ICF INTERNATIONAL

REVIEW OF NATURAL GAS SUPPLY PORTFOLIO OPTIONS FOR CENTRA GAS

Prepared for:

CENTRA GAS MANITOBA, INC.

Submitted By:

ICF INTERNATIONAL

9300 Lee Highway

Fairfax, VA 22031

USA

(703) 218-2758

Contacts:

Bruce Henning

Michael Sloan

June 2011

(Page Deliberately Left Blank)

DISCLAIMER

This report includes forward-looking statements and projections. ICF International (ICF) has made every reasonable effort to ensure that the information and assumptions on which these statements and projections are based are current, reasonable, and complete. However, a variety of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this report, including, but not limited to, general economic and weather conditions in geographic regions or markets that may affect the gas market.

(Page Deliberately Left Blank)

TABLE OF CONTENTS

1 INTRODUCTION 1

1.1 Scope of Report 1

2 NORTH AMERICAN GAS MARKET OVERVIEW 3

2.1 North American Market Outlook 3

2.1.1 North American Gas Market Shift 3

2.1.2 Power Sector Gas Demand Growth 5

2.1.3 Residential and Commercial Demand Outlook 7

2.1.4 Natural Gas Prices and Rig Activity Outlook 8

2.1.5 Unconventional Gas Resources 8

2.1.6 Shifts in Supply and Demand Cause Shifts in Pipeline Flows 11

2.1.7 Price Impacts 13

2.1.8 Projected Natural Gas Movements and Prices 15

2.2 Forecast Uncertainty 20

2.2.1 Key Areas of Forecast Uncertainty 20

2.2.2 Other Areas of Potential Market Uncertainty 24

2.3 Approach to Addressing Forecast Uncertainty 25

2.3.1 Alternative Natural Gas Market Scenarios 25

3 OVERVIEW OF CENTRA'S CURRENT OPERATIONS 27

3.1 Centra Natural Gas Demand 27

3.1.1 Forecasted Demand 29

3.1.2 Peak Day Demand 30

3.1.3 Impact of Manitoba Weather on Supply Planning 31

3.2 Centra Pipeline and Storage Capacity 36

3.2.1 Transportation and Storage Contracts 39

3.3 Existing Centra Supply Arrangements 43

3.3.1 Western Canadian Sedimentary Basin 44

3.3.2 Other Sources of Natural Gas Commodity 44

3.3.3 Interruptible Service and Alternate Supply Service 44

3.4 Swing Service and Balancing 45

3.4.1 The Nature of Swing Service 46
3.4.2 Balancing on the TransCanada System 47

3.5 Delivered Service and Delivered Peaking Service 47

3.6 Uncertainties Regarding Future Markets 48
3.6.1 Outlook for TransCanada 48
3.6.2 Impact on TCPL Tolls 48
3.6.3 Impact of Changes in Natural Gas Market Conditions on Centra Supply Planning 50

3.7 Impact of Liquids Extraction on AECO and Empress Market Prices 51

4 ISSUES AFFECTING TCPL 53

4.1 The Current Challenge 53

4.2 TCPL Rate Structure Sensitivities 54

5 APPROACH TO SUPPLY PORTFOLIO OPTIMIZATION ANALYSIS 59

5.1 Factors Considered In Analysis 59
5.1.1 Quantitative Factors Considered in the Optimization Analysis 59
5.1.2 Other Criteria Considered 60

5.2 Impact of Uncertainty on Portfolio Optimization 60

5.3 Analytical Tools 60

6 POTENTIAL SUPPLY OPTIONS FOR CENTRA 63

6.1 Alternative Sources of Natural Gas Commodity 64
6.1.1 AECO, Empress and the Western Canadian Sedimentary Basin 64
6.1.2 Western Canadian Sedimentary Basin Downstream of Empress 67
6.1.3 Manitoba Natural Gas Production 68
6.1.4 U.S. Rocky Mountains 72
6.1.5 U.S. Gulf Coast and Mid-Continent 75
6.1.6 Major Midwest Natural Gas Market Centers 76

6.2 Role of Natural Gas Storage 79
6.2.1 The Relationship Between Storage Capacity, Deliverability, Cyclability, and Seasonality 80
6.2.2 Transportation of Storage Gas and TCPL Storage Transportation Service 81
6.2.3 Term of Storage Arrangements 82
6.2.4 Storage Value 82

6.3 Natural Gas Storage Options 83
6.3.1 Alberta Storage 84

6.3.2	Saskatchewan Storage	84
6.3.3	Potential Manitoba Storage Development	86
6.3.4	Williston Basin	88
6.3.5	Northern Natural Gas Pipeline Storage	89
6.3.6	Michigan Storage	89
6.3.7	Ontario Storage	91
6.3.8	Virtual Storage Services	92
6.3.9	The No-Storage Portfolio	92
6.4	**Natural Gas Peaking Options**	**93**
6.4.1	Delivered Service	93
6.4.2	Liquefied Natural Gas Peaking Plant	94
6.4.3	TCPL Pipeline Capacity Conversion to High Deliverability Storage	94
6.5	**Other Portfolio Matters - WTS**	**95**

LIST OF TABLES

TABLE 1 ANNUAL HEATING DEGREE DAYS 32
TABLE 2 DAILY VOLATILITY OF REGIONAL WEATHER (1996-2006) 33
TABLE 3 DESIGN FIRM PEAK DAY REQUIREMENTS 38
TABLE 4 SUMMARY OF CENTRA PIPELINE AND STORAGE ARRANGEMENTS AS OF NOVEMBER 1, 2010 42

LIST OF FIGURES

FIGURE 1 U.S. AND CANADA NATURAL GAS PRODUCTION AND PRODUCTIVE CAPACITY 4
FIGURE 2 MONTHLY NATURAL GAS PRICES AT HENRY HUB, JAN 1995 – MAR 2011 4
FIGURE 3 U.S. ELECTRIC GENERATING CAPACITY BY FUEL, 1995-2009 6
FIGURE 4 U.S. NET ELECTRICITY GENERATION BY FUEL, 1995-2009 6
FIGURE 5 NATURAL GAS DEMAND IN THE U.S. AND CANADA, 1995-2010 7
FIGURE 6 U.S. GAS-DIRECTED DRILLING ACTIVITY AND NATURAL GAS PRICES 8
FIGURE 7 U.S. AND CANADIAN GAS SUPPLIES BY TYPE, 2000-2010 9
FIGURE 8 U.S. AND CANADIAN SHALE GAS PRODUCTION, 2000-2010 10
FIGURE 9 NORTH AMERICAN INTER-REGIONAL GAS FLOWS 2005 (MMCF/DAY) 11
FIGURE 10 NORTH AMERICAN INTER-REGIONAL GAS FLOWS 2010 (MMCF/DAY) 12
FIGURE 11 CHANGES IN INTER-REGIONAL PIPELINE FLOWS, 2005-2010 (MMCF/DAY) 13
FIGURE 12 REGIONAL AVERAGE ANNUAL GAS PRICES, 1995-2010 14
FIGURE 13 REGIONAL AVERAGE ANNUAL BASIS, 1995-2010 15
FIGURE 14 NORTH AMERICAN INTER-REGIONAL GAS FLOWS 2015 (MMCF/DAY) 16
FIGURE 15 NORTH AMERICAN INTER-REGIONAL GAS FLOWS 2020 (MMCF/DAY) 17
FIGURE 16 CHANGES IN INTER-REGIONAL PIPELINE FLOWS, 2010-2020 (MMCF/DAY) 18
FIGURE 17 CHANGE IN ICF FORECAST OF HENRY HUB PRICE SINCE PREVIOUS STAKEHOLDER CONFERENCE 19
FIGURE 18 CHANGE IN ICF FORECAST OF AECO PRICE SINCE PREVIOUS STAKEHOLDER CONFERENCE 19
FIGURE 19 ALTERNATIVE MARCELLUS SHALE PRODUCTION SCENARIOS 23
FIGURE 20 CENTRA NATURAL GAS CUSTOMERS 28
FIGURE 21 CENTRA NATURAL GAS DELIVERIES 2002-2010 29
FIGURE 22 ICF FORECAST OF MANITOBA NATURAL GAS DEMAND 30
FIGURE 23 MONTHLY NORMAL TRADITIONAL HEATING DEGREE DAYS 32
FIGURE 24 2010/11 CENTRA DEMAND (TJ/DAY) 34
FIGURE 25 CENTRA LOAD PROFILE 2006 - 2010 34
FIGURE 26 COMPARISON OF CENTRA AND NEW ENGLAND LOAD PROFILES 35
FIGURE 27 COMPARISON OF CENTRA AND NEW ENGLAND LOAD PROFILES 35
FIGURE 28 WEATHER VARIATION IN CENTRA LOAD DURATION CURVES 36
FIGURE 29 LOCATION OF CENTRA PIPELINE AND STORAGE ASSETS 39
FIGURE 30 CENTRA PIPELINE AND STORAGE ASSETS – SUMMER OPERATIONS 40
FIGURE 31 CENTRA PIPELINE AND STORAGE ASSETS – WINTER OPERATIONS 41

FIGURE 32 TRANSCANADA MAINLINE FT CONTRACT DEMAND AND RECEIPTS AT EMPRESS (BCF/DAY) 49
FIGURE 33 TRANSCANADA PIPELINE MAINLINE FT TOLLS, (100 % LOAD FACTOR, EXCLUDING FUEL) 49
FIGURE 34 IMPACT OF TCPL RATE STRUCTURE ON BASIS 57
FIGURE 35 ALLIANCE PIPELINE..................... 66
FIGURE 36 NORTHERN BORDER PIPELINE MAP..................... 67
FIGURE 37 2008 CSUG MAP OF SHALE GAS PLAYS IN WESTERN CANADA..................... 71
FIGURE 38 WILLISTON BASIN PIPELINE SYSTEM..................... 73
FIGURE 39 BISON PIPELINE SYSTEM 74
FIGURE 40 VIKING GAS TRANSMISSION 77
FIGURE 41 NORTHERN NATURAL GAS PIPELINE MAP 78
FIGURE 42 SEASONAL ARBITRAGE VALUE OF NATURAL GAS STORAGE..................... 83
FIGURE 43 STORAGE IN SASKATCHEWAN 85
FIGURE 44 WILLISTON BASIN PIPELINE MAP WITH INTERCONNECTIONS..................... 88
FIGURE 45 DTE AND MICHCON GAS STORAGE FACILITIES..................... 90
FIGURE 46 BLUEWATER STORAGE AND PIPELINE INTERCONNECTIONS 91

1
INTRODUCTION

1.1 Scope of Report

Historically, Centra Gas Manitoba, Inc. (Centra) has purchased gas from the Western Canadian Sedimentary Basin (WCSB) and has transported this gas over TransCanada's Mainline (TCPL) to Centra's facilities. Centra holds firm capacity on TCPL as well as pipeline storage services in Michigan and complementary U.S. pipeline capacity to meet the Manitoba market requirement for gas.

The current Centra gas supply portfolio is structured around two primary capacity constraints. First, Centra is dependent on the TransCanada Pipeline for natural gas deliveries, both from Alberta and the gas market center at AECO, and from natural gas storage in Michigan. Any natural gas supplies from other sources also are delivered via the TransCanada Pipeline System. Second, Centra has long term agreements with ANR for natural gas storage capacity in Michigan. These agreements expire in about two years at the end of the winter storage withdrawal season on March 31, 2013.

Developments in North American gas markets since the existing supply structure was established affect how Centra should plan for supply in the future. The key market change since the development of the existing supply portfolio strategy that is likely to influence future supply planning is the change in natural gas exports from the Western Canadian Sedimentary Basin on the TransCanada Pipeline to eastern Canada and U.S. markets. Natural gas flows east on the TransCanada system have declined dramatically in the last five years, and are not expected to return to historical levels for the foreseeable future. This has several critical impacts on the Centra supply plan:

- TransCanada rates have increased substantially, and are expected to continue to rise over time, increasing the cost of the existing supply portfolio.
- TransCanada pipeline capacity on forward haul capacity from Empress to the Centra citygate is currently unconstrained, and is expected to remain unconstrained for the foreseeable future. Hence the need to hold long term firm capacity on TransCanada may be reduced.
- Availability of highly discounted backhaul capacity from ANR storage on Great Lakes Gas Transmission to Emerson and economic backhaul on TCPL from Emerson to the Centra Citygate may be declining, potentially resulting in increases in the cost of using ANR Storage.
- The availability of TCPL capacity, along with changes in market structure that have increased the importance of midstream natural gas marketers in the last ten

years has resulted in the development of reliable delivered gas services that allow Centra to purchase natural gas at the Centra citygate on both a seasonal and peak day basis.

The expiration of the ANR storage contract, and associated pipeline capacity on ANR and Great Lakes in 2013 provides an opportunity to reevaluate the physical and contractual basis for natural gas deliveries to the Centra citygate. This White Paper provides an overview of the issues and options facing Centra during the reevaluation process. The White Paper provides an overview of the broad North American natural gas market trends influencing the Centra decision process in Section two, and highlights the issues and complexities of meeting the natural gas supply needs for Centra service territory in Section three. Section four provides a review of the issues facing TransCanada Pipeline, and highlights the difficulties that these issues create for the Centra planning process.

Section five provides a brief overview of the analytical process that will be used to help determine the best approach going forward, while Section six reviews various potential portfolio options.

2
NORTH AMERICAN GAS MARKET OVERVIEW

In ICF's projection, the outlook for the future environment for the U.S. and Canadian natural gas market is one where the supply and demand balance is largely driven by the technology breakthrough that has unlocked a huge resource of unconventional gas. Total gas demand is projected to grow robustly, led by growth in gas demand in the power sector. Led by the development of shale gas, new supplies are being developed such that the growth of North American production is outstripping the rebound in demand. As a result, the outlook for gas commodity prices, while somewhat above the price levels for 2009 and 2010, is for an extended period of prices well below the Btu equivalent of crude oil and other liquid fuel prices. Gas prices are not expected to return to 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 and forecast uncertainty in the market.

2.1 North American Market Outlook

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 (Figure 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 (Figure 2).

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.

Figure 1
U.S. and Canada Natural Gas Production and Productive Capacity

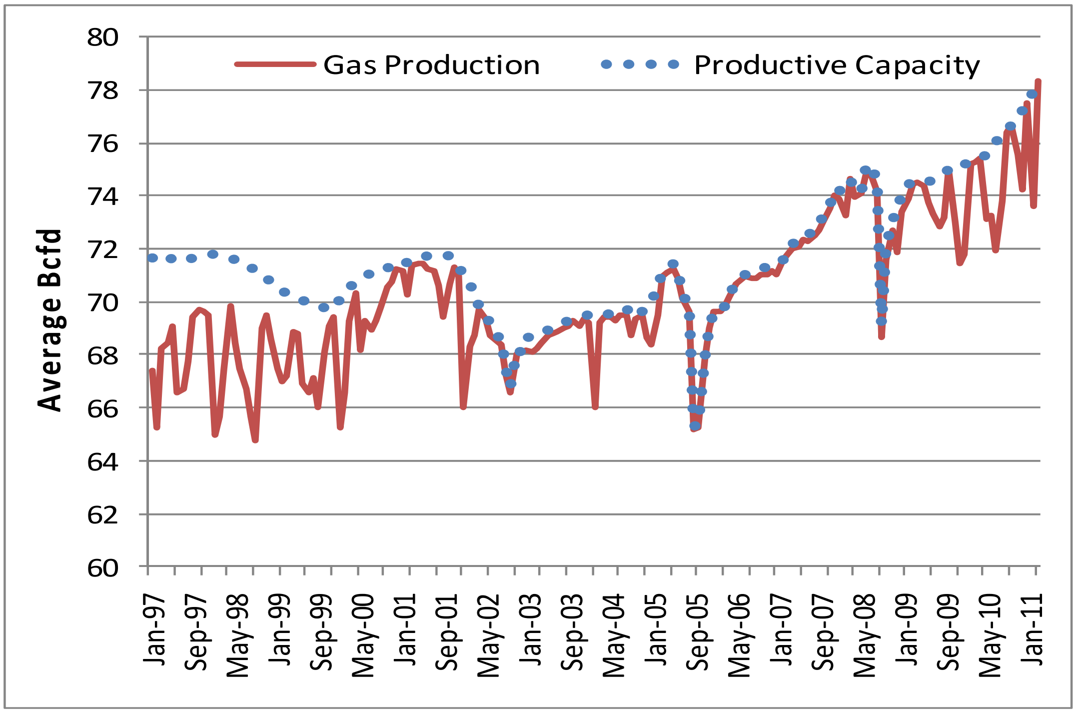
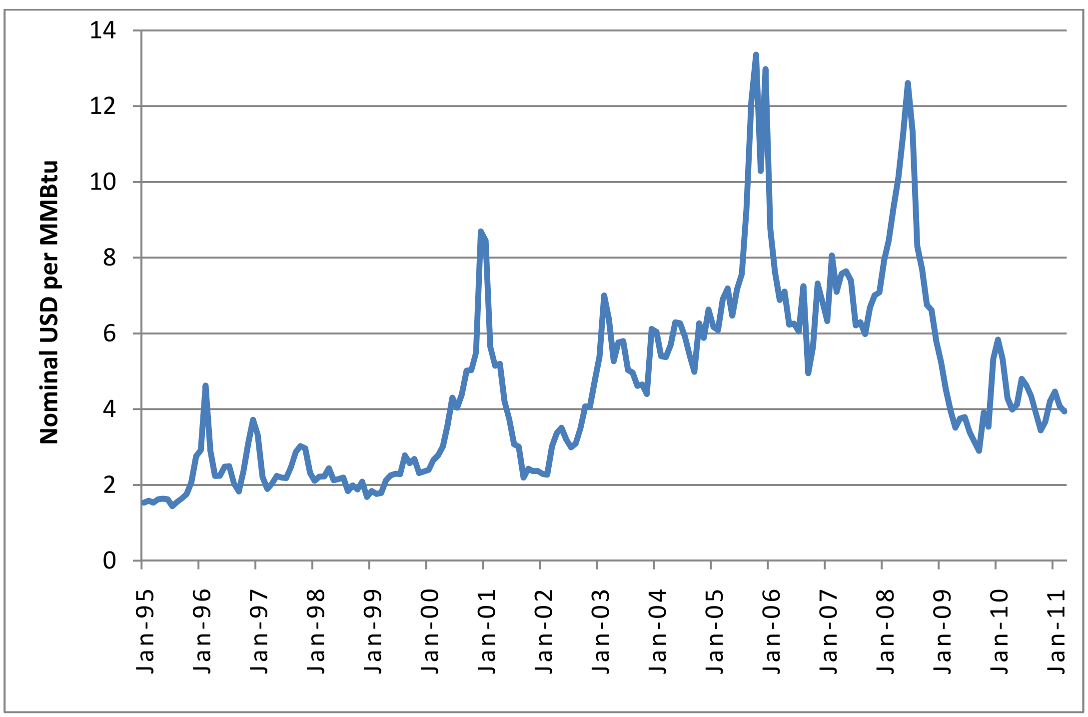


