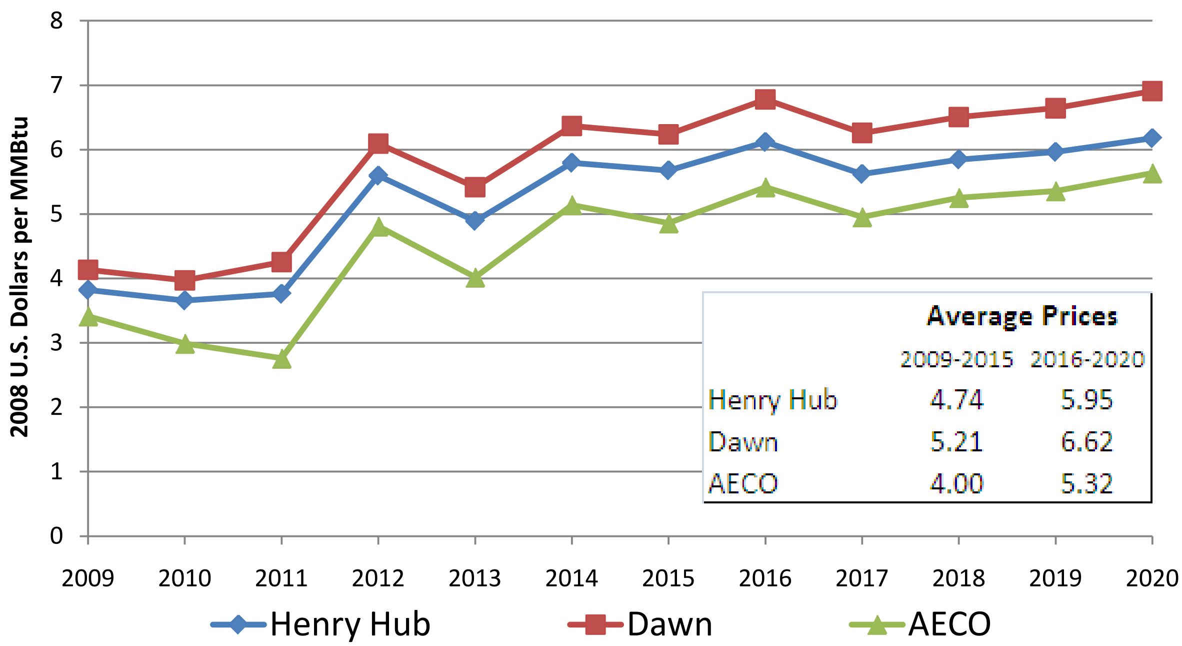
| | Supply (Bcfd) | | | As Percent of Total | | |
|---|---|---|---|---|---|---|
| **Supply Source** | **2009** | **2015** | **2020** | **2009** | **2015** | **2020** |
| WCSB (non-shale) | 1.66 | 1.60 | 1.49 | 58.9% | 46.8% | 41.1% |
| Western U.S. | 0.37 | 0.47 | 0.51 | 13.1% | 13.8% | 14.0% |
| Midcontinent U.S. | 0.28 | 0.39 | 0.38 | 10.0% | 11.4% | 10.4% |
| Midwest U.S. | 0.17 | 0.17 | 0.16 | 6.1% | 5.1% | 4.3% |
| Haynesville Shale | 0.11 | 0.23 | 0.31 | 3.9% | 6.9% | 8.6% |
| Fayetteville Shale | 0.09 | 0.19 | 0.26 | 3.0% | 5.6% | 7.1% |
| Barnett Shale | 0.06 | 0.07 | 0.06 | 2.2% | 2.1% | 1.7% |
| Woodford Shale | 0.05 | 0.09 | 0.12 | 1.7% | 2.8% | 3.2% |
| Western Canada Shale | 0.01 | 0.14 | 0.27 | 0.5% | 4.2% | 7.5% |
| Marcellus Shale | 0.00 | 0.00 | 0.04 | 0.0% | 0.0% | 1.2% |
| Ontario Production | 0.02 | 0.02 | 0.02 | 0.6% | 0.5% | 0.5% |
| All Other U.S. | 0.00 | 0.03 | 0.02 | 0.0% | 0.8% | 0.4% |
| *Shale Gas Subtotal* | *0.32* | *0.74* | *1.06* | *11.3%* | *21.6%* | *29.3%* |
| **Total Supply** | **2.83** | **3.41** | **3.63** | **100.0%** | **100.0%** | **100.0%** |

Source: ICF

### *Outlook for Gas Prices*

Natural gas prices are driven by changes in supply and demand over time, and by the changes in inter-regional pipeline flows. ICF projects an environment with growing gas demand, which requires continuing development of new supplies. North America has an ample gas resource base, but developing the resource requires continued investment to keep pace with demand growth. Thus, the continued growth of demand places upward pressure on natural gas prices. While gas prices are not expected to rise as high as their pre-recession peak, they are projected to rebound to a level that support continued development of the supplies necessary to satisfy the increasing gas demand. Through 2020, average annual gas prices at Henry Hub are projected range between $5.00 and $6.00 per MMBtu (in 2008 U.S. dollars). Gas prices in Ontario are expected to track Henry Hub prices, with prices at Dawn prices averaging between $5.20 and $6.60 per MMBtu, or about $0.50 to $0.70 per MMBtu above the Henry Hub average (Exhibit ES 5).

**Exhibit ES 5: Regional Average Annual Gas Prices, 2009-2020**




Source: ICF

***Summary of Key Findings***

*Demand for Natural Gas is Expected to Continue Growing, Led by Growth in the Power Sector*

- Total North American demand for natural gas is projected to continue growing, led by growth in the power sector.
- Ontario's power sector gas use is also expected to continue growing, climbing to nearly one-third of total demand by 2020.
- As power generation becomes a large part of natural gas demand, seasonal and daily use patterns will change.  These changes could place stresses on Ontario's pipeline and storage infrastructure.

*Supply Sources and Inter-regional Pipeline Flow Patterns are Changing*

- Unconventional gas resources, including shale gas, are expected to make up over 50 percent of total gas supply by 2020.
- Shale gas is expected to be the principle source of growth in North American gas supplies.
- Many shale resources, such as the Marcellus Shale, are located in geographically different regions than historic supplies. These shifts in supply sources will impact pipeline flows and the development of new pipeline capacity.
- Conventional gas production in Western Canada is expected to continue declining, and gas demand in Alberta for oil sands projects is expected to continue increasing.  This is expected to cause TCPL's mainline flows to continue decreasing.
- While Western Canadian gas (delivered via TCPL) is expected to remain the largest single supply source for Ontario, it is expected to decline both in absolute terms and as a as a share of the total supply.

- As a result of the decline in Western Canadian production, an increasing share of Ontario's gas supplies is expected to be met by gas from the U.S., especially shale gas.
- While Marcellus Shale production is not projected to be a major direct supply source for Ontario, it is projected to displace some exports of gas from Ontario to the Northeast U.S., allowing a greater share of gas transported on TCPL to remain in Ontario.

*Natural Gas Prices are Projected to Increase*

- Projected demand growth, principally from growth in the power sector, will drive North American gas prices higher.
- While gas prices are not expected to reach the very high levels seen in the mid- to late-2000s, average annual Henry Hub prices are projected to rebound to $5 to $6 per MMBtu.
- Given the ample North American resource base, the projected gas prices are adequate support continued development of the supplies necessary to satisfy the projected demand growth.
- While changes in supply and demand conditions are important in the determination of Ontario's gas prices, so are policies that impact TCPL's rate structure. The response to projected reductions in TCPL mainline flows is a critical issue for Ontario gas consumers.

***Key Uncertainties Which Could Affect the Projection***

- As environmental concerns grow and policy initiatives in both Canada and the U.S. gain traction, coal-fired power plants may be retired more quickly. In the case, gas use in the power sector may increase more rapidly than projected.
- A more aggressive approach to promoting the use of renewable energy resources to replace existing fossil fuel generation may decrease projected growth in gas-fired generation. However, gas will likely still play an important role in the power sector by providing firm generation to support intermittent renewable sources such as wind.
- Concerns have been raised about the environmental impacts of hydraulic fracturing, a technique used to produce shale gas. If regulation of hydraulic fracturing becomes more stringent, this could slow the growth of shale gas production.
- If economic growth in the U.S. and Canada is slower than projected, this would have negative impacts on gas demand growth, particularly in the industrial and power sectors. If industrial output continues to decline, this would reduce gas consumption. Likewise, reduced economic growth would imply less growth in demand for electricity, which would lead to less gas-fired generation.

# 1. Introduction

In light of the growing importance of unconventional gas supplies (particularly shale gas) in the North American market, the Ontario Energy Board (OEB) saw a need to review and examine changes in the North American market to better understand potential implications for Ontario's natural gas market. This report, prepared by ICF International, is intended to help focus discussions with stakeholders in this review process.

As stated in the OEB's 2010-2013 Business Plan, the overall objective of this initiative is to confirm that natural gas markets in Ontario are able to respond and adapt to changing market conditions. Through this process, the OEB will assess the impact of changing dynamics in the North American natural gas supply market on Ontario.

A specific objective of this initiative is to assess the need for regulatory changes, if and as appropriate, in response to changes in North American natural gas supply markets. In this report, we seek to identify and describe emerging trends in the broader North American market and their implications, particularly for the Ontario market and the surrounding markets. This report will help focus discussions with interested stakeholders in this Review. The market report will include, among other matters:

- identification of emerging North American trends in natural gas supply and demand;
- impact analysis of shale and other unconventional gas plays on Ontario market; and
- identification of trends in regulation and policy development in other jurisdictions and a discussion of potential impacts to Ontario.

This report is divided into five sections. The Executive Summary (above) provides a brief description of the report's findings and conclusions. Section 1 is this introduction. Section 2 is an overview of the recent history of the North American and Ontario gas markets. Section 3 is the main body of the report, containing a forward looking analysis of the changes that are continuing to occur in the North American and Ontario gas markets. Section 3 is divided into four subsections: Demand Trends, Supply Trends, Gas Pipeline and Storage, and Gas Prices and Basis. Section 4 summarizes the report's conclusions.

The natural gas market projections provided in this report are based on analysis from the *Gas Market Model* (GMM), ICF's proprietary model of the North American natural gas market. A description of the GMM is provided in the Appendix.

# 2. Overview of Recent Market Conditions

In ICF's projection, the future environment for the U.S. and Canadian natural gas market is one where the supply and demand balance remains relatively tight. After the 2008–09 recession, total gas demand is projected to grow robustly, led by growth in gas demand in the power sector. While new supplies such as shale gas are being developed, growth of domestic production will still be pressed to keep pace with growth in demand. As a result, gas prices are likely to increase from current levels, though they are not expected to reach the unusually high levels seen in the mid-2000s.

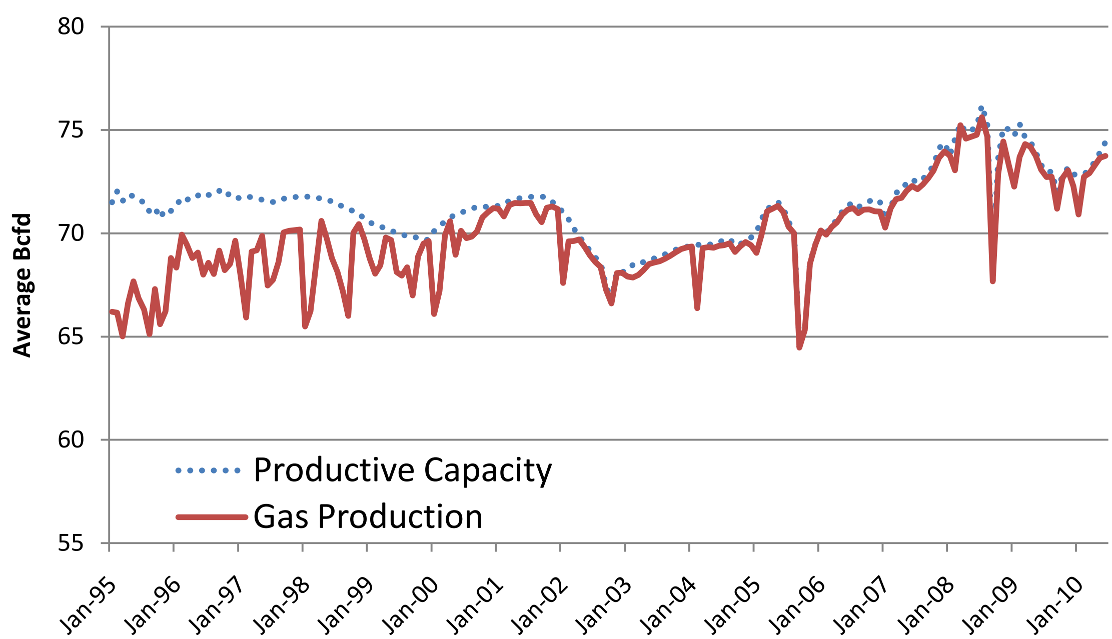
In this section, we first discuss recent historical changes in the North American natural gas market: demand growth, shifts in sources of gas supplies, changes in inter-regional pipelines, and changes in gas prices and basis. In the second part of this section, we focus on changing conditions in the Ontario market.

## 2.1 The North American Market

### 2.1.1 North American Gas Market Shift

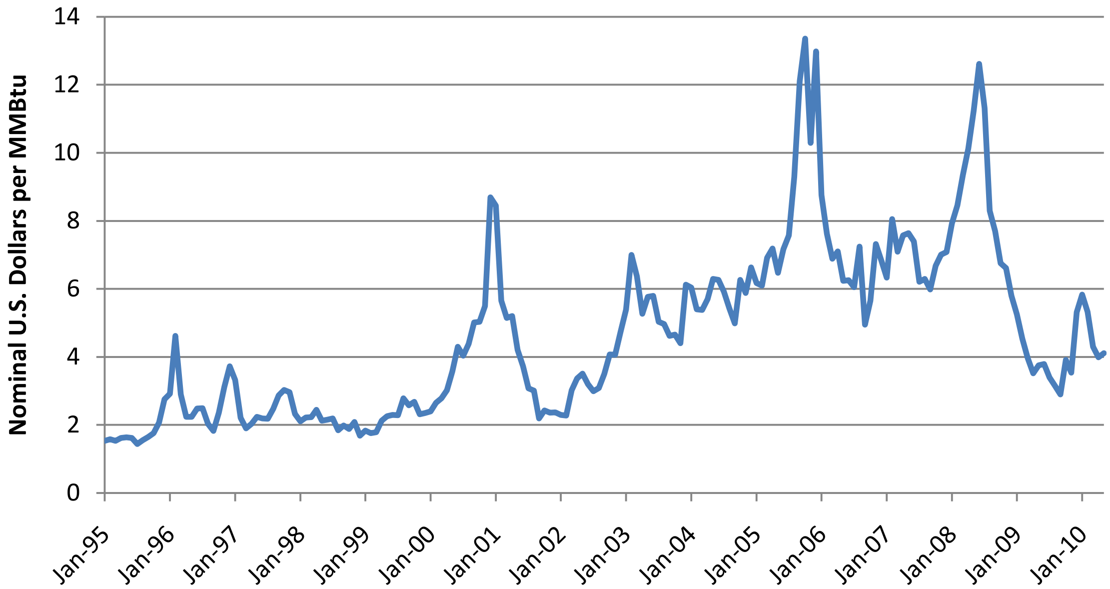
The North American natural gas market underwent a fundamental shift at the end of the 1990s. Through the mid-1990s, natural gas production was significantly lower than the productive capability of all the wells in service (Exhibit 1). With more productive capacity than demand, producers effectively bid against each other to sell gas into the market. ICF typically refers to this situation where there was an excess of productive capacity relative to the size of the demand market as a "gas bubble." This excess of productive capacity kept natural gas prices relatively low and stable through the mid-1990s (Exhibit 2).

**Exhibit 1: U.S. and Canada Natural Gas Production and Productive Capacity**




Sources: ICF

**Exhibit 2: Monthly Natural Gas Prices at Henry Hub**




Sources: Platts Gas Daily

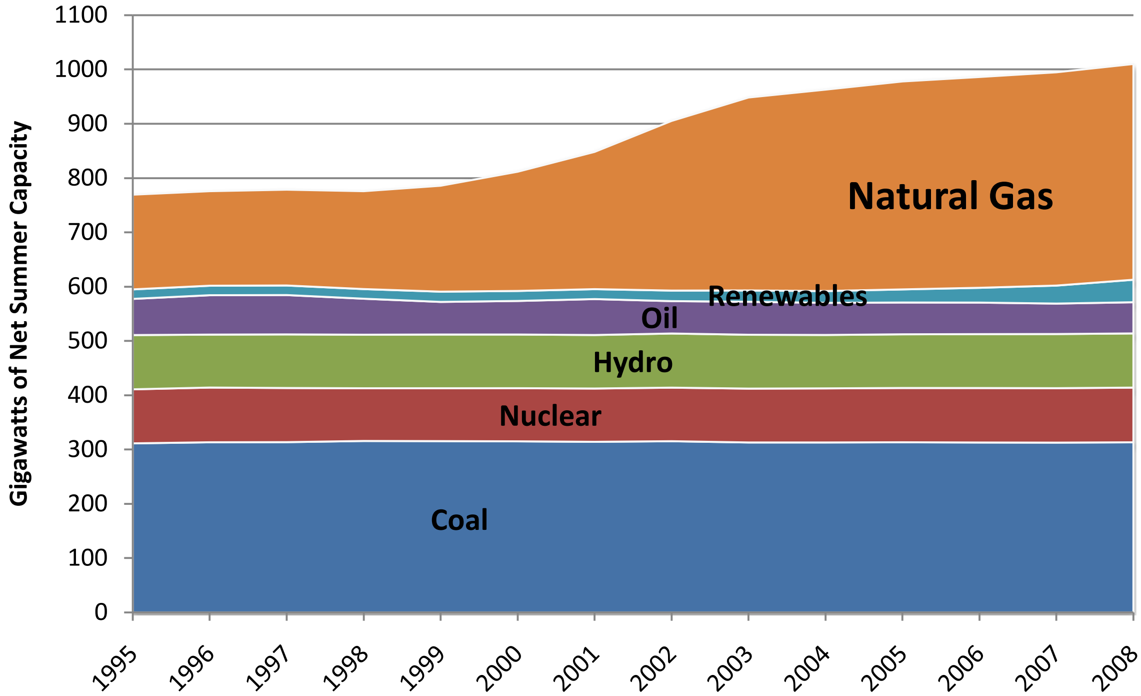
In the mid-1990s, two new trends started to reshape the North American gas market. First, natural gas production, which had long been slowly increasing, started to decline. Gas production from mature, conventional gas resources was declining, and the low price environment meant that there was not much money being invested in developing new technologies to increase gas production.

## 2.1.2 Power Sector Gas Demand Grows

The second trend was the growing demand for natural gas in the electric power sector. There were a number of factors driving the increase in gas-fired capacity and generation. Compared to other generating technologies, gas-fired combustion turbines (CTs) and combined cycle gas turbines (CCs) have relatively low capital costs. Whereas plants using coal-fired steam turbines rely on large scale (usually 200 megawatts or larger) to keep the per-kilowatt cost of capacity down, CCs and CTs can be built at a much smaller scale and still be economical. Gas-fired electric generators also have lower emissions for most air pollutants compared to coal and oil, making it easier for developers to get permits for CCs and CTs. Gas-fired capacity was also seen as a potential hedge against potential future regulations on greenhouse gas emissions, since gas-fired generation also emits less $CO_2$ per kilowatt-hour (kWh) of generation than either coal or oil.

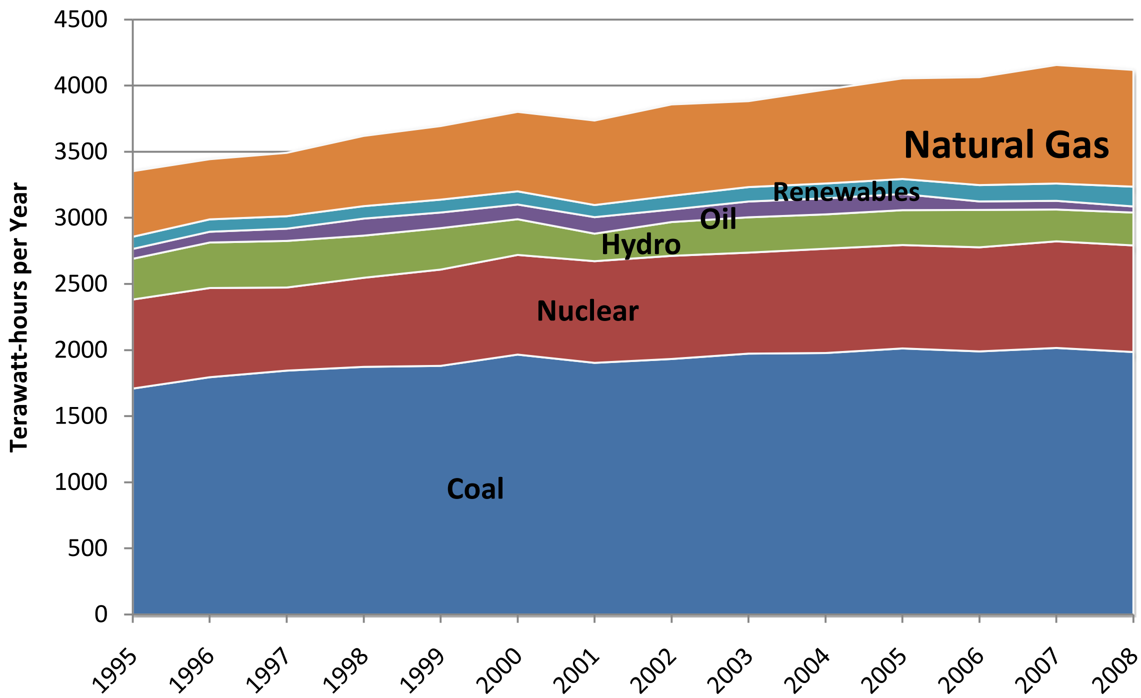
These and other factors lead to a construction boom in new CC and CT in the 1990s and early 2000s. Between 1995 and 2008, over 280 gigawatts (GW) of new gas-fired capacity were added in the U.S. and Canada, of which about 220 GW were in the U.S. (Exhibit 3). As a result of these additions, gas-fired capacity rose from about 23 percent to nearly 40 percent of total U.S. generating capacity. Over the same period, gas-fired generation increased by nearly 400 terawatt-hours per year and grew to over 20 percent of total U.S. generation (Exhibit 4).

**Exhibit 3: U.S. Electric Generating Capacity by Fuel, 1995-2008**




Source: EIA

**Exhibit 4: U.S. Net Electricity Generation by Fuel, 1995-2008**



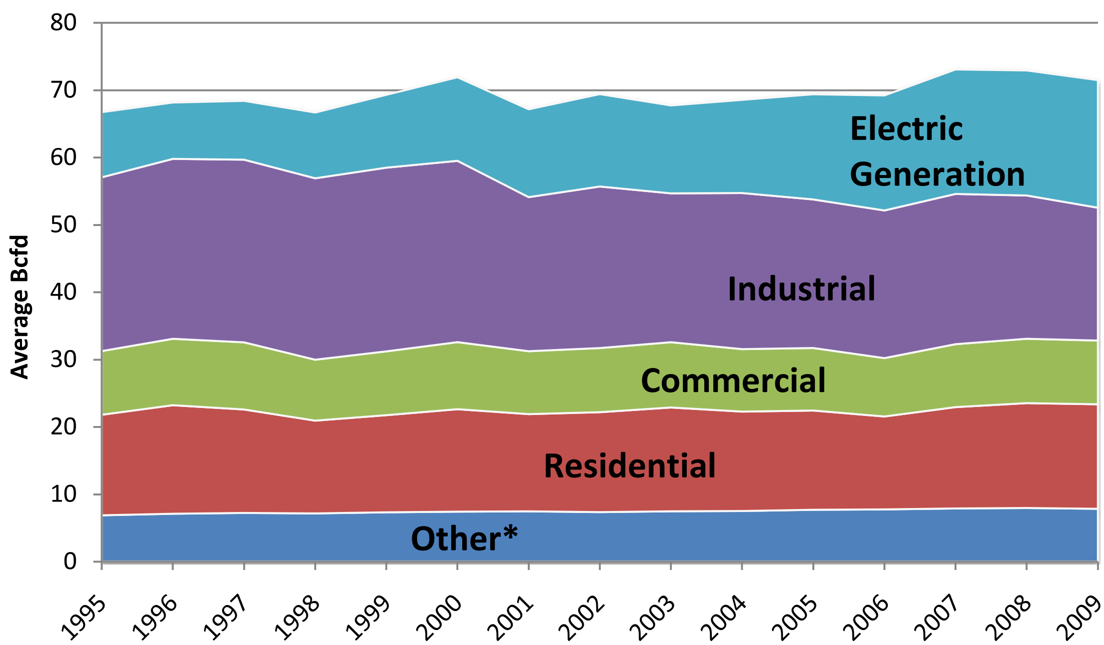

Source: EIA

Between 1995 and 2001, power sector gas consumption rose by over 3 Bcfd (Exhibit 5). Power sector consumption continued to rise in the 2000s, reaching nearly 19 Bcfd by 2009. The increase in power sector gas consumption combined with the flat-to-downward trend in gas production led to a sharp rise in gas prices in the late 1990s and early 2000s. With an increasingly tight supply-demand balance and rising prices, industrial gas consumers reduced their gas consumption. An example of this is the fertilizer industry. Natural gas is used as a feedstock for the production of nitrogenous fertilizers, and gas makes up a large share of the total production cost. As natural gas prices rose in the late 1990s, North American production of fertilizer declined and imports increased. Other gas-intensive industries, such as petrochemicals and primary metals, were also negatively impacted by the rise in gas prices. From 1995 to 2001, gas consumption in the industrial sector declined by 3 Bcfd, about the same amount as the increase in power sector gas consumption over the same period. Industrial demand recovered slightly as prices eased in the early 2000s, but it is still well below the 1999 level.

### 2.1.3 Residential and Commercial

Residential and commercial gas demand increased very little over this same time period. Both of these sectors are relatively price inelastic; that is, their demand levels respond very little to changes in gas prices. In the short term, the principal driver of both residential and commercial gas demand is weather. Much colder-than-normal winter weather can increase residential and commercial gas demand by as much as 12 percent, compared to a normal winter. In the long term, residential and commercial demands are driven by demographic factors such as population growth, increases in the number of households, the number of commercial buildings, and also changes in the efficiency of gas appliances, especially gas furnaces.

**Exhibit 5: Natural Gas Demand in the U.S. and Canada, 1995-2009**




* Other includes Pipeline Fuel and Lease and Plant gas use

Source: ICF International

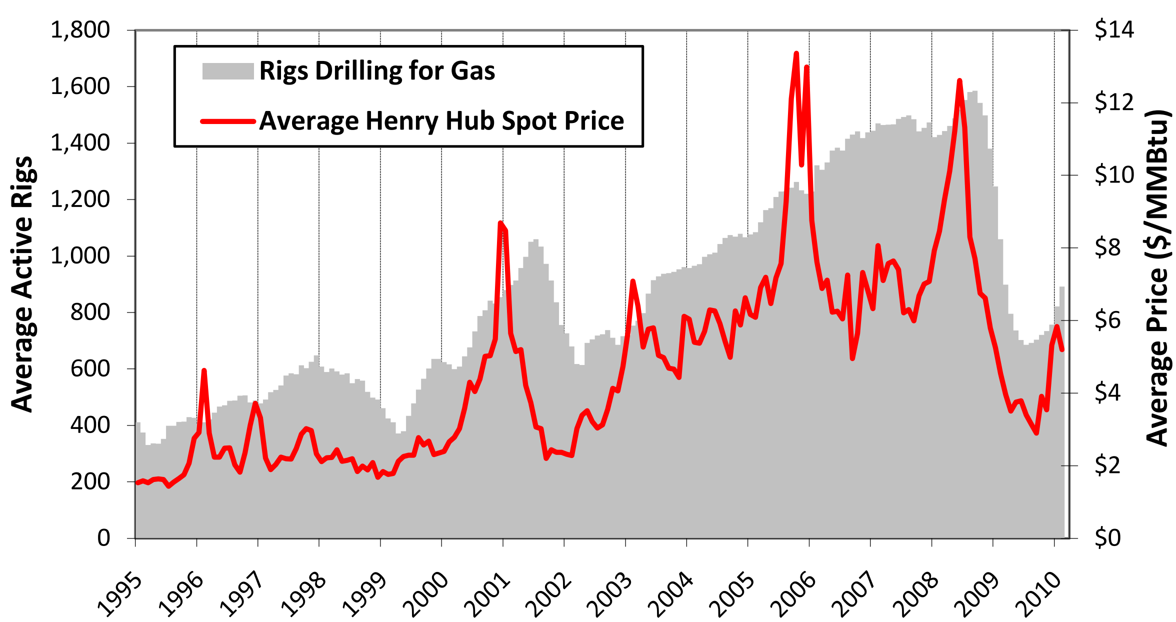
The balance of gas consumption is for pipeline fuel, lease use, and processing plant use. Pipeline fuel is the gas consumed to run the compressors that move natural gas through the pipeline network. Lease gas refers to natural gas used in well, field, and lease operations, such as gas used in drilling operations, heaters, dehydrators, and field compressors. Plant use is gas consumed at facility that process natural gas to remove excess natural gas liquids (NGLs), carbon dioxide, etc. The volume of pipeline fuel gas use is a function of the volume of gas transported on interstate pipelines; i.e., the more gas transported, the more pipeline fuel consumed. Similarly, both lease and plant gas use are functions of the level of natural gas produced; i.e., the higher the level of gas production, the more lease and plant gas use.

### 2.1.4 Gas Prices and Rig Activity

As natural gas prices rose, investments in gas exploration and production (E&P) activity increased. Between 1995 and 2001, the number of drilling rigs engaged in gas E&P activity more than doubled, increasing from about 400 to over 1,000 rigs (Exhibit 6). While rig activity fluctuated somewhat in concert with movements in gas prices, the general trend on both gas prices and rig activity was upward. Activity peaked just before the beginning of the 2008-09 recession at 1,600 active rigs.

However, it was not just the number of wells being drilled that increased. Gas producers were also starting to explore and produce gas from geological formations that had not typically been targeted in the past. In the Northern Rockies, coal bed methane (CBM) was a major new source of gas. In the Midcontinent area, deeper tight gas formations were being drilled. The most important change in the late 1990s was the development of new techniques for drilling and producing shale gas.