Figure 2
Monthly Natural Gas Prices at Henry Hub, Jan 1995 – Mar 2011



Source: ICF International

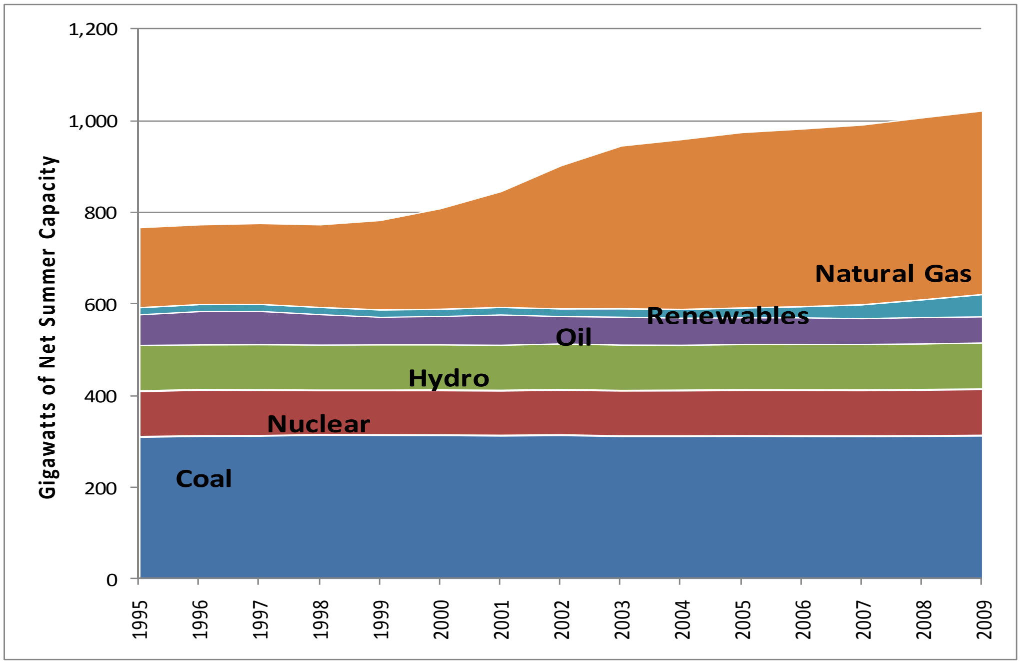
2.1.2 Power Sector Gas Demand Growth

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 led to a construction boom in new CCs and CTs 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. (Figure 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 (Figure 4).

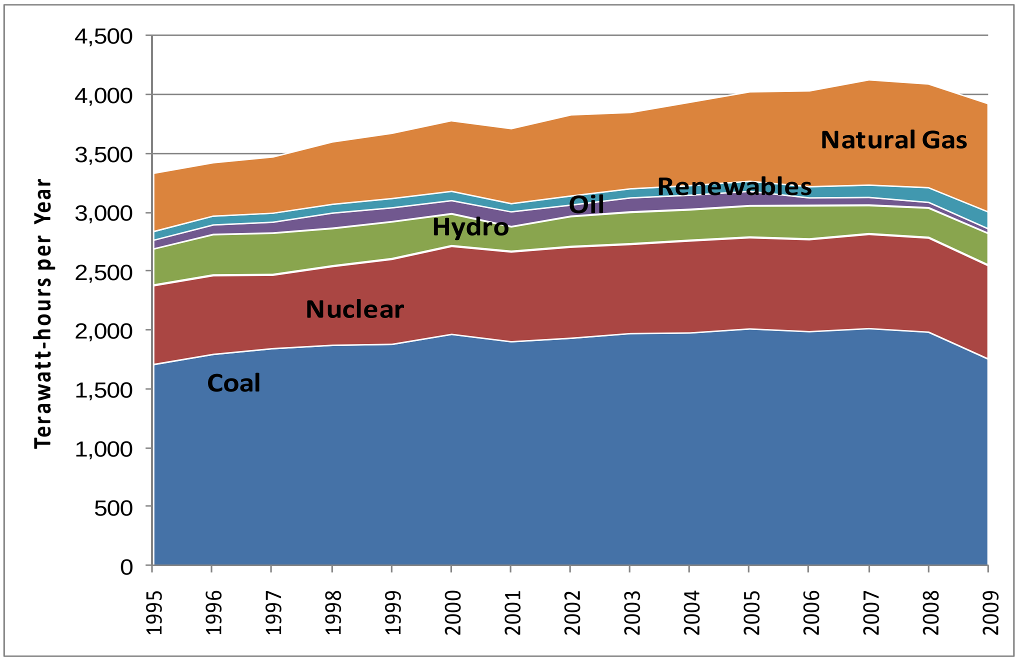
Between 1995 and 2001, power sector gas consumption rose by over 3 Bcf/day (Figure 5). Power sector consumption continued to rise in the 2000s, reaching nearly 19 Bcf/day by 2010. The increase in power sector gas consumption combined with the flat-to-downward trend in gas production led to a sharp rise 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 between 2007-2008 (-5.1%) and 2008-2009 (-5.5%). 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 Bcf/day, 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 2000 level.

Figure 3
U.S. Electric Generating Capacity by Fuel, 1995-2009



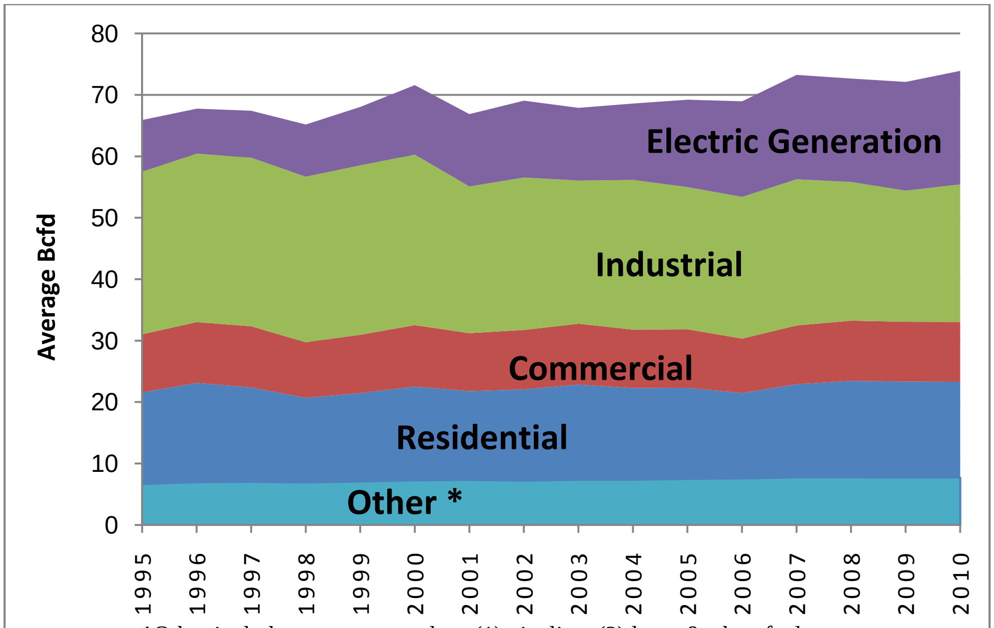
Source: EIA

Figure 4
U.S. Net Electricity Generation by Fuel, 1995-2009



Source: EIA

Figure 5
Natural Gas Demand in the U.S. and Canada, 1995-2010



*Other includes gas consumed as: (1) pipeline, (2) lease & plant fuel.

Source: ICF International

2.1.3 Residential and Commercial Demand Outlook

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.

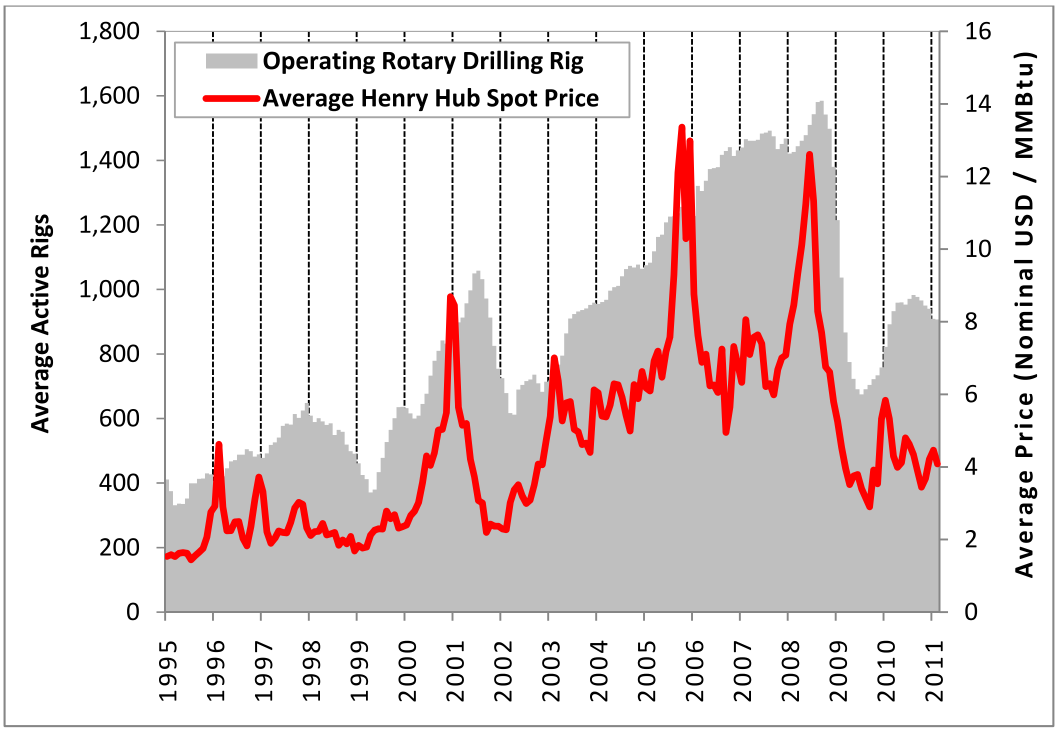
The balance of gas consumption is for pipeline fuel, lease use, and processing plant use. Pipeline fuel is the gas consumed to run the compressors that move natural gas through the pipeline network. Lease gas refers to natural gas used in well, field, and lease operations, such as gas used in drilling operations, heaters, dehydrators, and field compressors. Plant use is gas consumed at facilities 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 Natural Gas Prices and Rig Activity Outlook

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 (Figure 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.

Figure 6
U.S. Gas-directed Drilling Activity and Natural Gas Prices

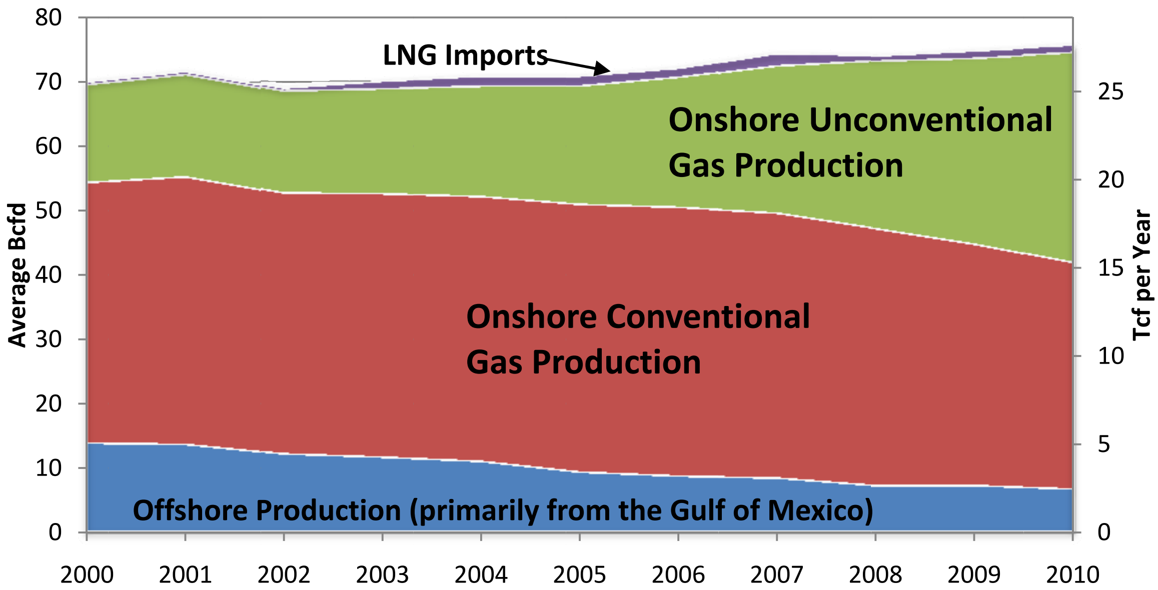


Source: EIA (rig counts), ICF International (Average Henry Hub Spot Price)

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 (Figure 7).

Figure 7
U.S. and Canadian Gas Supplies by Type, 2000-2010



Source: ICF

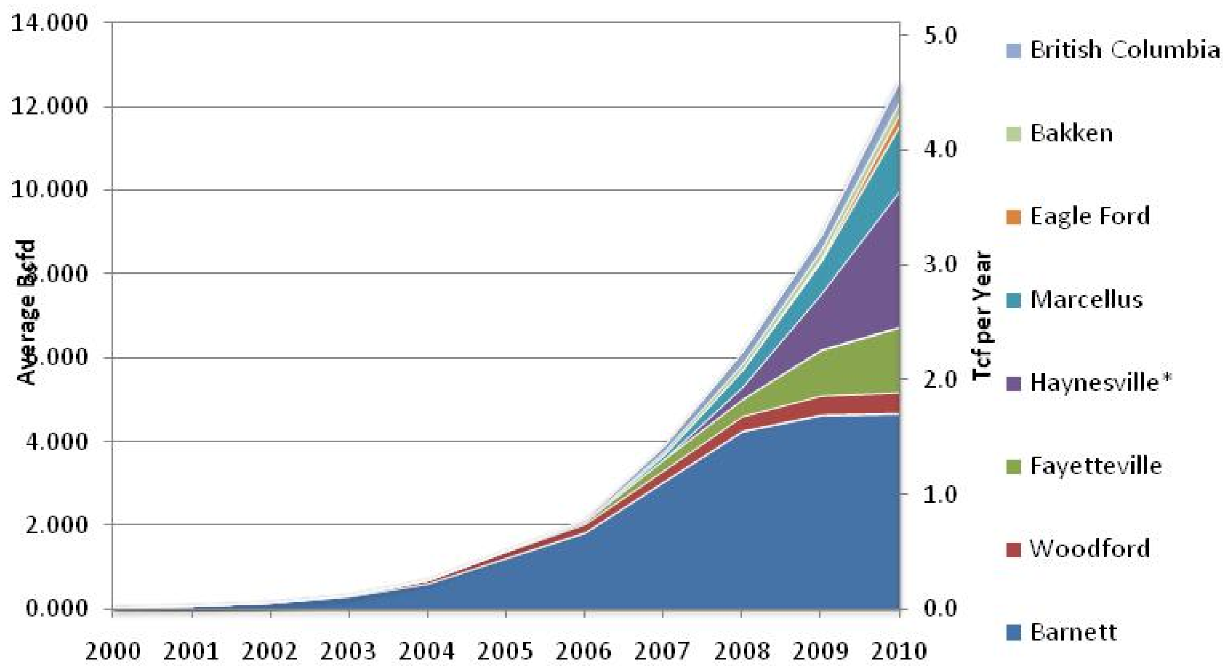
While conventional onshore and offshore production continued to decline, unconventional production was rising rapidly. By 2010, unconventional gas production increased to over 30 Bcf/day, which amounts to about 40 percent of all U.S. and Canadian gas supplies. The increase in unconventional gas production was more than enough to offset the declines in conventional gas; from 2000 through 2010, total gas production increased by over 4 Bcf/day.

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 2010, shale gas production increased from negligible levels to about 12 Bcf/day (Figure 8). As of 2010, shale gas production made up about 16 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 2,755 Tcf, or about 60 percent of the total remaining resource of 4,446 Tcf.

Figure 8
U.S. and Canadian Shale Gas Production, 2000-2010



*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 Bcf/day. Other terminals currently under construction should bring the total import capacity to over 22 Bcf/day 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 Bcf/day, 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 development 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 2015.

2.1.6 Shifts in Supply and Demand Cause Shifts in Pipeline Flows

Shifts in gas production and differences in regional gas demand growth result in changes in inter-regional flows of natural gas. Figure 9 and Figure 10 illustrate the patterns of gas movement for 2005 and 2010, respectively. In both years, the movement of gas from the Western Canadian Sedimentary Basins (WCSB) along the TCPL Mainline to markets in Eastern Canada and the Northeast United States is clearly evident. But close examination indicates that a significant change has occurred between 2005 and 2010.