**Exhibit 6: U.S. Gas-directed Drilling Activity and Natural Gas Prices**

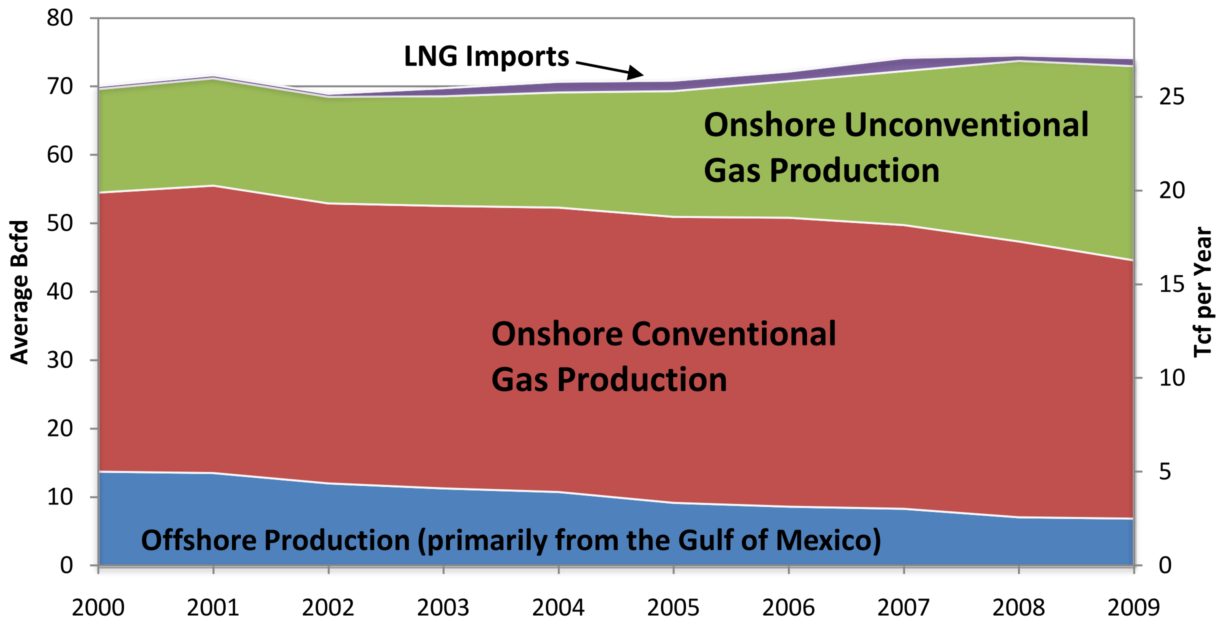



Sources: Baker Hughes (rig counts); Platts Gas Daily (Henry Hub price)

## 2.1.5 Unconventional Gas Resources

The development of unconventional gas resources reversed the overall downward trend in North American gas production. Gas production, which had been declining in the 1990s and early 2000s, rose steadily from 2002 through the beginning of the 2008-09 recession (Exhibit 7). While conventional onshore and offshore production continued to decline, unconventional production was rising rapidly. By 2009, unconventional gas production increased to over 28 Bcfd, which amounts to about 38 percent of all U.S. and Canadian gas supplies. The increase in unconventional gas production was more than enough to offset the declines in conventional gas; from 2000 through 2008, total gas production increase by over 4 Bcfd.

**Exhibit 7: U.S. and Canadian Gas Supplies by Type, 2000-2009**



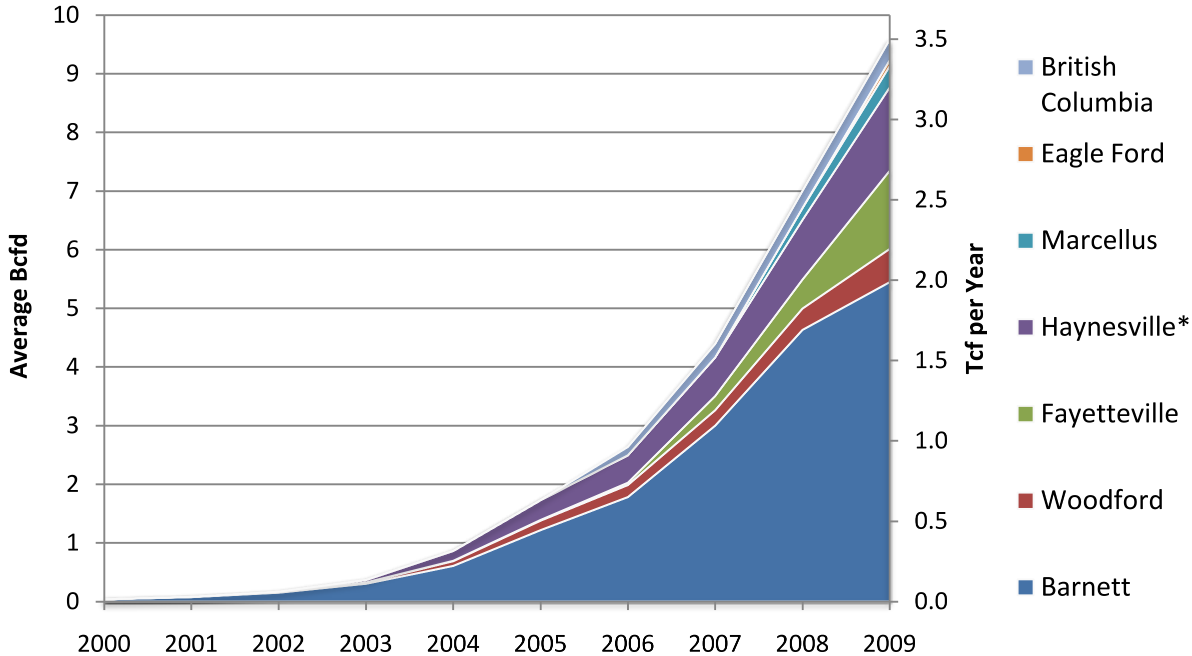

Source: ICF

While it was long known that shale formations contained vast quantities of natural gas, until recently producers did not have a cost effective way to produce the gas. In the late 1990s, new techniques that combined directional drilling with hydraulic fracturing (or “fracking”) opened up the shale resource for development. Though they are costly to drill, shale wells can produce large volumes of natural gas (and in some cases also natural gas liquids, or NGLs), which makes them an attractive option for E&P companies.

The development of shale gas resources was (and still is) a “game changer” for the North American natural gas market. Between 2000 and 2009, shale gas production increased from negligible levels to nearly 10 Bcfd (Exhibit 8). As of 2009, shale gas production made up about 13 percent of total U.S. and Canadian gas supplies. The majority of current shale gas production comes from the Barnett Shale, which is located in the Dallas/Fort Worth area of Texas. The Barnett Shale, which began producing in the late 1990s, was the first of the new shale gas plays to be developed. Since then, several other shale gas plays in the Midcontinent area have been developed, including Haynesville, Woodford, and Fayetteville. The newest shale resources to be developed include two plays in British Columbia (Montney Shale and

Horn River Shale), Eagle Ford shale in south Texas, and the Marcellus Shale, which stretches across West Virginia, Pennsylvania, and New York. While all of the shale plays have significant potential for further development, the Marcellus Shale, with over 700 Tcf of economically recoverable resource, has by far the greatest potential for future growth. ICF has estimated that the total North American shale gas resource is approximately 1,900 Tcf, or about half of the total remaining resource of 3,700 Tcf.

**Exhibit 8: U.S. and Canadian Shale Gas Production, 2000-2009**




*Haynesville production shown here includes gas from other shale plays in vicinity, e.g., the Bossier Shale.

Source: ICF

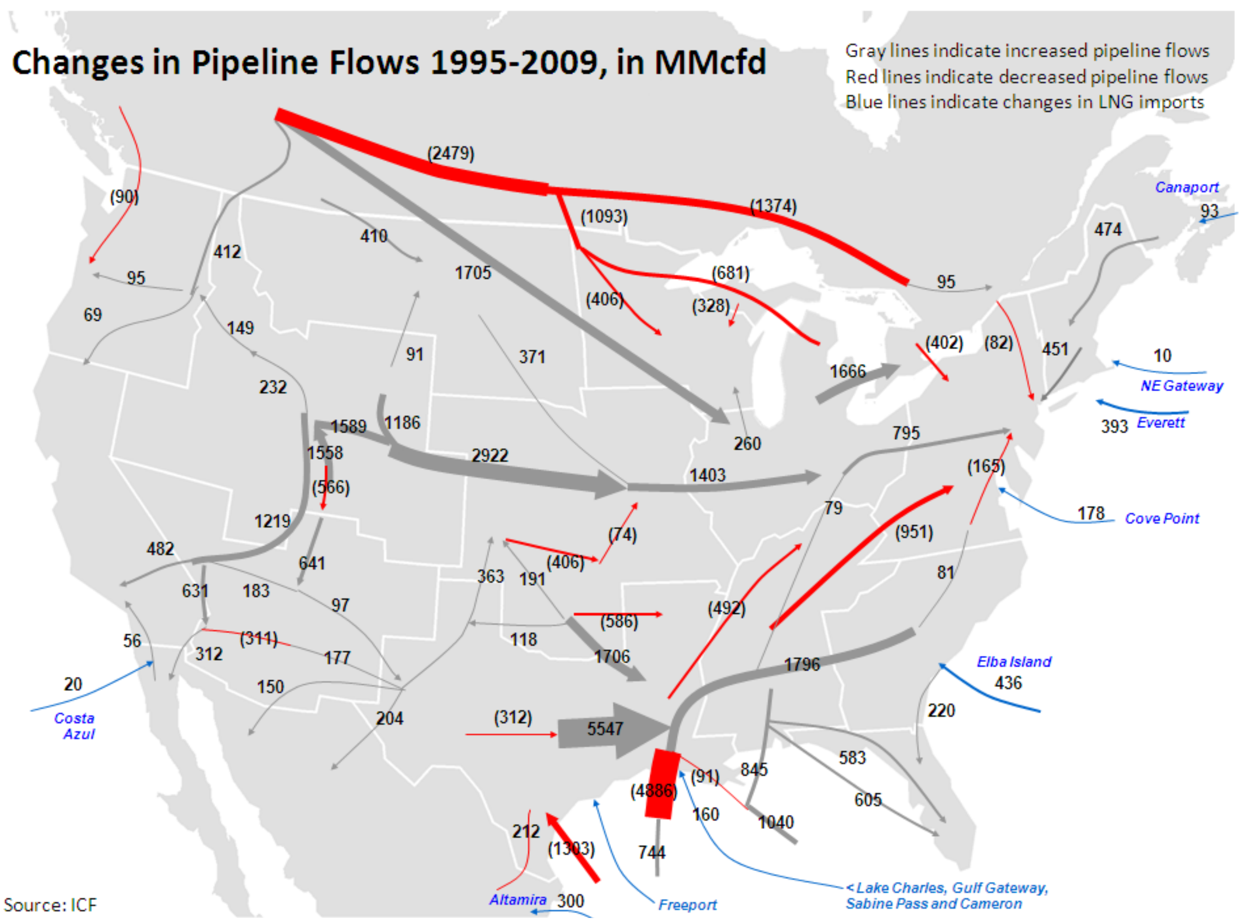
Liquefied natural gas (LNG) imports have also increased over the past decade, although LNG currently plays a much smaller role in the total North American supply picture than was envisioned just a few years ago. In the past five years, eight new LNG import terminals came on-line in North America (five in the U.S., two in Mexico, and one in Canada), and three of the existing U.S. terminals were expanded. By the end of 2009, total North American LNG import capacity had grown to 15 Bcfd. Other terminals currently under construction should bring the total import capacity to over 22 Bcfd by 2015. However, the increased domestic supplies from the growth of shale gas production combined with decreased demand due to the recession has kept the utilization of the LNG import terminals relatively low. In 2009, North American LNG imports averaged 1.5 Bcfd, or roughly 10 percent of the total import capacity. With North American natural gas prices relatively low, there are more attractive markets in Europe and Asia for LNG exporters. In fact, a new facility currently under construction in Kitimat, British Columbia, aims to take advantage of the relatively low natural gas prices in Western Canada by *exporting* LNG to Asian markets. The Kitimat LNG export facility is expected to come on-line in 2014.

## 2.1.6 Shifts in Supply and Demand Cause Shifts in Pipeline Flow

Shifts in gas production and differences in regional gas demand growth result in changes in inter-regional flows of natural gas (Exhibit 9). Flows on TransCanada Pipeline (TCPL) have been steadily declining over the past ten years. There are several reasons behind this decline. The Alliance Pipeline created an alternate path for gas to flow from Western Canada to the U.S. Midwest. Also, declining conventional production in the Western Canadian Sedimentary Basin (WCSB) combined with increased demand for gas in Alberta to develop the oil sands resource reduces the supplies available to TCPL.

Increased production in the U.S. Rockies led to the construction of the Rockies Express (REX) pipeline, which increased the flow of gas from the Rockies eastward. The growth of shale gas production in the Midcontinent area created a large surge of flow eastward, more than replacing the decrease in Gulf of Mexico offshore production. Increased power sector gas demand in the Southeast U.S. meant that more of the gas flowing eastward from the Midcontinent was staying in the Southeast. The growth of Marcellus Shale gas production has reduced flows from the Gulf Coast in to the Northeast U.S., freeing up gas supplies for the Southeast.

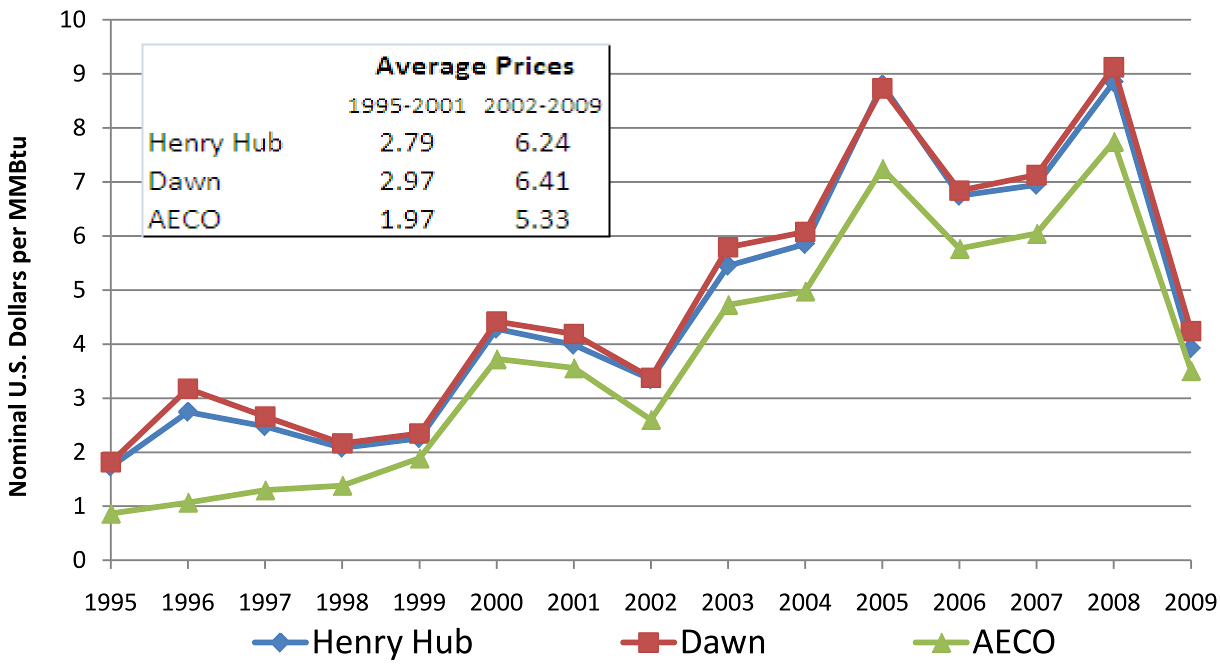
**Exhibit 9: Changes in Inter-regional Pipeline Flows, 1995-2009**



## 2.1.7 Price Impacts

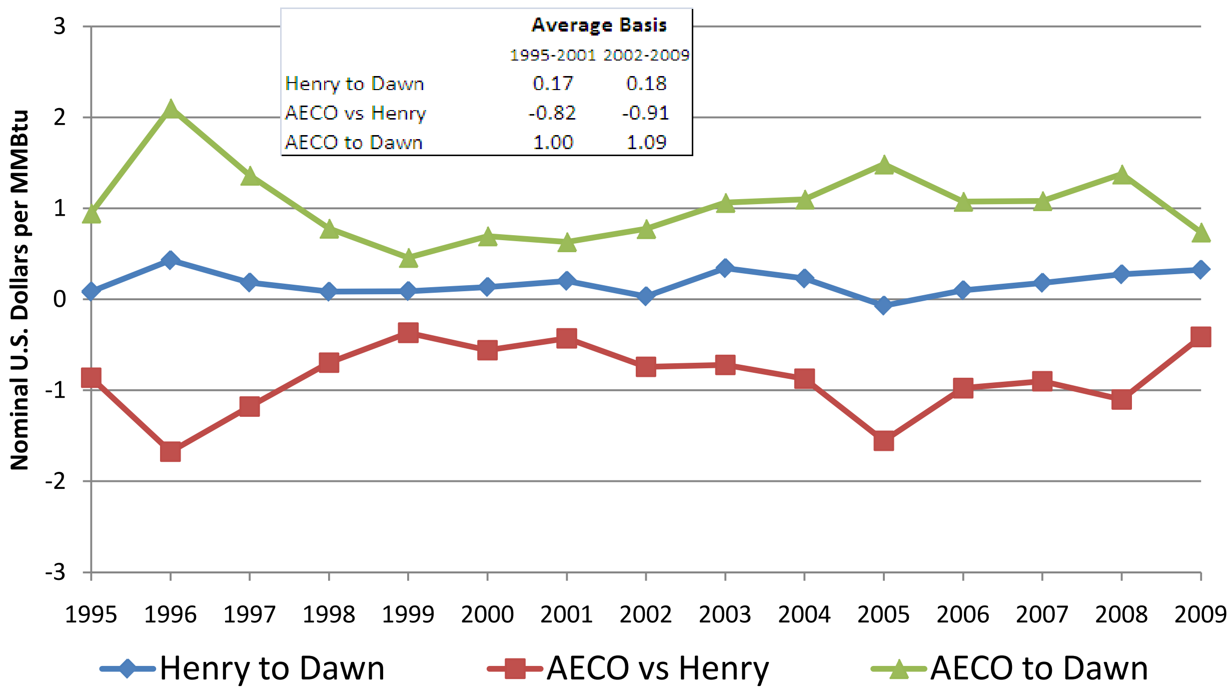
As discussed above, North American gas prices were trending upward until the onset of the 2008-09 recession. Regional prices all followed this general trend, with average gas prices rising to more than double the very low prices of the gas bubble era (Exhibit 10). Changes in basis differentials between markets reflected the changes in regional supply and demand and constraints on the pipeline capacity serving individual markets (Exhibit 11). Basis to New York City and New England tended to increase over this period, as load factors increased on pipelines delivering gas into the Northeast U.S. Chicago prices, which had been trading above Henry Hub, moved below Henry Hub after the startup of the Alliance gas pipeline which increased gas supplies to the northern Illinois market. Opal prices were pushed lower relative to Henry Hub as Rockies gas production increase but flows out of the Rockies were constrained by limited pipeline capacity. The REX Pipeline, which started operation in 2008, relieved some of the constraints on the movement of Rockies gas and raised Opal prices relative to Henry Hub.

**Exhibit 10: Regional Average Annual Gas Prices, 1995-2009**




Source: Platts Gas Daily

**Exhibit 11: Regional Average Annual Basis, 1995-2009**




Source: Platts Gas Daily

## 2.2 The Ontario Market

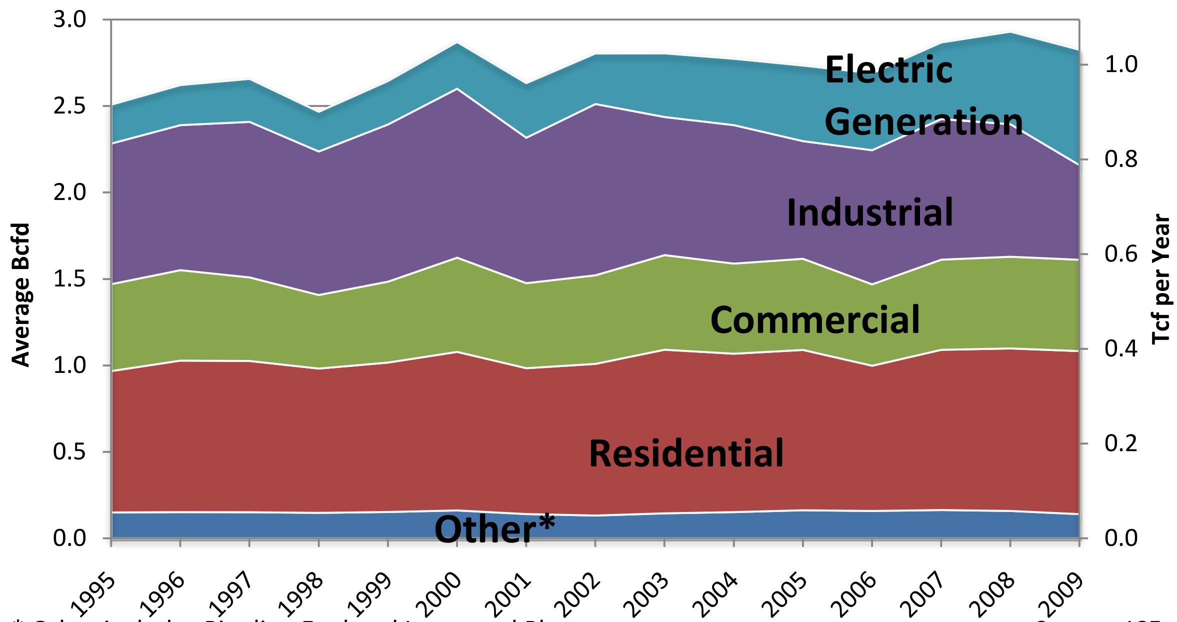
Ontario's total natural gas demand in 2009 was about 2.8 Bcfd on average (Exhibit 12). Ontario is a relatively small portion of the total North American market, accounting for about 3 percent of total U.S. and Canadian gas consumption. In terms of Canada's gas market, Ontario makes up a much larger share, accounting for about 30 percent of all Canadian gas consumption.

### 2.2.1 Demand Summary

The majority of Ontario's gas consumption is in the residential and commercial sectors. Together, these two sectors accounted for over 50 percent of Ontario annual gas consumption in 2009 (Exhibit 13). In the peak demand months of winter, combined residential and commercial gas demand makes up about two-thirds of total demand. Over the last decade, both residential and commercial gas demand have grown at about 1 percent per year. The industrial sector currently makes up 27 percent of the province's demand. Industrial gas demand declined at a modest rate from the mid-1990s to 2008, but then dropped sharply with the recession in 2009. The manufacturing sector, which makes up about two-thirds of industrial output, was very hard hit in the recession, with output dropping by nearly 15 percent in 2009. Ontario's automobile industry, which had been about one quarter of the manufacturing sector's output, dropped by nearly 30 percent in 2009. Consequently, natural gas consumption in the manufacturing sector is continuing to drop by about 3 percent annually.

In contrast to the industrial sector, gas consumption in the power sector has been steadily growing. Traditionally, much of Ontario's electricity supplies have come from nuclear, hydroelectric, and coal-fired generation. However, environmental concerns and the shift from provincially-owned generation to privately owned generation has driven Ontario's increase in gas-fired CC and CT capacity. From 1999 to 2009, gas use for electricity generation in Ontario more than doubled. Currently, power generation gas use accounts for 20 percent of Ontario's gas demand.

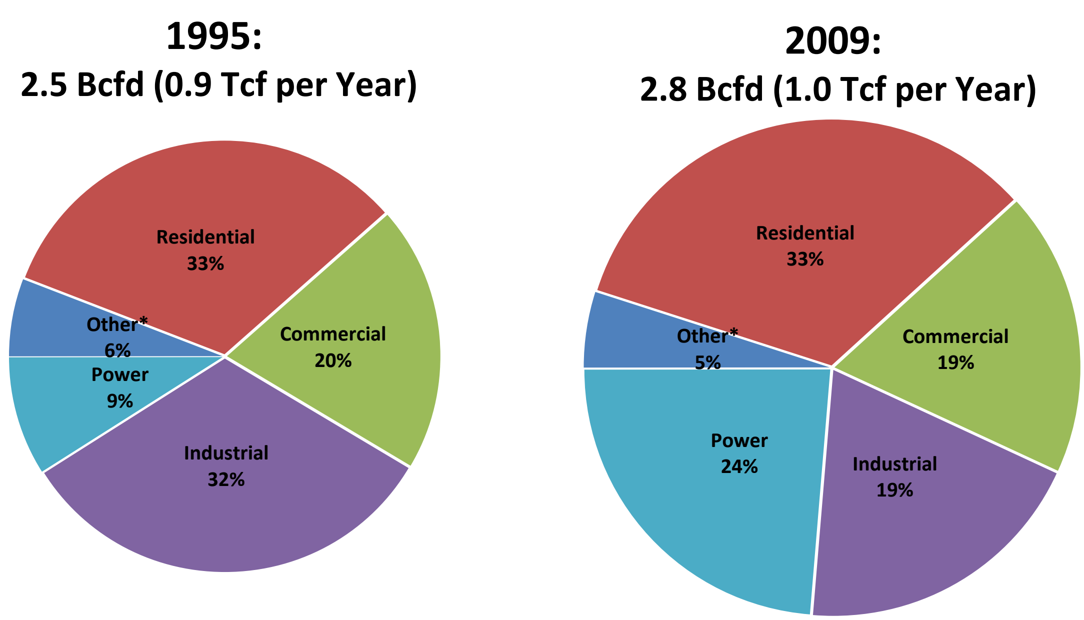
**Exhibit 12: Natural Gas Demand in Ontario, 1995-2009**




* Other includes Pipeline Fuel and Lease and Plant gas use

Source: ICF

**Exhibit 13: Ontario Natural Gas Demand by Sector, 1995 and 2009**



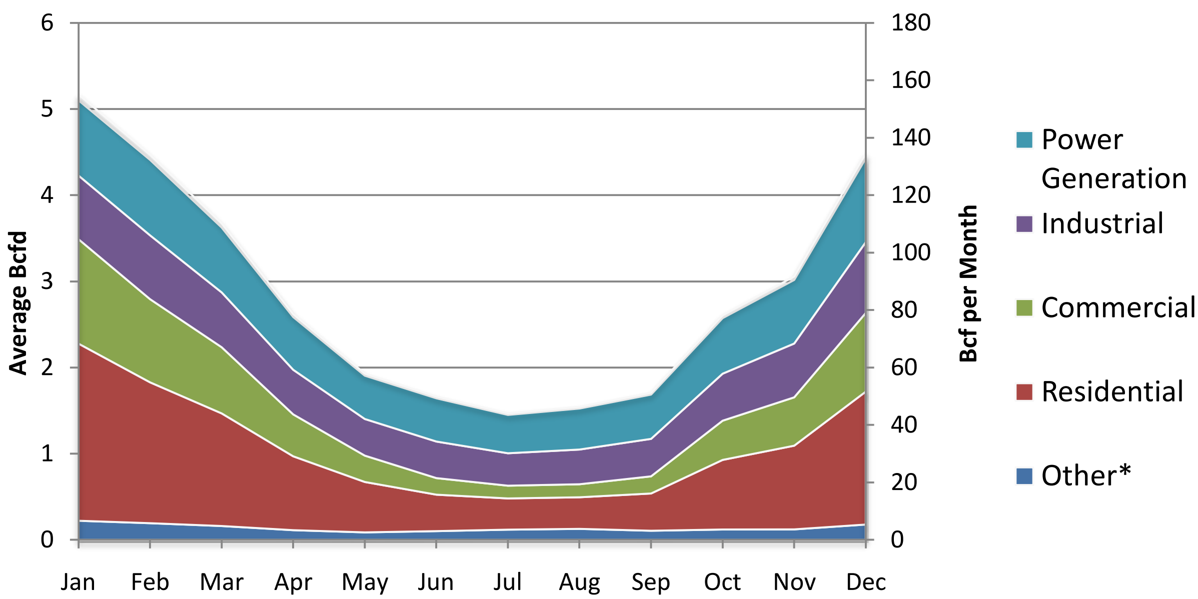

* Other includes Pipeline Fuel and Lease and Plant gas use

Source: ICF

Ontario's natural gas consumption is very seasonal. While total gas consumption in 2009 averaged about 2.8 Bcfd over the entire year, January consumption averaged over 5 Bcfd, while July consumption was only 1.5 Bcfd (Exhibit 14). Most of the seasonal fluctuations in gas consumption occur in the residential and commercial sectors. Residential and commercial consumers use natural gas mostly for space heating, so their consumption levels change dramatically as temperatures vary. In January 2009, residential and commercial gas demand totaled nearly 3.3 Bcfd, while residential and commercial demand in July was only 0.5 Bcfd.

The industrial sector also has seasonal fluctuations in gas demand, although they are not as extreme as in the residential and commercial sectors. Since a portion of the gas used by industrial facilities is for space heating, industrial gas demand is also higher in the winter months. Gas demand in the power sector tends to follow the seasonal fluctuations in demand for electricity. Ontario's electricity demand peaks in the summer when air conditioning loads are the highest, with a smaller secondary peak in the winter. The remainder of Ontario's gas consumption is to fuel pipeline compressor stations with transport natural gas within the province. Pipeline fuel use also increases in the winter months, when larger volumes of natural gas are being transported. Ontario produces a small amount of natural gas, so lease and plant gas use is insignificant. In 2009, natural gas production within the province was only about 0.03 Bcfd.

**Exhibit 14: Ontario's Seasonal Gas Demand in 2009**




* Other includes pipeline fuel and lease and plant gas use. Source: ICF

## 2.2.2 Key Ontario Pipelines and Flow

Since Ontario's domestic production is less than its demand, it has to import natural gas from other areas via gas pipelines. The largest single natural gas pipeline serving Ontario is TCPL, which carries gas produced in the WCSB to Ontario and other markets in the eastern parts of Canada and the U.S. TCPL enters Ontario at the Manitoba border with a capacity of about 4 Bcfd. Several other pipelines connect to Ontario at the Dawn Hub. Pipelines connecting to

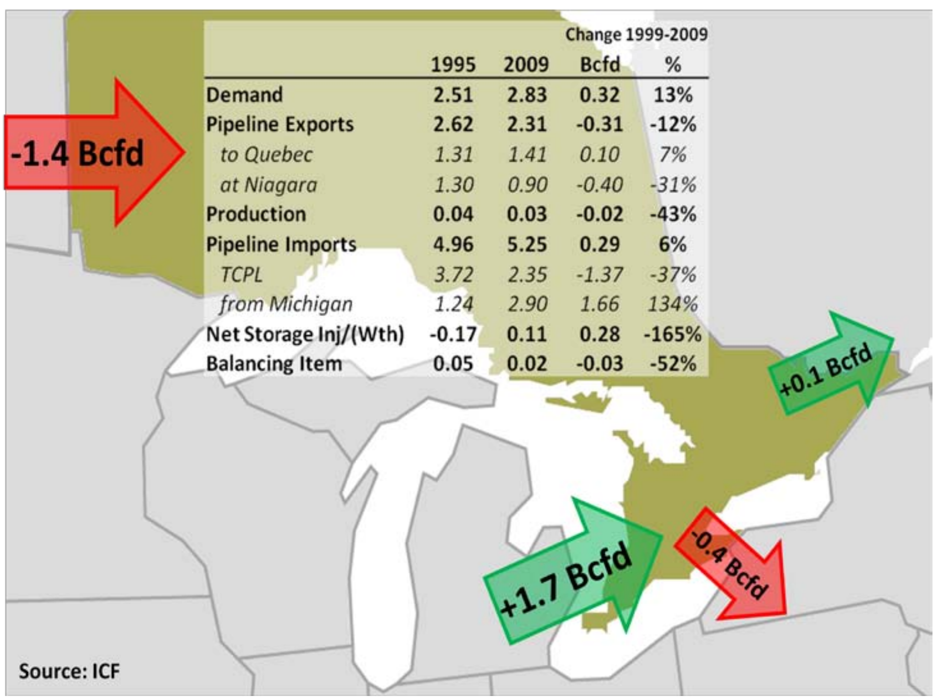
Dawn from Michigan include Great Lakes Gas Transmission, Vector, MichCon, and CMS. Dawn is a major storage hub, so these pipelines can also transport gas from Dawn-area storage fields back to Michigan. As of the end of 2009, total pipeline delivery capacity between Michigan and Ontario was about 3.9 Bcfd. (Natural gas pipelines serving Ontario are discussed in more detail in Section 3.3.1.)