Figure 9
North American Inter-regional Gas Flows 2005 (Mmcf/day)

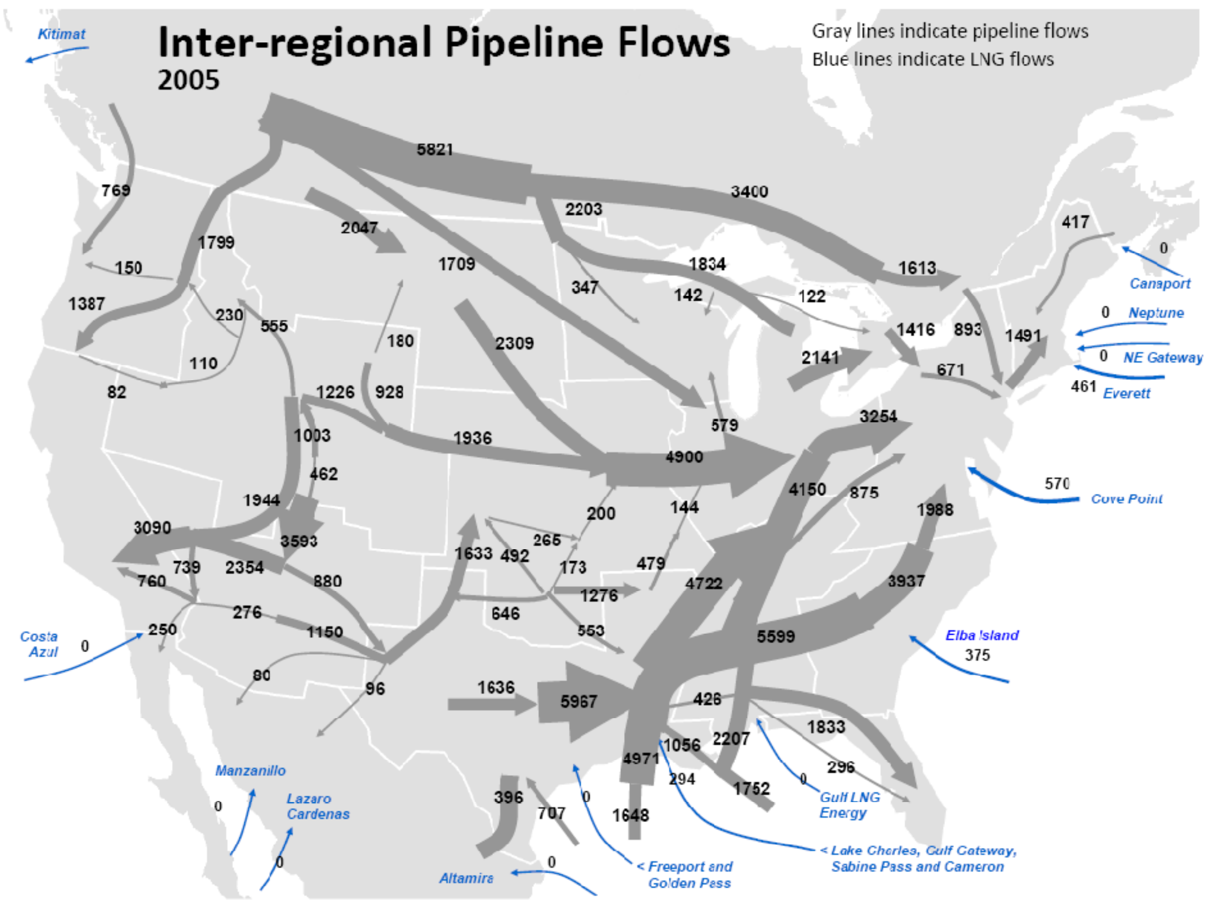


Figure 10
North American Inter-regional Gas Flows 2010 (Mmcf/day)

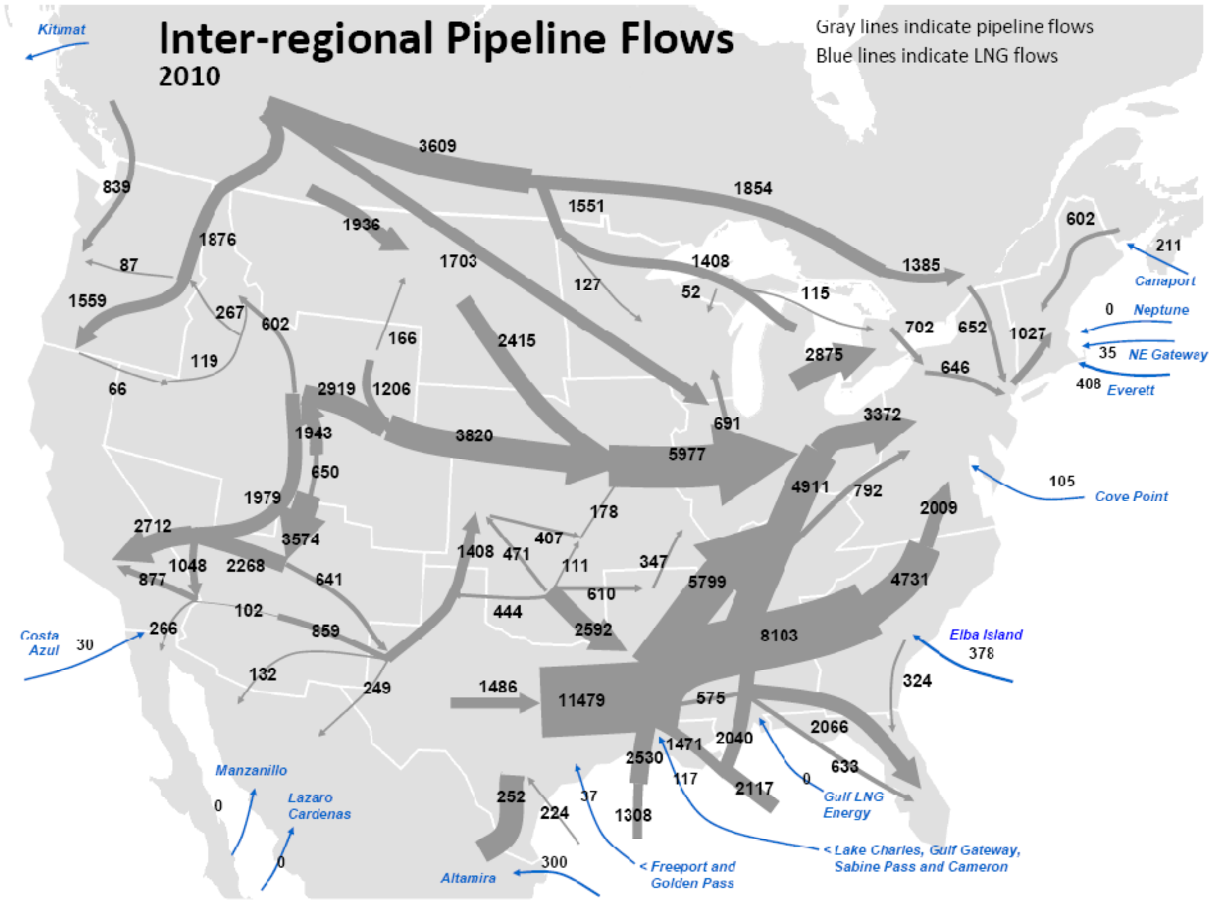
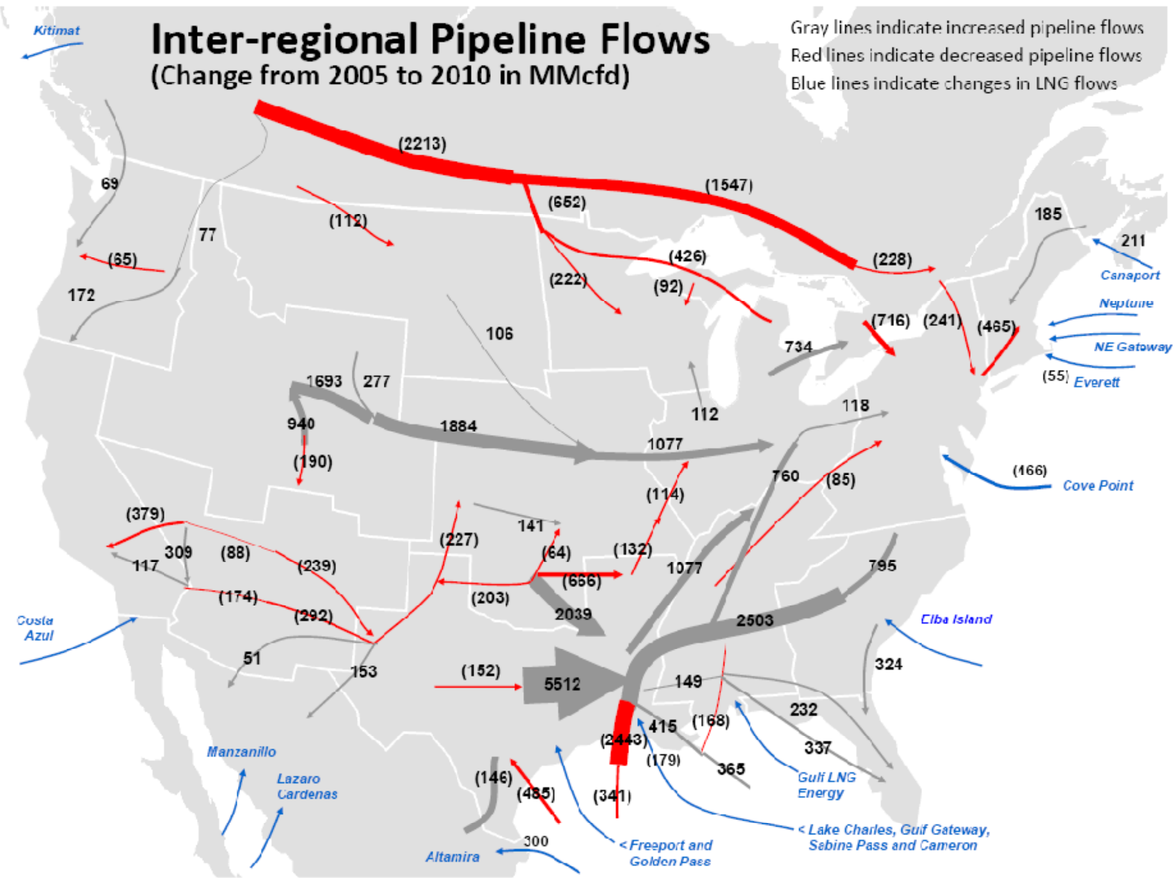


Figure 11 illustrates the changes from 2005 to 2010. The chart reflects the difference between the interregional flow of gas in 2010 and the flow in 2005. Increases in flow are represented by the gray arrows. Decreases in flows in 2010 from the 2005 level are presented as red arrows.

Flows on TransCanada Pipeline (TCPL) declined dramatically over the period. There are several reasons behind this decline. 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. Moreover, with the Alliance Pipeline providing an alternate path for gas to flow from Western Canada at lower cost than the TCPL path to the U.S. Midwest, the declines in the availability of gas production for export out of the WCSB to other Canadian provinces and U.S. markets was concentrated onto the TCPL Mainline.

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.

Figure 11
Changes in Inter-regional Pipeline Flows, 2005-2010 (Mmcf/day)

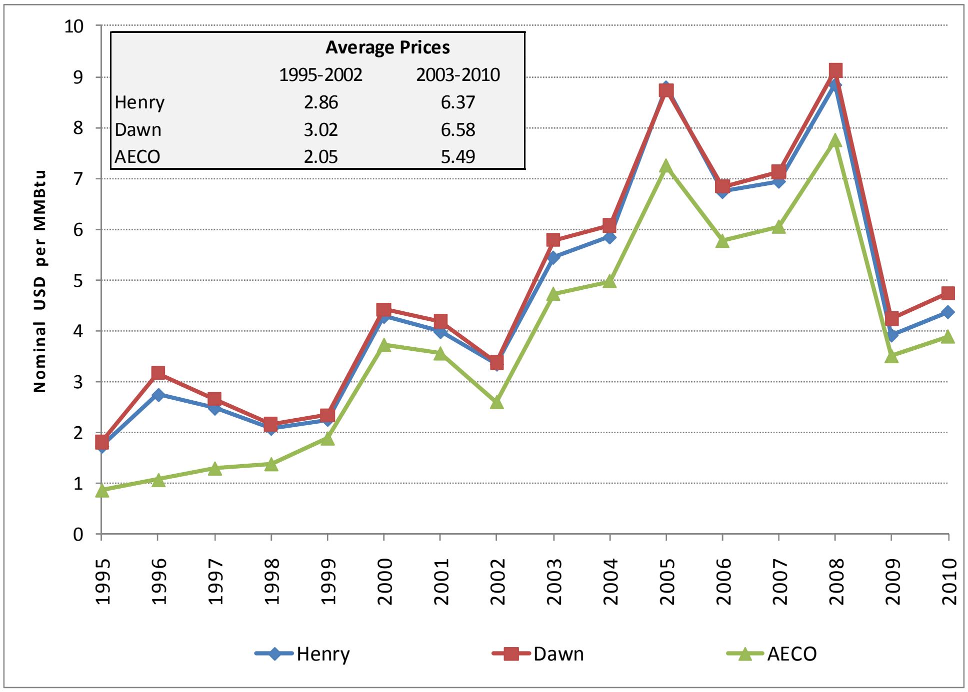


Source: ICF International

2.1.7 Price Impacts

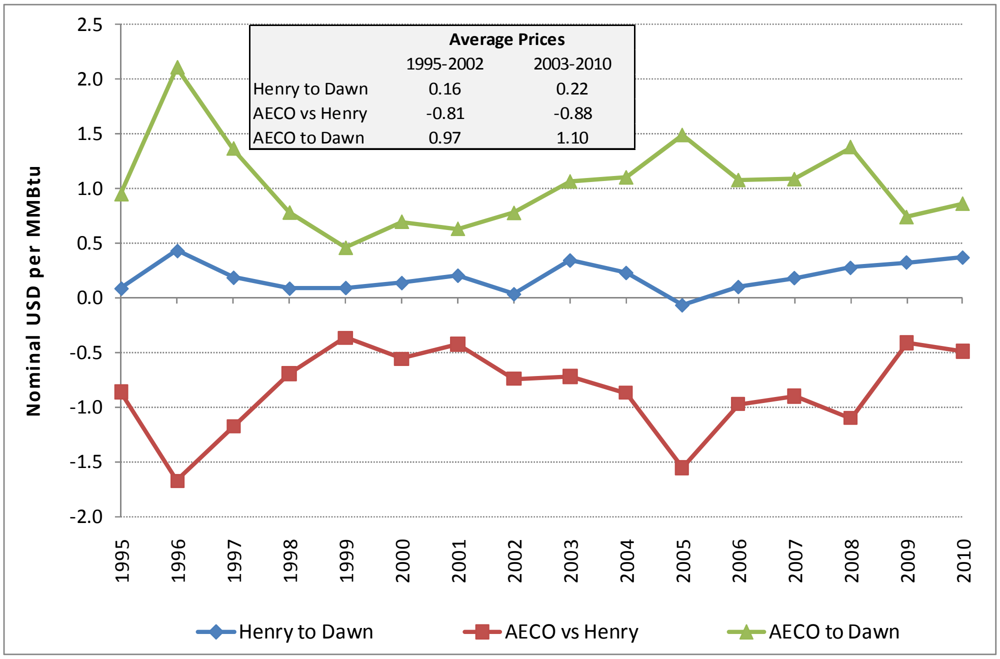
As discussed above, North American gas prices were trending upward until the onset of the 2008-09 recession. Regional prices all followed this general trend, with average gas prices rising to more than double the very low prices of the gas bubble era (Figure 12). Changes in basis differentials between markets reflected the changes in regional supply and demand and constraints on the pipeline capacity serving individual markets (Figure 13). 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 increased 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.

Figure 12
Regional Average Annual Gas Prices, 1995-2010



Source: Platts Gas Daily

Figure 13
Regional Average Annual Basis, 1995-2010



2.1.8 Projected Natural Gas Movements and Prices

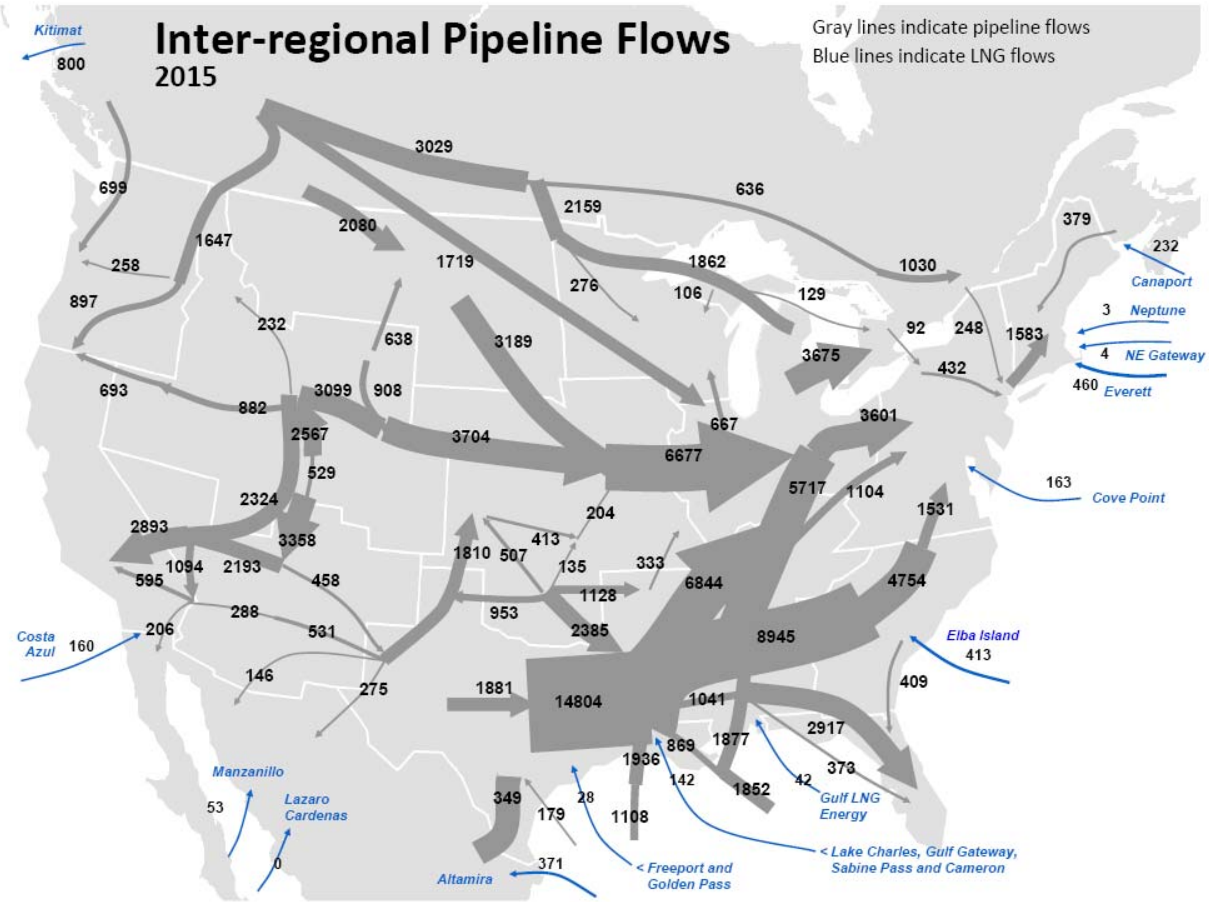
The market developments that resulted in the changes in natural gas flow patterns over the past ten years are likely to continue to affect the movement of gas in the future. Figures 14 and 15 present the projected inter-regional gas movements for 2015 and 2020 respectively. Figure 16 presents the change in the projected flow of gas in the period.