Ontario also has outbound pipeline connections to deliver some of the imported gas to markets further downstream east. TCPL has outbound pipeline connections at the borders with New York State (at Niagara) and Quebec, which move gas into markets in New York, New England, and Quebec. Only about half of the natural gas that enters Ontario via pipeline is consumed within the province – the rest is transported to other markets.

In addition to its pipeline capacity, Ontario also has a considerable amount of storage capacity. Ontario's natural gas storage is located in 35 depleted reservoirs, most located in Lambton County (in southwestern Ontario), with a total working gas capacity of about 240 Bcf. Ontario's natural gas storage is important for both meeting peak winter demand within the province and in surrounding markets both in the U.S. and Canada. On a peak winter day, nearly 60 percent of the natural gas consumed in Ontario is supplied from gas storage. (Ontario gas storage is discussed in more detail in Section 3.3.3.)

The impact of changing pipeline flows on Ontario's gas balance between 1995 and 2009 is shown in Exhibit 15. On an average annual basis, flows on TCPL into Ontario fell by 1.4 Bcfd. While flows on TCPL have decreased, net flows into Ontario from Michigan have increased by 1.7 Bcfd. The declines on TCPL have also resulted in lower gas export from Ontario at Niagara, which have declined by 0.4 Bcfd. With the decline in gas exports from Canada to the U.S., consumers in the Northeast U.S. have replaced Canadian gas supplies with domestic production, particularly from shale gas production in the Marcellus area.

**Exhibit 15: Ontario Annual Natural Gas Market Balance, 1995 versus 2009**



| | | | Change 1999-2009 | |
|---|---|---|---|---|
| | 1995 | 2009 | Bcfd | % |
| **Demand** | **2.51** | **2.83** | **0.32** | **13%** |
| **Pipeline Exports** | **2.62** | **2.31** | **-0.31** | **-12%** |
| *to Quebec* | *1.31* | *1.41* | *0.10* | *7%* |
| *at Niagara* | *1.30* | *0.90* | *-0.40* | *-31%* |
| **Production** | **0.04** | **0.03** | **-0.02** | **-43%** |
| **Pipeline Imports** | **4.96** | **5.25** | **0.29** | **6%** |
| *TCPL* | *3.72* | *2.35* | *-1.37* | *-37%* |
| *from Michigan* | *1.24* | *2.90* | *1.66* | *134%* |
| **Net Storage Inj/(Wth)** | **-0.17** | **0.11** | **0.28** | **-165%** |
| **Balancing Item** | **0.05** | **0.02** | **-0.03** | **-52%** |

Over the same period of time, Ontario's total gas demand increased by 0.3 Bcfd. TCPL also supplies Quebec via the Trans Québec & Maritimes (TQM) Pipeline (of which TCPL is a part owner). Since Quebec's gas demand has also increased, flows on TQM have also increased by 0.1 Bcfd.

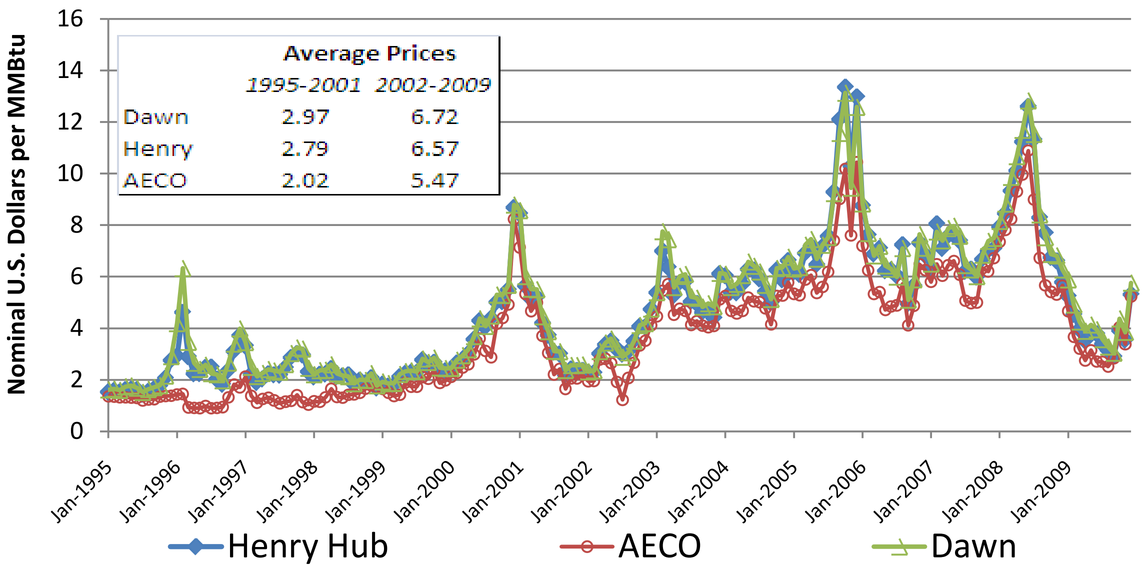
## 2.2.3 Ontario Price Summary

The Dawn Hub, located in Lambton County, is the major trading point for natural gas in Ontario. As the majority of Ontario consumers are located in the southern portion of the province, the price at Dawn is a good representation of the spot price of natural gas in Ontario. In Alberta, prices at the AECO Hub are representative of the price of gas being supplied upstream to TCPL. Henry Hub in Louisiana is the most widely traded price point in the North American market. Because of this, the price at Henry Hub is generally used to represent overall movements in North American natural gas prices.

The trend in Dawn gas prices has very closely followed the overall trend in North American gas prices, as represented by the Henry Hub price (Exhibit 16). As the overall North American supply-demand balance tightened in the 1990s and 2000s, gas prices at Dawn increased along with the Henry Hub price, rising from around $2 to $4 per MMBtu in the 1990s to as much as $13 per MMBtu just prior to the 2008-09 recession.

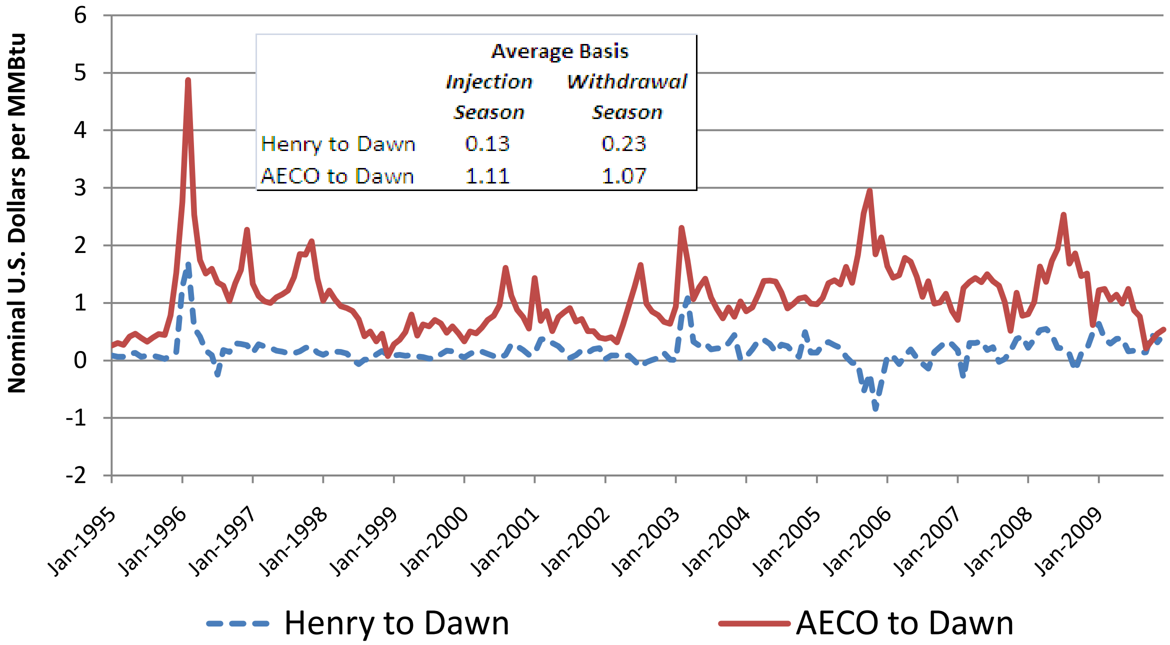
While basis differentials fluctuated considerably over the period, the average Dawn basis values generally remained around $0.20 per MMBtu versus Henry, and around $1.10 per MMBtu versus AECO (Exhibit 16). Basis from Henry to Dawn tended to average higher in the withdrawal season, when pipelines from the Gulf Coast to the Northeast are relatively full. Basis from AECO to Dawn was more consistent throughout the year, with no significant difference between withdrawal and injection season basis. This is because load factors on TCPL have tended to be more consistent across the injection and withdraw seasons within each year, although the overall trend for TCPL's load factor has been decreasing.

**Exhibit 16: Average Monthly Gas Prices, 1995-2009**




Source: Platts Gas Daily

**Exhibit 17: Average Monthly Basis, 1995-2009**




Source: Platts Gas Daily

# 3. Detailed Natural Gas Market Review

This section examines the Ontario gas market in greater detail, including projections for natural gas demand, supply, and prices through 2020. This examination includes a discussion of factors driving market change within Ontario, as well as changes in the surrounding North American gas market that have both direct and indirect impacts on the Ontario natural gas market. The natural gas market projections are based on ICF's June 2010 Natural Gas Market Compass, a comprehensive projection of activity for both the North American market as whole and for regional markets, including Ontario.

First, we examine trends in gas demand, including the major drivers behind growth in each demand sector. Second, we explore gas supply, including the growth of shale gas supply and its impact on the Ontario market, as well as other gas supplies such as LNG. Third, we look at gas pipelines and storage. This includes how the utilization of existing pipelines is changing, what new pipelines are planned, and the impact these changes may have on Ontario's gas imports. We also examine how changes in the market may affect the utilization of gas storage in Ontario. Lastly, we look at the expectation for future gas prices and basis, in light of the projected changes in the market.

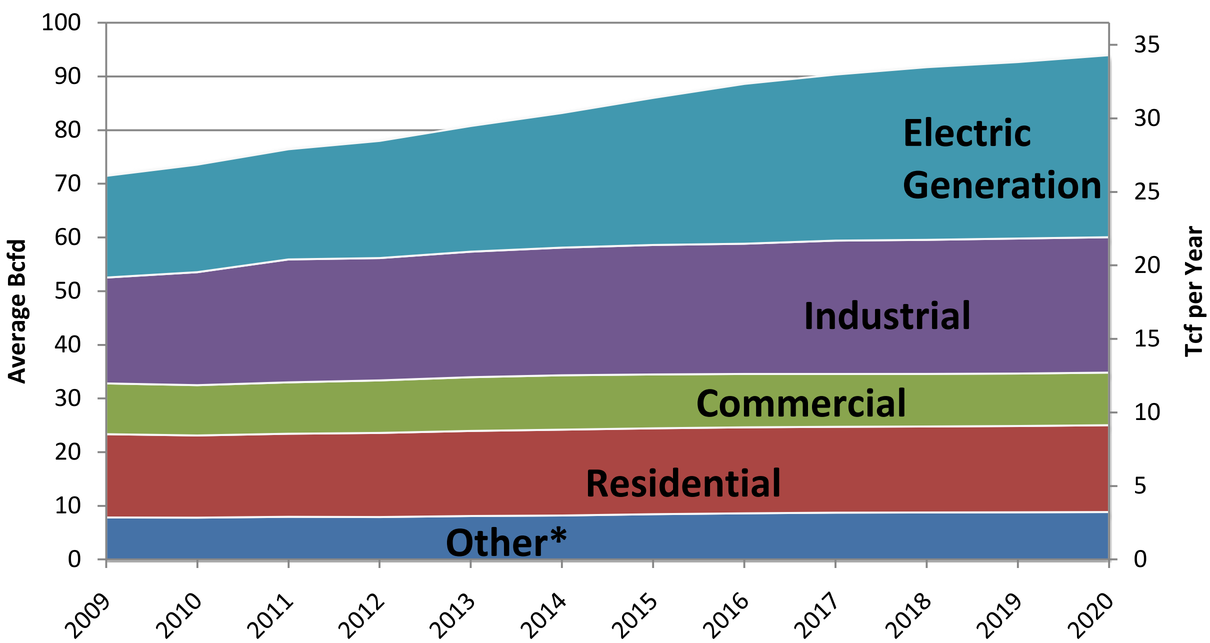
## 3.1 Demand Trends

ICF's current natural gas market projection forecasts total U.S. and Canadian gas demand to increase from about 71 Bcfd in 2009 to 94 Bcfd by 2020, an average growth rate of 2.5 percent per year (Exhibit 18). About two-thirds of the total growth in gas use, or almost 15 Bcfd, is projected to occur in the power generation sector, where gas consumption increases by 5.4 percent per year on average over the time period.

Projected growth in gas demand for power generation is estimated to be driven by many of the same factors that have driven its growth in the recent past. Historically, North American electricity demand growth has decelerated over time, as energy efficiency increased and the economic growth shifted away from manufacturing towards the service sector. Over the next ten years, electricity demand growth is projected to increase at about 1.9 percent per year, somewhat slower than the historical trend of about 2.5 percent. Even with a reduced rate of demand growth, this still amounts to an increase in total electricity demand. In the past decade, there have been 280 GWs of new gas-fired generating capacity built in the U.S. and Canada. In some markets, the utilization of gas-fired capacity is relatively low; so much of the projected incremental electric load growth could be met by increasing output from this existing capacity.

ICF's projection assumes that in the U.S., a Federal cap-and-trade system to control $CO_2$ emissions is implemented within the next decade, which leads to reductions in coal-fired capacity and generation. While other types of generation, such as nuclear and renewable generation, are expected to grow as $CO_2$ allowance prices steadily increase, switching from coal to gas-fired generation is one of the more cost-effective ways to reduce $CO_2$ emissions. As a result of the growth in electric load and environmental policies, gas-fired generation is expected to increase. This growth in gas generation is the primary driver of growth in total U.S. and Canadian gas demand.

**Exhibit 18: Projected Natural Gas Demand in the U.S. and Canada, 2009-2020**



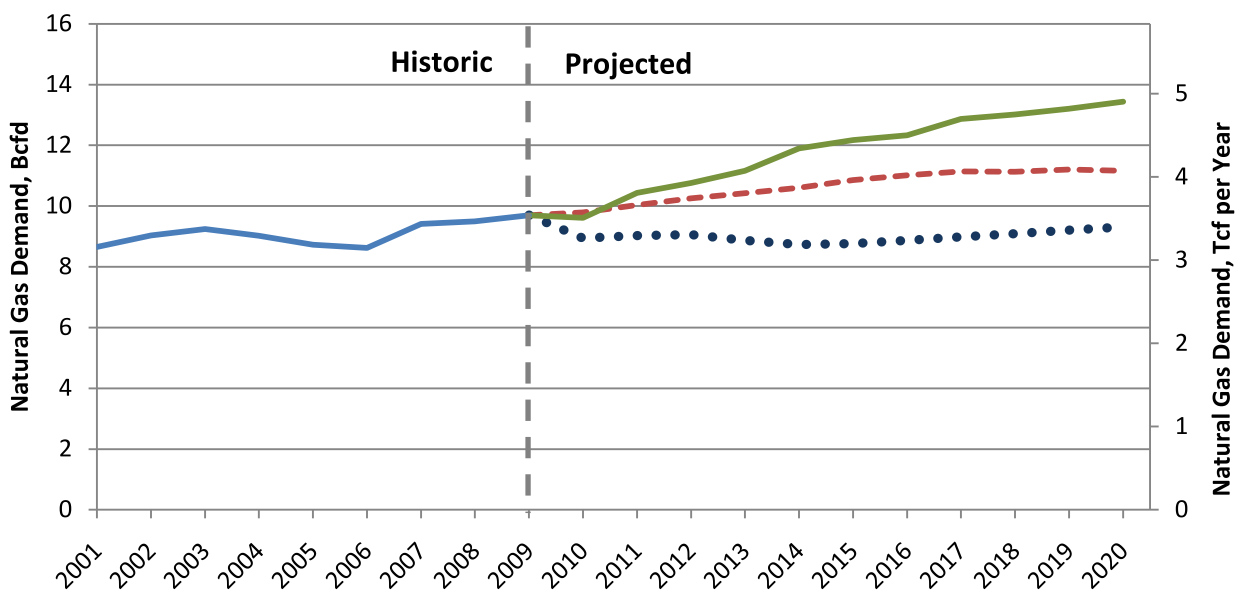

* Other includes Pipeline Fuel and Lease and Plant gas use

Source: ICF

In Canada, natural gas demand growth slowed in 2009 and 2010, as the impacts of the recession have trickled through the economy. Since 2001, total annual demand growth for natural gas has equaled about 2 percent and even though we have experienced some periods of decline in gas use, such as in the 2004 to 2006 period, strong recoveries have followed, driving the overall trend upwards. Typically, gas demand volatility in Canada can be attributed extreme winter weather, which impacts the gas demand for space heating, as well as to swings in world oil prices, which impacts the output (and gas demand) from the oil sands projects in Western Canada. The recent declines in gas consumption are primarily the result of the recession's impacts on Canada's manufacturing industries, which are centered in Ontario, as well as on slowed development of oil sands projects.

The impacts of the recession on Canada's industrial gas demand have largely been offset by increases in demand from the power sector, particularly in Alberta and Ontario. It is expected that demand from 2009 to 2010 will remain relatively flat, or show marginal decline. However, as the worldwide economy recovers, we see growth in 2011 led by the strength of power sector and oil sands demand. Also, other industrial demand begins to recover and contribute to demand growth.  ICF's outlook for natural gas use in Canada show's strong growth over the next 5 years, which aligns with the NEB's forecast, albeit slightly more aggressive (Exhibit 19). Ontario plays a large role in this gas demand recovery and we will explore some of the factors in detail throughout this section.

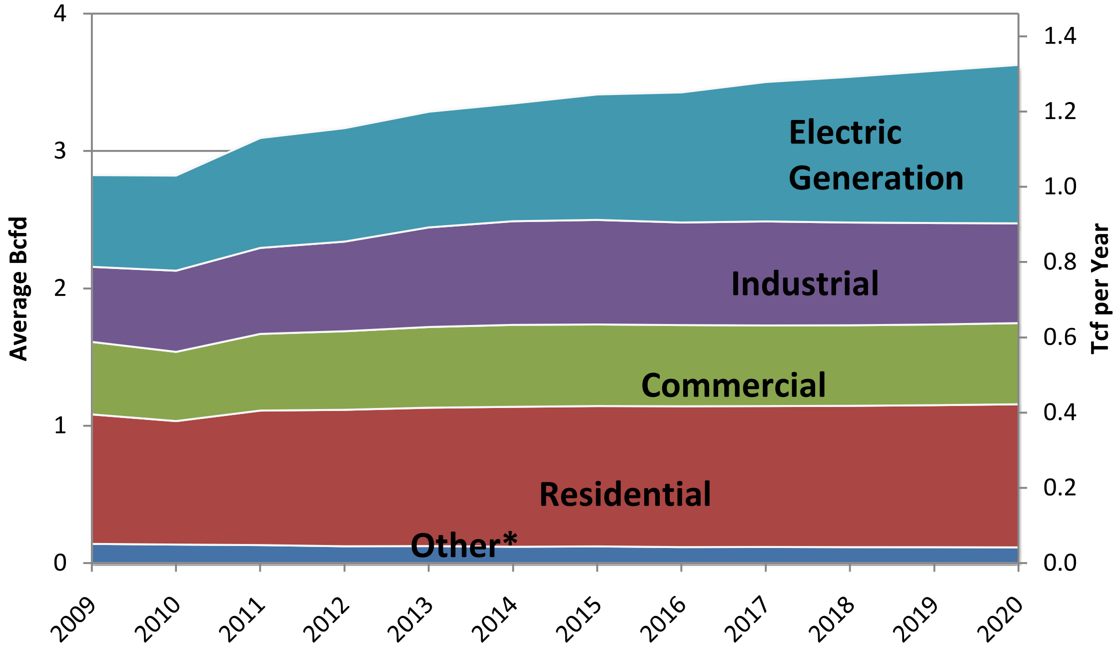
**Exhibit 19: Canada Natural Gas Demand Trends**




Sources: ICF International
National Energy Board, 2009 Reference Case Scenario: Canadian Energy Supply and Demand to 2020
Energy Information Administration, 2010. Independent Statistics and Analysis.

In two important respects, the projection for Ontario gas demand is similar to the overall projection for the U.S. and Canada: 1) there is significant growth in total gas demand, and 2) the majority of that growth comes from increased gas consumption in the power sector.  Total natural gas consumption is projected to increase from 2.8 Bcfd in 2009 to 3.6 Bcfd by 2020, an average annual growth rate of 2.3 percent (Exhibit 20).  As is the case for the whole of the U.S. and Canada, increasing gas demand in the power sector is expected to be the primary driver of Ontario's total growth in demand.  Over 70 percent of the incremental increase in Ontario gas demand is projected to come from increased gas use in the power sector.  By 2020, power sector gas demand is projected to account for nearly one-third of Ontario's total gas demand (Exhibit 21). The drivers behind the growth in Ontario's power sector and the other demand sectors are discussed in this section.

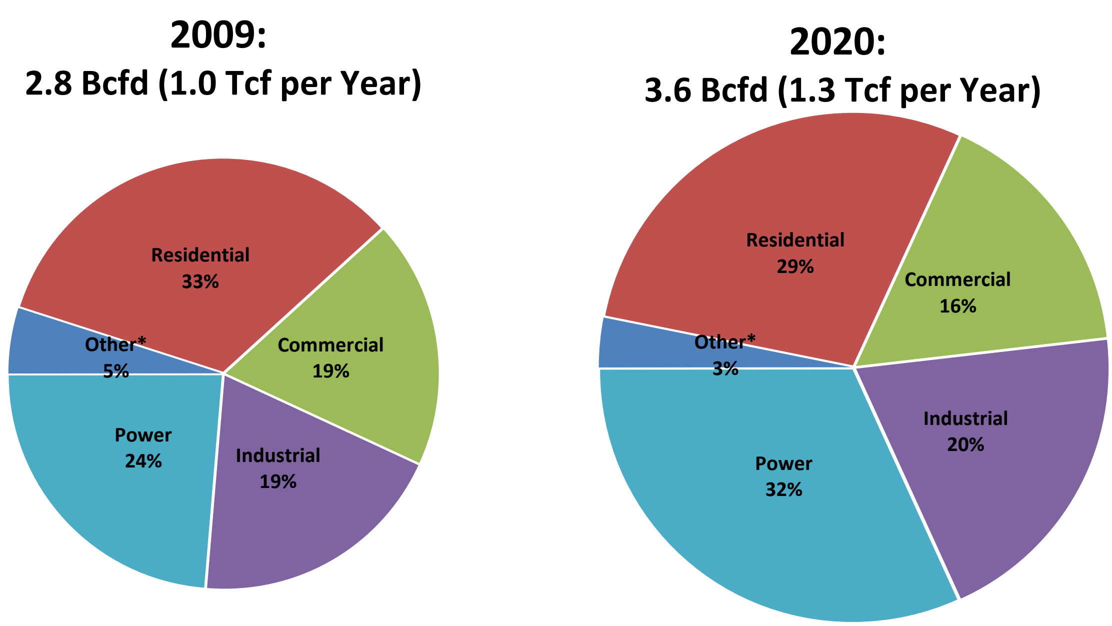
**Exhibit 20: Projected Natural Gas Demand in Ontario, 2009-2020**




* Other includes Pipeline Fuel and Lease and Plant gas use

Source: ICF International

**Exhibit 21: Ontario Natural Gas Demand by Sector, 2009 and 2020**




* Other includes Pipeline Fuel and Lease and Plant gas use

Source: ICF

# 3.1.1 Power Sector

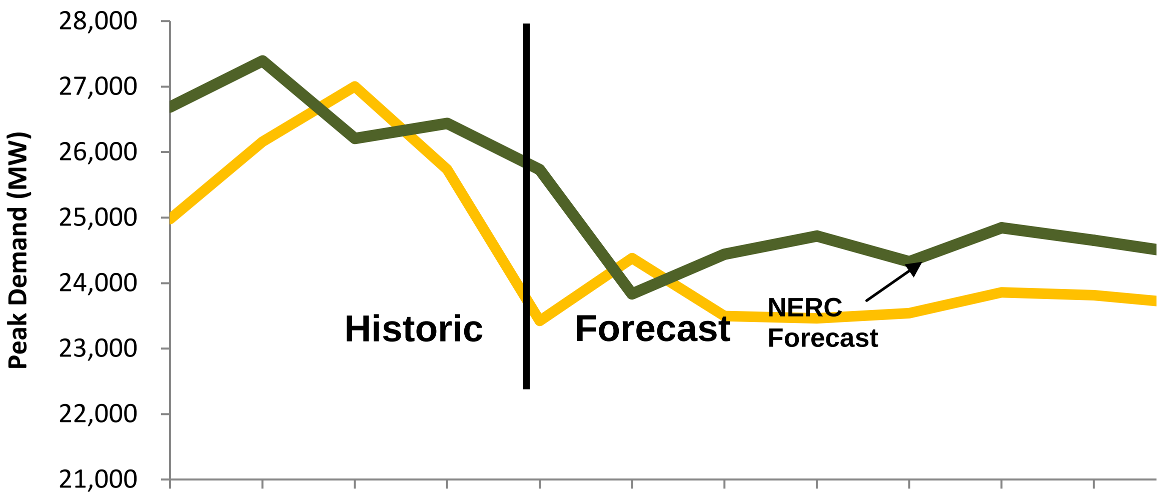
The power sector in Ontario is currently going through a period of substantial change. As a result of the restructuring of the electric power market, which began 10 years ago, Ontario now has a partially competitive wholesale market for electricity and a number of new players who are shaping the industry. One of the newest entities in the sector is the Ontario Power Authority (OPA), an organization tasked with long term system planning to ensure adequate supply through the appropriate procurement measures and conservation program design and deployment. Over the past several years, the OPA (combined with policy initiatives from the provincial government) is acting to change the face of the Ontario electricity industry.

***Electricity Demand Growth***

Ontario's electricity demand profile has been changing in recent years. Overall, energy demand has been declining as a result of conservation and because energy-intensive industries have been reducing output since 2004 (indicative of the general economy's trend in Ontario, moving from heavy manufacturing toward less energy intensive services)[1]. Additionally, the economic slowdown since 2008 has had a deflationary action on industrial electricity use. Peak demand has also been declining due to aggressive conservation efforts and the current economic situation. As the OPA and local distribution companies continue to implement conservation and as time of use rates and smart metering take hold, peak demand is expected to continue to face downward pressure. Electricity demand is expected to have some rebound in 2010, but remain relatively flat through 2015. Peak demand will likely continue to be deflated, although as the economy continues recovery through 2012, some marginal growth is expected (Exhibit 22).

In terms of total net energy, The North American Electric Reliability Council (NERC) is forecasting a longer more drawn out period of declining electricity demand (Exhibit 22). However, our demand forecast also includes views from the IESO and OPA, who also perform long-term demand forecasting for Ontario.

**Exhibit 22: Ontario Peak Electricity and Energy Demand**




Sources:
NERC, 2009 ES&D and IESO Longterm Demand Forecast

[1] "Ontario's Changing Demand Profile" IESO and The Ontario Reliability Outlook, 2009

The flattening of electricity demand in the province is not reducing power sector demand for natural gas as one might expect. In fact, we find that due to the decline in electricity demand growth, the province has the opportunity to accelerate a number of other policy initiatives that will have the combined impact of increasing gas-fired generation. As the demand outlook falls, the acute reliability concerns of the mid-2000s are no longer as primary a concern. The expected retirement of coal-fired electricity has now become a realistic option. Once the coal-fired assets are removed, gas will fill a large part of their role and any uncertainty in demand growth must be covered by gas generation, since coal will not be available. We believe that realistic goals for the phase out of coal in Ontario are now set and interim objectives are being made. Coal electricity production has been declining. The impact of the quicker phase out of coal may increase the requirement for natural gas generation in the short term, both to offset coal reductions and to "firm up" the increasing variability in the system due to the strong wind and solar development in the province. Under-utilized gas assets and new plants being constructed in key demand centres will supply the expected energy.

### *Changes in Installed Capacity*

Since the OPA was instituted in 2004, it was challenged with devising a strategy to close the gap between supply and demand (that was an identified and growing problem at the time). The OPA is an independent non-profit corporation acting on ministerial directives from the Minister of Energy. They would also continue long term planning of supply and conservation resources to help ensure Ontarians adequate and reliable electricity delivery. Early initiatives were aimed at the development of procurement processes to secure the necessary supply for current and projected demand. This task was completed with the consideration of several market dynamics that would become important as time progressed. An aging nuclear fleet, with several units coming to the end of their economic lives, as well as the desire to remove coal-fired generation from the system, would compound the expected supply short falls. The result of this planning was a number of standard offer programs, procurement RFPs and the development of the Integrated Power System Plan (IPSP).

The initial processes for procuring new capacity in Ontario were focused on "clean" energy and renewable energy. This included direct negotiations to secure 2,768 MW of renewable energy supply and a set of renewable RFP programs securing about 1,550 MW of contracted supply. The Renewable Energy Standard Offer Program followed, which contracted another 1,017 MW of supply[2]. The recent implementation of the Feed-in Tariff program for renewables, as instituted through the Green Energy and Green Economy Act of 2009, will continue securing renewable resources in Ontario. These programs have made Ontario a leader in wind energy in Canada. The province currently operates more wind capacity than any other province.

### *Gas Resources Critical in Supply Mix*

The OPA's Clean Energy Supply contract process and Combined Heat and Power RFP, were the beginning of procurement efforts by the OPA which focus on gas resources. Since 2004, the province has added approximately 4,700 MW of gas-fired generation to the system. As described below, gas now represents a higher percentage (26 percent)[3] of the supply mix than coal. In fact, later this year, most of Ontario's new gas supply will have been in commercial operation over at least two peak operating seasons. This will set the stage for the closure of the

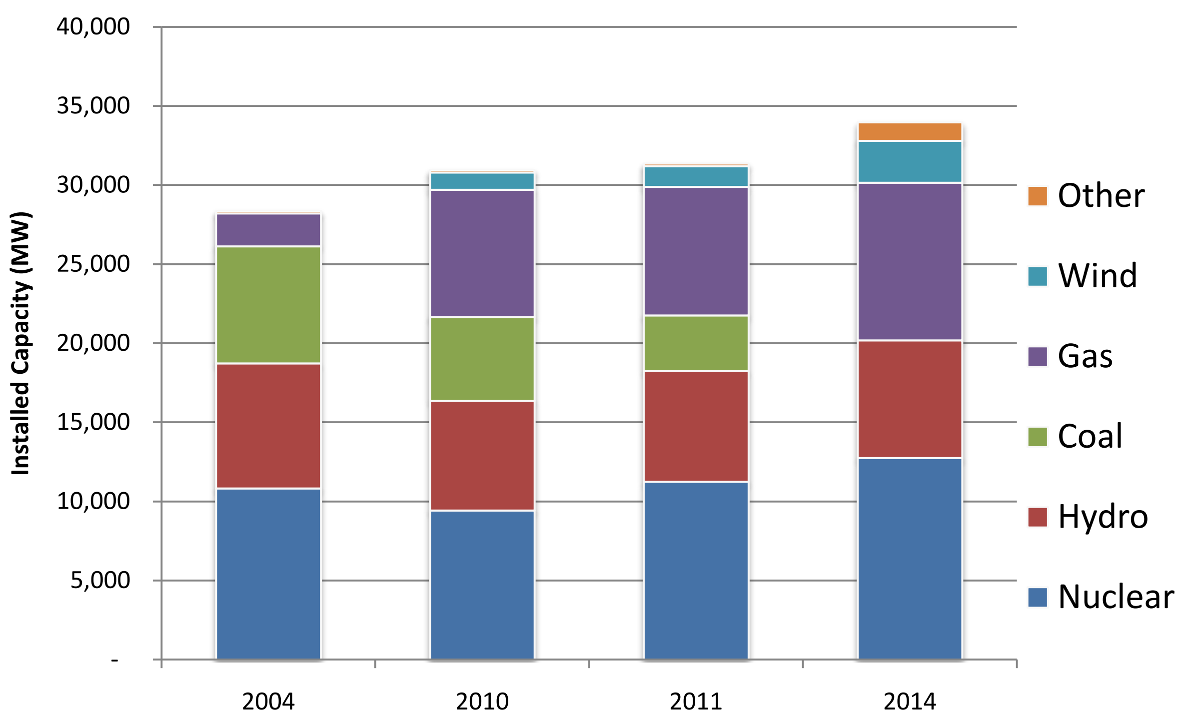
[2] OPA, 2010 A Progress Report on Electricity Supply Q1 2010
[3] IESO Output and Capability Reports

4 coal units in operation, further described in the section on coal phase out. Generally, we see these gas facilities serving several longer term purposes, including:

1. Securing substantive, dispatchable generation to address demand growth;
2. Support the phase out of coal;
3. “Firm up” intermittent renewable resources;
4. Providing flexibility and reliability in the system; and
5. Include enough reserve capacity to ramp up in support of nuclear refurbishment.

During the period 2004 to 2011 and looking out to 2014, the Ontario supply has and will continue to change, shifting away from coal and toward natural gas, nuclear, and renewables (Exhibit 23). We also identify gas-fired capacity as the critical, dispatchable and flexible generation type to respond to demand increases due to weather or economic activity and to respond during peak hours. With the anticipation that coal will be removed from the system, gas will remain the only fully reliable, dispatchable generating assets to be relied upon during the highest demand periods. Although OPG can operate some hydro facilities as peaking plants, their output is subject to water conditions.

**Exhibit 23: Ontario Electric Capacity Mix**



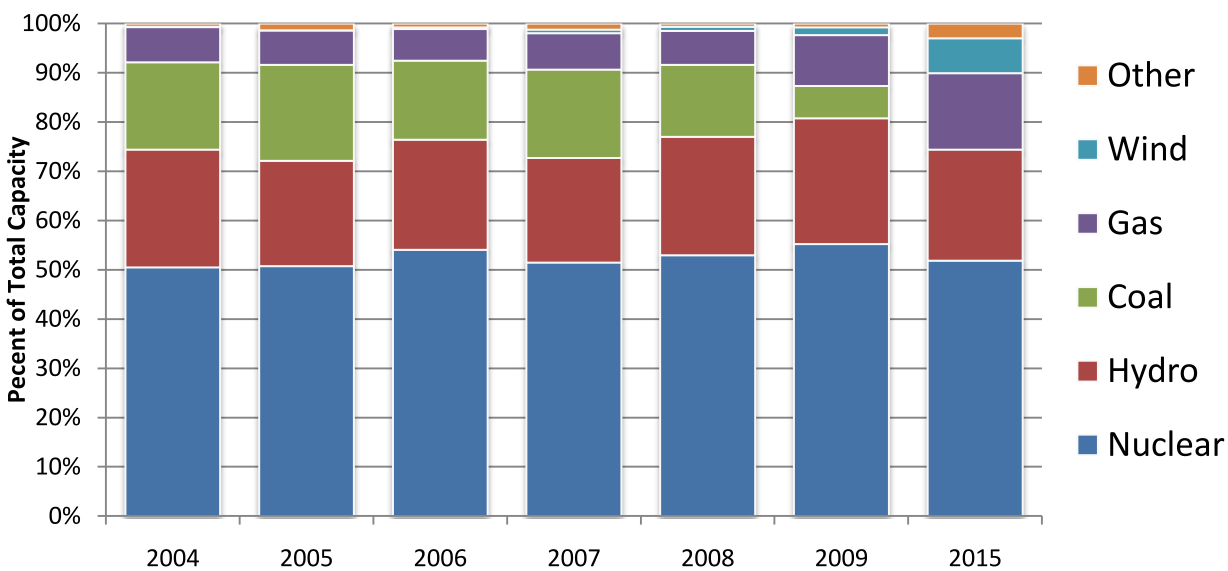

Note: Available capacity at peak hour. 2011 and 2014 estimates based on expected project completion dates.
Sources: IESO, 2010. Hourly Output and Capability Report, and IESO, 2009. The Ontario Reliability Outlook.

### *Changes to the Generation Mix*

The previous section identified the investment in gas-fired generating capacity and expected closure of Ontario's coal assets. The affect on the natural gas sector in Ontario will depend on the utilization of the new gas-fired facilities. The historical trend of the last few years shows a marked decrease in generation from coal (nearly 60 percent from 2006 levels)[4], even with the plants still being available to the system. The bearish electricity demand in Ontario has meant the coal fleet is underutilized relative to historic use. However, we can also see a trend of increasing gas-fired dispatch (Exhibit 24). We estimate that this generation is likely to grow as future developments are commissioned, economic recovery drives industrial demand higher and as coal capacity becomes less available due to policy actions.

As noted above, over the past few years the types of capacity used to generate electricity in Ontario have been changing. Nuclear and hydro remain the base load fuel types. However, mid load and peaking energy is growing in gas-fired generation, while coal generation continues a downward trend. By 2009, coal use was a record low, at only about 7 percent of total energy generated, while gas accounted for over 10 percent (Exhibit 24).

**Exhibit 24: Ontario Electricity Generation**

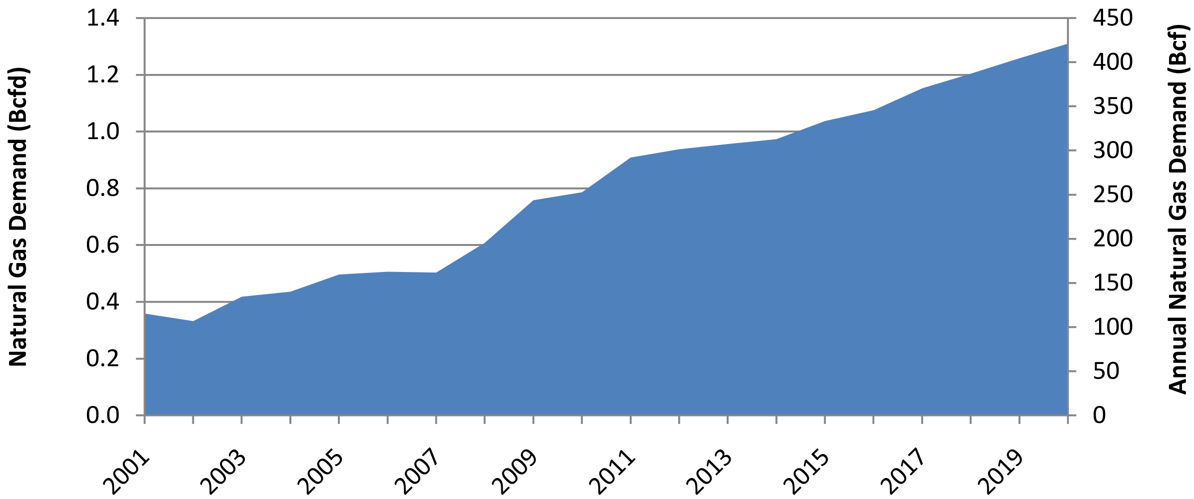



Sources: IESOMonthly Generator Reports and Annual Generation Summaries

With gas-fired generation expected to continue increasing, natural gas demand from the electricity generation sector is also forecasted to increase. Compared to 2009 levels, ICF estimates that the power sector is likely to consume about 37 percent more natural gas to support the new gas-fired fleet by 2015 (Exhibit 25). The gas units are expected to dispatch to meet electricity demand growth and to support decreases in coal generation.

[4] IESO Generator Output and Capability Reports.

**Exhibit 25: Electricity Sector Natural Gas Demand**




Source: ICF

In the longer term, we also expect continued growth in gas electricity generation, as all coal units in Ontario are retired and as refurbishments of nuclear units force extended shut downs. Post 2015, we anticipate gas demand by electricity generators may continue to grow annually by 5% or greater. As policy initiatives continue to drive more renewables onto the grid, the impact of their variability is also likely to further increase the demand for natural gas generation.

On July 8th of this year, the extremely hot weather pushed Ontario peak demand over 25 GW as air conditioning loads swelled. Much of the electricity supply resources during these periods are required to meet the system's demands. However, of the approximately 1,100 MW of wind capacity, only 107 MW were supplying electricity that day[5]. Wind resources in Ontario are typically much stronger in the winter than in the summer when typical peak periods occur. This example demonstrates that during peaks in electricity demand, renewable resource may not necessarily be available to generate electricity because the wind may not be blowing. In these cases, other forms of generation must be dispatched to keep supply and demand in balance. In other cases, we may see a substantial amount of wind drop out of the supply stack during specific periods. In this case, other dispatchable forms of generation must provide the "firm up" power as well.

Once coal is removed from the system, gas will be left as the most reasonable generating capacity to serve a firming function. Gas-fired turbines are flexible and can respond quickly to balance the system, where as other generating types are either too slow to respond and dispatch, or are not dispatchable on demand. Certain types of hydro facilities may be able to provide balancing services, but they too are not fully able to provide this function with certainty. As more wind capacity is added to the electricity system in Ontario, new gas generation and excess capacity from older plants will be dispatched more and more to support peak demand periods when wind capacity is not available.

[5] Ottawa Citizen, 2010. "Why Wind Power is More Complicated than People Imagine". August 8, 2010.

Since the OPA began procuring supply, a number of projects have been negotiated, contracted and developed. Because coal generation is declining and gas generation is likely to increase, it is important to have an understanding of the assets that will be available for generating grid electricity. The table below summarizes the natural gas-fired capacity that has been contracted by the OPA. Many of these projects have already achieved commercial operation and account much of the increase in gas generation in Ontario over the last few years. Other projects will be brought online in the near future and will continue to provide large-scale and flexible options for electricity generation to respond to increases in demand, coal plant closures and nuclear outages.

**Exhibit 26: Gas-Fired Capacity Projects**

| Energy Source | | Project Name | Contracted Capacity (MW) | Commercial Operation Date |
|---|---|---|---|---|
| Clean Energy Supply Contracts, Clean Energy Standard Offer, CHP RFP, CES Early Movers, Downtown Toronto and Goreway Contracts, Western GTA Supply, Northern York Region, Southwest GTA Supply, | Simple/Combined Cycle | Brighton Beach Power Station | 541 | Jan-06 |
| | | Goreway Station | 839 | Jun-09 |
| | | Greenfield Energy Centre | 1,005 | Oct-08 |
| | | GTAA Cogen | 90 | Feb-06 |
| | | Portlands Energy Centre | 550 | Apr-09 |
| | | Sarnia Regional Cogen | 444 | Jan-06 |
| | | St. Clair Energy Centre | 577 | Mar-09 |
| | | Sudbury District Cogen | 5 | Jan-06 |
| | | Sudbury Hospital Plan | 7 | Jan-06 |
| | | Greenfield South Power | 280 | Aug-12 |
| | | Halton Hills Station | 631 | Aug-10 |
| | | Oakville Station | 900 | Jan-14 |
| | | York Energy Centre | 393 | Dec-11 |
| | Combined Heat and Power | Trent Valley Cogen | 8 | Jan-06 |
| | | Algoma Energy Cogen | 63 | Jun-09 |
| | | Durham College Cogen | 2 | Mar-08 |
| | | East Windsor Cogen | 84 | Nov-09 |
| | | Great Northern Tri-Gen | 11 | Oct-08 |
| | | London Cogen | 12 | Dec-08 |
| | | Thorold Cogen | 236 | Mar-10 |
| | | Warden Energy Centre | 5 | Jun-08 |
| | | Becker Cogen Plant | 15 | Aug-11 |
| Total | | | 6,699 | |

Source: Ontario Power Authority, A Progress Report on Electricity Supply Q1 2010.

### *Provincial Environmental and Energy Policies*

In Ontario, there are a number of different environmental and energy policies that could substantially impact the energy markets. Several are broad policy initiatives at the federal level or through multijurisdictional agreements. Others are Ontario specific and aimed at mitigating greenhouse gases directly in Ontario, or directly impacting the energy sector. This section will summarize these policy initiatives.

### *Coal Phase Out*

Ontario Power Generation (OPG), the province's largest electricity generator, currently operates 6,316 MW of coal-fired capacity. These plants have long been a staple in the generating fleet of Ontario and have provided mid-load, peaking and export generation for over 30 years. Political initiatives have brought a substantial amount of uncertainty to the future availability of these large assets and have increased the complexity of the demand and supply situation looking forward. The proposed coal phase out in Ontario can be traced back many years, to the political promises of the then, newly elected Liberal government. Since this time, a tremendous level of ambiguity has existed on the level and timing of the coal phase out. Several targeted dates for removing coal from the system have been passed, including the original political target of 2007 and a subsequent adjusted target of 2009. Most recently however, more meaningful announcements have been made and conditions in the electricity market seem to indicate that the coal phase will realistically occur.

To align with the IPSP, a substantive announcement was made in August 2007 and included the issuance of a legally binding regulation for the "cessation" of coal use to generate electricity by 2014. O.Reg. 496/07 requires the owner and operator of the Atikokan, Lambton, Nanticoke and Thunder Bay generating stations to cease using coal as of December 31, 2014. The regulation leaves the door open for using something else as a fuel source, perhaps gas, or biomass. OPG is actively exploring the biomass option for the Atikokan station.

Current initiatives have been set that limit OPG to operate the four facilities so that they do not collectively emit more than 11.5 Mt of $CO_2$ from the use of coal in any calendar year starting in 2011. This commitment requires that that the government's coal cessation policy has legally binding interim carbon dioxide limits and reporting requirements. This is an important objective because the coal fleet has historically emitted between 30 and 40 Mt of $CO_2$. This will force a reduction in coal use, creating limitations on how Ontario Power Generation can operate its coal fleet, particularly in the short term. In September 2009, an announcement from the government of Ontario was released indicating that 2 coal-fired units at Lambton and 2 units at Nanticoke would be closed in late 2010 and that a target of 15.6 Mt or less of $CO_2$ emissions would be achieved by OPG in 2010. Considering the dramatic reduction of coal use in 2009, it is expected to be achievable.

#### *Policy Analysis and Implications*

Coal phase out promises have provided their share of skepticism in the marketplace. However, we are reasonably certain that OPG will not be burning coal to generate electricity at some point in the future and that the output from the relevant facilities will continue to be reduced relative to historic levels. We believe this for several reasons:

1. The Political Will is Strong – The political signals are strong, with other major government energy and climate initiatives linked to the coal phaseout.

2. Slowed Demand Growth – With demand expected to be flat or in decline between now and 2015, the province has been given the opportunity for capacity development to catch up. This window of opportunity will mean that the currently planned deadlines are more achievable.

3. The Trend in Coal Use is Declining – Coal generation in the province declined by 14% between 2004 and 2008; and was 58% lower in 2009 than the previous year.

4. Low Gas Price Trend – The low gas price trends we expect moving forward will make higher dispatch at Ontario's new gas facilities able to offset coal generation more quickly than originally expected.

The reduced coal generation is being offset by several forms of generation, and gas is a substantial part of that mix. Processes developed to procure large gas generation investment have been successful. These procurements are designed to meet demand growth and support the phase out of the coal plants.

***U.S. and Canadian Climate Change Policies***

In Canada, a regulatory design document was released in 2007 outlining specific targets for achieving GHG emissions reductions in Canada. The Regulatory Framework for Air Emissions targets for reducing GHG emissions. Rather than aiming to reduce absolute emissions, Canada's GHG regulations were to require facilities to reduce their emissions intensity. Covered industrial sectors included electricity generation and oil and gas and they would be set to participate through a market-based mechanism including an offset system. In March of 2008 the "Turning the Corner" document was released, further elaborating on the approach set in 2007 and committing Canada to reduce its total emissions by 20% relative to 2006, by 2020. Although Canada has continued to be publically committed to the 20% below 2006 target, international politics on climate change have slowed the aggressiveness with which the federal government is pushing for implementation.

Canada's most current position is to move away from an intensity-based system and will aim to harmonize as much as is reasonable to a United States-designed system to better integrate North America into one policy. As a result, Canada is waiting to see what comes out of the political process in the US. Meanwhile, the provinces are implementing their own policy initiatives, either alone or by committing to regional policy initiatives like the Western Climate Initiative (WCI) like Ontario has. Canada continues to introduce one-off regulatory initiatives that impact energy use and CO2 emissions. The most significant of these initiatives includes the announcement this past June that all coal-fired electricity generation in Canada will be subject to stringent performance standards. New units must meet emissions performance of natural-gas combined cycle to qualify for operating licenses, while existing units will be subject the same standards once their calculated economic lives have been reached. This will effectively phase out coal generation in the country save those projects that can implement successful carbon capture and sequestration technologies.

At the same time, several U.S. Senate bills have led the possibility of national climate change policy in the U.S. The most recent two include the Practical Energy and Climate Plan, table by Senator Richard Lugar (R-In) and the American Power Act, introduced by Senators Kerry (D-Ma) and Boxer (D-Ca). Pieces of legislation like this would drive economy-wide changes in energy production, use and $CO_2$ emissions. These legislative actions have continued to be debated in the House of Representatives. However, at this time it is unlikely that anything significant will be passed this year. We do not expect mandated implementation of any program until at least 2015. Most of the U.S. designs would place initial focus on the power sector, with other sectors to follow.

*Analysis and Implications*

These policy processes have created uncertainty as they have developed, and now it is likely that neither, Canada, or the US, will have a comprehensive climate change policy in place anytime soon. In any case, it is likely that these policies will contribute to the trends within the power sector that we have identified as expected. Further analysis is not necessary for the following reasons:

1. These policies will drive coal to gas fuel switching in the electricity generation sector. In the early to mid term, gas would provide significant emissions reductions in the U.S. and even though it would eventually become the highest emitting generating type, it would take many years outside the time horizon of study for other infrastructure to supplant the requirement for gas generation.
2. In Ontario, complementary policies are already driving significant coal to gas fuel switching. Federal policies would not compound this trend.
3. ICF's expected case for natural gas outlook already includes the policies impacting removal of coal from the Ontario system and increases in renewable and gas-fired generation.

***Western Climate Initiative***

Similarly to federal-level policies, the Western Climate Initiative (WCI) has run into a number of hurdles while attempting to implement its cap and trade mechanism. Although the WCI has had many successes in terms of multilateral negotiation and bringing a number of states and provinces together, the timelines originally expected have become a topic of concern to many of the participating regions. Participation has now become fragmented. On July 27, 2010, a new detailed design document for the regional cap and trade program was introduced by the WCI.

Ontario, along with two other Canadian provinces (Quebec and British Columbia) and two U.S. states have committed to implementing the design and adhering to the originally agreed to starting date of 2012. However, the other participating members have not made these commitments. We believe Ontario's agreement should be viewed with a level of caution. The stakeholder process within the WCI has often impeded specific targets and timelines and the provinces still fully participating have the option to exit at any time.

*Analysis and Implications*

We assume that regardless of Ontario's position within the WCI, little impact will be possible while the initiative finalizes its design elements and many of the participants continue to wait for federal leadership to signal their own final policy paths. It is expected that given the aggressive push towards renewable energy, on conservation and with the considerable increase in natural gas generation expected in the power sector, participation in a regional cap and trade through 2015 will have minimal incremental impacts within the energy sector.

### *The Green Energy and Green Economy Act*

The Green Energy and Green Economy Act (GEA) is envisioned to make Ontario a global leader in the development of renewables, clean distributed energy and conservation, while driving economic activity, creating jobs and providing energy security. The GEA was passed into law in May, 2009. Further amendments and regulations required to fully implement the legislation were introduced through the month of September. These regulations will become the primary driver for energy policy and investment moving forward. Through a statutory requirement, the OPA is expected to submit an updated or amended IPSP to the OEB that could supplement the GEA and allow for strategic elements to develop. The natural gas-fired fleet that has been procured and contracted will continue to be a significant part of the supply mix as time goes on. Also, the question of nuclear will continue to be debated and decisions on the amount of refurbishment and new build will still be answered. Nuclear will continue to be a substantial part of the generation mix well past 2015.

The GEA has implemented two important features that will impact the shape of the power sector. These include the Feed-in Tariff (FIT) system and the obligation for utilities to give priority grid access to "green" energy projects. The FIT provides incentives for renewable energy and allows for much broader participation in the electricity market, including home owner and small business-based generation.

We also see synergies in the IPSP and GEA in terms of renewable development, both support an increase in Ontario's use of renewable energy from hydro, wind, solar and biomass for electricity generation. Renewables have been the fastest growing capacity type in Ontario, albeit from a small baseline. OPA designed procurement has increased renewable investment and renewable energy will continue to grow at a fast pace as the FIT program takes over. The FIT will also be managed by the OPA. Although gas capacity has not had the same level of growth from early in the decade, the total amount of capacity developed far exceeds that of renewables and has equaled about 4,700 MW since 2004. As noted in the section on capacity changes, increased renewables will continue to increase the requirements for gas generation to provide firm power and ancillary services to support shifts in renewable output and generation during peak periods when wind is typically unavailable.

### *OPA Procurement and the FIT Program*

The OPA has contracted substantial amounts of renewable energy to the system and continued growth is expected to be quite strong. However, it must be recognized that the basis for growth is only a fraction of the total installed capacity in Ontario and it will take many years for wind and solar to become dominant forms of generation. The OPA's most recent Progress Report on Electricity Supply[6] estimates that the current amount of contracted renewable capacity that has reached commercial operation, equals 2,388 MW, which is still much less than the 4,700 MW of natural gas capacity from clean energy supply contracts. It is expected that 3,785 MW of renewables will be available by 2014 as a result of the OPA's procurement activities. In addition, The OPA has announced FIT contract offers for over 2,500 MW of additional renewables. However, ICF estimates connection, manufacturing and construction constraints will inevitably slow the pace at which these projects will be able to connect to the grid. Nearly 700 FIT contracts have been offered by The OPA and it is reasonable to assume that some will either not be executed or will fail to complete the development process.

[6] Ontario Power Authority, 2010. A Progress Report on Electricity Supply

Many project proponents offered contracts through the micro-FIT program are losing confidence in the program over a reduction in the price that small ground mounted solar projects will receive. We believe this will reduce the number of successfully completed projects over the next five years. By the end of the first quarter this year, thousands of micro-FIT contracts had been awarded; only 127 had been executed.

We believe that the total amount of installed renewable capacity by 2015 in Ontario is more likely to be about 5,000 MW, not the 10,000 MW targeted for by the GEA, as the program details continue to evolve, development constraints become more evident and contracting issues prevent finalization of projects. These factors, combined with the coal phase, out will mean gas will continue to play an important role.

## 3.1.2 Industrial Sector

As the economy continues to recover in 2011, natural gas demand in the industrial sector is expected to have a strong response. In Canada, the industrial sector is expected to have the strongest gas demand growth potential (besides electric power) when compared to other economic sectors. This growth is almost entirely driven by growth in oil sands operations using natural gas for various processes. However, large industry in Canada and particularly in Ontario has been declining for several years. Even with the high growth in the oil and gas sector, (as oil sands development pushes ahead) demand for gas in the industrial sector has been fairly stagnant. Manufacturing and other energy intensive industries have for several years been experiencing increasing closures and cutbacks. Many of these mature industries face increasing global market pressure, higher energy prices, uncompetitive exchange rates against foreign currency and labour market competition.

In Ontario, we expect some recovery in the industrial sector. Industrial gas demand is projected to increase in 2010 and 2011 by 6 and 8 percent respectively. Although some initial growth is forecasted, annual gas demand is anticipated to flatten out at about 0.75 Bcfd, never reaching past demand levels. The limited near-term growth projection is caused by economic recovery expectations and industry beginning to ramp back up. This trend is reinforced by continued low gas prices in relation to historic price. Because the economic slowdown has been experienced across North America at the same time that natural gas supplies are rising, the resulting lower prices are expected to help reinvigorate industrial sector demand. However, the economy as a whole is becoming much more productive relative to energy use and Ontario's overall long-term energy intensity is declining. This contributes to flatter gas demand growth.

***Oil Sands Development***

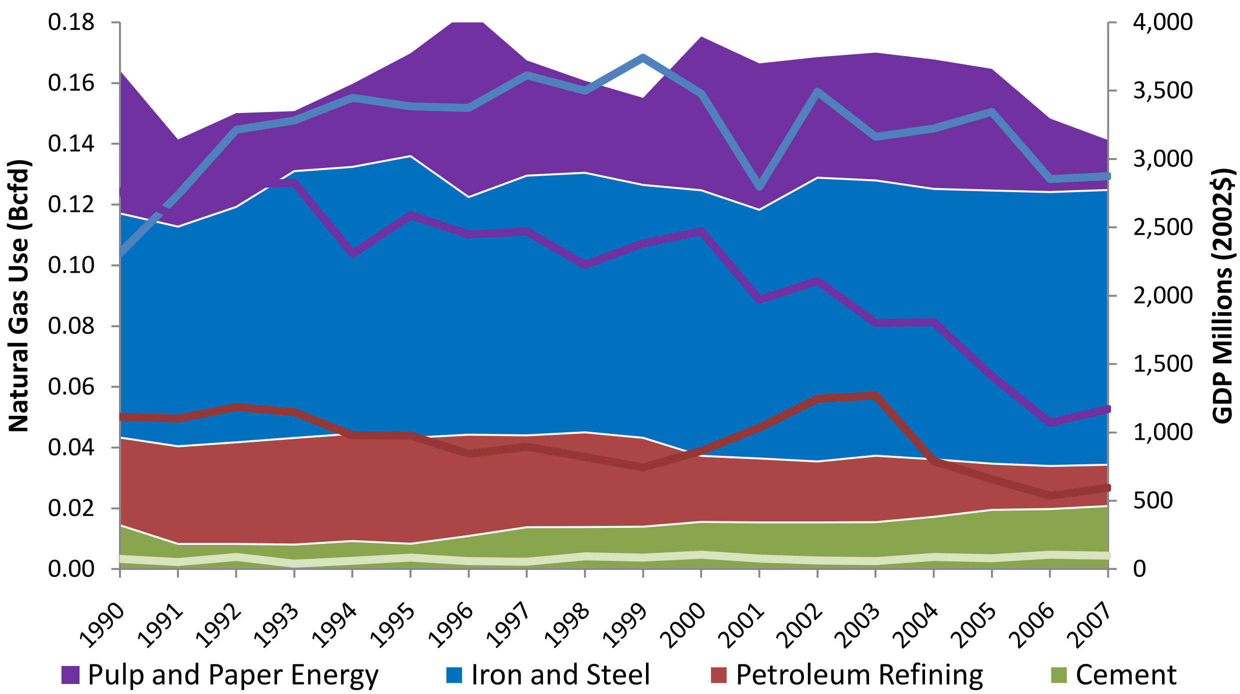
Oil sands development is the primary driver of natural gas demand growth in Western Canada. While this does not have a direct impact on Ontario gas demand, it does have an impact on Ontario since Western Canada is Ontario's primary source of natural gas supplies (gas supply trends are discussed in more detail in Section 3.2 below). Oil sands development was bullish through most of the 1990s and 2000s, but has slowed recently due to the worldwide economic downturn, which brought lower oil prices and stagnation in credit markets. Regardless of the recent downturn, the oil and gas sector is still expected to be the strongest performing industrial sector in Canada. The NEB's current forecast projects that oil sands production will climb to over 2.8 million barrels per day by 2020, and that natural gas use will reach 1.4 Bcf per day by 2020. However, due to the relatively high ratio of world oil prices to our projected Western

Canadian gas prices, ICF expects even stronger growth in oil sands oil production and gas use. We project that oil production from the oil sands will reach 3.4 million barrels per day by 2020, and that natural gas consumption will increase to 2.2 Bcfd.

### *Manufacturing Industries*

The majority of Canada's manufacturing industries are in Ontario, and the manufacturing sector is a key component of industrial gas demand. Many of the key manufacturing subsectors have been in decline in recent years. Competitive forces from international markets, rising energy costs and the strength in the Canadian dollar have all contributed to the falling growth trends. The current recession has also contributed to increased sector losses and continued decline. Total economic output has been declining in three of four major manufacturing sectors, particularly in the most recent years (Exhibit 27). As expected, these sectors' natural gas use is declining as well. Cement has experienced some increases due to robust construction. However, the sector's natural gas use is fairly flat.

**Exhibit 27: Ontario Economic Output and Natural Gas Use for Selected Industries**




Note: Lines represent gas use, areas represent industry GDP.
Source: NRCAN, 2010. Office of Energy Efficiency.