The continued development of gas supply in the Rocky Mountains in the U.S. in conjunction with the construction of the Ruby Pipeline to move incremental supply to Northern California displaces significant volumes of WCSB gas production along the GTN corridor. This gas becomes available to meet Alberta requirements and to flow along the TCPL Mainline to markets east of Alberta. Despite the availability and the projected robust development of shale in Western Canada, the volume of gas available for movement on TCPL is not sufficient to offset the declines that have occurred in since 2005.

There has been an extremely important change in the ICF Base Case since the last review performed for Centra. As a result of the review of the unconventional resource base, primarily shale gas, that is now deemed to be technically recoverable and the analysis of the cost of developing that resource, the ICF Base Case no longer assumes that any of the arctic gas pipelines that have been proposed is built in the forecast time frame, 2035. The lack of the availability of arctic gas to augment WCSB and Western

Canadian Shale gas results in much lower pipeline flows on the TransCanada Mainline relative to previous projections.

Figure 14
North American Inter-regional Gas Flows 2015 (Mmcf/day)



With the recognition of the size of the unconventional gas resource base and the updated cost of exploration and production associated with newly deployed technologies, the ICF Base Case projects North American gas prices that are substantially below the levels that were projected in early 2009 when ICF last reviewed the market for Centra.[1] Figures 17 and 18 present the projected prices for Henry Hub and AECO, respectively, and juxtapose the current Base Case projected prices to the prices in the earlier report.

[1] Assessment of Natural Gas Commodity Options, ICF International, February 2009.

Figure 15
North American Inter-regional Gas Flows 2020 (Mmcf/day)

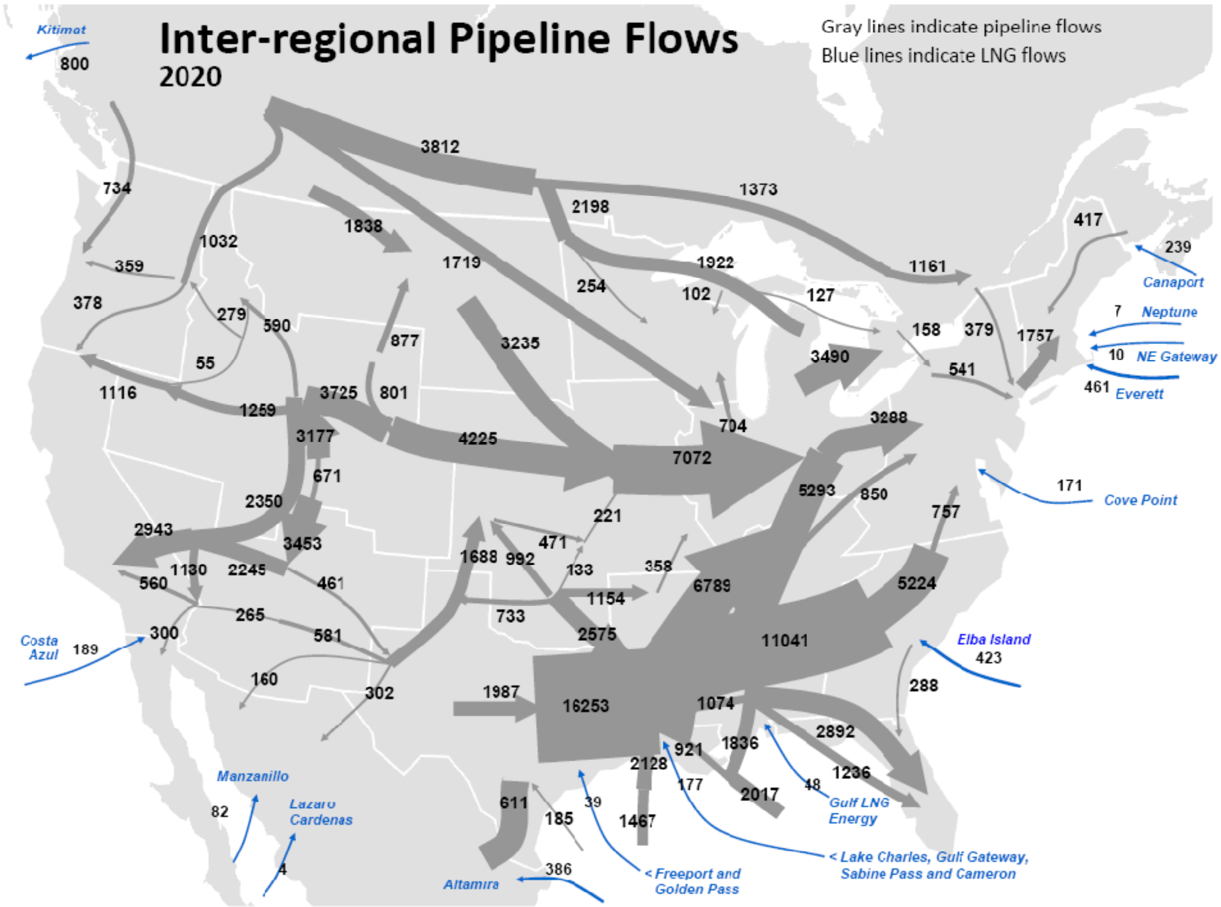


Figure 16
Changes in Inter-regional Pipeline Flows, 2010-2020 (Mmcf/day)

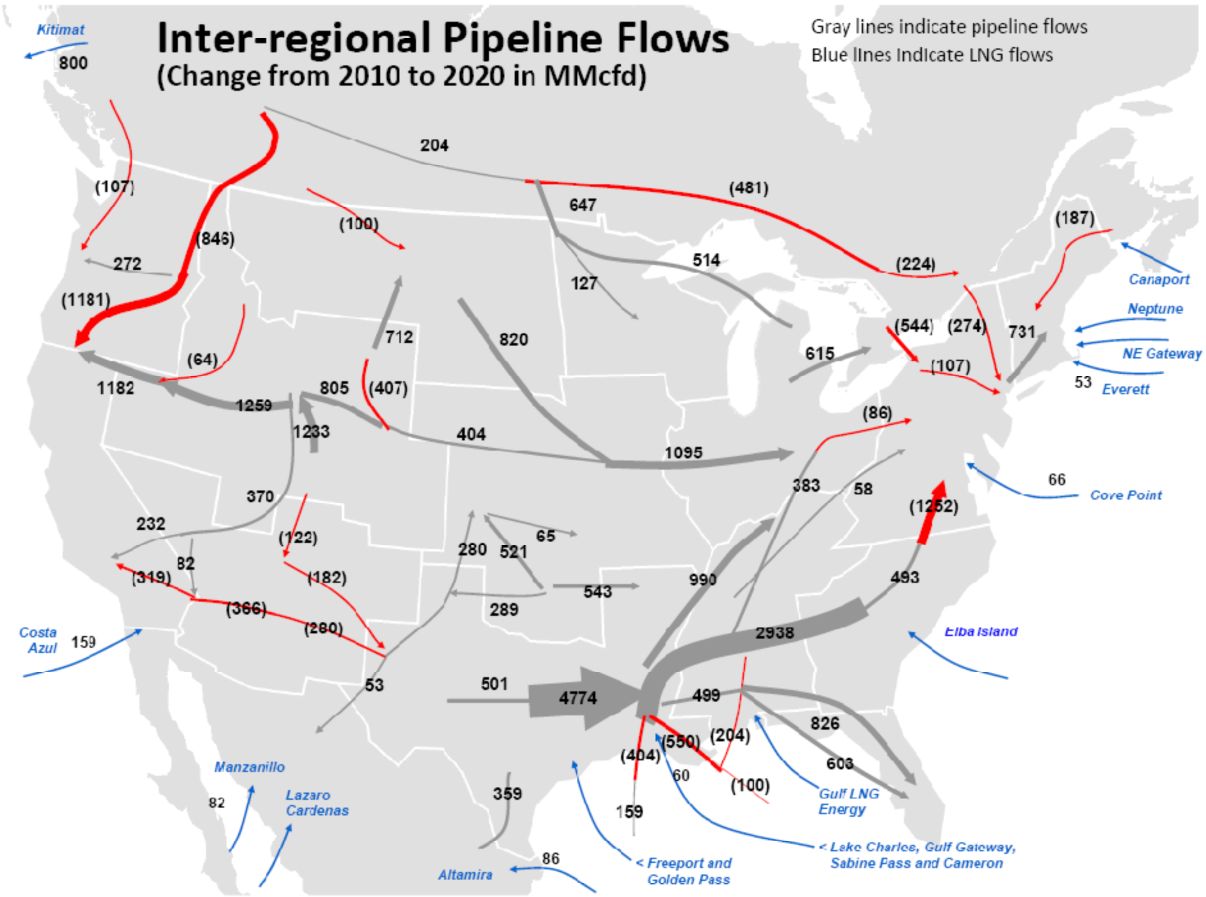


Figure 17
Change in ICF Forecast of Henry Hub Price Since Previous Stakeholder Conference

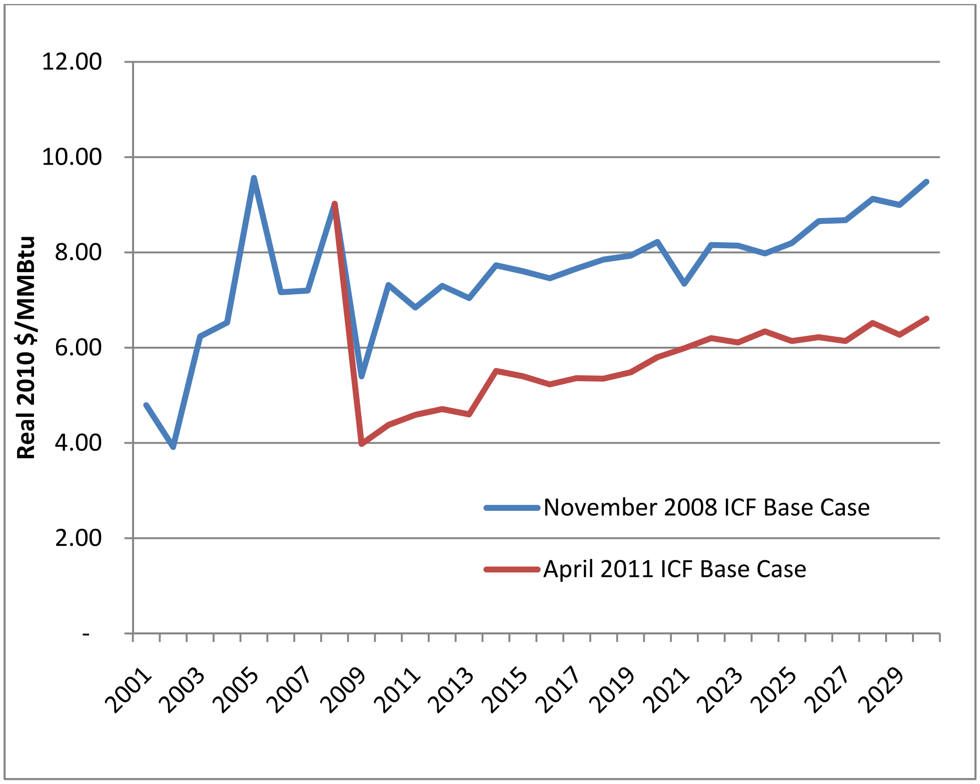
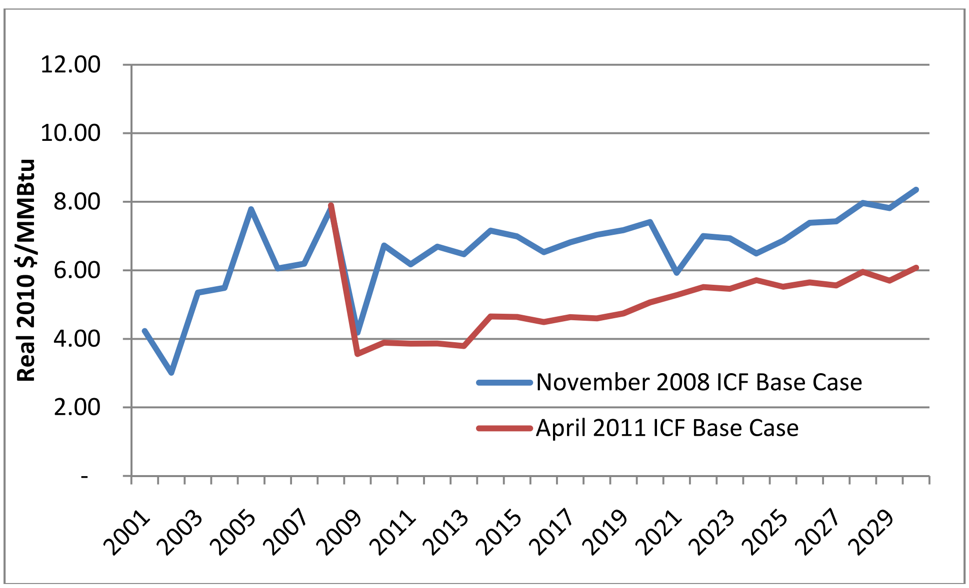


Figure 18
Change in ICF Forecast of AECO Price Since Previous Stakeholder Conference



2.2 Forecast Uncertainty

The natural gas market outlook summarized above is based on the April 2011 ICF Base Case, which represents ICF's "Most Likely" forecast of the natural gas market conditions expected to be faced by Centra over the next 20 years. As with any forecast, there are significant uncertainties associated with the ICF Base Case forecast. The key uncertainties and ICF's approach to evaluating these uncertainties are discussed below.

2.2.1 Key Areas of Forecast Uncertainty

1) Economic Growth:

One of the greatest risks for any energy infrastructure is that the U.S. and Canadian economies will continue to suffer from some of the problems that it has experienced over the past few years. Economic growth has resumed in the past six months, but there are still signs of weakness in parts of the economy. Unemployment has remained relatively high and job creation has lagged. In addition, the amount of federal deficit spending remains a concern that the U.S. government may need to address. High oil prices also have potential to slow down economic growth. In short, it is not altogether clear that the economy has returned to solid footing even though economic growth has resumed.

The uncertainty associated with economic growth is likely to have a significant impact on the overall demand for natural gas, resulting in changes in the overall outlook for natural gas prices.

2) Environmental Policy:

In addition to the economy, environmental policies pose a great uncertainty for natural gas markets. Generally speaking, the U.S. has well defined and established environmental policies. Many of the policies have been established over a number of years, e.g., the Clean Air Act has been in place since 1990. However, some potential new regulations loom. The federal government has been discussing various forms of climate change policy for much of the past decade, however given the current political climate the direction of new policies is not clear. The shape and form of climate change regulation is very uncertain. Will the policy take the form of a cap and trade program, or will it be promulgated into law as a clean energy standard that create incentives for various forms of "clean energy", including renewable generation, nuclear, and "clean coal" capacity? Will natural gas be included among the clean options? The answers to these questions are very uncertain, and the direction of natural gas use will ultimately be determined by the new policies. For the purposes of the scenario analysis for Centra, the primary impact of the environmental policy uncertainty is expected to be on natural gas demand. Hence, high and low demand cases are expected to reasonably encompass the uncertainty related to environmental policy issues.

3) *Natural Gas Resources and Production Technologies:*

Beyond the economic and environmental uncertainties, robust development of competing gas supplies also presents a significant market uncertainty. The most noteworthy of the supply alternatives is gas from the Marcellus Shale. We project Marcellus shale gas production to grow significantly, and it will become an important gas supply for Northeast gas consumers. However, our Base Case projection falls well below certain high production scenarios that have been discussed by the industry.

At this time, we know that Marcellus Shale production is increasing rapidly, and will be a major source of natural gas supply for the Northeast U.S. However, we don't know just how much production is likely to occur. There are a variety of factors likely to influence the ultimate production path for this resource, including:

- Issues related to environmental impacts, primarily water, have already resulted in significant portions of Marcellus resource being effectively placed off-limits for drilling for the foreseeable future. These regions include the New York City, Syracuse, and Philadelphia watersheds. The Marcellus resource base is vast, and these regions comprise only a small portion of the total potential drill sites in the resource. Hence the existing constraints are unlikely to significantly impact overall Marcellus production. However, a more aggressive regulatory regime that increases the costs of exploration and development throughout the resource base could substantially delay exploration and development in the region, and reduce the ultimate level of production from the Marcellus Shale.
- Currently, gas prices are ranging from $4.00 to $5.00 per MMbtu. At these gas prices, we anticipate that drilling activity not needed to hold leases is likely to decline. In addition, actual drilling activity is likely to be concentrated in the areas with very high associated liquids. This may lead to constraints on production caused by limited gas processing facilities.
- On the upside, in the last two years, the resource base has been expanding much more rapidly than anticipated due to improvements in technologies and a better understanding of the available resource base. It is very possible that the resource base will continue to expand more rapidly than we anticipate, leading to additional economic drilling opportunities and significantly higher production in both the near and long term outlook.

The overall level of Marcellus production will have a significant impact on natural gas supply patterns in the Northeast U.S., and is likely to determine the level and value of new transportation and storage facility investments in the region. In order to assess the impact of this uncertainty on North American gas markets, we recommend evaluating three different levels of Marcellus Shale production. The three different production profiles include the ICF Base Case, and a high and low Marcellus production case.

- ***ICF Base Case Marcellus Shale Production***: The ICF Base Case projection of Marcellus Shale reflects a balanced view concerning the rapidly expanding estimates of the natural gas resource base in the Marcellus and the environmental sensitivities and issues associated with increased drilling. The ICF Base Case reflects a continuation of current drilling levels, at about 1,200 wells per year over the forecast period. This is well under the economic level of drilling that could occur if all environmental concerns are alleviated, but well above the level that might occur if environmental issues force a reduction in future drilling activity.