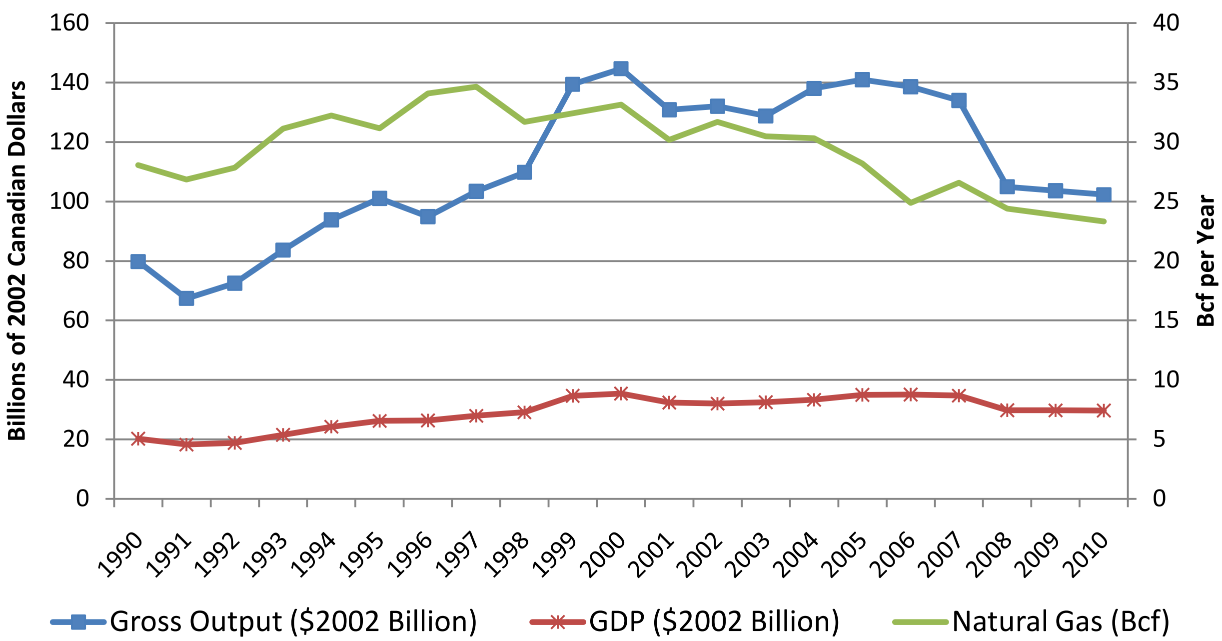
As noted, the decline in Ontario's manufacturing industries accelerated during the 2008-09 recession. Overall, Ontario's total annual manufacturing sales declined by 5.3 percent in 2008 and another 18.5 percent in 2009, showing a trend that has been increasing in severity over the past decade[7]. Ontario's total manufacturing sector accounted for about 16.5 percent of GDP at the end of 2008. At that time, manufacturing GDP had declined for the seventh straight quarter, while employment in the sector had fell for the twenty-third straight quarter[5].

[7] Ontario Economic Update, July 23, 2010. Ministry of Finance.

### *Auto and Auto Parts Manufacturing*

Ninety-two percent of Canada's total auto industry is located in Ontario. Ontario's auto manufacturing sector has been particularly hard hit by the recession. According to Industry Canada, auto manufacturing represents 4 percent of Ontario's GDP. In the fourth quarter of 2008, auto manufacturing GDP was down 17 percent, bringing 2008 annual losses to 22.7 percent. In 2009, data had not rebounded. All of the major auto manufacturers reported substantial production declines in Q1 2009 when compared to Q1 2008 (on average, 47 percent). These figures have broad impacts. The entire auto parts supply chain is affected with production slowdowns and plant shutdowns[8]. Auto manufacturing has had declining gross output and GDP figures since the mid-2000s (Exhibit 28). In the most recent two years, declines have been particularly sharp. Today, it is estimated that the sector is 15 percent smaller in terms of its contribution to GDP when compared to 2005. This decline had impacts along the sector's entire supply chain and auto parts manufacturing is in decline as well. Consequently, natural gas use has been falling annually by 3 percent on average in the overall auto manufacturing sector[9].

**Exhibit 28: Ontario Auto Manufacturing Economic Output and Gas Use**




Source: Canadian Industrial Energy End Use Database and Analysis Centre 2010

## 3.1.3 Residential and Commercial Sectors

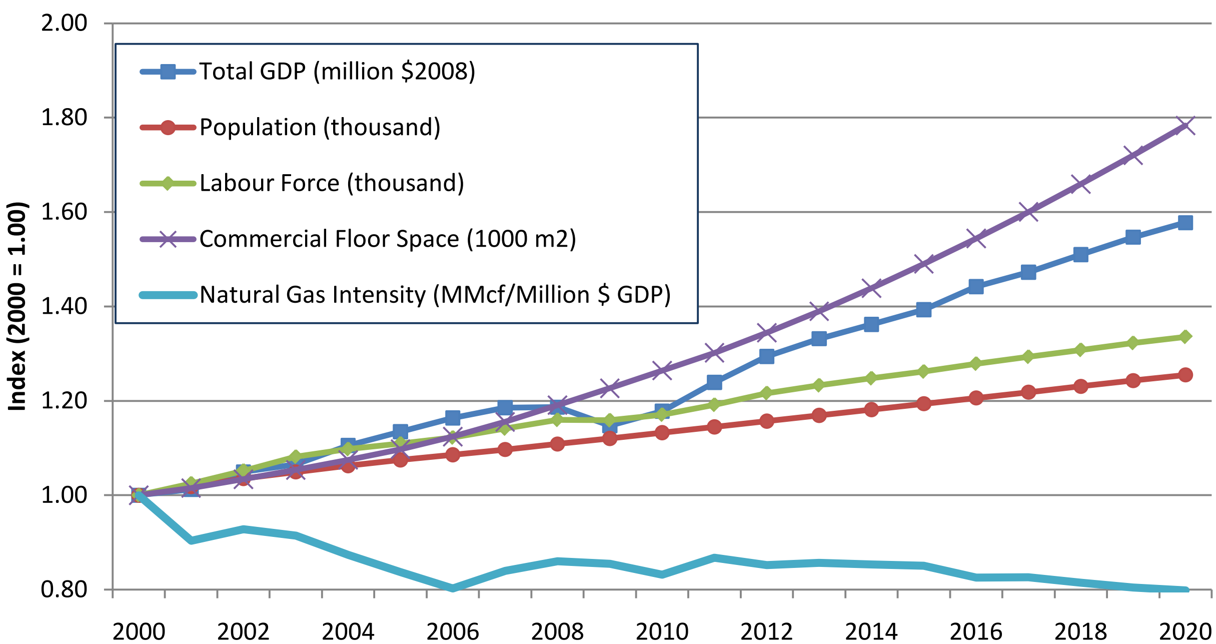
According to the NEB, end-user energy demand growth is slowing. As estimated in July 2009, energy demand is projected to grow at only 0.7% per year between 2007 and 2020. This is

[8] Ontario Economic Overview, May 2009 Update. Industry Canada.
[9] Canadian Industrial Energy End Use Database and Analysis Centre, 2010.

compared to the historical growth rate of 1.6% since 1990[10]. Several factors are leading to this trend, including lower workforce and population growth, increasing oil prices, slower economic growth and implementation of conservation and demand management programs. In the residential and commercial space, the most significant factor to the historical and expected flat trends in gas demand is energy efficiency improvements in end-use devices. These improvements are driven by natural improvements in design and technology manufacture, but also by changes in consumer values as they relate to energy use and the environment.

While energy indicators have shown flat or declining trends, all demographic data, both historical and future estimations, are showing strong growth. Generally, over the past 10 years, the energy intensity of the economy has been decreasing (Exhibit 29). The natural gas intensity of the economy has also been declining and is expressed below as volume of natural gas consumed per dollar of GDP. Declining energy intensity will mean productivity is increasing. This is represented by concurrent increases in GDP, population, labor force and commercial floor space as the energy intensity declines. These factors have all been indexed to 2000 values to get a clear picture of their trends.

**Exhibit 29: Demographic Indicators and Gas Intensity (Indexed to 2000)**



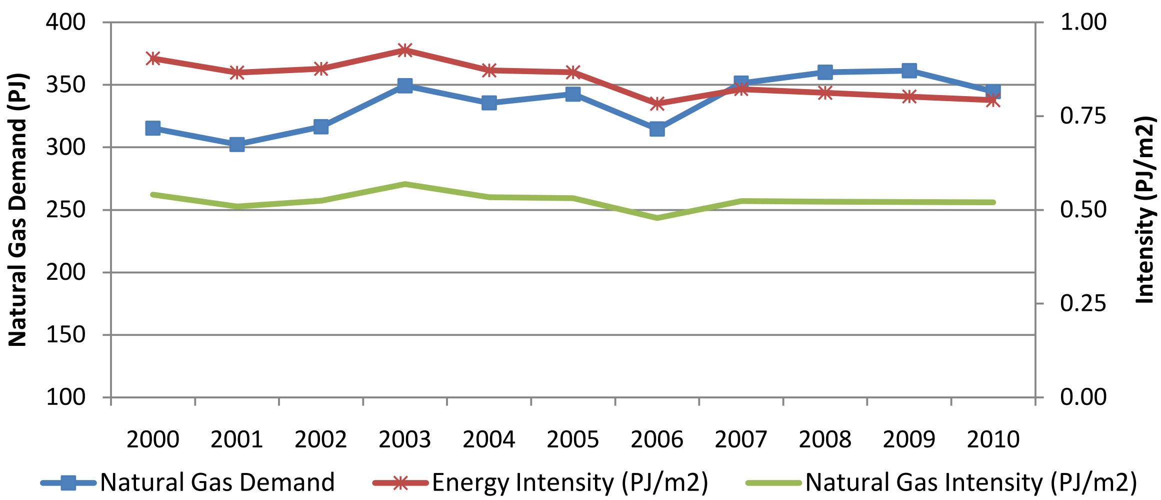

Sources: ICF and NEB 2009 Reference Case Scenario

As with the NEB, ICF projects a slowing growth trend in Ontario's end-user sectors. In the residential sector, efficiencies gained in gas furnaces and other gas equipment combined with more energy efficient building construction has led Ontario residential gas demand growth to fall from an average of 1.8% annually since 2001, to a projected growth of 1.4% per year looking forward. In 2009 we saw zero growth and in 2010 we expect negative growth. However, as the economy recovers in 2011, demand growth resumes.

[10] National Energy Board, 2009. Reference Case Scenario

Over the past few years, government policies and programs directed at reducing energy use have been seen across North America and Ontario is no exception. Ontario has implemented conservation and demand management programs directed at reducing electricity and natural gas consumption. The province has also recently changed building code standards to improve the energy intensity of housing stock and implemented new furnace and boiler efficiency standards. The phasing out of inefficient lighting is currently being undertaken and a number of home appliances are now having minimum energy efficiency standards placed on them. Measurable improvements in the efficiency of major appliances and equipment have resulted. Some of the gains in energy efficiency are offset by increased total demand due to larger home sizes, preference for air conditioning and widening number of consumer electronics and other energy using equipment, but the net effect is a slowing of demand growth for natural gas. Over the past ten years, energy intensities have been declining even as total annual gas consumption increased (Exhibit 30).

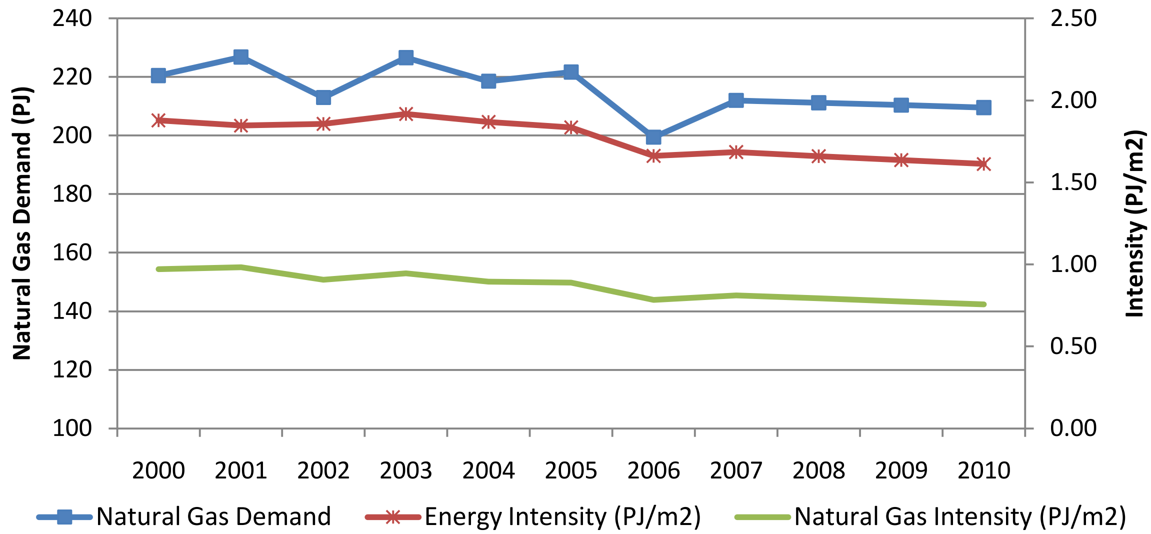
**Exhibit 30: Residential Gas Demand and Energy Intensity (PJ/m$^2$)**




Source: Natural Resources Canada, Office of Energy Efficiency, Comprehensive Energy Use Database

The commercial sector in Ontario generally uses far less natural gas than the residential sector. However, the trends over the last decade are virtually identical. The commercial sector includes offices, retail, food and entertainment, warehousing, government and institutional buildings, utilities, communications, hospitals and service industries. Commercial gas demand has been trending downward over the past decade, partially due to the economic downturn, but also due to significant energy efficiency improvements in the commercial sector. The total energy intensity and natural gas intensity for commercial buildings has been declining more than in the residential sector at 1.5 percent and 2.3 percent respectively (Exhibit 31). Commercial gas demand is projected to increase as the economy recovers. The pace of commercial sector growth is somewhat greater than recent history, as the service sector is expected to be a greater source of economic growth in the future.

**Exhibit 31: Commercial Gas Demand and Energy Intensity**




Source: Natural Resources Canada, Office of Energy Efficiency, Comprehensive Energy Use Database

### 3.1.4 Implications and Uncertainties for Demand Trends

The changing nature of gas demand in Ontario and surrounding gas markets will have significant impacts on these markets. Gas demand is both growing and changing in composition, as demand in the power sectors increases more rapidly than in other sectors. The increased use of natural gas for power generation has implications for the gas market as a whole. Power sector gas demand has a different seasonal pattern than the other sectors, with peaks in both the summer and winter. Power sector gas demand can also be quite volatile, with demand shifting dramatically on a daily and even hourly basis. These differences from the traditional patterns in demand can create stresses on the regional natural gas pipeline and storage infrastructure.

The greatest uncertainty for long-term gas demand is the pace of future demand growth, which may be faster or slower than projected. National and provincial environmental and energy policies have been setting a trend for increased gas demand growth, particularly in the power sector. However, the pace of gas demand growth could vary significantly depending on exactly how these new policies are implemented. Accelerated retirements of coal plants to meet climate policy initiatives could cause a sudden surge in gas demand, which would place upward pressure on gas prices. Also, the pace of economic growth after the recent recession will have an effect on the pace of gas demand growth, particularly in the industrial sector. If the industrial sector does not recover and output continues downward, then industrial gas demand in Ontario could continue to contract, lowering the rate of total demand growth.

## 3.2 Supply Trends

Growth in natural gas demand puts upward pressure on prices, which in term prompts E&P companies to increase their investments and develop more natural gas resources. The U.S.

and Canada have ample remaining resources for natural gas, with over 300 Tcf of proven gas reserves and over 3,700 Tcf of economically recoverable resource, assuming current E&P technologies (Exhibit 32). The resource base is more than enough to meet the projected growth in North American demand, but most of the resource has yet to be developed. If the market is to meet the projected demand growth, the projected levels of development for new gas supplies would have to be much greater than in the past. As a result, the potential amount of E&P investment and the potential activity levels for resource development are significant.

**Exhibit 32: U.S. and Canada Natural Gas Resource Base, in Tcf**

| | Proven Reserves | Unproved Plus Discovered Undeveloped | Total Remaining Resource | Shale Resource[1] |
|---|---|---|---|---|
| Alaska | 7.7 | 153.6 | 161.3 | 0.0 |
| West Coast Onshore | 2.3 | 24.6 | 27.0 | 0.3 |
| Rockies & Great Basin | 66.7 | 388.3 | 454.9 | 37.9 |
| West Texas | 27.6 | 47.7 | 75.3 | 17.5 |
| Gulf Coast Onshore | 70.1 | 684.7 | 754.8 | 476.9 |
| Mid-continent | 37.0 | 205.0 | 241.9 | 133.9 |
| Eastern Interior [2] | 18.6 | 795.7 | 814.3 | 728.1 |
| Gulf of Mexico | 14.0 | 238.6 | 252.5 | 0.0 |
| U.S. Atlantic Offshore | 0.0 | 32.8 | 32.8 | 0.0 |
| U.S. Pacific Offshore | 0.8 | 31.7 | 32.5 | 0.0 |
| WCSB | 60.4 | 664.0 | 724.4 | 508.8 |
| Arctic Canada | 0.4 | 45.0 | 45.4 | 0.0 |
| Eastern Canada Onshore | 0.0 | 12.8 | 12.8 | 0.0 |
| Eastern Canada Offshore | 0.5 | 71.8 | 72.3 | 0.0 |
| Western British Columbia | 0.0 | 10.9 | 10.9 | 0.0 |
| **US Total** | **244.7** | **2,602.6** | **2,847.3** | **1,394.5** |
| **Canada Total** | **61.3** | **804.5** | **865.8** | **508.8** |
| **US and Canada Total** | **306.0** | **3,407.1** | **3,713.0** | **1,903.3** |

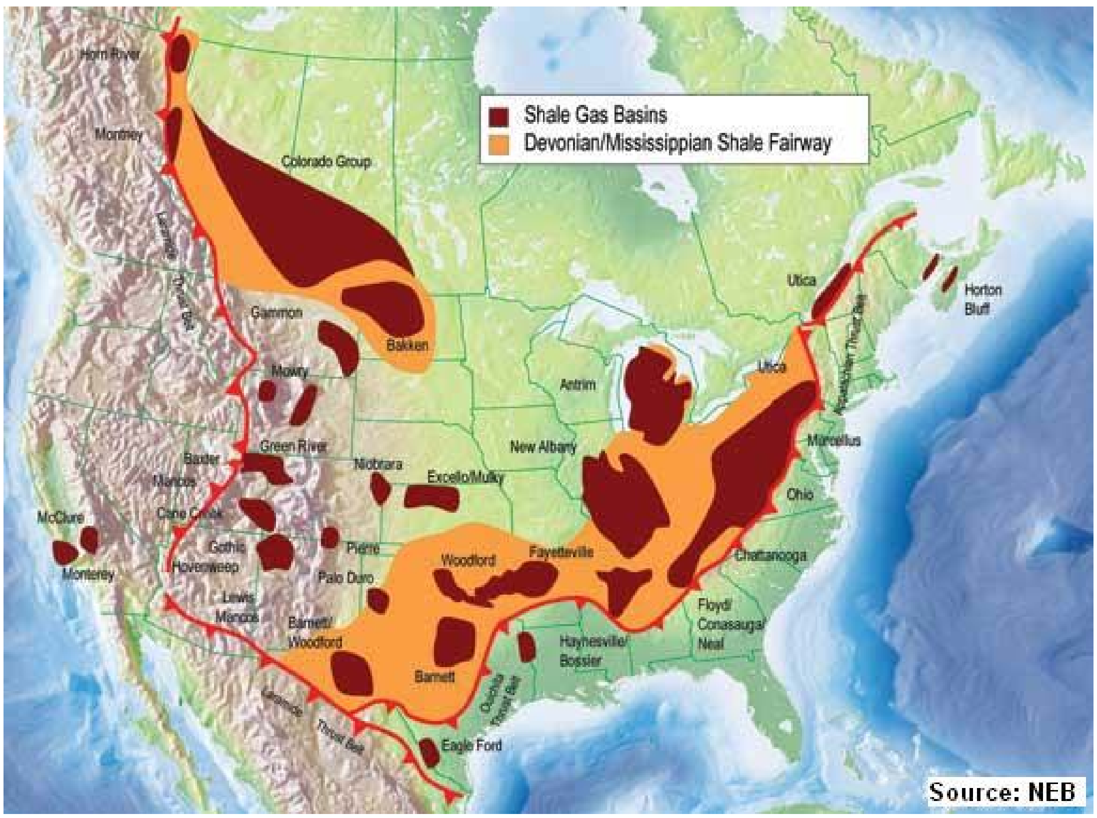
1 . Shale Resource is a subset of Total Remaining Resource Source: ICF International

2. Resource estimate for Eastern Interior assumes drilling levels are held constant at today's level over time, reflecting restricted access to the full resource development.

### *Shale Gas*

Over half of the total remaining resource is in shale gas formations. Shale formations are widely spread across North America (Exhibit 33). While producers have turned their focus to shale gas over the past decade, extracting hydrocarbons from shale is not new. In fact, there has been some natural gas produced from shale in the Appalachian Mountains since the late 1800s. However, because of the low permeability of shale formations compared to conventional sandstone formations, until recently shale formations were not a major source of North American gas supplies. By using a combination of horizontal drilling and multi-stage hydraulic fracturing, the productive potential of shale gas has increased dramatically. Hydraulic fracturing involves injecting fluid at a very high pressure into underground rock formations to fracture the shale. For shale drilling, the fracturing fluid is typically a mixture of water, sand, and a small amount of other chemicals. The sand (or "proppant") helps prop open the fractures, which allows the gas to escape the shale and flow to the surface. By drilling horizontal wells, where the drill bit is steered along a horizontal trajectory through the shale formation, the wellbore is exposed to much more of the reservoir than in a vertical well. The trade-off between horizontal wells and conventional vertical wells is increased access to reserves but at a higher cost. The technology and the extra time needed to drill horizontally, and apply fracturing treatments to a well, makes shale gas wells relatively expensive. Horizontal shale gas wells can cost as much as $5 million, but costs have been declining as E&P companies gain experience and refine their techniques. Also, since shale gas wells provide access to such a large quantity of gas resource, the per-unit cost of shale gas development is favorable compared to alternative gas supplies.

**Exhibit 33: Map of North American Shale Gas Plays**



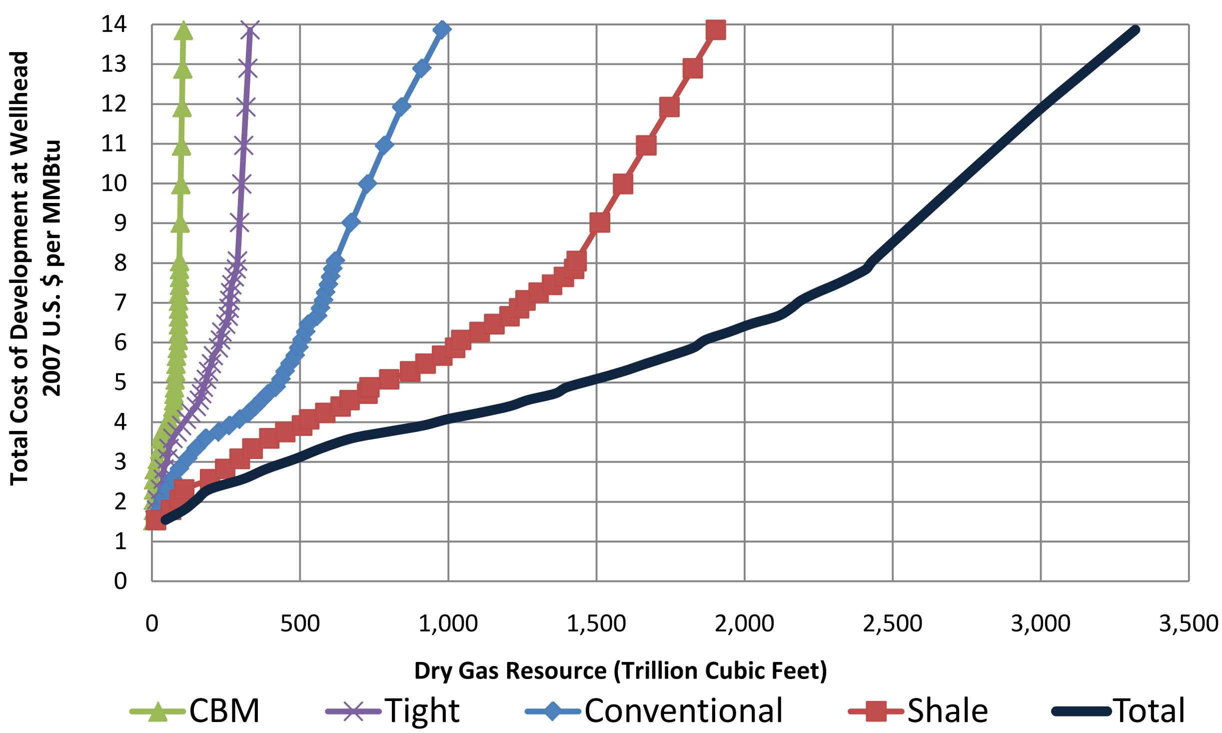

Modern shale gas drilling techniques are relatively new, having been developed in the late 1990s and refined over the past decade. To date, only a few shale plays have been developed, but shale gas production is growing very rapidly. The Barnett Shale, located in the Dallas/Fort Worth area of Texas, was the first major shale play to be developed at the end of the 1990s. Barnett was a huge success, with production growing to over 5 Bcfd by 2009. As shale gas production was proven to be very successful, development spread to other shale plays. Much of the initial shale gas development has been in the Gulf Coast and Midcontinent states, where much of the conventional onshore gas and oil development has been in the past. The Woodford Shale (primarily in Oklahoma), Fayetteville Shale (in Arkansas), and Haynesville Shale (in northwest Louisiana and northeast Texas) have all been under development for several years. The Haynesville Shale has been the fastest growing area, and it appears to be on track to surpass the Barnett Shale's rate of production within the next several years.

Including Barnett, total production from the Gulf Coast and Midcontinent shale plays averaged over 8 Bcfd in 2009.

Other shale plays more recently under development include Eagle Ford in south Texas, Montney and Horn River in British Columbia, and Marcellus, which stretches across several states in the northeast U.S. While development has only recently begun in these plays, the Marcellus Shale has drawn the most attention from producers for several reasons. First, it has a very large resource potential, with over 700 Tcf of gas economically recoverable using current technologies. Second, being located in the Northeast U.S., it is close to one of the largest market areas in North America. While development of the Marcellus Shale began only a few years ago, production has increased rapidly and is already approaching 1 Bcfd.

Shale gas has had not just an impact on the total amount of available resource, but also on resource costs. Based on current E&P technologies and costs, there is about 750 Tcf of shale gas resource that can be develop for a total wellhead cost of $5 per MMBtu or less (Exhibit 34). After adding other unconventional resources (tight gas and CBM) and conventional resources, the total amount of resource available at $5 per MMBtu or less rises to 1,500 Tcf. Constraints such as the availability of rigs and the personnel limit the amount of resource that can be developed in any one year, but the amount of gas available in the supply curves at wellhead prices of $5 per MMBtu and below indicates that not only are there ample gas supplies in North America, but they can be developed at a reasonable cost.

**Exhibit 34: North American Natural Gas Supply Curves**

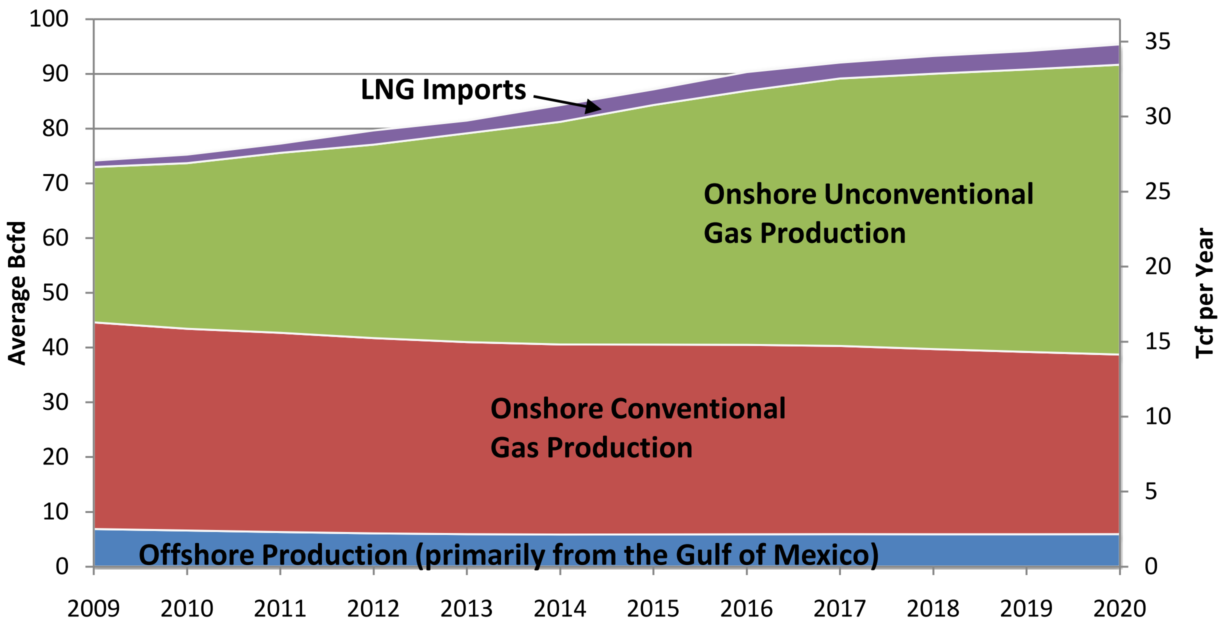



Source: ICF

In this environment, total U.S. and Canada gas production is projected to grow from about 73 Bcfd in 2009 to nearly 92 Bcfd by 2020, an average annual growth rate of over 2 percent (Exhibit 35). Unconventional production is projected to increase to 53 Bcfd, while offshore and conventional onshore production is projected to decline to 39 Bcfd. In short, unconventional gas production becomes the dominant gas supply in our projection, and many of the currently conventional supplies become the marginal sources of gas supply in the future.

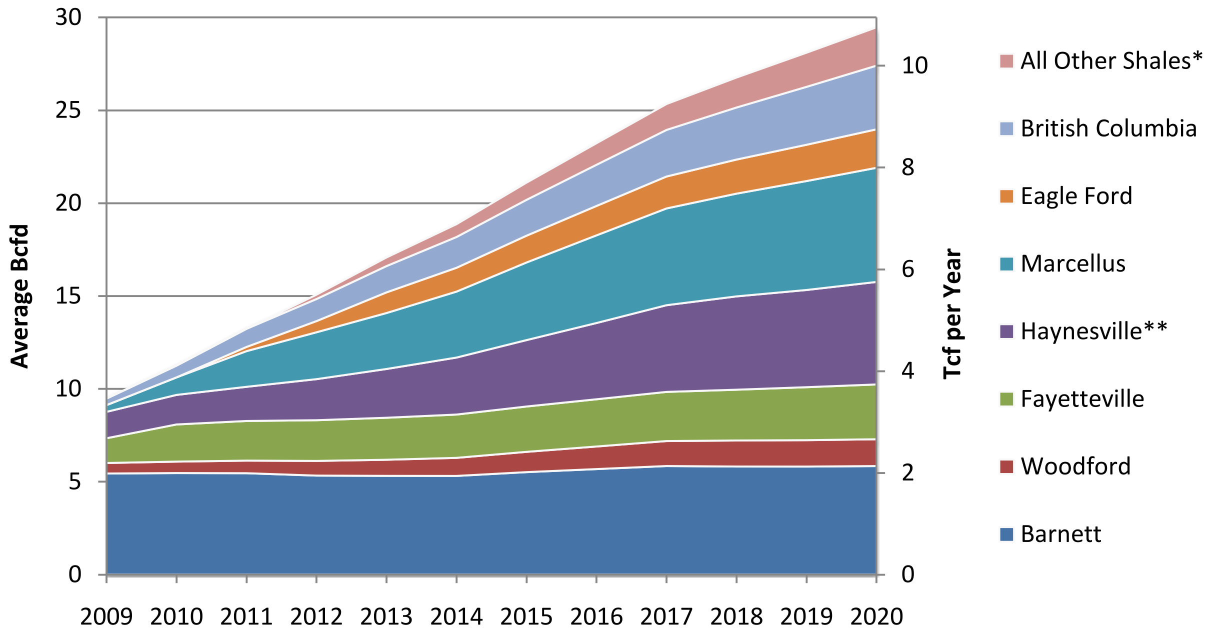
As discussed above, shale gas makes up the vast majority of unconventional gas production. By 2020, shale production rises to nearly 30 Bcfd (Exhibit 36). While the Barnett Shale has been the largest shale production area to date, growth here is expected to slow as this is a relatively mature area. In the future, producers are likely to focus their efforts on newer shale plays. The biggest growth potential is in the Haynesville and Marcellus Shale; together, these two areas account for about half of the growth in shale production. By 2020, ICF projects that the Haynesville Shale increases to 5.5 Bcfd, and Marcellus Shale increases to 6.1 Bcfd.

**Exhibit 35: U.S. and Canadian Gas Supplies by Type, 2009-2020**




Source: ICF

**Exhibit 36: U.S. and Canadian Shale Gas Production, 2009-2020**




* By 2020 the "All Other" category includes approximately 0.5 Bcfd of production from Alberta shale plays.
**Haynesville production shown here includes gas from other shale plays in vicinity, e.g., the Bossier Shale.
Source: ICF

### *The Potential Role of LNG*

North American LNG imports are also projected to increase in our projection, rising from about 1.2 Bcfd in 2009 to 3.7 Bcfd by 2020. In terms of market share, imported LNG is projected to grow from less than 2 percent of U.S. and Canadian gas supplies to nearly about 4 percent by 2020. While LNG imports are projected to increase, they still make up a relatively small share of total North American demand. Given the relatively abundant supplies of natural gas in North American, gas prices in Europe and Asia are likely to be higher, and therefore these markets are likely to attract more of the world LNG supply than the U.S. and Canada.

The only LNG import terminal in Canada is Canaport in Saint John, New Brunswick, with a maximum send out capacity of 1.2 Bcfd. Since its start up in 2009, the average monthly send out from Canaport has ranged from about 0.1 to 0.4 Bcfd. Projected imports to Canaport average between 0.4 and 0.5 Bcfd, similar to NEB's projections. Most of the LNG imported to Canaport makes its way to New England consumers via the Maritimes and Northeast pipeline.

While other import terminals have been proposed, relatively low natural gas prices are likely to discourage development of additional import capacity, so we have no additional U.S. or Canadian import terminals (other than those currently operational or under construction) being added in our projection. In fact, due to the relatively low gas prices, LNG exports from Canada are a very realistic possibility. We assume that the Kitimat LNG export facility in British Columbia will be completed and start exporting in 2014. Given projected demand in Asian markets, we assume that the Kitimat facility will export 0.4 Bcfd initially, and increase its exports to about 0.8 Bcfd by 2017.

### 3.2.1 Ontario's Gas Supply Outlook

Changes in Ontario's gas supply generally reflect the overall changes in North American gas production. Exhibit 37 shows current and projected Ontario gas supply, based on an analysis of interregional gas flows.[11] Historically, more than half of Ontario's gas supplies came from the WCSB. While the WCSB is expected to remain the largest single supply source for Ontario, both its absolute supplies to Ontario and its share of total supply are expected to decrease as shale gas production grows. In terms of market share, ICF projects WCSB (non-shale) gas decreases from nearly 60 percent of Ontario's total supply in 2009 to only 41 percent by 2020.

Over the same time period, supplies of gas from shale plays are projected to increase from about 11 percent in 2009 to about 29 percent in 2020. The increase in gas supply coming from Midcontinent area shale plays (Barnett, Haynesville, Fayetteville, and Woodford) reflects the change in the pool of gas available to the Midwest U.S. The Midcontinent shale gas can move into Ontario through Michigan via the Dawn Hub. Some of the production from the Western Canada shale plays (Montney and Horn River) enters TCPL and flows to Ontario, but much of those supplies either stay in western markets or are exported at the Kitimat LNG export facility. The primary impact of increasing Marcellus Shale production is to supply markets in the Northeast U.S., replacing the declining exports from Canada. However, by 2020 we project that, due to the anticipated increases in Marcellus production and anticipated decreases in flows from Western Canada, some Marcellus gas will flow into Canada at Niagara in the summer months, helping to fill gas storage in the Dawn area.

**Exhibit 37: Ontario Natural Gas Supplies by Source, 2009-2020**

| | Supply (Bcfd) | | | As Percent of Total | | |
|---|---|---|---|---|---|---|
| **Supply Source** | **2009** | **2015** | **2020** | **2009** | **2015** | **2020** |
| WCSB (non-shale) | 1.66 | 1.60 | 1.49 | 58.9% | 46.8% | 41.1% |
| Western U.S. | 0.37 | 0.47 | 0.51 | 13.1% | 13.8% | 14.0% |
| Midcontinent U.S. | 0.28 | 0.39 | 0.38 | 10.0% | 11.4% | 10.4% |
| Midwest U.S. | 0.17 | 0.17 | 0.16 | 6.1% | 5.1% | 4.3% |
| Haynesville Shale | 0.11 | 0.23 | 0.31 | 3.9% | 6.9% | 8.6% |
| Fayetteville Shale | 0.09 | 0.19 | 0.26 | 3.0% | 5.6% | 7.1% |
| Barnett Shale | 0.06 | 0.07 | 0.06 | 2.2% | 2.1% | 1.7% |
| Woodford Shale | 0.05 | 0.09 | 0.12 | 1.7% | 2.8% | 3.2% |
| Western Canada Shale | 0.01 | 0.14 | 0.27 | 0.5% | 4.2% | 7.5% |
| Marcellus Shale | 0.00 | 0.00 | 0.04 | 0.0% | 0.0% | 1.2% |
| Ontario Production | 0.02 | 0.02 | 0.02 | 0.6% | 0.5% | 0.5% |
| All Other U.S. | 0.00 | 0.03 | 0.02 | 0.0% | 0.8% | 0.4% |
| *Shale Gas Subtotal* | *0.32* | *0.74* | *1.06* | *11.3%* | *21.6%* | *29.3%* |
| **Total Supply** | **2.83** | **3.41** | **3.63** | **100.0%** | **100.0%** | **100.0%** |

Source: ICF

[11] The Ontario supply source analysis is based on ICF's projected inter-regional gas flows, and treats gas supplies within each market as fungible.

## 3.2.2 Implications and Uncertainties for Supply Trends

The shift in North American gas supplies from conventional to unconventional supplies has implications for all facets of the natural gas market. The growth of shale gas production requires significant investment in gas infrastructure, particularly pipeline capacity to move these new supplies to demand markets downstream. While considerable investments in new pipeline have already been made, much more will be needed as shale gas supplies continue to grow. Growth in Marcellus Shale production in particular will pose certain challenges for the existing infrastructure (changes in gas pipelines and storage are discussed in more detail in Section 3.3 Gas Pipelines and Storage below).

The Ontario gas market can benefit both directly and indirectly from the increases in shale gas production. Ontario benefits directly by receiving additional gas supplies from shale sources to help meet growth in gas demand and replace declining conventional gas supplies from Western Canada. Ontario also benefits indirectly from the increased supply of shale gas (particular from Marcellus Shale) to Northeastern U.S. markets. As the Northeastern U.S. gets more shale gas, there is less competition for the decreasing supplies of gas from conventional sources in Western Canada, preventing Ontario prices from rising dramatically as gas demand increases further downstream to the east. A higher percentage of the gas from Western Canada can stay in Ontario, as Northeastern U.S. market demand is increasingly met with shale gas from the U.S.

The potential of the shale resource is undisputed, but there are uncertainties as to whether the rapid pace of development will continue. While total North American drilling activity declined during the recession, activity in the shale plays has been remarkably resilient. Continued sluggishness in the North American economy could delay development of new gas resources, but due to the sheer size of the shale resource it appears likely that shale gas will be the dominant gas supply in the future.

***Environmental Uncertainties***

Among the uncertainties associated with projected shale gas production is the extent to which environmental concerns will affect the projected rate of production. ICF's projection for production is based both upon our estimate of the total amount of shale resource available and our projection for producer activity in the shale plays over the next ten years.

As discussed above, most shale gas production is dependent on the use on hydraulic fracturing. While hydraulic fracturing techniques have been used for decades in other areas, concerns have been raised at both the U.S. state and Federal level about the potential environmental impacts of hydraulic fracturing, which could reduce producer activity. Water use for hydraulic fracturing is currently exempt from U.S. Federal clean water regulations, but the U.S. Environmental Protection Agency is conducting a new study on its environmental impacts. Also, there have been proposals in the U.S. Congress for new regulations on drilling activity (e.g., the so-called "FRAC Act"). The New York State Senate recently passed a bill that would place a moratorium on the use of hydraulic fracturing through May 2011. The environmental concerns about hydraulic fracturing and drilling activity in general are summarized below:

- *Drilling in densely populated areas.* The spacing of well-sites, the presence of large rigs moving about on local roads, the foot print of drilling sites, and air and noise pollution, all have contributed to siting issues of these well sites.

- *Water requirements.* Wells need substantial amount of water to pump into the deep-underground shale formation for hydraulic fracturing. The demand for water competes with other water resource needs.
- *Chemical exposures.* Hydraulic fracturing fluid is a mixture of water, sand, and chemicals that include friction reducers, biocides, surfactants and scale inhibitors, acids. The principal concern, however, is whether these chemicals could come in contact with ground water and water supplies.
- *Produced contaminated water management.* Wells produce significant amounts of water along with the gas; this occurs mostly in the early stages of production. The produced water will have the fracking chemicals in it as well as other contaminants from the shale. One of these is a class of materials referred to as normally occurring radioactive materials (NORMs) which collect in the holding tanks. Management of produced water including reprocessing and removal to keep it out of streams and water sources is required by environmental law and regulations.

Another environment concern that has been raise regarding the Horn River Shale in British Columbia is the $CO_2$ content of the raw gas which is produced. While it is not unusual for the raw gas produced from either conventional or shale gas wells to contains some $CO_2$, the $CO_2$ content of the Horn River Shale gas is relatively high at 11 to 12 percent.[12] Typically, any $CO_2$ above two percent of the total dry gas volume is removed at a gas processing before it enters the interstate pipeline system. The $CO_2$ can then be sold by the processing plant for use in industrial processes, or in some cases it is vented directly into the atmosphere. If Horn River Shale production increases to the projected levels, it could become a major source of $CO_2$ emissions in British Columbia. These emissions could be avoided by re-injecting the separated $CO_2$ underground, a process referred to as carbon capture and sequestration (CCS), but this would impose additional costs upon the natural gas producers and/or processors.

## 3.3 Gas Pipelines and Storage

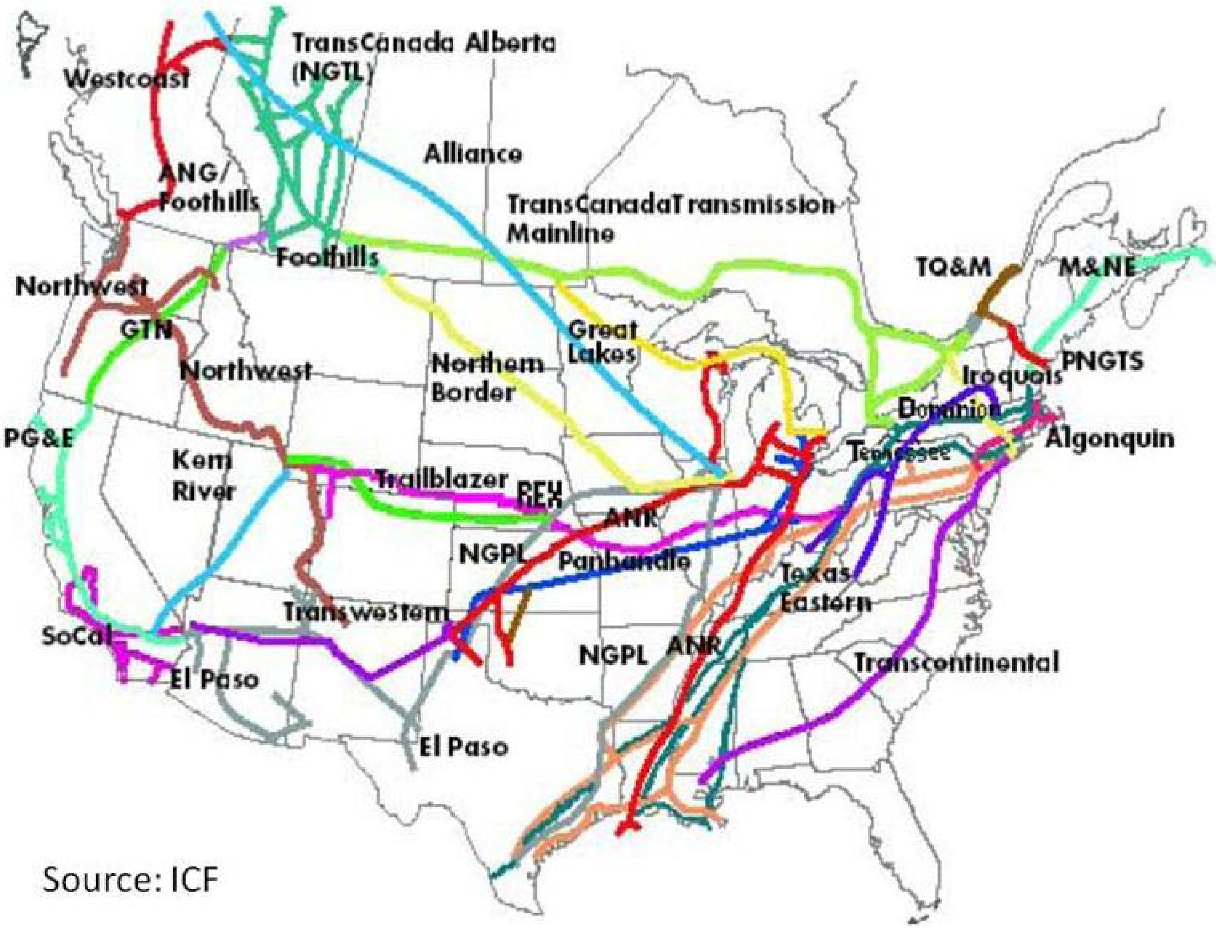
In this section we address the implications of supply and market trends for natural gas pipelines and storage. First, we take an overview of the natural gas pipeline network, both for North America as a whole and for Ontario and surrounding areas. Second, we look at some of the specific issues facing pipelines serving Ontario. Third, we examine issues surrounding natural gas storage in and around Ontario. Lastly, we look at the potential implications and uncertainties surrounding these pipeline and storage issues.

### 3.3.1 Overview of Natural Gas Pipeline Network

Ontario is significant in the North American pipeline network both as a major consuming market and as a transshipment center for gas supply transportation and re-delivery to Quebec and the Northeast U.S. Traditionally gas has flowed west out of the WCSB over TCPL and Great Lakes Transmission into Ontario. From Ontario, gas was sent on to Quebec, New York, and New England over various pipeline systems. Exhibit 38 provides an overview of the North American pipeline network and Ontario in this context.

[12] "Shale Gas and Climate Targets: Can They Be Reconciled?", Mark Jaccard and Brad Griffin, Pacific Institute for Climate Solutions 2010.

**Exhibit 38: Overview of the Major North American Natural Gas Pipelines**

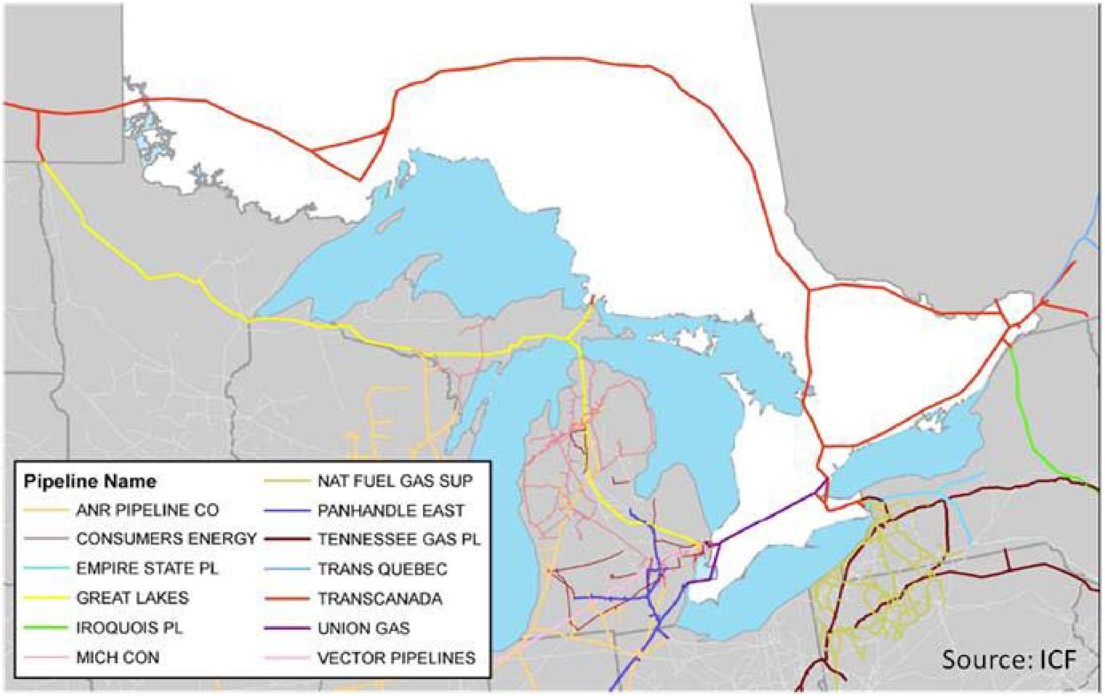



Historically, Ontario has been Canada's largest consuming gas market, with a total market size just over 1 Tcf annually, or an average of just under 3 Bcfd. As discussed in Section 3.1.4 above, nearly all of Ontario's gas supply comes from outside the province, principally from WCSB, with additional supplies from the U.S.

Exhibit 39 shows in more detail the natural gas pipeline network into and around Ontario. Natural gas traditionally has entered the Province over the northern mainline of TCPL and through the Dawn Hub in southwestern Ontario. Gas then exits Ontario towards the United States at Niagara and Waddington, as well a travelling on to Quebec.

TCPL's northern mainline has a capacity of 4 Bcfd at the Manitoba border, being directly interconnected with the WCSB. Three major border crossings connect Ontario with supply entering from the west: ANR Pipeline (wholly owned by TransCanada), MichCon (a division of DTE Energy), Great Lakes Gas Transmission (GLGT – 68.5 percent owned by TransCanada), CMS (formerly Panhandle), Trunkline, and Vector (connecting through Chicago to the Alliance and Northern Border systems). Another pipeline connects Michigan Blue Water Storage into Union at the border. The total border capacity from the United States into southwestern Ontario is currently about 3.9 Bcfd. (Spectra and DTE have filed with the OEB to construct the Dawn Gateway pipeline from Michigan storage to Dawn, with 350 MMcfd of capacity. The Board has approved this application but at this time, Dawn Gateway Pipeline Limited Partnership has request to delay construction, due to evolving market dynamics.)

**Exhibit 39: Ontario Regional Natural Gas Pipelines**




Dawn is the storage hub of Ontario where all of the above pipes feed into the hub which has multiple pipeline takeaway interconnections. The Parkway interconnect between Enbridge and TCPL has an easterly capacity of about 5 Bcf per day. The Kirkwall interconnect to the Tennessee, Empire and National Fuel systems in New York has a capacity of 1.6 Bcfd. Underground storage capacity in the Dawn area is about 260 Bcf, with about 4.5 Bcfd of deliverability. Through the pipelines feeding Dawn from the U.S., Ontario has access to approximately another 600 Bcf of underground storage in Michigan. While the southern Ontario "panhandle" area has multiple pipeline connections, northern Ontario is served solely by TCPL.

The excess of pipeline capacity over Ontario's own needs is used to transport gas to Quebec and the Northeast U.S. Historically, about 60 percent of the gas entering Ontario moves across the province into these markets. Gas is delivered across the international border at Niagara into the Empire and National Fuel systems feeding northern New York State and into Tennessee pipeline serving New England. The total capacity at Niagara is about 2.3 Bcfd. At Waddington, TCPL interconnects with the Iroquois Pipeline (44.5 percent owned by TransCanada), at a capacity of about 1.2 Bcfd for the New York City metropolitan area. Farther northeast, TCPL's TQM system in Quebec serves Montreal and ties into the Portland Natural Gas Transmission System (PNGTS, 61.7 percent owned by TransCanada).

Ontario's two major distribution companies are Enbridge Gas Distribution (Enbridge) and Union Gas Limited (Union). Other smaller systems include Natural Resource Gas, the City of Kitchener, and the City of Kingston. Union's service territory includes communities along the TCPL northern main line from the Manitoba border, along Lakes Superior and Huron as well as much of southwestern Ontario and the northern shore of Lake Ontario. Enbridge serves primarily Toronto and environs, the area around Niagara, and eastern Ontario including Ottawa.

## 3.3.2 Natural Gas Pipeline Issues

With the expansion of shale production and increasing production from the Rocky Mountains, the U.S. has seen major new pipeline expansions in recent years to bring this gas to market. Since 2006, major new pipelines include the following:

- Centerpoint, Carthage to Perryville (Texas/Louisiana), 1.2 Bcf/d
- Rockies Express (Wyoming to Ohio), 1.8 Bcf/d
- Gulf South (Louisiana, Mississippi, Alabama), 560 MMcf/d
- Fayetteville Expansion (approved by FERC, 2009, Arkansas/Mississippi), 2.0 Bcf/d
- Ruby Pipeline (approved by FERC, 2010, Wyoming/California), 1.5 Bcf/d

While none of these pipelines are directly aimed at Ontario, they are aimed at markets that have been served by WCSB supply. Rockies Express carries Rockies gas into the Chicago market and points east where it can reach New York. The Ruby pipeline will take Rockies gas west to California, backing out Alberta supply. The pipelines across the south represent major expansions of shale gas from the Barnett, Fayetteville, and Haynesville formations into the pipeline networks serving the industrial belt from Chicago easterly to New York. Looking more specifically at Ontario and the northeast, there have been over 5 Bcfd of expansions since 2007 (Exhibit 40).

**Exhibit 40: Recent Northeast Pipeline Expansions**

| Year | Pipeline - Expansion Name | Area | Capacity (Bcfd) |
|---|---|---|---|
| 2007 | Union Gas - Dawn to Trafalgar | Ontario | 0.5 |
| | Columbia Gas - Hardy-Homestead | Southern Virginia | 0.2 |
| | Texas Eastern - Time II | Pennsylvania and New Jersey | 0.2 |
| | Vector Expansion 2007 | Chicago to Dawn Ontario | 0.2 |
| 2008 | Transco - Leidy to Long Island | Into NYC | 0.1 |
| | Northern Natural -Northern Lights Exp. | REX to Minnesota | 0.4 |
| | Texas Eastern - Time II | Lebanon OH to Leidy PA | 0.2 |
| | Union Gas - Dawn East 2008 | Dawn to Toronto | 0.3 |
| | Guardian - Expansion & Extension | Chicago to Wisconsin | 0.5 |
| | Colorado Interstate - High Plains Exp. | Cheyenne WY to Denver CO | 0.9 |
| | Empire Connector & Millennium Pipeline | Across NY | 0.5 |
| | Algonquin - Ramapo Exp. | Millennium into NYC | 0.3 |
| 2009 | Transwestern - Phoenix Lateral w/ SJ Loop | Arizona & New Mexico | 0.5 |
| | Transco - Sentinal Expansion | Eastern PA and New Jersey | 0.1 |
| | Vector Pipeline 2009 | Chicago to Dawn Ontario | 0.2 |
| | Iroquois 08/09 Expansion | Into NYC | 0.2 |
| | Northern Bridge | REX Clarington OH to Oakford PA | 0.2 |
| Total | | | 5.4 |

Source: ICF, compiled from various sources

Exhibit 41 lists the announced projects to serve the Marcellus shale and Northeast markets over the next five years; others could still be announced. ICF projects that between 2011 and 2015 there will be 2.5 Bcfd of expansions in the Northeast, with new capacity transporting gas through the Appalachia region into eastern New York, New Jersey, and New York City.

## Exhibit 41: Announced Northeast Pipeline Expansion Projects

| Pipeline - Expansion Name | Area | Capacity (MMcfd) | Planned In Service |
|---|---|---|---|
| Dominion Transmission - Dominion Hub II | Leidy PA to Albany NY | 20 | Nov-10 |
| Dominion Transmission - Dominion Hub III | Clarington OH Reciepts | 224 | Nov-10 |
| Dominion Transmission - Rural ValleyLine 19/20 | NW PA to Oakford PA | 57 | Apr-10 |
| Dominion Transmission - Appalachia Gateway | West Virginia to Oakford PA | 550 | Sep-12 |
| Dominion Transmission - Marcellus 404 Project | West Virginia | 300 | Jan-00 |
| Texas Eastern - TIME III | Oakford PA to Transco | 60 | Nov-11 |
| Texas Eastern - TEMAX | Clarington to Transco | 395 | Nov-10 |
| Texas Eastern - TEAM 2012 | Interconnects OH, WV, PA | 300 | Nov-12 |
| Texas Eastern - TEAM 2013 | Interconnects OH, WV, PA | 500 | Nov-13 |
| Spectra -TETCO - Algonquin - NJ-NY Expansion | Linden NJ to Staten Island NY | 800 | Nov-13 |
| Spectra -TETCO - Algonquin - NJ-NY Expansion | Reverse flow of Algonquin | 1150 | Nov-13 |
| National Fuel - West to East Phase 1 | Overbeck PA to Leidy | 200 | Nov-11 |
| National Fuel - West to East Phase 2 | Overbeck PA to Leidy | 300 | Nov-12 |
| National Fuel - Lamont Compression | Lamont PA | 40 | May-10 |
| National Fuel/Empire - Tioga County Extension | Tioga PA to Corning NY | 200 | Sep-11 |
| National Fuel - Line N Expansion | Alnong Western PA border | 150 | Sep-11 |
| National Fuel - Appalachian Latteral | Clarington OH to Overbeck PA | 625 | Nov-11 |
| Tennessee Gas Pipeline - Line 300 Line Upgrade | Line 300 across northern PA | 350 | Nov-11 |
| Tennessee Gas Pipeline - Northeast Supply Diversification | New copression station near Niagara NY | 50 | Nov-12 |
| Tennessee Gas Pipeline - MLN Project (Marcellus-Leidy-Niagara) | New copression station near Niagara NY | 118 | Nov-12 |
| Tennessee Gas Pipeline - Northeast Upgrade Project | Line 300 to Interconnects with NJ Pipelines | 636 | Nov-13 |
| Columbia Gas Transmission - Line 1570/Marcellus Shale | Northwest Pennsylvania | 150 | Jun-10 |
| Columbia Gas Transmission - Line 1570/Line K Replacment | Northwest Pennsylvania | TBD | 2011? |
| Columbia Gas Transmission - Columbia Penn Corridor Phase 1 | Waynesburg PA to Delmont PA | 101 | Mar-10 |
| Columbia Gas Transmission - Columbia Penn Corridor Phase 2 | Leidy PA to Corning NY | 500 | Jun-12 |
| Williams Transcontinetal - Northeast Supply Project | St195 SE PA to Rockway Deliv Lateral - National Grid NYC | 625 | Nov-13 |
| Williams/Domminon - Keystone Connector | REX Clarington OH to Transco St195 SE PA | 1000 | Nov-13 |
| Iroquois Gas Transmission - Metro Express | Waddington or Brookfield to Market areas | 300 | Nov-12 |
| Iroquois Gas Transmission - NYMarc | Sussex NJ to Pleasant Valley NY | 1000 | Nov-14 |
| Inergy Midstream - Marc I Hub Line | Bedford PA (Tenn) to Columbia Co PA (Transco) | 550 | Oct-11 |
| Inergy Midstream - North-South Project | Tioga NY (Millenium) to Bradford PA (Tenn/Transco) | 325 | Nov-11 |
| Laser Marcellus Midstream - Marcellus Gathering | Susquehanna PA to Millenium (NY) | 60 | 2011 |
| Williams Partners - Susquehanna Gathering(Cabot Oil) | Susquehanna PA to Luzerne PA (Transco) | 250 | Jun-11 |
| EQT Midstream - EQT Gathering Expansion | WV and West PA | 300-900 | 2013 |
| EQT Midstream - Marcellus Eastern Access Hub | Braxton WV and Upshur WV | TBD | TBD |
| Dominion Transmission - Marcellus Gathering Enhancement | with Appalachia Gateway | 50 | Sep-12 |
| PVR Midstream - AMI Gathering | Lycoming PA, Tioga PA, and Bradford PA | 700 | Nov-10 |

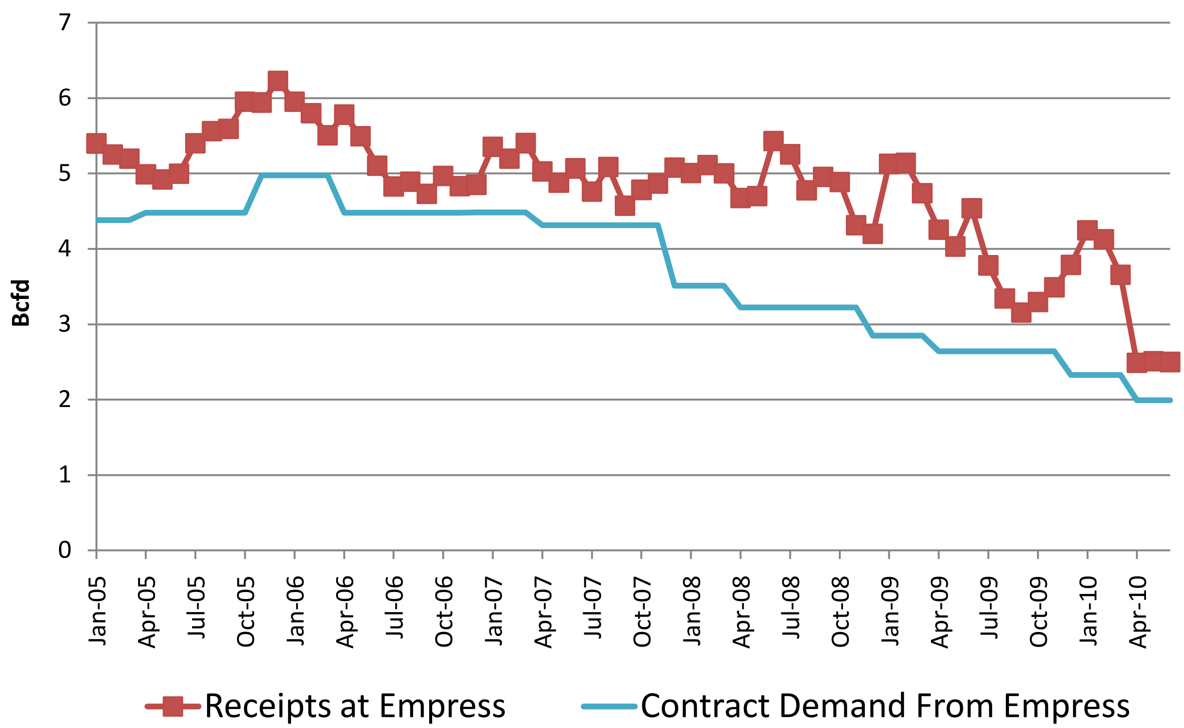
Source: ICF, compiled from various sources

Thus, there are several developments that will affect the gas transmission flows and costs on TCPL's systems serving Ontario:

- WCSB is a mature resource and has begun to decline in productive capacity and gas deliverability into exporting pipelines.
- Increasing gas demand in Alberta for the production of oil from tar sands and growing power generation, are keeping more of the gas in-province.
- At the same time, increases in gas production from shales and the Rockies, along with expanded pipeline capacity to get these supplies to eastern markets, have provided competitively priced alternatives to TCPL.