- ***High Marcellus Shale Production***: The high Marcellus shale production case represents faster growth in Marcellus shale production consistent with resolution of environmental concerns that limit production growth in the ICF Base Case. The case includes both accelerated Marcellus shale production and pipeline expansions that "de-bottleneck" gas flows in Northeast U.S and Canada to minimize market disruptions resulting from pipeline constraints. The case is based on expectations that resolution of environmental concerns allows drilling to increase from Base Case levels of 1,200 wells per year to 1,800 wells per year.
- ***Low Marcellus Shale Production:*** The low Marcellus shale production case represents slower growth in Marcellus shale production consistent with acceleration of environmental concerns that will further constrain drilling activity. The case is based on expectations that environmental concerns reduce the number of wells drilled per year from Base Case levels of 1,200 wells per year to 600 wells per year.

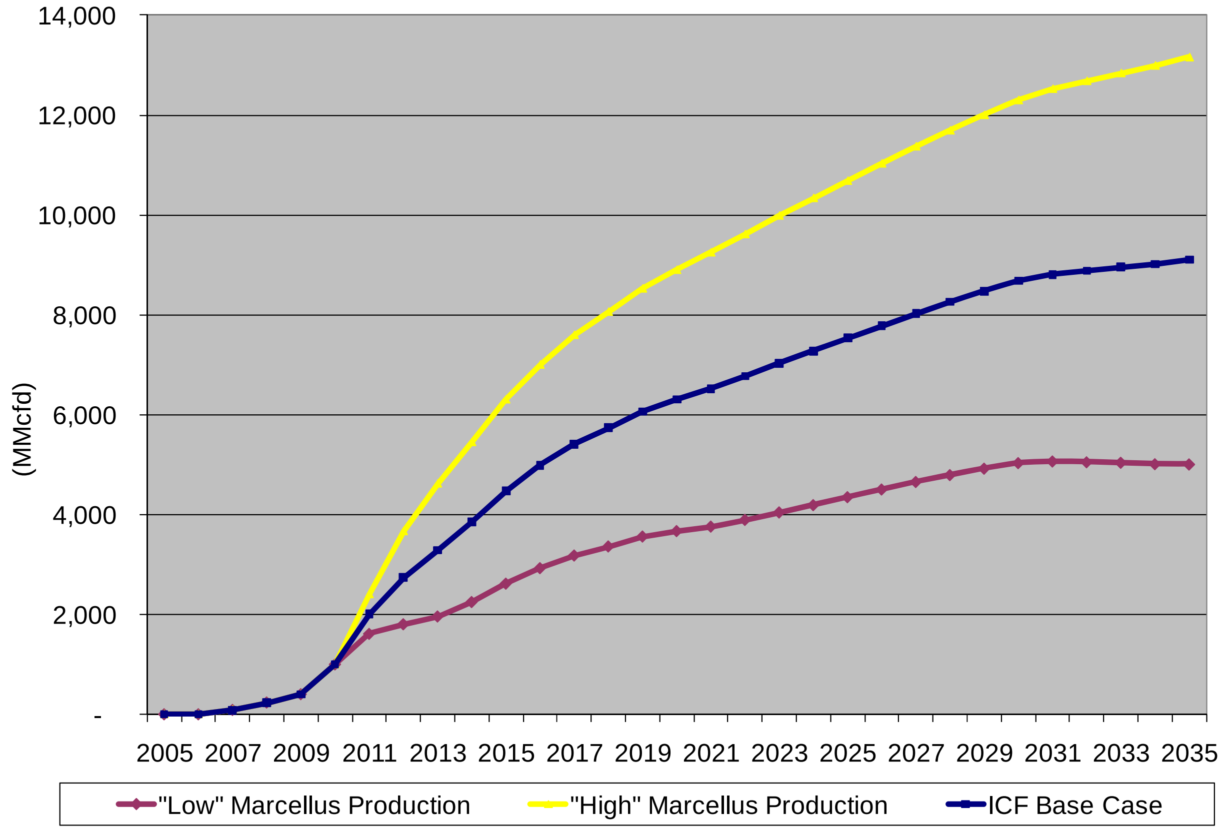
The three production profiles are shown in Figure 19 below.

In addition to the Marcellus Shale, there are other unconventional gas supplies that require a close watch. Other shales, like the Devonian Shale west of the Marcellus and Utica Shale in Eastern Canada could become economically viable sources of supply, particularly as E&P technologies continue to advance. In fact, the Utica Shale formation is in very early stages of development, and the potential for its development is likely to become apparent soon.

Further west, the Montney and Horn River Shales in British Columbia could become a prominent source of gas supply. This area is particularly important to the TCPL Mainline as much of the incremental production may flow on the pipeline. However, there remains significant uncertainty about the pace of development of these resources. In particular, the Horn River shales are generally dry gas, and development in this region will be uncertain until natural gas prices increase to more economic levels.

There is also significant uncertainty in the outlook for production from MidContinent and Gulf Coast shales, including the Barnett and Woodford shales as well as Eagleford and other plays.

Figure 19
Alternative Marcellus Shale Production Scenarios



4) TransCanada Pipeline

In our opinion, the largest uncertainty influencing Centra portfolio development is related to the rates and operating conditions on the TransCanada Pipeline. The rates and operating conditions on the TCPL Mainline will have a fundamental impact on several key variables affecting Centra. These include:

- Natural gas supply prices in Alberta and other potential supply regions.
- Pipeline transportation costs to the Centra citygate from Alberta.
- Pipeline transportation costs from other sources of supply to the Centra citygate.
- Value and costs associated with the use of potential natural gas storage options located in Alberta, Saskatchewan, Manitoba and further downstream.

The uncertainty related to TransCanada Pipeline rates and operating conditions is driven by two distinct types of issues. The first area of uncertainty is related to the market conditions that will drive natural gas flows on the TCPL Mainline. These areas of uncertainty include:

- Potential exports of BC shale gas production from the proposed Kitimat LNG export facility.
- Natural gas demand in Alberta and BC for tar sands oil production, gas to liquids production, power generation and other applications.
- Growth in WCSB shale gas production and related pipeline infrastructure.

The second area of uncertainty is the TCPL rate structure. At this point, it is unclear how TCPL rates will change over the next few months, let alone the next 10 years.

2.2.2 Other Areas of Potential Market Uncertainty

We have also considered several other important areas of uncertainty that could significantly impact natural gas market conditions. However, as discussed below, we do not believe that these issues will have a fundamental impact on Centra supply portfolio decisions in the next five to ten years:

1) Arctic Gas Supply

Arctic gas supply has the potential to fundamentally alter the economics of natural gas supply in Manitoba, as well as resolving transportation volume issues on TransCanada Pipeline. However, at this time, we do not anticipate completion of any of the pipeline options into Alberta prior to 2030, and the ICF Base Case does not include completion of an Arctic gas pipeline during the 2010 – 2035 time horizon. Even in the best case scenario, an Arctic Gas pipeline could not be completed prior to 2020, hence will not impact near and mid-term portfolio decisions by Centra. As a result, we are not proposing to include Arctic gas in any of the potential scenarios.

2) Incremental Storage Development

The ICF Base Case is a relatively low storage growth scenario, reflecting aggressive storage expansion in the last five years, and the relatively soft gas market, and relatively low seasonal natural gas price spreads for the next 10 years. Storage development will have an impact on seasonal price spreads, and will impact the value of any storage capacity utilized by Centra. An aggressive North American storage development scenario would reduce the seasonal price spreads seen by Centra and would reduce the economic value of any storage capacity contracted for or constructed by Centra. ICF does not consider an aggressive storage development scenario to be a critical element of the analysis however as the current base case already reflects a relatively low storage value scenario. In addition, most of the value associated with Centra storage decisions will be determined by avoided pipeline capacity costs and operational factors rather than seasonal price spreads.

3) LNG Import and Export Levels

There remains significant uncertainty in LNG import and export levels. In the current natural gas price environment, we anticipate much lower LNG imports than projected in the past. Changes in LNG import levels influence the overall natural gas supply/demand balance and hence prices. Changes in LNG imports are also likely to be seasonal, with incremental LNG imports during the summer months. The seasonality of LNG imports can have a large impact on seasonal natural gas prices and the value of natural gas storage.

There is also uncertainty related to potential LNG exports. Current export capability is limited to reexportation of imports. However, a number of facilities, including Sabine Pass[2], Freeport and Lake Charles in the Gulf, and Kitimat in British Columbia have filed applications to develop LNG export capacity.

While LNG scenarios can impact storage value, with the exception of exports from Kitimat, we consider this area of uncertainty to be less important to Centra than other issues. The Kitimat LNG exports directly impact TransCanada Pipeline flows, and are an important driver of potential changes in TCPL rates and operations.

2.3 Approach to Addressing Forecast Uncertainty

In order to address the uncertainty in natural gas market conditions impacting the Centra gas supply planning decisions that need to be made, ICF developed a series of alternative natural gas market scenarios addressing the factors described above.

2.3.1 Alternative Natural Gas Market Scenarios

In addition to the ICF Base Case, the following natural gas market scenarios were developed by ICF to represent a reasonable range of natural gas market conditions to be considered during the Centra supply portfolio planning process.

1) **Tight Gas Market Scenario**: The tight gas market scenario is based on potential gas market conditions that can be expected to increase the value – and price -- of natural gas throughout the North American market. The scenario includes:

    - Slower growth in North American Shale Gas Production
    - Faster economic recovery and natural gas demand growth than represented in the ICF Base Case.

    This scenario allows us to evaluate the impact of a tight natural gas market on Centra portfolio options, and is considered to be an important bounding case for the ICF analysis.

2) **Optimistic Mainline Market Drivers Scenario**: The TCPL Optimistic Market Scenario reflects the optimum gas market scenario from the TCPL perspective, including assumptions on supply and demand likely to increase pipeline flows on the TransCanada system.

    - Slow growth in Marcellus Shale Production
    - Low Alberta Demand Growth

[2] The Sabine Pass application has been approved by the U.S. Department of Energy, the Freeport and Lake Charles applications are pending. Export facilities in the U.S. also require approval from the U.S. FERC.

- High growth in WCSB Production and Exports
- No incremental LNG Exports from North America (E.g., no Kitimat)

3) **Pessimistic Mainline Market Drivers Scenario**: The TCPL Pessimistic Market Scenario includes a series of assumptions related to gas market development that would minimize pipeline flows on the TransCanada Pipeline system.

   - High growth in Marcellus Shale Production
   - High Alberta Demand Growth
   - Continuing decline in WCSB Production and Exports
   - BC Shale Gas exported as LNG

3
OVERVIEW OF CENTRA'S CURRENT OPERATIONS

This section provides a description of the gas demand, supply, storage and transportation portfolio and arrangements that Centra currently manages on a day to day basis to meet Manitoba's market requirements.

3.1 Centra Natural Gas Demand

In 2010, Centra served approximately 264,000 residential, commercial, and industrial natural gas customers throughout Manitoba. A very large percentage of these natural gas customers reside in the Winnipeg area, with the majority of the others located within a corridor that extends approximately 100 kilometers on either side of the TransCanada Mainline.

As shown in Figure 20, the total number of customers served by Centra has been growing steadily at slightly less than one percent per year since 2000. Over the same period, total volumes delivered by Centra have been relatively stable (Figure 21), with most of the year-to-year variation in delivery volumes resulting from differences in weather, rather than underlying market trends. Overall, volumes flowing under Centra's Transportation Service have grown slightly and Centra's Sales Service volumes have declined slightly.

Centra customers have the option of receiving their gas supply either from Centra or via direct purchases from a third party broker. However Centra, as the major distributor of natural gas in the province, retains a continued responsibility to all of its customers, including those who elect to purchase their gas supply from others.

The service provided by Centra to facilitate the transportation of direct purchase supplies is known as the Western Transportation Service ("WTS"), in which the consumer arranges, through a broker, a source of gas in Western Canada and Centra transports the gas from Western Canada to the consumer.

In accordance with the terms of the WTS agreement, Centra is responsible for transporting the gas purchased by the consumer or broker from Western Canada to the consumer. The broker or supplier of the gas sets the sales price of the gas for its customers. As of November 1, 2010, Centra transported gas for 29,300 WTS customers or about 11% of Centra's customer base, and accounted for approximately 15% of Centra's firm transportation Maximum Daily Quantity ("MDQ") from Western Canada.[3] The WTS volumes are transported using Centra's firm TCPL Mainline

[3] Excluding Transportation-Service Volumes.

transportation capacity. In addition, WTS customers are allocated a share of the costs of pipeline and storage capacity held by Centra that is used to meet peak day and seasonal requirements of both system customers and WTS customers.

Transportation Service, or "T-Service", customers not only acquire their own gas supply, but also make their own transportation arrangements on TCPL to ship their supply to Centra's delivery areas on the TCPL Mainline. Centra provides delivery service from TCPL to the meters of T-Service customers on its distribution system. There are currently seventeen T-Service customers served by Centra, which tend to be larger industrial loads.

Figure 20
Centra Natural Gas Customers

Source: Manitoba Hydro 2010 Annual Report

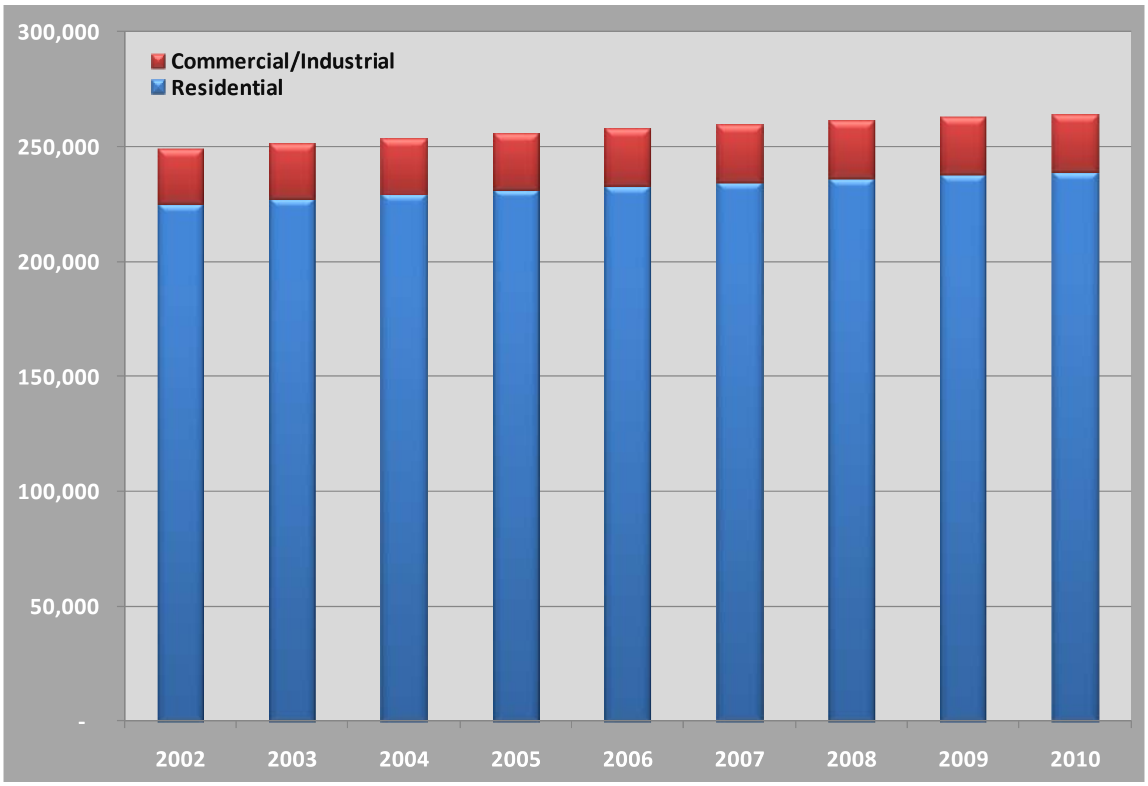
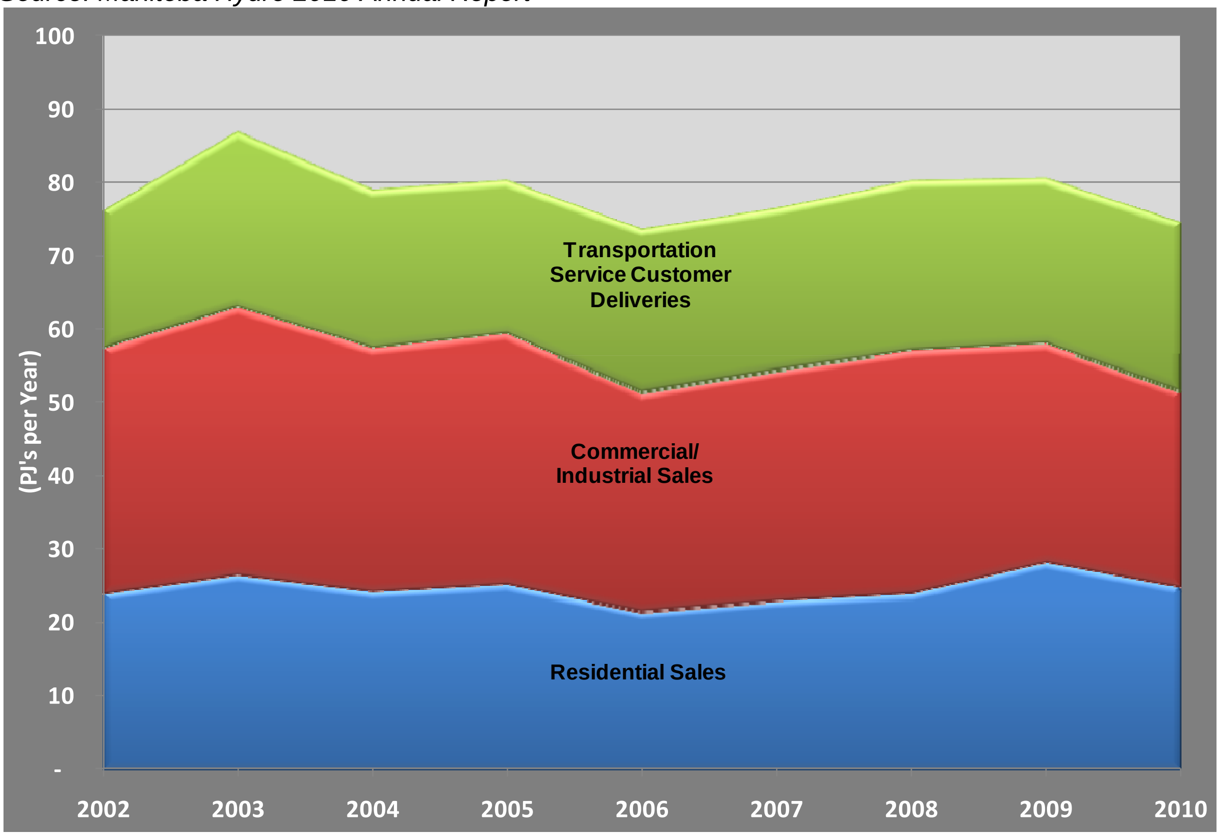