From the standpoint of the Albertan producers seeking to maximize the value of their gas, the TCPL mainline to Parkway is the high cost pipeline out of the WCSB and would yield the lowest netback price at the wellhead. The other options producers have besides TCPL mainline are TCPL/Great Lakes to Dawn, Foothills/Northern Border to Chicago, Alliance to Chicago, or Foothills/GTN to California. On TCPL, a producer would pay either the interruptible transportation (IT) rate (approximately $2.00/MMBtu) or a firm rate (approximately $1.85/MMBtu, assuming he used capacity released by a firm shipper). Estimates based on average annual 2009 market prices at the various markets accessible over these alternative pipeline routes indicate that producers would have to accept $0.60/MMBtu less than the next best alternative.  Thus, producers will choose ship first over the lower cost pipelines and once these lines are full, shippers will turn to TCPL.  As production declines in the WCSB or more gas is consumed in province, volumes over TCPL will diminish.  Shippers already have begun to de-contract, allowing their capacity reservations to expire. Exhibit 42 shows the recent history of contract capacity and flows on TCPL at Empress.

**Exhibit 42: TransCanada Mainline FT Contract Demand at Empress versus Flows from Empress**



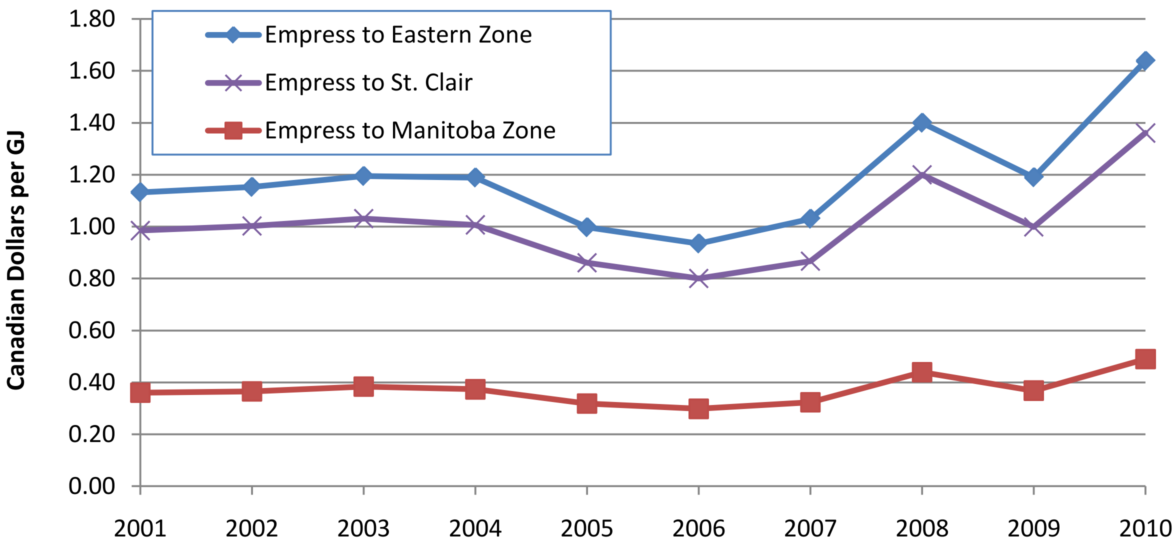

Source: Pipeline electronic bulletin board data.

This is relevant to Ontario in that declining throughput will lead to higher transportation tolls.  As the paid-for reserved capacity and throughput decline[13], the cost-of-service declines less rapidly.  The result is that tolls increase as the costs must be borne by fewer shippers across lower throughput volumes (Exhibit 43).

The full implication of the TCPL tolling situation is demonstrated in Exhibit 44 and Exhibit 45, which show changes in natural gas flow patterns between 2009 and 2020.

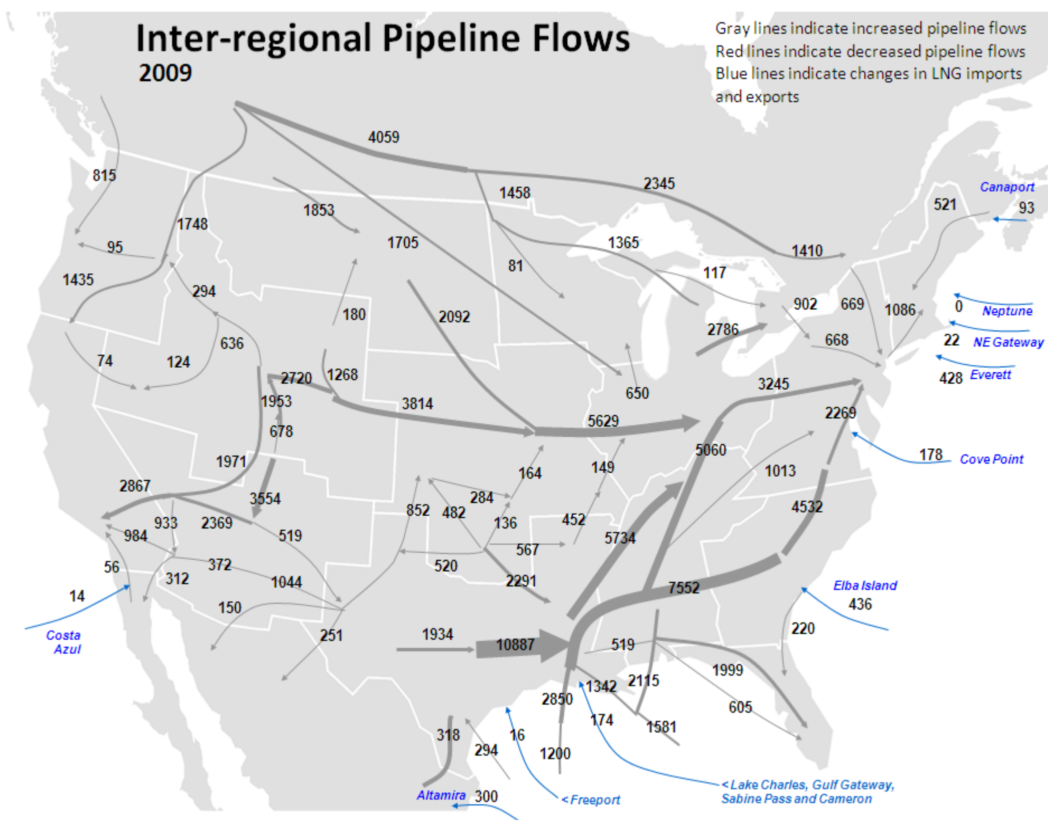
[13] On October 31, 2010, TCPL has 2,693TJ/d (2,558 MDth) of capacity contracts expiring of which 1,856 TJ/d (1,763 MDth) has been renewed.  (Source TCPL website, Informational Postings, Mainline Contract Renewals for Nov. 1, 2010) Similarly, the Great Lakes system has 900 MMcf/d of capacity expiring, of which 470 MMcf/d has been renewed through October 31, 2011. (Source: TC Pipelines LP, Form 10-K, Feb. 26, 2010

**Exhibit 43: TransCanada Mainline FT Tolls (100% Load Factor)**



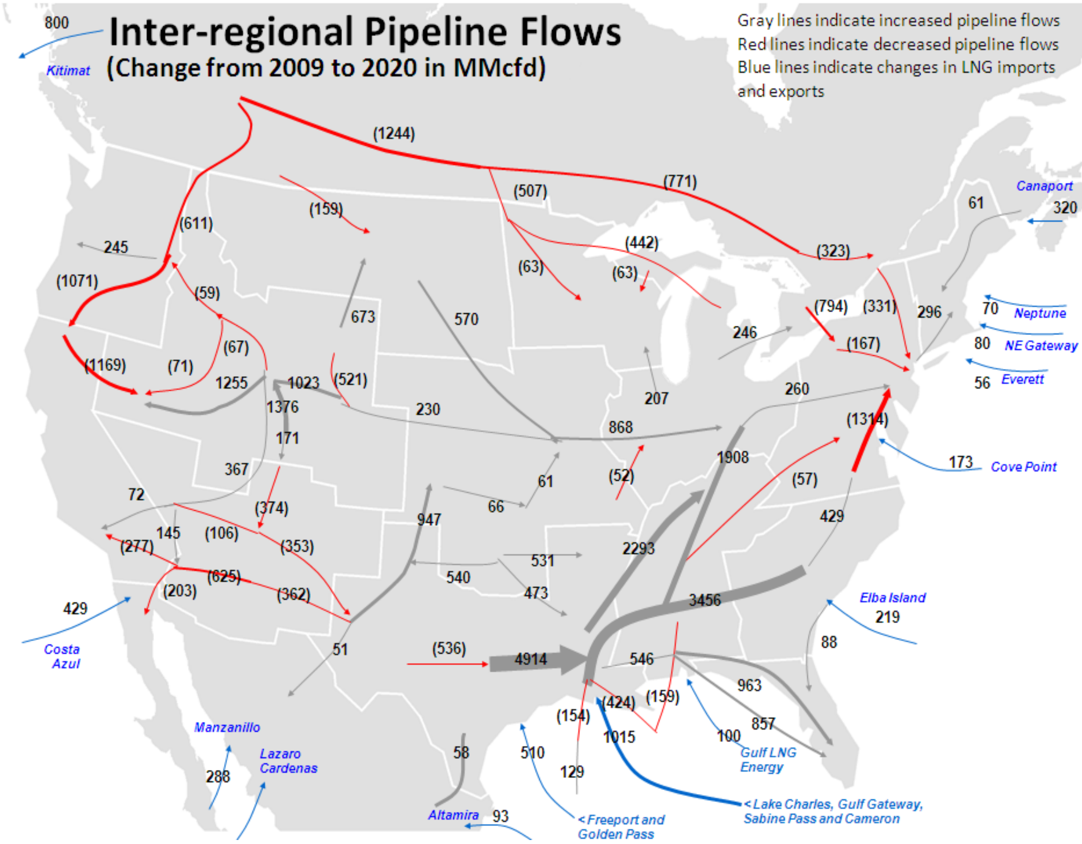

Source: TCPL toll data

**Exhibit 44: Inter-regional Pipeline Flows in 2009**




Source: ICF

**Exhibit 45: Changes in Inter-regional Pipeline Flows, 2009 to 2020**

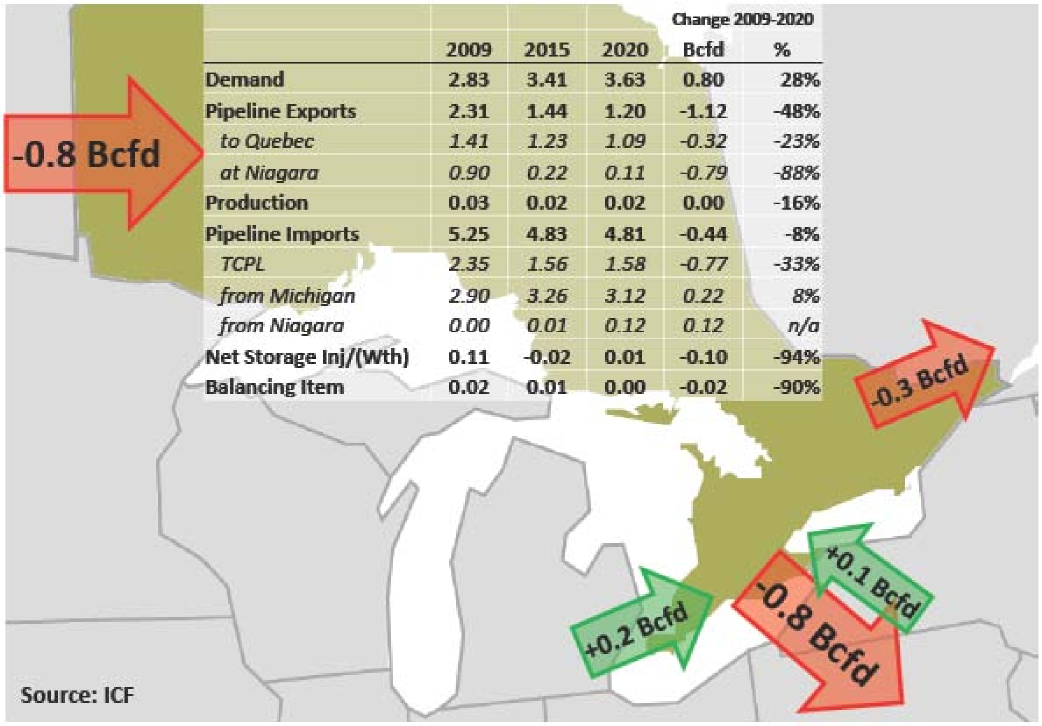



Source: ICF

Several changes are notable in the forecast of flows above. First is continued reduction in future flows eastward from the WCSB across the TCPL system, including its Great Lakes pipeline. Next is the reduction in exports through Niagara and Waddington. Offsetting the drop in supply from WCSB will be an increase in flows from Michigan to Dawn from points south. While the net annual flow of gas at Niagara is expected to be toward the U.S., in some months (particularly shoulder months, between the heating and cooling seasons), gas is forecast to flow into Ontario through the Niagara interconnect. A summary of the forecast changes in flows into Ontario is shown below in Exhibit 46.

Two independent developments will contribute to the forecast change in flows into and around Ontario. The first as discussed above is the declining WCSB production resulting in declining TCPL flows. The second is the growth of Marcellus production. The effect of the latter is seen in the forecast decline in flows across Niagara and potential back-flow into Ontario from New York. It may also be a factor in the increase in flow from Michigan to Ontario, since Marcellus would fill up the eastern pipes and redirect flows from the Midcontinent and Rockies into Ontario.

**Exhibit 46: Changes in the Ontario Natural Gas Balance, 2009 to 2020**



| | 2009 | 2015 | 2020 | Change 2009-2020 Bcfd | Change 2009-2020 % |
|---|---|---|---|---|---|
| **Demand** | 2.83 | 3.41 | 3.63 | 0.80 | 28% |
| **Pipeline Exports** | 2.31 | 1.44 | 1.20 | -1.12 | -48% |
| *to Quebec* | *1.41* | *1.23* | *1.09* | *-0.32* | *-23%* |
| *at Niagara* | *0.90* | *0.22* | *0.11* | *-0.79* | *-88%* |
| **Production** | 0.03 | 0.02 | 0.02 | 0.00 | -16% |
| **Pipeline Imports** | 5.25 | 4.83 | 4.81 | -0.44 | -8% |
| *TCPL* | *2.35* | *1.56* | *1.58* | *-0.77* | *-33%* |
| *from Michigan* | *2.90* | *3.26* | *3.12* | *0.22* | *8%* |
| *from Niagara* | *0.00* | *0.01* | *0.12* | *0.12* | *n/a* |
| **Net Storage Inj/(Wth)** | 0.11 | -0.02 | 0.01 | -0.10 | -94% |
| **Balancing Item** | 0.02 | 0.01 | 0.00 | -0.02 | -90% |



As discussed in Section 3.2 above, ICF projects that gas production from the Marcellus Shale will increase to over 6 Bcfd by 2020. ICF has also looked at two alternate sensitivity cases for Marcellus Shale to determine the potential impacts on TCPL's mainline flows (Exhibit 47). In the first alternate case, we assumed Marcellus production increases to 9 Bcfd by 2020. In the second alternate case, we assumed Marcellus production increases to only 3.8 Bcfd by 2020. The results of the sensitivity cases indicate that changes in Marcellus production have very little impact on TCPL, changing the projected flows in 2020 by only ± 0.1 Bcfd (± 6 percent). The principle driver of flows on TCPL is changes in Western Canadian production, not changes in Marcellus production.

**Exhibit 47: Impacts of Marcellus Shale on TCPL Flows in 2020**

| | Marcellus Shale Gas Production in 2020 (Avg Bcfd) | TCPL Mainline Flows in 2020 (Avg Bcfd) |
|---|---|---|
| Base: | 6.1 | 1.6 |
| Alternate 1 | 9.0 | 1.5 |
| Alternate 2* | 3.8 | 1.7 |

* In addition to the decrease in Marcellus Shale, Alternate Case 2 also assumed no LNG exports from Kitimat, which increases gas supplies available to TCPL.

Source: ICF

One of the principal concerns about TCPL's declining throughput is whether the resulting higher per unit cost of transportation would lead to continued decontracting of TCPL capacity, wherein the higher costs of transportation may drive more shippers off the pipeline and further reduce throughput, which would lead yet again to higher tolls. ICF has conducted a sensitivity analysis that shows higher tolls would reduce throughput, in one case to 2.6 Bcfd in Manitoba upstream of Emerson (from our base case of 2.9 Bcfd) in the 2016 to 2020 time-frame. Conversely, when tolls are discounted, throughput would increase and at very steeply discounted tolls, throughput could increase to levels significantly higher than our base case. The steeper discounts on the mainline, however, increase throughput at the expense of flows on TCPL's other pipelines – GTN, Northern Border and Great Lakes (the latter very slightly). Mainline discounting would not affect Alliance pipeline flows except at the steepest discounts, and then only very slightly. More gas flowing into Ontario over TCPL would also back out flows into Dawn from Michigan.

In the U.S., pipelines can discount their transportation tolls in response to market developments; this is not the case in Canada. While our analysis suggests that discounting may help in slowing the decline in TCPL throughput, the main driver of the declining throughput remains the declining WCSB production.

Developments that could increase Western Canadian supply include a higher British Columbia shale production from Horn River and Montney. While we project production from Western Canadian shales will increase to 3.4 Bcfd by 2020, the majority of that production goes to serve western markets or as LNG exports at Kitimat. ICF assumes Arctic gas supplies (Alaska and Mackenzie Delta) are unlikely to make it to market within in the timeframe of our projection.

### 3.3.3 Natural Gas Storage Issues

Ontario is rich in natural gas storage assets. As noted earlier, Ontario has about 260 Bcf of storage, with a peak send-out capability of about 4.5 Bcfd (Exhibit 48). This is a valuable resource for balancing seasonal loads and managing swing load requirements for daily balancing of the power generation demand.

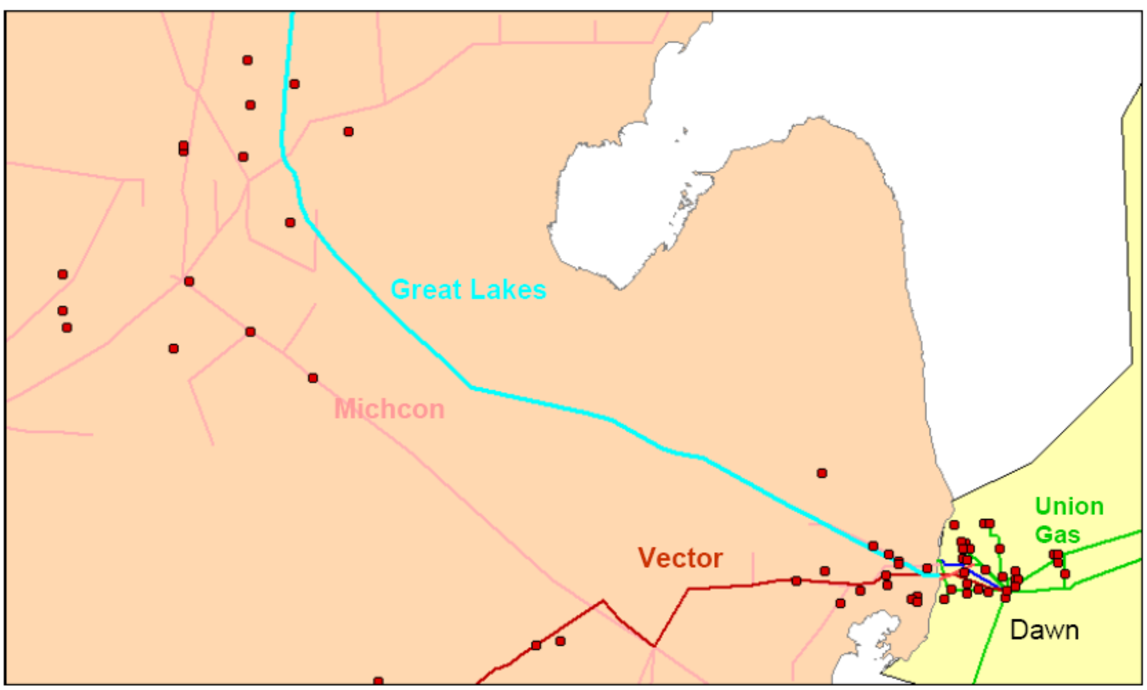
Storage is geographically concentrated in the southwestern corner of Ontario around Dawn. Ontario's storage market also encompasses storage in Michigan accessible to the pipelines that provide supply at the border. Exhibit 49 shows the locations of storage fields in Ontario and Michigan.

## Exhibit 48: Ontario Natural Gas Storage Fields

| Operator / Field Name | Working Gas Capapacity (MMcf) | Peak Day Deliverability (MMcf) |
|---|---|---|
| ***Enbridge Gas Distribution Inc.*** | ***102,426*** | ***1,645*** |
| Black Creek | 911 | 14 |
| Chatham D | 1,000 | 15 |
| Corunna | 4,469 | 50 |
| Coveny | 3,592 | 54 |
| Crowland | 290 | 35 |
| Dow Moore | 26,424 | 285 |
| Kimball-Colinville | 35,244 | 635 |
| Ladysmith | 6,495 | 97 |
| Seckerton | 10,496 | 120 |
| Wilkesport | 8,005 | 100 |
| Tecumseh Gas Storage | 5,500 | 240 |
| ***Market Hub Partners, LP.*** | ***6,400*** | ***214*** |
| St. Clair Pool | 1,100 | 55 |
| Sarnia Airport Pool | 5,300 | 159 |
| ***Tribute Resources*** | ***3,000*** | ***90*** |
| Tipperary | 3,000 | 90 |
| **Ontario Total** | **260,602** | **4,476** |

| Operator / Field Name | Working Gas Capapacity (MMcf) | Peak Day Deliverability (MMcf) |
|---|---|---|
| ***Union Gas Limited*** | ***148,776*** | ***2,527*** |
| Bentpath | 4,829 | 67 |
| Bentpath East | 4,723 | 71 |
| Bickford | 20,309 | 286 |
| Bluewater | 1,829 | 27 |
| Booth Creek | 1,839 | 28 |
| Dawn 156 | 26,599 | 371 |
| Dawn 167 | 4,677 | 57 |
| Dawn 47-49 | 3,908 | 59 |
| Dawn 59-85 | 5,602 | 75 |
| Dow Sarnia Block A | 6,142 | 70 |
| Edys Mills | 2,425 | 26 |
| Enniskillen | 3,357 | 50 |
| Mandaumin | 4,201 | 63 |
| Oil City | 1,723 | 26 |
| Oil Springs East | 3,502 | 62 |
| Payne | 23,383 | 337 |
| Rosedale | 2,895 | 40 |
| Sombra | 2,372 | 35 |
| Terminus | 10,499 | 147 |
| Waubuno | 9,062 | 130 |
| Mutiple Fields (enhancement) | 4,900 | 500 |

## Exhibit 49: Map of Natural Gas Storage Fields in Ontario and Michigan



Between 2000 and 2006, new storage capacity increased on average by 46 Bcf per year; since then capacity additions have averaged 109 BCF per year through 2009. Based on new storage projects already in progress, this trend will continue through the end of 2011. Several factors have contributed to this growth in storage capacity:

- Regulatory changes have encouraged more development at market based rates, thus increasing the potential return to storage developers.
- The growth in natural gas power generation increased the need for high deliverability storage to meet swings in gas load.
- Actual and anticipated growth in LNG imports has led to demand for storage to manage LNG delivery patterns.
- The extremely volatile prices of the early 2000s, through 2008, increased the value of storage to a broader array of market participants.
    - Utilities needing to manage seasonal and daily price risk.
    - Marketers and financial traders wanting to benefit from price volatility through arbitrage
    - Suppliers interested in maximizing opportunities created by price swings.
- The consequential increase in liquidity and deliverability at gas market hubs has reduced reliance on long-haul pipeline capacity to meet winter load, and further increased the need for market area storage as supplements to gas supply.

The expansion of storage has been especially notable in Ontario and surrounding regions, since there is a strong regional market, high variability in gas demand, and abundant storage development property (Exhibit 50).

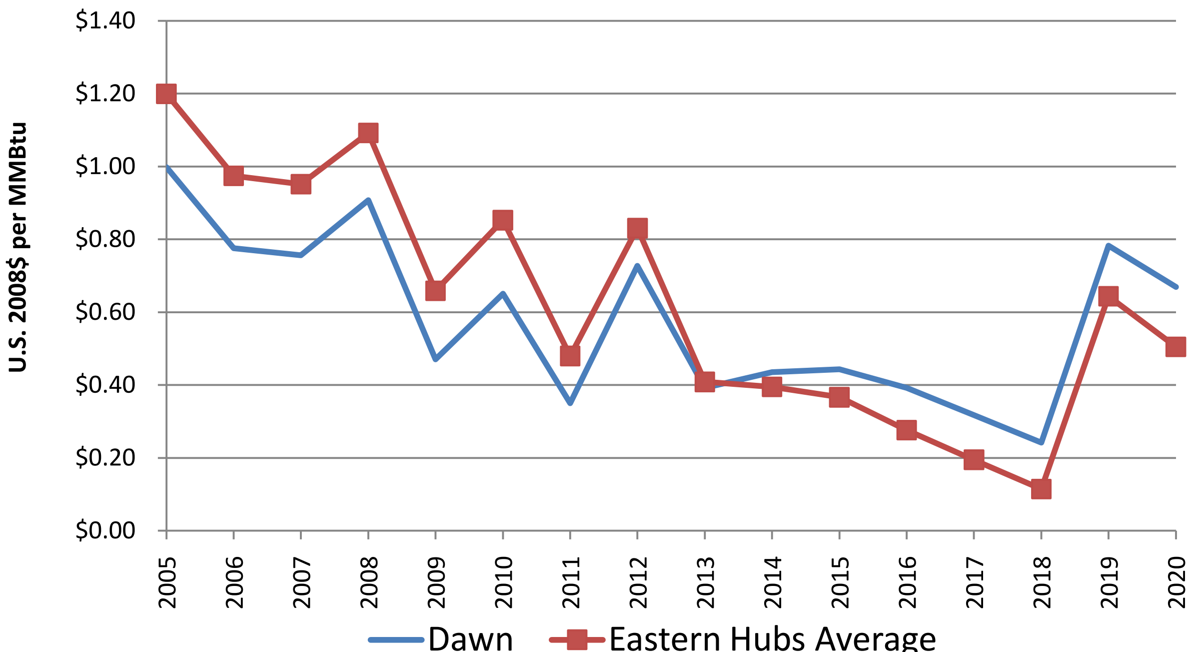
### Exhibit 50: Storage Capacity Additions In and Around Ontario

| Storage Field Name | State / Province | In-Service Year | County | Reservior Type | Working Gas Capacity (mmcf) | Deliverability (mmcfd) |
|---|---|---|---|---|---|---|
| Quinlan Storage Field | NY | 2006 | Cattaraugus | Depleted | 4,000 | 200 |
| Washington 10 Phase II Expansion | MI | 2006 | Macomb | Depleted | 15,000 | 650 |
| ANR Goodwell | MI | 2007 | Newaygo | Depleted | 13,000 | 420 |
| Stagecoach Phase IIb Expn | NY | 2007 | Tioga | Depleted | 13,000 | 500 |
| Wyckoff | NY | 2007 | Steuben | Depleted | 6,000 | 250 |
| Washington 28 | MI | 2007 | Macomb | Depleted | 4,500 | |
| Cohocton Valley (Avoca) | NY | 2007 | Steuben | Salt Cavern | 5,000 | |
| Tipperary Storage Pools | ON | 2008 | Ontario | Depleted | 3,200 | 3,000 |
| Cold Springs 1 (Step 2008 Project) | MI | 2008 | Kalkaska | Depleted | 14,100 | 200 |
| Sarnia Airport Pool | On | 2008 | Ontario | Depleted | 5,300 | |
| Washington 28 | MI | 2008 | Macomb | Depleted | 1,800 | |
| Bluewater Expansion | MI | 2008 | St. Clair | Depleted | 4,500 | |
| Union Gas - Delta Pressuring | ON | 2008 | Ontario | Depleted | 4,900 | 500 |
| Dominion Woodhull | NY | 2009 | Steuben | Depleted | 3,290 | 357 |
| Washington 10 Shelby Expn | MI | 2009 | Macomb | Depleted | 1,500 | 750 |
| Steckman Ridge Field | PA | 2009 | Bradford | Depleted | 12,000 | 300 |
| Thomas Corners | NY | 2009 | Steuben | Depleted | 7,700 | 100 |
| Tecumsah | ON | 2009 | Ontario | Depleted | 5,500 | 200 |
| Midway | ON | 2009 | Ontario | Depleted | 1,000 | |
| Heritage | ON | 2009 | Ontario | Depleted | 1,000 | |
| CGT Ohio Storage Expansion Project | OH | 2009 | Multiple | Depleted | 6,700 | 250 |
| **Total 2006 - 2009** | | | | | **132,990** | |

Source: ICF, compiled from various sources

In the near term, North American storage levels at the end of the 2010 winter heating remained at the high end of the 5-year average storage levels as growth in production capacity offset weak growth in demand, reducing the need for storage withdrawals. As of July 29, 2010, the Energy Information Administration reports that eastern storage levels are running slightly behind last year's record levels but still well above the 5-year average. The growth of storage capacity and the high build up in stored gas are contributing to a narrowing of the seasonal spread between injection prices and withdrawal prices of gas (Exhibit 51).

**Exhibit 51: 10-Year Rolling Average of the Seasonal Price Spread at Dawn**




Source: ICF
The seasonal price spread is the withdrawal-weighted average of winter (December through February) prices less the injection-weighted average of injection season (April through October) prices.

ICF has forecasted a declining spread between the summer and winter prices, suggesting that the value of storage will decline in the near to medium term before turning back up towards the end of the 2020 period. The decline in seasonal gas price spread is due to a number of factors including:

- Over the last five years, completed and committed storage expansion has exceeded growth in the demand for seasonal storage services, resulting in an abundance of storage capacity in North America.
- Rapid increases in natural gas production in the Marcellus Shale is resulting in an increase in winter gas deliverability relative to summer deliverability. Growth in the Marcellus Shale alone is expected to increase natural gas deliverability in the Northeast U.S. by the equivalent of between 0.2 and 0.5 Bcfd each year between 2012 and 2016, depending on the specific Marcellus Shale production case and year.
- As a greater share of natural gas production shifts away from the Gulf Coast, the amount of natural gas supply vulnerable to hurricane disruptions will decrease, reducing natural

gas supply uncertainty and price volatility during hurricane season (July through October).

These developments notwithstanding, high deliverability storage, and storage that supports system balancing will remain highly valuable as more gas fired electric generation is built and more renewable energy is added to the power system (requiring gas fuelled back-up.)

### 3.3.4 Implications and Uncertainties for Pipelines and Storage

The forecasted declines in TCPL throughput will impact the Ontario natural gas utilities' exposure to carrying capacity on TCPL's mainline and Great Lakes. The decline in TCPL throughput is expected to be largely independent of the growth in Marcellus production; higher Marcellus output could reduce flows more, while lower Marcellus production could lessen the reduction. It is not sustainable to have tolls increasing as throughput declines due to de-contracting, since this results in the average unit cost of delivered natural gas increasing. While new supplies from British Columbia and other potential Albertan shale developments could help sustain the pipeline, TCPL is expected to remain the marginal pipeline out of the WCSB. There appear to be three options.

- Do nothing in the expectation that Western Canadian supply will be greater, and therefore mitigate any potential increase in TCPL's transportation rates. Ontario may actively support new supply developments with contracts and long term commitments. This would be risky approach, given producers' options for improving net-backs by seeking other markets.
- Support a policy that would allow TCPL to offer discounts on transportation in response to market dynamics. This approach would tend to improve netbacks to producers and could lower costs to consumers. The potential decline in revenue for TCPL may or may not be offset by greater throughput. Allowing discounting, however, can introduce a number of issues related to how it is implemented, including whether discounts should be offered to all shippers or only some.
- Diversify sources of natural gas supply away from TCPL's mainline. With growing supply from shale production in the United States, as well as from the U.S. Rocky Mountains, Ontario utilities could take steps to increase pipeline capacity and deliverability into Dawn from Michigan and into Kirkwall through reverse flows across Niagara. This option, however, would exacerbate the de-contracting problem on TCPL. While southern and eastern Ontario can benefit from these options, northern Ontario (principally served by Union) does not have alternatives to TCPL.

Storage will remain a strategic asset in Ontario. Although the forecasts suggest declining seasonal basis spreads that affect the seasonal value of storage, the uncertainties in the market with respect to price volatility, TCPL developments, and growth in power generation, all support storage valuations in Ontario.

## 3.4 Expectations for Gas Prices and Basis

### 3.4.1 Natural Gas Market Dynamics

ICF's natural gas market projection is based on fundamental market operations and structures that reflect the major liberalizing changes that have occurred in the United States and Canada, over the last 25 years. The North American natural gas market is an efficient and well functioning free market system, in that:

- There are numerous participants,
- The participants have access to information that provides for maximum opportunities effect transactions with minimum transaction costs, and
- The participants can response freely to price signals and adjust their behavior accordingly.

On the production side of the market, E&P companies respond to increases in gas prices with both short-term and long-term investments. In the short-term, they can hire additional personnel and rigs, and increase drilling activity. In the long-term, producers can increase their investments in new technologies, which open up new resources or make existing resources more productive. On the consumption side of the market, the supplies available are allocated among consumers by gas prices. If supplies are scarce, then natural gas prices increase as consumers, who value gas the most, bid supplies away from others who value it less. Pipeline companies also respond to price signals, by building new infrastructure to connect new supply sources with growing demand markets.

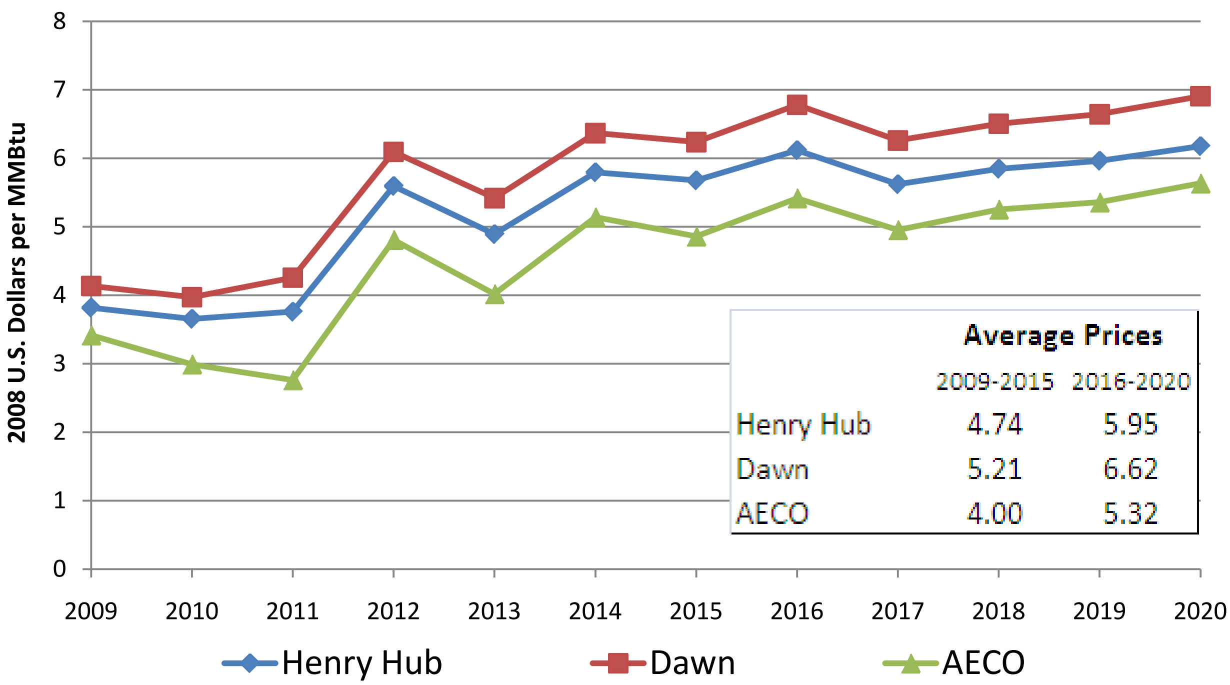
This North American gas market is a highly integrated market where the forces of supply and demand determine prices over a continent-wide pipeline network. The commodity market – that is the pricing of gas itself – is deregulated. While the pipelines remain under economic regulation (by FERC in the United States and by the NEB in Canada), regulation in the U.S., has evolved into a more light-handed form to encourage pipelines to become more responsive to market developments. New pipes and expansions demonstrate to FERC economic need by showing there are contracts to support the costs of the new projects. Expansions of existing facilities also must show FERC that the incremental revenue from the expansion covers the incremental costs, without existing customers subsidizing new customers. An active secondary market for pipeline capacity exists in both countries and in the U.S. pipelines can discount their rates to be competitive. These characteristics have contributed to efficient market outcomes across the gas industry where price signals effectively guide investments, determine gas flows, and drive production and consumption decisions.

### 3.4.2 Expectations for Future Gas Prices and Basis

Natural gas prices and basis are driven by changes in supply and demand over time, and by the changes in inter-regional pipeline flows due to those changes in supply and demand. From a North American price perspective, ICF projects an environment with growing gas demand, which should encourage continuing development of new supplies. This environment places upward pressure on natural gas prices. While North America has an ample gas resource base, developing new resources to keep pace with demand growth requires continued investment in gas production and infrastructure. While prices are expected to remain relatively low as we exit the recession, they are ultimately expected to rebound to levels that support continued development of the supplies necessary to satisfy the increasing gas demand. Through 2020, average annual gas prices at Henry Hub are projected to range between $5.00 and $6.00 dollars per MMBtu in 2008 dollars (Exhibit 52).

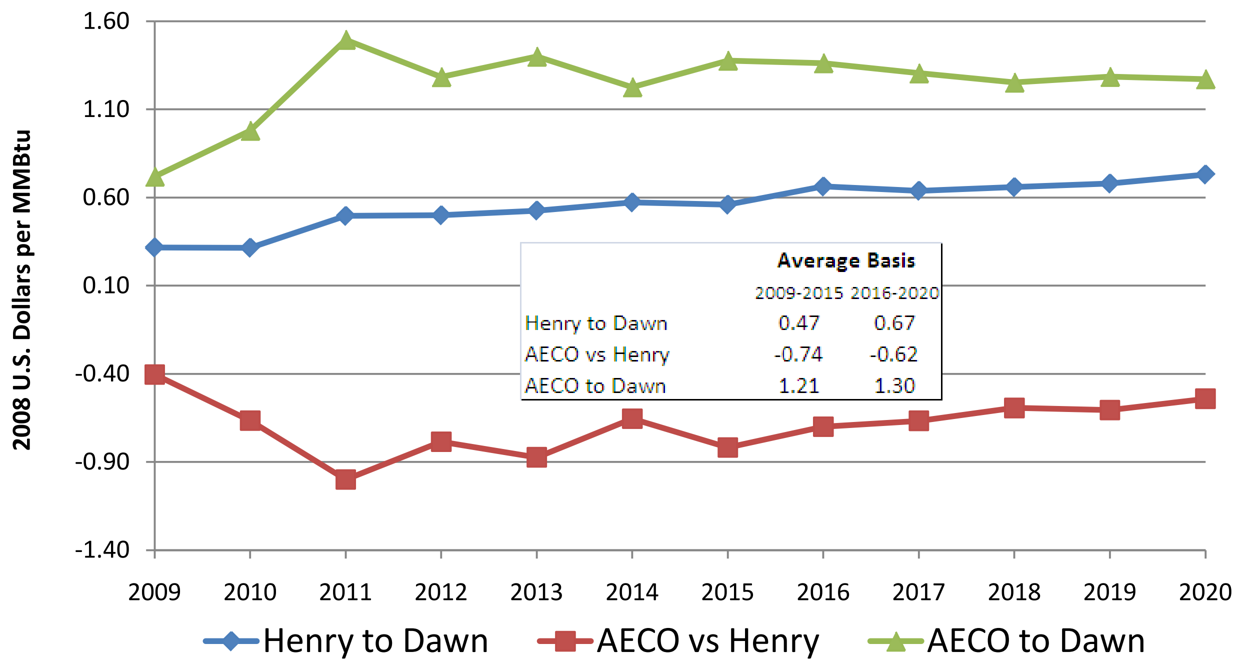
Generally speaking, gas prices at markets throughout the U.S. and Canada track Henry Hub prices.  Projected Dawn prices average between $5.20 and $6.60 per MMBtu, or about $0.50 to $0.70 per MMBtu higher than the Henry Hub average (Exhibit 53).  This is somewhat higher than the historical average, because as load factors on pipelines from the Gulf Coast to the Midwest U.S. and Ontario are projected to increase over time, this would increase the basis. Projected basis from AECO to Dawn averages between $1.20 and $1.30 per MMBtu. As discussed in Section 3.1 above, flows from Western Canada to Ontario continue to decline, but our projection assumes that TCPL will continue to raise tolls to compensate for the decline, thereby increasing basis.

**Exhibit 52: Regional Average Annual Gas Prices, 2009-2020**




Source: ICF

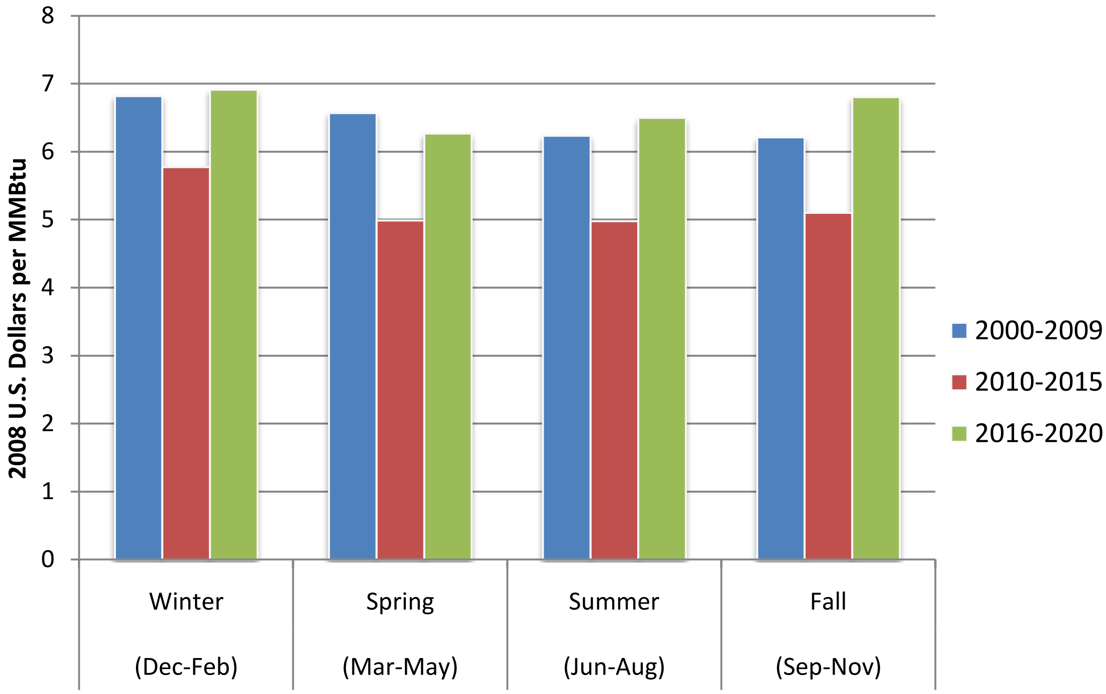
**Exhibit 53: Regional Average Annual Basis, 2009-2020**




Source: ICF

Projected seasonal gas prices at Dawn are shown in Exhibit 54. Over the next five years, seasonal gas prices average the $5 to $6 per MMBtu range, as gas prices gradually recover after the recession. After 2015, seasonal prices increase to the $6 to $7 per MMBtu range. Compared to the historical period, projected prices in the summer and fall are rising more than winter and spring prices. This is due to the increased use of natural gas in the power sector, not just in Ontario but throughout North America. While winter still remains the peak gas demand season throughout the projection, growing gas use in the power sector leads to greater increases in summer gas consumption, when electricity demand (and gas-fired generation) peaks.

**Exhibit 54: Average Seasonal Gas Prices at Dawn**




Source: ICF

### 3.4.3 Implications and Uncertainties for Gas Prices and Basis

As in all competitive commodity markets, prices in the natural gas market are an indication of the relative balance between supply and demand. To the extent that supplies keep pace with demand, gas prices can be relatively stable. However, when supply and demand trends diverge, then price movements can be volatile. The decrease in gas demand during the recession has kept gas prices quite low compared to the previous ten years. While low prices may be seen as beneficial to consumers, they cannot be sustained indefinitely. Low gas prices (below the level needed to provide a reasonable rate of return for E&P companies) discourage investment in gas exploration and production, which will ultimately lead to decreases in supplies and increases in prices. This was the pattern that occurred in the natural gas market in the late 1990s and 2000s.

The North American gas market is well integrated; therefore, gas prices in Ontario are not solely determined by the supply and demand balance within the province. Changes in markets both upstream and downstream affect the prices Ontario consumers see. The same uncertainties that apply to gas demand, supply, pipelines, and storage apply to gas prices, since it is these factors that ultimately drive gas prices. For example, if economic recovery is slower than projected and gas demand remains low, then prices are likely to remain relatively low for a longer period of time. However, a sudden shift to natural gas in the power sector could potentially cause gas demand (and gas prices) to spike.

While conditions in the broader North American gas market are important in the determination of Ontario's gas prices, there are factors more immediate to the province that have impacts as well. As discussed in Section 3.3 above, the tolls on TCPL have a significant impact on Ontario gas consumers. Ontario relies almost exclusively on pipeline imports to satisfy its gas demand, and the largest single supply pipeline is TCPL. Conventional gas production in Western Canada has been declining, and with that decline has come declines on the flows on TCPL. TCPL's response to the decline in production has been to increase its tolls in order to try to maintain revenues, which has had an impact on gas prices in Ontario. As TCPL tolls rise, shippers moving gas to Ontario consumers will seek to import gas on other pipelines. However, the alternative pipelines serve more than just Ontario consumers, and the total amount of capacity available is finite. As the alternative pipelines become more crowded over time, the cost of transporting gas on these pipelines may also increase, which would increase gas prices in Ontario. Even by moving to alternative pipelines for their gas supplies, Ontario consumers cannot completely escape the impact of transportation toll changes.

# 4. Summary of Key Findings and Uncertainties

***Summary of Key Findings***

*Demand for Natural Gas is Expected to Continue Growing, Led by Growth in the Power Sector*

Following the trend set over the past decade, total North American demand for natural gas is projected to resume growth as we exit the recession, increasing by over 30 percent in the next ten years. As it has in the recent past, demand growth is expected to be primarily driven by growth in the power sector.

Ontario's power sector gas use is also expected to continue growing, climbing to nearly one-third of total demand by 2020. The push to replace coal-fired power plants is the key driver behind demand growth in Ontario. As the power sector becomes a large part of Ontario's total demand, seasonal and daily use patterns will change. Higher gas demand in the summer months to meet peak electricity demand may mean less gas is available for storage injection. Also, the daily and hourly fluctuation in gas loads from gas-fired power plants may place stresses on the pipeline network.

*Supply Sources and Inter-regional Pipeline Flow Patterns are Changing*

Shale gas is expected to be the principle source of growth in North American supplies. Some of the new supplies, like the mid-continent shales, are located near traditional supply areas. However, many of the newly developed resources, such as the Marcellus Shale, are located in geographically different regions than where supplies have historically been developed. As a result, the growth of these new supplies will have an impact on existing pipeline flows and the development of new pipeline capacity.

While shale gas production is projected to increase, conventional gas production is expected to continue declining. Conventional production in Western Canada has traditionally been the largest source of natural gas supply for Ontario, and it has been declining over the past decade. Western Canadian production is expected to continue declining, while at the same time gas demand in Alberta, for oil sands projects, is projected to increase. This combination of decreasing supply and increasing demand is expected to cause TCPL's mainline flows to continue decreasing.

Western Canadian gas (delivered via TCPL) is expected to remain the largest single supply source for Ontario. However, it is expected to decline both in absolute terms and as a share of the total supply. As this supply declines, an increasing share of Ontario's gas needs is expected to be met by gas from the U.S., especially shale gas. While production from the Marcellus Shale is not projected to be a major source of supply for Ontario, it does have an important impact on the overall supply projection. Growth in Marcellus Shale production is projected to displace some exports of gas from Ontario to the Northeast U.S., allowing a greater share of gas entering Ontario on TCPL's mainline to remain in Ontario.

The projected demand growth is expected to drive North American gas prices higher as we exit the recession. While gas prices are not expected to reach the very high levels seen in the mid- to late-2000s, annual average Henry Hub prices are projected to rebound to a range of $5 to $6 per MMBtu. Given the ample North American resource base, the projected gas prices are adequate to support continued development of the supplies necessary to satisfy the projected gas demand growth.

While changes in supply and demand conditions are important in the determination of Ontario's gas prices, so are policies that impact TCPL's rate structure. TCPL's response to the projected reduction in its mainline flows is a critical issue for Ontario gas consumers. There appear to be three policy options:

- Do nothing in the expectation that Western Canadian supply will be greater, and therefore moderate any potential increase in TCPL's transportation rates.
- Support a policy that would allow TCPL to offer discounts on transportation in response to market dynamics.
- Diversify sources of natural gas supply away from TCPL's mainline.

***Key Uncertainties Which Could Affect the Projection***

The increase in natural gas consumption in the power sector has been driven by a number of factors, including environmental concerns. As environmental concerns grow and carbon policy initiatives in both Canada and the U.S. gain traction, coal-fired power plants may be retired more quickly. If this is the case, gas use in the power sector may increase more rapidly than projected.

Another potential policy approach to address environmental concerns is the aggressive promotion of renewable energy resources, such as wind, solar, and geothermal. A more aggressive approach to promoting the use of renewable resources to replace existing fossil fuel generation, could decrease or increase the projected growth in gas-fired generation. The dynamics of wind's impacts on electricity systems and the need for firming power (often in the form of gas) are still not fully understood. On the other hand, enough renewables, given the appropriate system design and function, might reduce total gas-fired generation. We expect that within the 5 to 10 year timeframe in Ontario, gas will likely still play an important role in the power sector by providing firm generation to support intermittent renewable sources such as wind.

Over the past two years, concerns have been raised about the environmental impacts of hydraulic fracturing, a technique used to produce shale gas. If the regulation of hydraulic fracturing becomes more stringent, this could slow the growth of shale gas production.

The projections for the North American gas market presented in this report are contingent on recovery from the recent recession and continued economic growth. If economic growth in the U.S. and Canada is slower than projected, this would have negative impacts on gas demand growth, particularly in the industrial and power sectors. If industrial output continues to decline, this would reduce gas consumption. Likewise, reduced economic growth would imply less growth in demand for electricity, which would lead to less gas-fired generation. Less demand growth would likely lead to lower gas prices and, as a result, reduced development of new natural gas resources.

# Appendix:  ICF's Gas Market Model (GMM)

ICF's *Gas Market Model (GMM)* is an internationally recognized modeling and market analysis system for the North American gas market.  The GMM was developed by Energy and Environmental Analysis, Inc. (EEA), now a wholly owned business unit within ICF International, in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions.  In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace.  For example, much of the initial work with the model in 1996-97 focused on assessing the impact of the Alliance pipeline completed in 2000.  The questions answered in the initial studies include:

- What is the price impact of gas deliveries on Alliance at Chicago?
- What is the price impact of increased takeaway pipeline capacity in Alberta?
- Does the gas market support Alliance?  If not, when will it support Alliance?
- Will supply be adequate to fill Alliance?  If not, when will supply be adequate?
- What is the marginal value of gas transmission on Alliance?
- What is the impact of Alliance on other transmission and storage assets?
- How does Alliance affect gas supply (both Canadian and U.S. supply)?
- What pipe is required downstream of Alliance to take away "excess" gas?

Subsequently, GMM has been used to complete strategic planning studies for many private sector companies.  The different studies include:

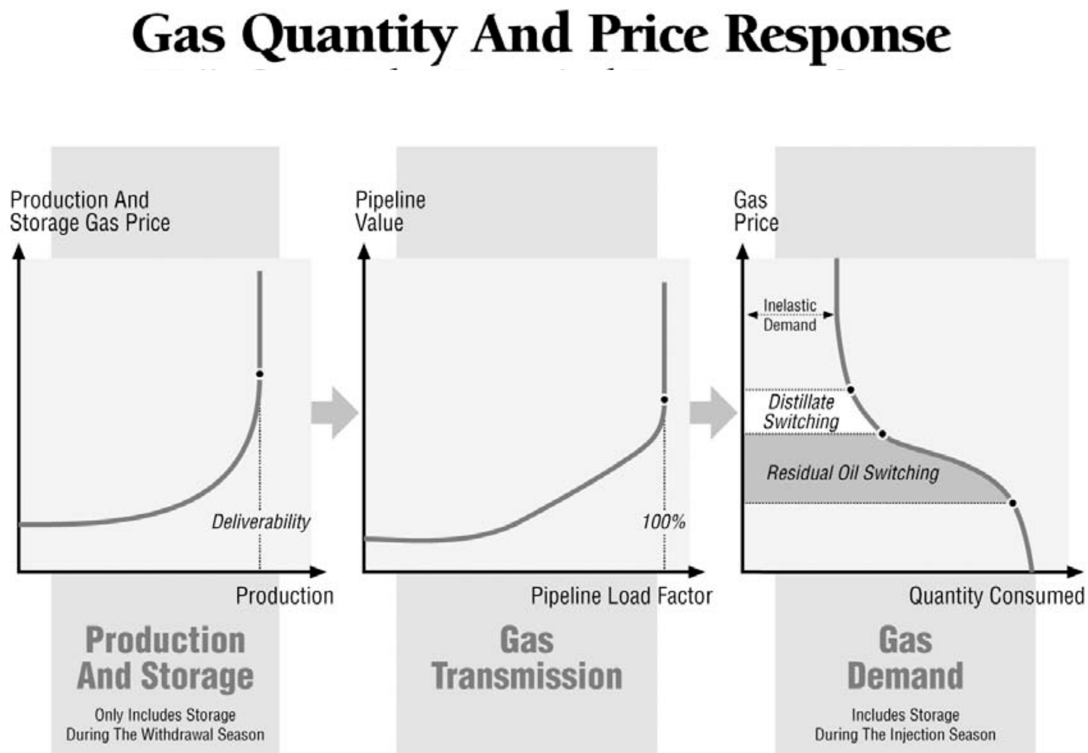
- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including INGAA, who relied on the model for the 30 Tcf market analysis completed in 1998 and again in 2004.  The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes.  On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Exhibit 55).  Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor.  On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels.  The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves.  Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

**Exhibit 55: Natural Gas Supply and Demand Curves in the GMM**




There are nine different components of EEA's model, as shown in Exhibit 56. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit 57. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The Hydrocarbon Supply Model (HSM) may be integrated with the GMM to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

**Exhibit 56: GMM Structure**

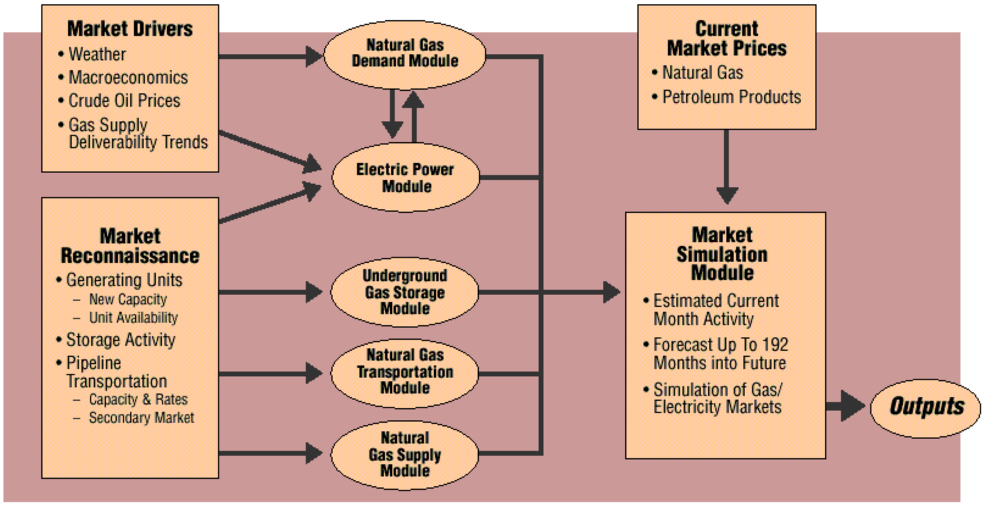
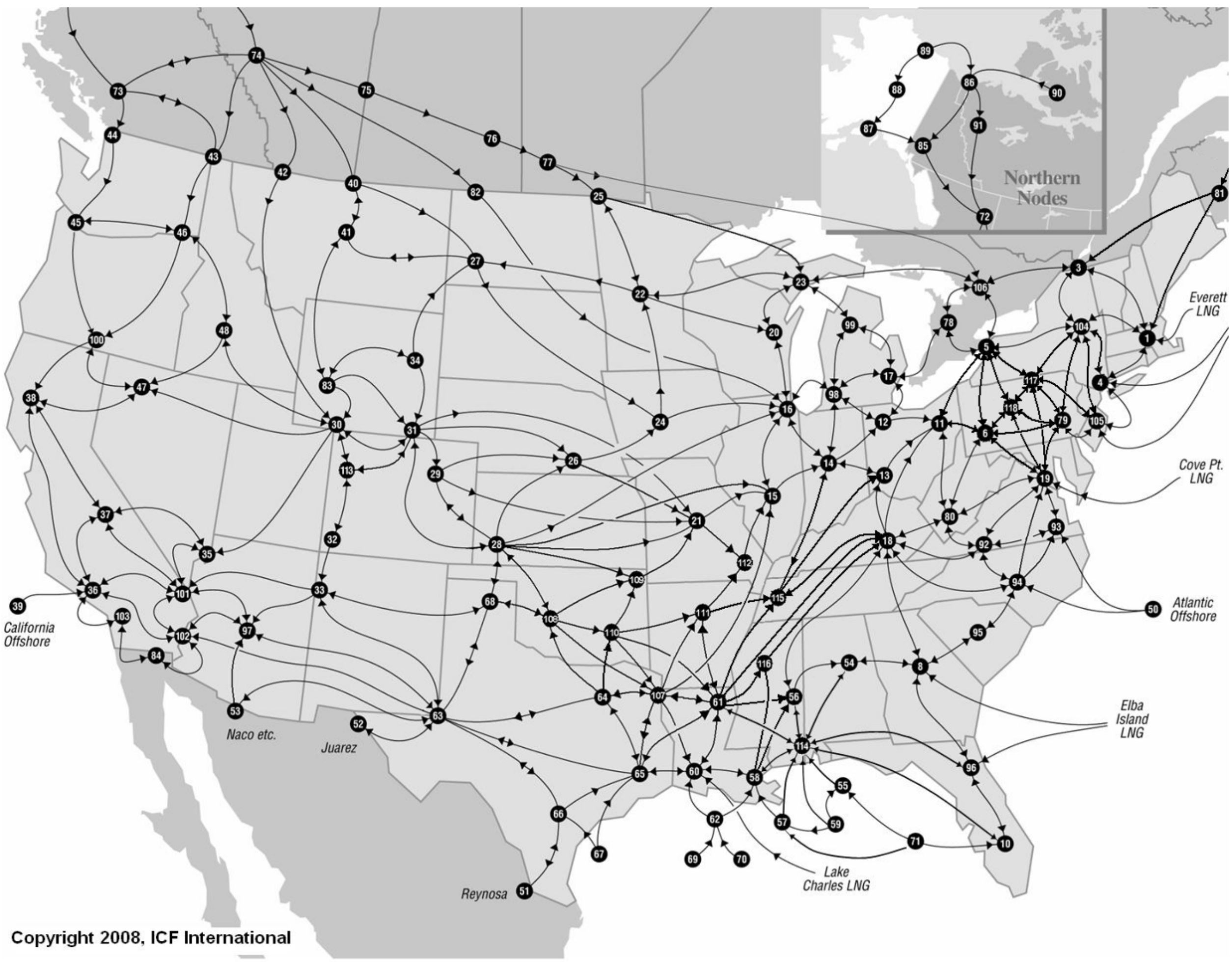



**Exhibit 57: GMM Transmission Network**



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