Figure 21
Centra Natural Gas Deliveries 2002-2010

Source: Manitoba Hydro 2010 Annual Report

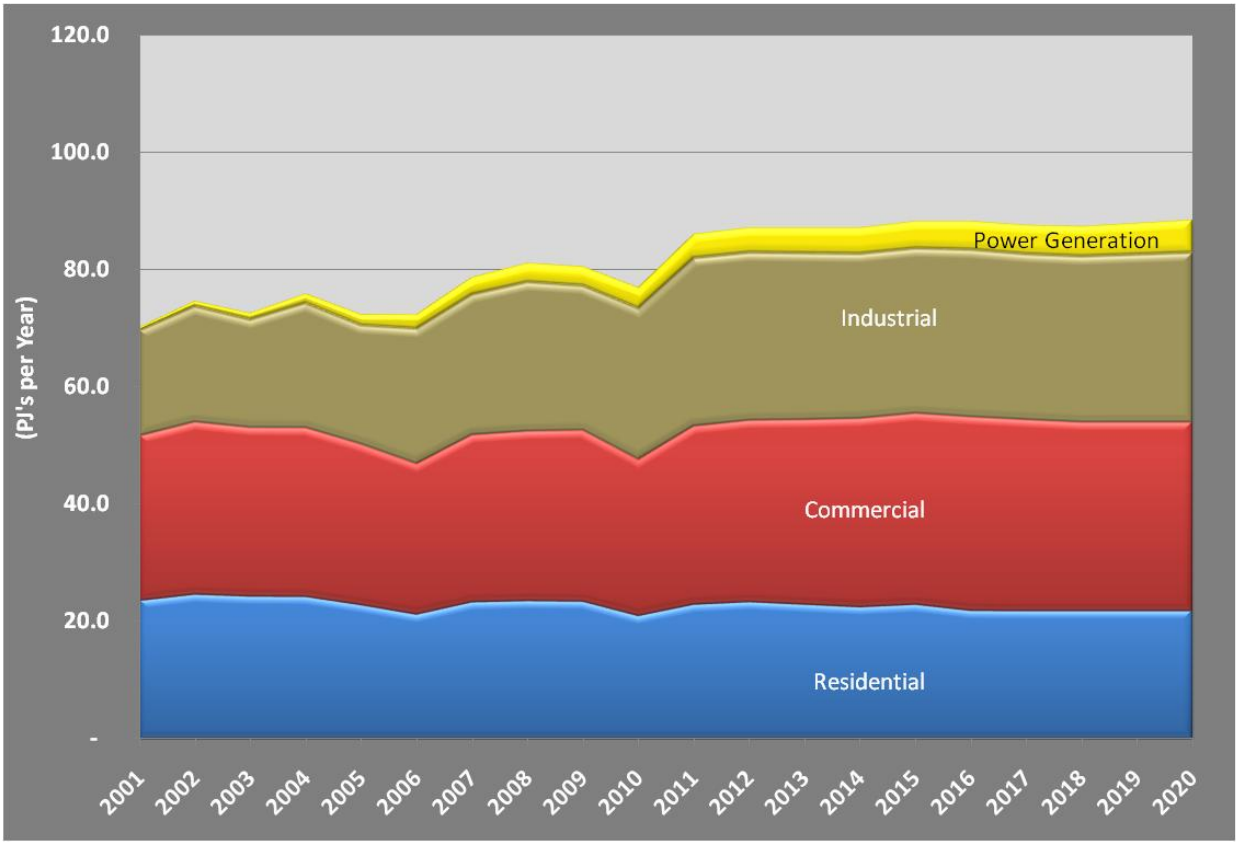


3.1.1 Forecasted Demand

ICF's Base Case projects that demand for natural gas in Manitoba for firm service residential and commercial customers will remain essentially flat between now and 2020 (Figure 22). ICF is projecting a continuation of growth in the number of residential and commercial sector natural gas customers in Manitoba at slightly less than one percent per year. However, improvements in overall efficiency of natural gas use are expected to offset most of the growth in the number of customers, resulting in stable natural gas demand in the residential and commercial sectors for the foreseeable future.

Most of the growth in ICF's forecast is expected to occur in the industrial sector. The growth in industrial demand is driven primarily by the broad economic growth trends in the province. The new industrial sector demand is expected to have a relatively flat load profile, and is expected to primarily utilize Centra's Transportation-Service (in which customers acquire their own gas and transportation on the TCPL Mainline to Centra's distribution system). As a result, the load growth in this sector is not expected to have a major impact on Centra seasonal or peak natural gas requirements.

Figure 22
ICF Forecast of Manitoba Natural Gas Demand



Residential and commercial sector demands are expected to be the primary demand drivers for the Centra system. The relatively stable outlook for residential and commercial sector demand indicates that no fundamental shifts in the type of load to be served by Centra are expected and that the current load profile represents a reasonable expectation for the future for load planning purposes.

3.1.2 Peak Day Demand

Under the terms of Centra's service territory (i.e., franchise) agreements with the Province of Manitoba, Centra is responsible for ensuring reliable service to all firm delivery customers including WTS customers. Centra's firm design peak day (the volume of gas projected to be required to serve all Firm Sales customers, including WTS customers, on the coldest winter day experienced) is estimated as of November 1, 2010 to be 481,300 GJ/day during the 2010/11 winter.

While ICF is forecasting minimal growth in total Manitoba demand, we are not forecasting near-term growth in the peak day demand to be served by Centra. The growth in demand is expected to occur primarily in the industrial sector, and will be served directly by TransCanada, or as Transportation-Service (T-Service) by Centra. Centra T-Service requires Centra to maintain distribution system capacity to meet the growth in load, however it does not require Centra to provide for peak day natural gas commodity or transportation capacity for T-Service customers. While the number of residential and commercial customers is expected to increase steadily over time, residential and commercial requirements are expected to remain relatively stable as improvements in natural gas usage efficiency offset customer growth.

3.1.3 Impact of Manitoba Weather on Supply Planning

The majority of Centra's load is in the residential and commercial sector where daily and monthly load requirements are determined primarily by weather. As a result, weather plays the major role in determining annual, seasonal and day-to-day natural gas demand. Centra's supply planning process is complicated by the fact that weather in Manitoba is more uncertain and more volatile than the weather in any of the other major markets served by TransCanada or consuming WCSB natural gas.

Figure 23 illustrates ICF's estimation of the normal traditional heating degree days[4] in a variety of different regions served by natural gas supply produced in the WCSB. As shown in this figure, Manitoba has the highest degree of seasonal variation in heating requirements due to seasonal weather patterns of any of the regions considered.

Manitoba also experiences the greatest uncertainty in terms of weather, both on an annual as well as a daily basis.

Table 1 shows total annual heating degree days for Winnipeg and a variety of other market regions served by TransCanada for a normal year, as well as for the warmest year and the coldest year between 1995 and 2005. As shown on this table, Manitoba weather exhibits both the largest absolute amount of spread in traditional heating degree days (coldest year – warmest year) as well as the largest relative range in traditional heating degree days ((coldest year – warmest year)/normal year).

In terms of utility operations and supply planning requirements, day-to-day volatility in demand may be more important than annual uncertainty. Utility planning must account for changes in day-to-day weather to ensure that the proper volume of gas is available to meet demand so that the utility is not generating pipeline imbalance fees. The Manitoba service territory served by Centra also experiences the greatest volatility in day-to-day weather of any of the market centers considered. Table 2 provides a comparison of the standard deviation in the change in daily mean temperature from one day to the next for a variety of market centers served by TransCanada between November 1995 and September 2006.

[4] For all of ICF's analysis, the number of Heating Degree Days (HDD) is defined as the sum of the number of degrees Fahrenheit below 65 degrees Fahrenheit during each month or year. "Normal" is defined as the average HDDs for the 30 year period from 1971 through 2000.

Figure 23
Monthly Normal Traditional Heating Degree Days

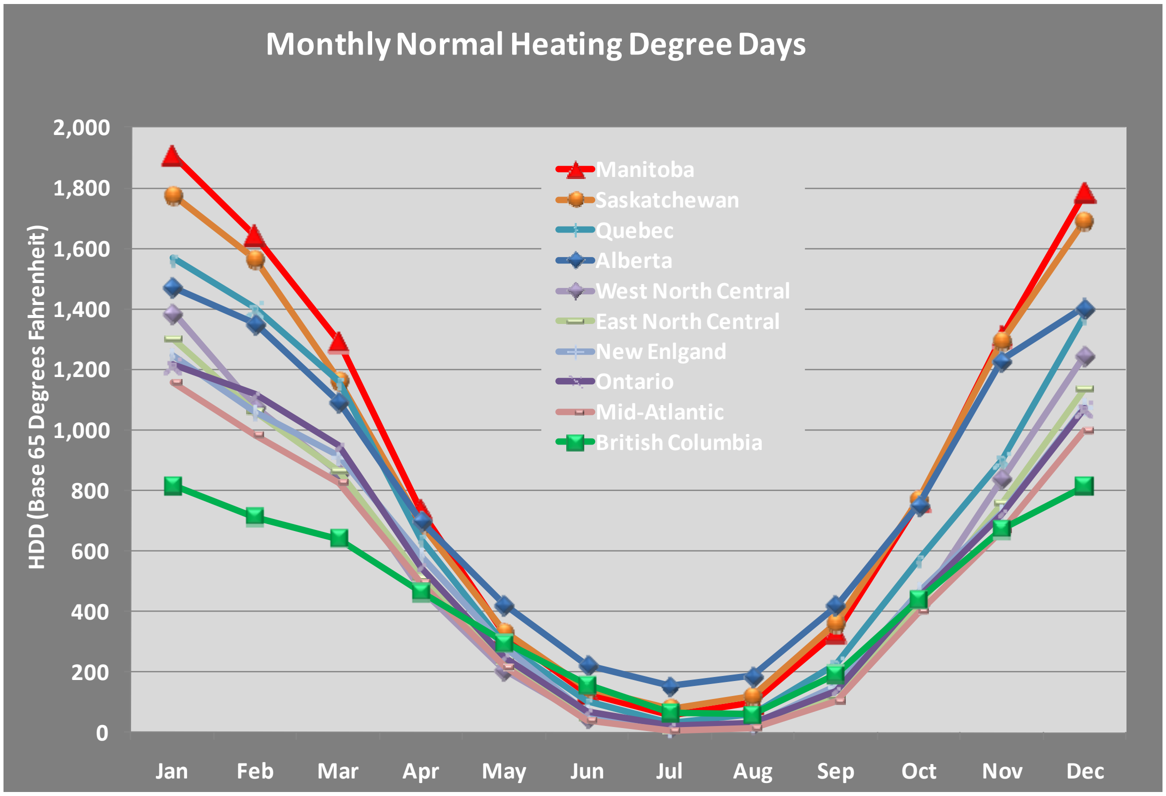


Table 1
Annual Heating Degree Days

	Normal Weather	Warmest Year	Coldest Year	Absolute Range	Relative Range
Manitoba	10,378	9,332	12,301	2,969	29%
Alberta	9,423	8,568	11,146	2,578	27%
Saskatchewan	10,003	9,633	12,370	2,737	27%
British Columbia	5,339	4,846	5,724	878	16%
Ontario	6,582	6,087	7,742	1,655	25%
Quebec	8,338	6,824	8,803	1,979	24%
New England	6,611	5,742	6,967	1,225	19%
Mid-Atlantic	5,911	4,923	6,276	1,353	23%
East North Central	6,497	5,317	7,004	1,687	26%
West North Central	6,750	5,725	7,431	1,706	25%

Table 2
Daily Volatility of Regional Weather (1996-2006)

Standard Deviation of Daily Changes in Temperature (Degrees Celsius)			
	Summer (April - Oct)	Winter (Nov - Mar)	Average
Manitoba (Winnipeg)	3.12	4.96	4.13
Alberta (Calgary)	3.03	4.81	4.01
Saskatchewan (Saskatoon)	3.04	4.67	3.93
Ontario (Toronto)	2.00	3.49	2.83
Quebec (Montreal)	2.70	4.50	3.69
U.S. North East Central (Chicago)	2.93	4.08	3.54
Rocky Mountains (Denver)	3.58	4.43	4.02
New England (Boston)	2.90	3.81	3.38

The volatility in Manitoba weather is reflected in Centra's potential range of daily sales requirements by month, based on historical weather. Figure 24 illustrates the potential for wide variations in daily demand within each month, as well as the broad seasonal differences in demand. While the daily variation differs from year to year, the general pattern remains the same. Figure 25 shows the annual load factor for each year from 2006 through 2010 (a period with both warm (2006) and cold (2008) years, where days have been sorted from highest demand to lowest demand.

As we would expect, given the weather patterns in Manitoba and the preponderance of residential and commercial demand, a very high percentage of Centra's demand is weather sensitive. The high percentage of Centra's load that is weather sensitive, combined with the very cold winter weather in Manitoba, results in a load profile that is amongst the most highly seasonal of any LDC in North America.[5] This comparison is illustrated in Figure 26, which compares the average 1996-2001 Centra load profile to the normal weather load profile for New England. This figure, which compares daily load to the average load for the year suggests that the Centra load profile is more than twice as seasonal as the natural gas load profile in New England.

However, the Centra load profile is also somewhat less "peaky" than demand in other cold weather regions. Figure 27 shows the same load profile as Figure 26, but normalizes the data to the peak day, rather than to the annual average. This figure indicates that for the 35 days with the highest demand, the Centra load profile is somewhat less "peaky" than the New England load profile.

[5] Enstar, in South Central Alaska, has a more seasonal load profile for residential and commercial demand; however, there is also a large industrial load that stabilizes the average overall load profile.

Figure 24
2010/11 Centra Demand (TJ/day)

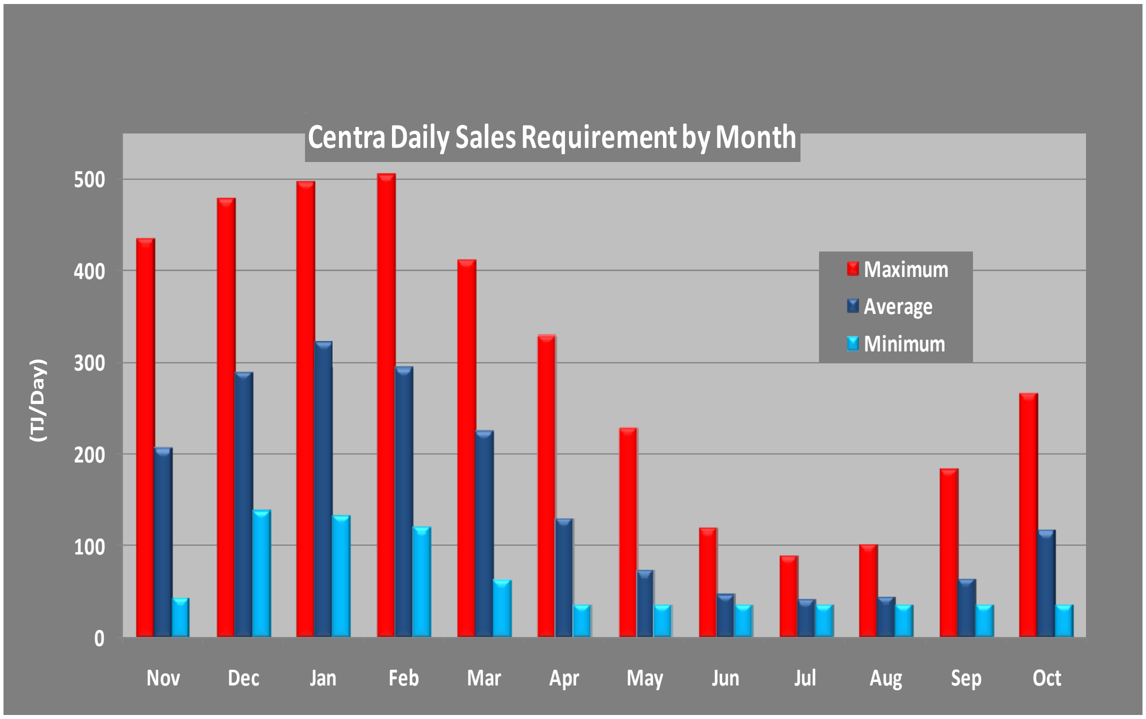


Figure 25
Centra Load Profile 2006 - 2010

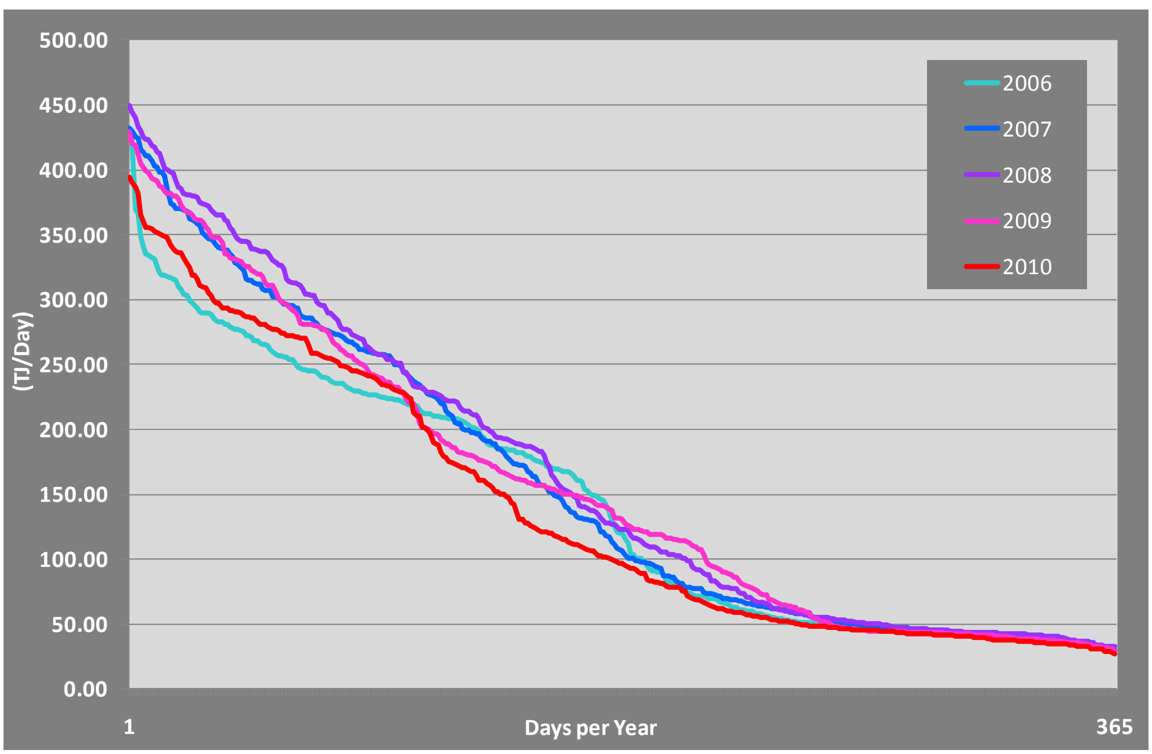


Figure 26
Comparison of Centra and New England Load Profiles

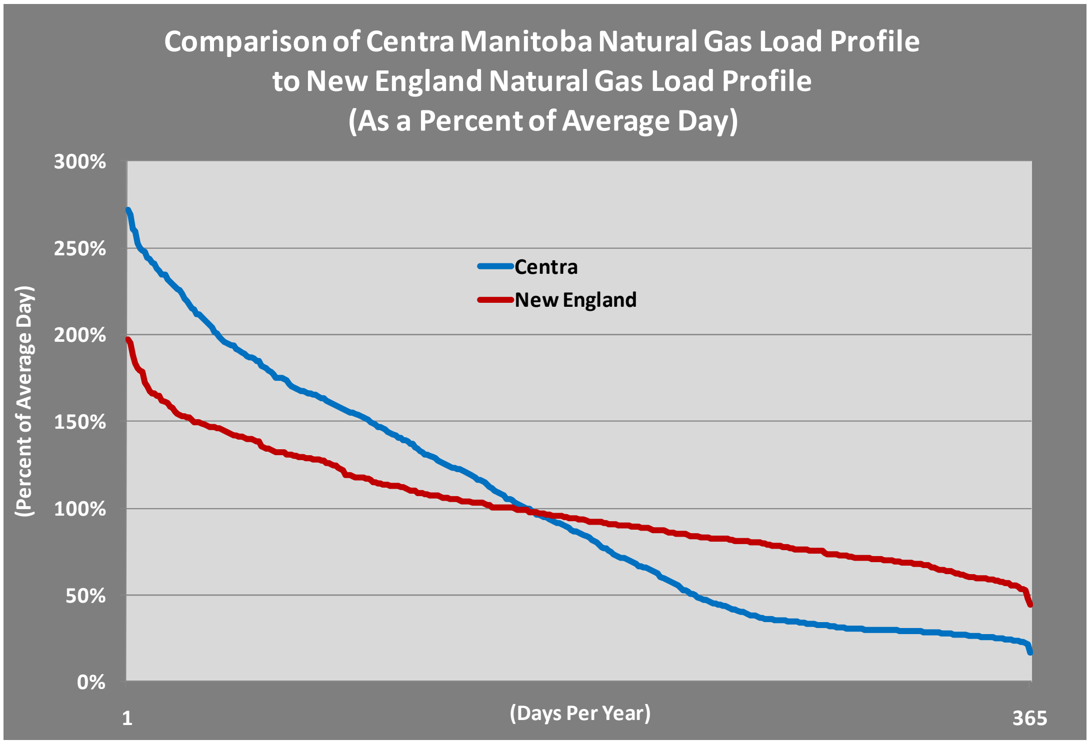
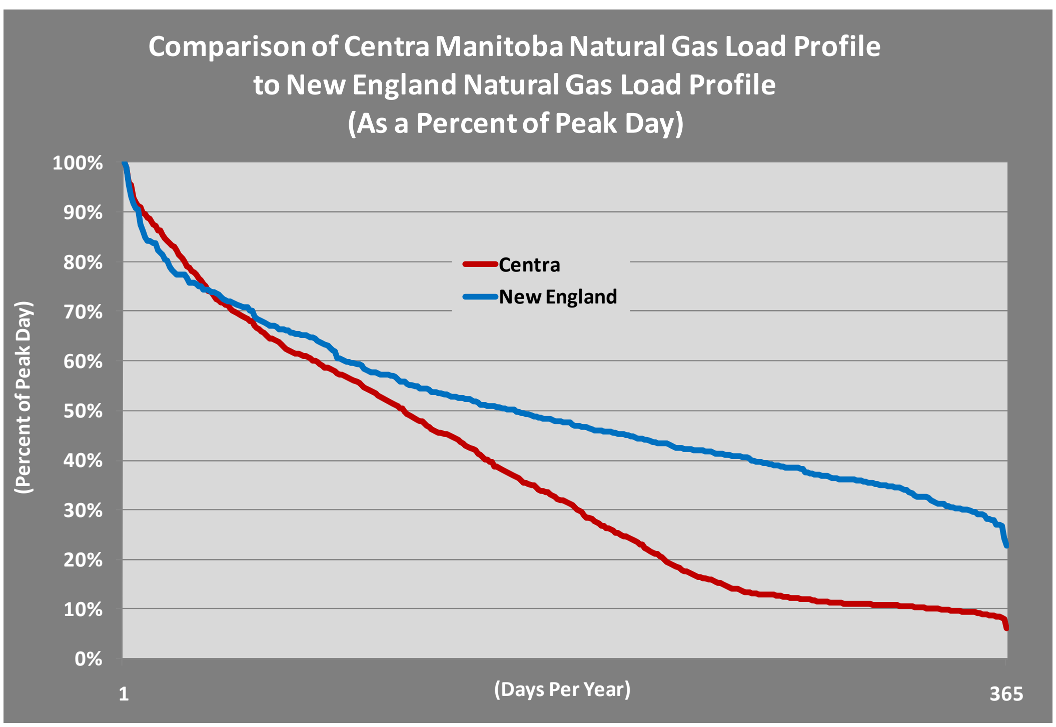


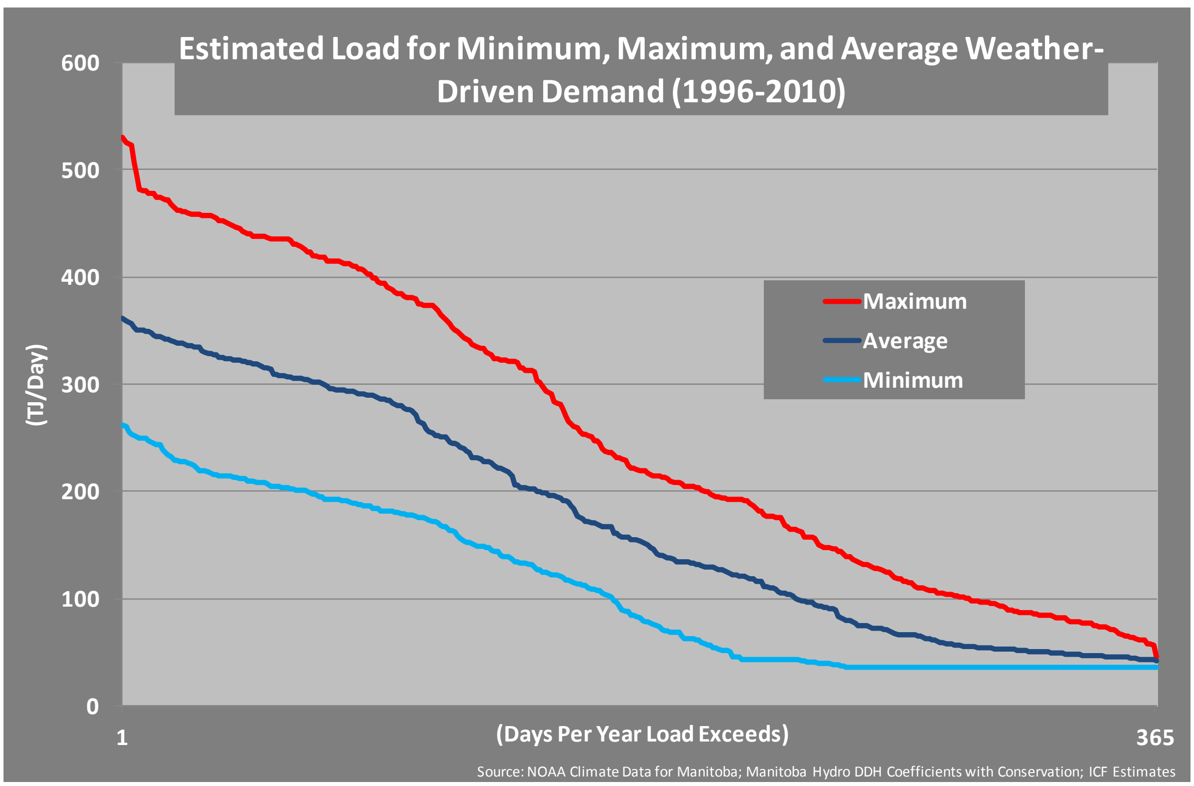
Figure 27
Comparison of Centra and New England Load Profiles



As a result, Centra requires more seasonal gas resources and more flexibility in day-to-day gas supply requirements, but also requires a smaller share of "needle peak" gas resources than other cold weather markets.

The volatility in the weather patterns in Manitoba, combined with the high degree of weather sensitive load, can substantially increase daily swings in demand in the province. Figure 28 illustrates the range of forecasted demand based on weather. This figure illustrates the demand curve for the theoretical coldest year (maximum), warmest year (minimum) and average year, where the weather for each day of the year represents the coldest/warmest weather for that date over a 15 year historical period. These demand profiles indicate that for much of the year, demand can vary by 100 percent or more from day to day based on differences in weather.

Figure 28
Weather Variation in Centra Load Duration Curves



3.2 Centra Pipeline and Storage Capacity[6]

Currently, there is essentially no natural gas produced and marketed in Manitoba. Most of the natural gas commodity purchased by Centra is sourced from the Western

[6] The information in this section was taken from reviews of regulatory documents, and contracts with commodity, pipeline and storage providers provided to ICF by Centra.

Canadian Sedimentary Basin (WCSB) to the west of the Centra service territory. Centra holds a significant amount of storage capacity in Michigan to meet winter seasonal load, and to improve its purchase load factor on the Mainline from Alberta to Manitoba. Centra also purchases seasonal natural gas supplies from the Mid-Continent along the southwest leg of the ANR pipeline system for winter supply and for summer injection into ANR Storage in Michigan, and from Louisiana along the southeast leg of the ANR pipeline system for summer injection into ANR storage in Michigan. Centra also acquires seasonal and peak day supplies, as required, as a Delivered Service at the Centra city gate.

Centra's pipeline and storage capacity holdings are determined by Centra's long-term strategy for meeting peak day, seasonal, and annual gas requirements. As of November 1, 2010, Centra provides natural gas delivery and supply to about 85 percent of Centra's firm transportation MDQ from Western Canada, and provides delivery service, but not gas purchase service, to the remaining 15 percent. Under the terms of Centra's service territory agreements with the Province of Manitoba, and consistent with the WTS agreements with third party marketers, Centra is responsible for ensuring reliable service to all firm delivery customers.

Centra's design firm peak day (the volume of gas forecasted to be required to serve all Firm Sales customers, including WTS customers, on the coldest winter day experienced) is 481,300 GJ/day. Table 3 depicts the sources of supply used to meet design firm peak day requirements for the 2010/11 gas year.[7]

According to the 2010/11 peak day plan, TransCanada firm service transportation from Alberta, including both Centra system supply and WTS volumes, would provide 28.5 percent of the total peak requirements, and withdrawals from ANR storage in Michigan would be used to meet 43.3 percent of peak day requirements. Delivered Services account for 26.5 percent, with the remaining 1.6 percent of requirements met with Oklahoma supply.

Figure 29 shows the location of the pipelines and storage fields serving Manitoba requirements relative to the Centra service territory. As shown on this figure, the location of the storage and pipeline assets on Great Lakes Gas Transmission and ANR are downstream of the Centra service territory.[8]

---

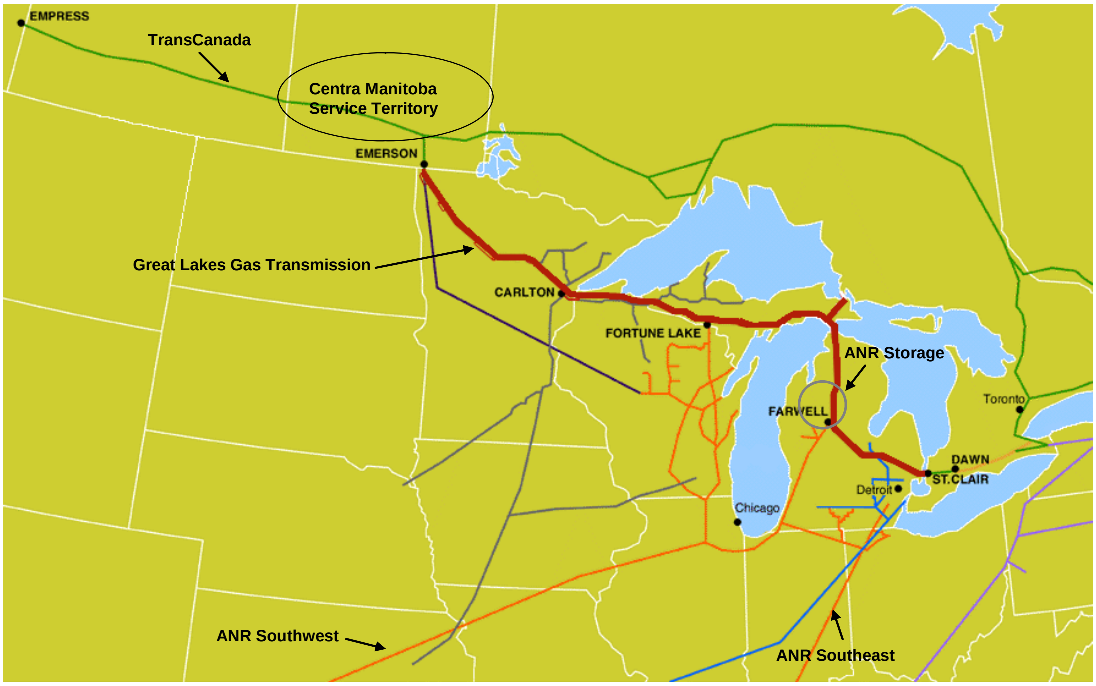
[7] Centra 2011/12 Cost of Gas Application, Tab 3, Section 3.1.1.

[8] It is important to highlight that even though Centra has some supply diversity in its purchasing strategy, and holds pipeline capacity to enable deliveries of natural gas from Michigan to the Centra service territory during the winter, 100 percent of the physical natural gas supply used by natural gas consumers in the Centra service territory is produced in the WCSB and is delivered to the Centra system from the west on the TCPL Mainline. Even on peak day, when about 45 percent of the nominal supply of natural gas delivered to the Centra service territory comes from withdrawals from Michigan storage and from purchases in Oklahoma, and reaches the Centra service territory via backhaul on Great Lakes Gas Transmission and TransCanada Pipeline, the physical gas consumed is coming from the west. In physical terms, Centra customers are using natural gas delivered to the TransCanada system by other TransCanada customers located downstream of Centra. This gas is replaced further east by natural gas withdrawn from ANR storage in Michigan by Centra.

Table 3
Design Firm Peak Day Requirements
(As of November 1, 2010)

	GJ/day	%
System Supply	**116,406**	**24.2%**
Direct Purchase (WTS)	**20,794**	**4.3%**
Total Under FS Transportation	**137,200**	**28.5%**
Oklahoma Supply	**7,860**	**1.6%**
Storage Withdrawal	**208,591**	**43.3%**
Delivered Service	**63,269**	**13.1%**
Peaking Delivered Service	**64,380**	**13.4%**
	481,300	**100.00**

Figure 29
Location of Centra Pipeline and Storage Assets



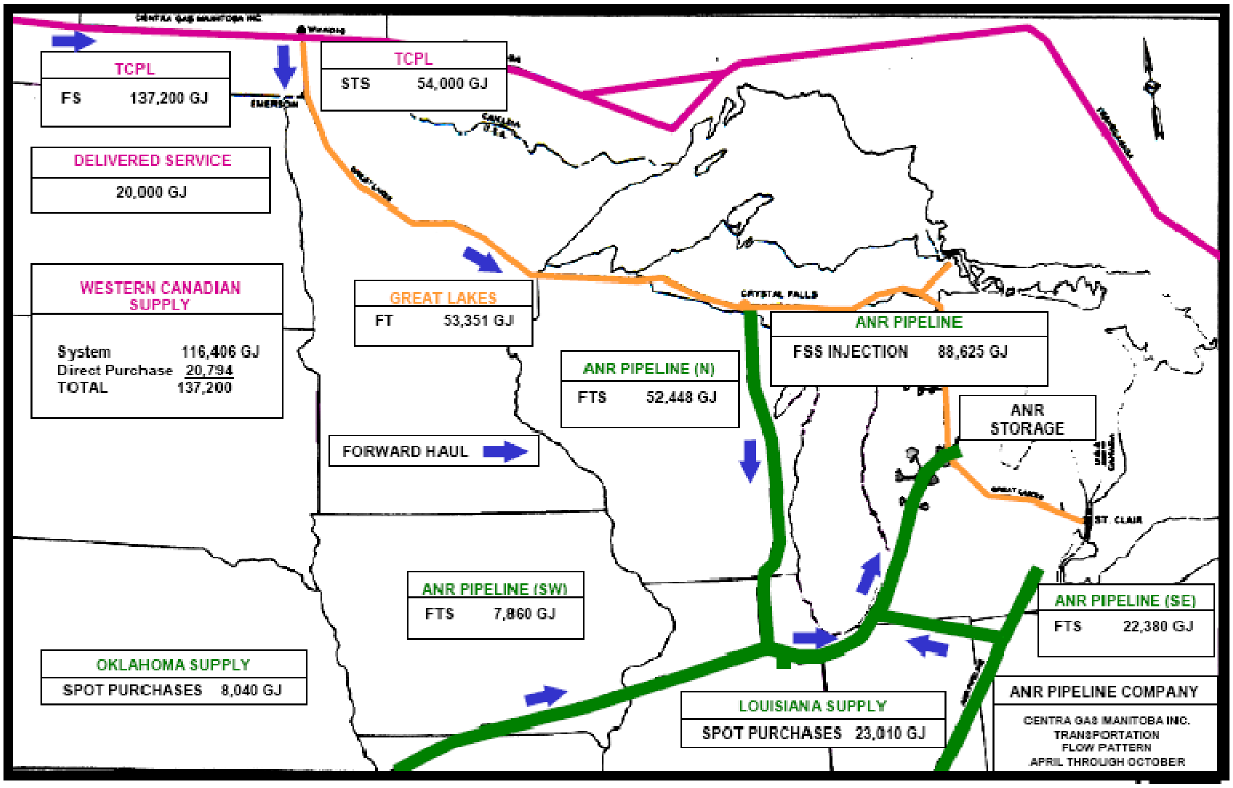
3.2.1 Transportation and Storage Contracts

Centra holds a combination of pipeline and gas storage assets designed to provide secure gas deliverability across summer and winter demand patterns. These assets are shown in Figure 30 (summer periods) and Figure 31 (winter periods), and summarized in Table 4.

Centra has firm pipeline capacity on TCPL from Empress, Alberta to Saskatchewan, Manitoba, and Emerson at the U.S. border. From Emerson, Centra has firm pipeline capacity on Great Lakes Gas Transmission (Great Lakes) to Michigan where Centra has contracts with ANR Storage. Centra also holds pipeline capacity on ANR Pipeline's southwest and southeast legs. The southwest leg interconnects with MidContinent supply basins in Oklahoma and Kansas; the southeast leg interconnects with the Gulf Coast (Louisiana).

The backbone of Centra's contracted pipeline services is TransCanada's Mainline. Centra holds firm capacity on the Mainline to supply its Saskatchewan Southern Delivery Area (an area of customers in the Parkland region that are supplied through a TCPL meter station in Saskatchewan) or SSDA, and its Manitoba Delivery Area, or MDA. Between Manitoba and Emerson, Centra holds Storage Transportation Service (STS) for delivering gas to storage (via Great Lakes), and to receive gas from storage as a backhaul. On a peak day basis, Centra can receive 137,200 GJ from the WCSB and 215,614 GJ via its STS backhaul. These Mainline contracts are renewable on an annual basis. Entering the 2010/2011 contract year, Centra reduced its TCPL Mainline contract to the MDA by 25,000 GJ/day, replacing it with Delivered Service, and to the SSDA by 800 GJ/day, replacing it with greater reliance on storage withdrawals.

Figure 30
Centra Pipeline and Storage Assets – Summer Operations
April 1, 2011 through October 31, 2011

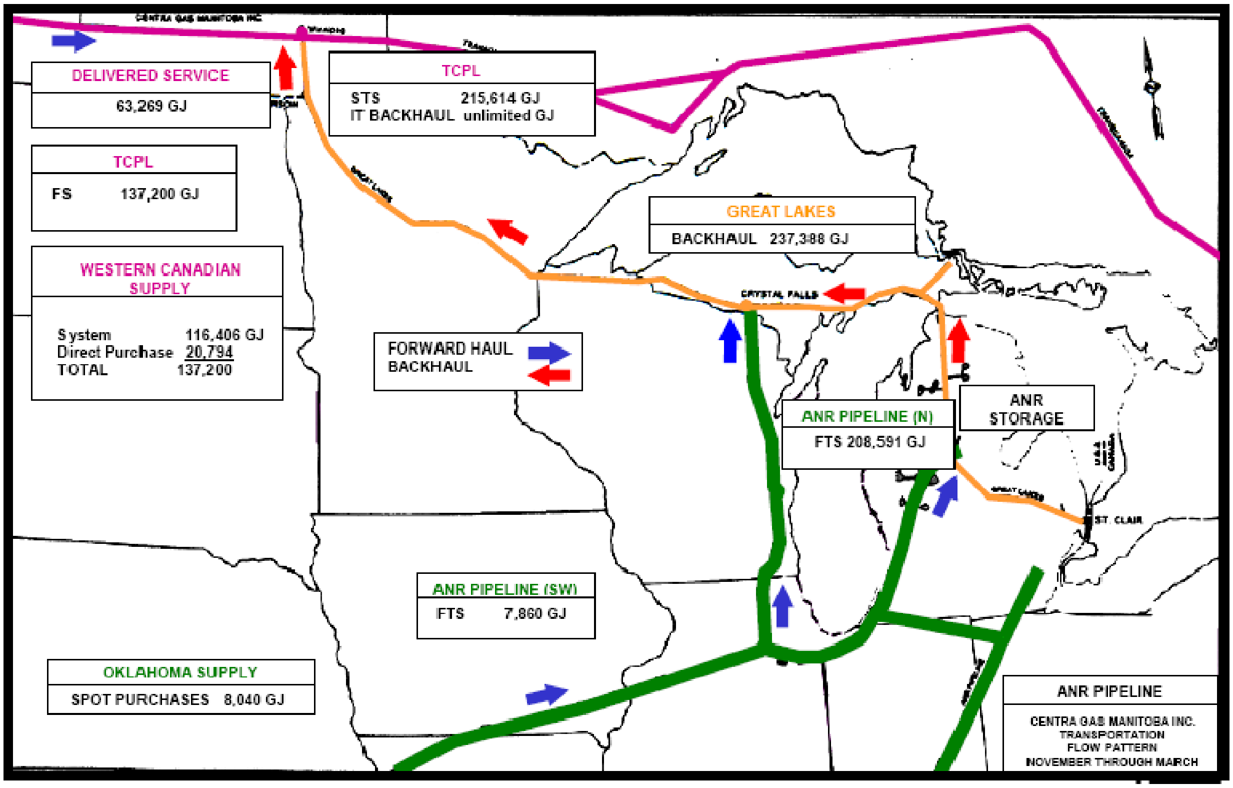


Centra also has Interruptible Transportation (IT) rights on TCPL for both forward haul and backhaul service. These contracts have no end date but can be terminated by either party with 30 days notice.

Centra has FT capacity on Great Lakes to deliver gas to storage in the summer and backhaul capacity to deliver stored gas in the winter. These contracts terminate at the end of March 2013.

Similarly, Central holds FT capacity on ANR to deliver gas to be injected into storage and to deliver gas withdrawn from storage to Great Lakes. Centra also holds small amounts of FT capacity on ANR's southeast and southwest legs. These also can be used to transport gas to storage from Louisiana and Oklahoma. The capacity on the southwest line is available year round; in winter it flows directly into Great Lakes whereby gas can be delivered to Centra via backhaul; in summer it feeds storage. The southeast line is a summer only FT service intended to refill storage. All of the ANR contracts expire in March 2013.

Figure 31
Centra Pipeline and Storage Assets – Winter Operations
November 1, 2010 to March 31, 2011



Storage capacity at ANR storage is shown in terms of cavern capacity where Centra can store up to 15,509,323 GJ of gas; injection capacity of 88,625 GJ per day; and withdrawal capacity of 208,591 GJ per day.

Centra actively manages gas pipeline capacity to generate revenues from the release of spare capacity on a daily, monthly and seasonal basis into the capacity release markets, and executes exchanges of gas with counterparties. Over the five year period ending October 31, 2010, Centra generated an annual average of $6.9 million in revenues from these activities.

Table 4
Summary of Centra Pipeline and Storage Arrangements as of November 1, 2010

Services	Type of Service	Annual	Summer	Winter	Expiration
TCPL (GJ/d)					
Empress to Saskatchewan	FS	2,200			10-31-2011
Empress to Manitoba	FS	135,000			10-31-2011
Manitoba to Emerson	STS		54,000		3-31-2012
Emerson to Manitoba	STS			215,614*	
Delivered Service	FS		20,000	63,269	
Great Lakes (GJ/d)					
Emerson to Crystal Falls	FT		53,351		3-31-2013
Deward to Emerson	FT			237,388*	
ANR (GJ/d)					
Crystal Falls to ANR Storage	FTS		52,448		3-31-2013
ANR Storage to Deward	FTS			208,591	
Oklahoma to ANR Storage/Crystal Falls	FTS	7,860			
Louisiana to ANR Storage	FTS		22,380		
ANR Storage					
Storage annual capacity (GJ)	FSS	15,509,323			3-31-2013
Withdrawal (GJ/d)	FSS			208,591	
Injection (GJ/d)	FSS		88,625		

* Backhaul

Great Lakes Gas Transmission (GLGT) Transportation

In order to use ANR storage capacity in Michigan, Centra holds pipeline capacity on the Great Lakes Gas Transmission system between the TransCanada/Great Lakes interconnect at Emerson, and the Great Lakes/ANR interconnects at Crystal Falls and Deward. The capacity contracts are structured separately for summer and winter periods.

1) During the summer (April 1 to October 31), Centra holds 53,351 GJ/day of Firm Transportation (FT) capacity from Emerson, Manitoba to Crystal Falls, Michigan where Great Lakes Gas Transmission interconnects with ANR Pipeline.
2) During the winter (November 1 to March 31), Centra has 237,388 GJ/day of Firm Transportation (FT) capacity from the ANR Pipeline/GLGT interconnect at Deward to the TransCanada/GLGT interconnect at Emerson. This transportation capacity provides access to Centra's ANR Pipeline Storage inventory to serve winter load demand.

ANR Pipeline

Centra holds four different types of capacity on the ANR Pipeline system. The most critical contracts provide transportation into and out of ANR storage. Centra also holds long haul transportation capacity to provide access to natural gas produced in Louisiana and Oklahoma:

1) 52,448 GJ/day of Firm Transportation from the GLGT Crystal Falls interconnect to ANR Pipeline's storage facilities. This capacity is only available during the summer storage injection period to move WCSB gas to storage.
2) 208,591 GJ/day of Firm Transportation from ANR Storage to the Deward Interconnect with GLGT. This capacity is only available during the winter storage withdrawal period.
3) 7,860 GJ/day of Firm Transportation Service from Oklahoma. During the winter this capacity is used to deliver gas to the Manitoba market via transportation to the ANR/GLGT interconnect and then backhaul on Great Lakes and TransCanada to Manitoba. During the summer this capacity is used to assist in refilling gas withdrawn from storage.

   The final component is summer-only Firm Transportation Service from Louisiana of 22,380 GJ/day that is also used to assist in refilling storage.

3.3 Existing Centra Supply Arrangements

Centra purchases system supply for the sales customers who buy gas from Centra. Centra also transports gas on behalf of third party brokers who provide sales gas to customers on Centra's system – WTS customers. Centra holds firm transportation capacity on TCPL from Empress to ship both system supply and broker supplies to the Manitoba market. Centra also acquires Delivered Service (supply delivered directly to Centra's citygate) from counterparties, in addition to system supply from Oklahoma and Louisiana that are shipped on ANR Pipeline and Great Lakes to the TCPL system or to storage.

Centra purchases Western Canadian supplies in conjunction with TransCanada's Firm Service ("FS") from Empress, Alberta to Saskatchewan and Manitoba. During the summer, TransCanada FS capacity may exceed Manitoba market requirements. The firm Manitoba market requirements are met first and any capacity in excess of those requirements is used to refill ANR storage in Michigan, serve interruptible load, and/or is sold to other parties where feasible and economic. The storage refill is largely accomplished by using the TransCanada FS capacity to Manitoba, TransCanada Storage Transportation Service ("STS") to the Emerson interconnect with Great Lakes, Great Lakes Firm Transportation (FT) to the interconnect with ANR Pipeline at Crystal Falls, Michigan and ANR Pipeline Firm Transportation Service ("FTS") to the ANR Pipeline storage facilities in Northern Michigan.

3.3.1 Western Canadian Sedimentary Basin

The majority of the natural gas supplied to Centra and to Centra storage in Michigan is natural gas sourced from Western Canadian production at the Alberta border (Empress) and transported on Centra's firm pipeline capacity on the TransCanada system to the Manitoba market. Most of the system supply gas for Centra's sales customers is bought through an intermediate-term contract with ConocoPhillips that expires October 31, 2012. WCSB gas is also directed to storage in Michigan.

Broker-supplied natural gas is also sourced from the WCSB and delivered on TransCanada via Empress. Any Manitoba natural gas consumer (including residential, commercial and industrial customers) may purchase gas directly from a broker independent of Centra via WTS. The consumer arranges, through a broker, a source of gas in Western Canada and Centra transports the WTS gas from Western Canada to the consumer on its TransCanada firm capacity. The broker or supplier of the gas sets the price of the gas to its customers.

3.3.2 Other Sources of Natural Gas Commodity

Centra also purchases natural gas from sources other than the WCSB, including, but not limited to, U.S. supplies and Delivered Service. Natural gas from these sources is used to serve the Manitoba market seasonal and peak day requirements.

- Natural gas can be sourced at market centers located on ANR Pipeline in Oklahoma and Louisiana. This gas can be delivered to Michigan storage and redelivered to Manitoba in the winter. Oklahoma gas can also be shipped to Great Lakes directly in winter, for delivery via backhaul to Centra.
- Delivered Service is supply delivered directly to Centra's citygate by counterparties. The price of delivered service considers both commodity costs and transportation costs to Centra's citygate. Peaking arrangements may also take the form of a delivered service.

3.3.3 Interruptible Service and Alternate Supply Service

Interruptible demand is a small part of Centra's winter load, constituting about 5% of peak day requirements. Curtailment of these customers can occur when there is insufficient gas to meet both interruptible and firm customer requirements or when Centra determines that storage levels are falling below forecast firm requirements.

Centra monitors the extent to which the weather has been colder than normal and monitors the level of storage withdrawals. When storage withdrawals are greater than normal, Centra may make the determination to curtail Interruptible customers in order to conserve storage gas for the firm market. Interruptible customers will be offered the opportunity to buy Alternate Supply Service on a case-by-case basis, at prices that reflect the cost of obtaining the Alternate Supply in the spot market. Alternate Supply Service is a delivered gas supply, at prevailing spot market prices. Arrangements are usually made on a daily basis.

3.4 Swing Service and Balancing

The Manitoba service territory served by Centra has one of, if not the most, variable seasonal demand profile of any major LDC in North America. Figure 23 (shown previously) illustrates the seasonal nature of weather requirements in Manitoba relative to other areas serviced by TransCanada Pipeline and WCSB supply. This figure indicates that the seasonal weather pattern is more extreme in Manitoba than in any of the other represented regions. In addition, both the year-to-year weather uncertainty (Table 1, Figure 25), and the day-to-day weather uncertainty (Table 2, Figure 24) are generally greater than other regions.

The combination of high weather volatility and a high concentration of Manitoba load in the weather sensitive residential and commercial sectors results in much larger day-to-day swings in gas load than almost any other LDC in North America. The high day-to-day swings in demand also lead to significant forecasting volatility in daily requirements. As a result, the Centra supply portfolio needs to be structured to provide cost-effective natural gas service over a wide variety of natural gas demand levels, as well as providing flexibility to meet wide variations in daily natural gas demand, and balancing services to account for differences between nominations and actual takes.

Currently, Centra meets these requirements through the use of natural gas storage injections and withdrawals, and through daily purchases of WCSB gas based on the "Swing Gas" provisions of the ConocoPhillips contract. Centra is responsible for balancing nominations and takes on the TCPL Mainline within its delivery areas. Within the volumes specified in the ConocoPhillips contract, ConocoPhillips is responsible for deliveries of the nominated natural gas to Empress.

During the summer period, on days when demand exceeds the baseload gas purchases, Centra typically purchases additional "swing" gas according to the terms of the ConocoPhillips contract to meet demand, since storage withdrawals are not available. During the winter, natural gas demand above the "baseload" gas purchases is usually first met through purchases of swing gas according to the terms of the contract and up to Centra's contract demand levels on the Mainline and then storage and other sources as required.

3.4.1 The Nature of Swing Service

The management of supplies making up the equivalent of Centra's Swing Service is one of the key elements in a utility's supply plan. With respect to the acquisition of swing services, Centra is relatively unique in terms of geographic constraints and opportunities. The current lack of storage capacity in Manitoba, combined with the existence of only one major pipeline into and out of the service territory limits the options available to Centra and forces Centra to rely on pipeline services and supply contracts to meet swings in daily load.

However, the limitations imposed by the lack of local storage and the lack of pipeline options are somewhat offset by Centra's location halfway between the major production region in Alberta and the major pipeline interconnects and storage regions around Chicago, Michigan, and Ontario.

The cost of swing service to the Centra service territory can be minimized by leveraging a combination of upstream and downstream assets. The differences between swing requirements in Manitoba and the downstream markets serviced by TransCanada provide an opportunity to reduce the costs of serving both markets if market requirements in Manitoba and downstream can be combined into a single portfolio.

The primary sources of Centra's current swing service likely utilize the combination of upstream and downstream assets to minimize total costs. Centra contracts for swing services with a major integrated producer and marketer (ConocoPhillips) holding both upstream and downstream assets and serving both upstream and downstream markets. By optimizing assets to serve multiple markets, an integrated company such as ConocoPhillips should be able to provide a specific service at a lower cost than a dedicated service unable to take advantage of the synergies associated with multiple markets. In addition, ConocoPhillips is one of the largest producers in the WCSB and accordingly has significant intra-Alberta operations and capabilities that enable it to manage Centra's swing service requirements.

The cost of swing service is determined by two major factors. The first is the management cost of monitoring nominations, and daily gas volume management. The management of daily gas purchasing in a volatile market is significantly more expensive than the management of monthly baseload supplies.

The second element reflects the cost of providing the capability to meet the daily and intra-daily swings in demand. The contract allows Centra to change swing supply nominations at Empress, *higher or lower*, on an intraday basis on the TransCanada nominations schedule. These nomination changes include use of the late-afternoon "Intraday 2" (ID2) nomination cycle, and full nomination flexibility on weekends and holidays when gas markets may be illiquid or closed. ConocoPhillips is responsible for providing firm natural gas to meet Centra's nominations on TCPL at Empress. As Empress is downstream of AECO, ConocoPhillips must also be prepared to ensure firm transportation of the gas supply to Empress, including the ability to respond to ID2 nomination changes and the corresponding need for greater or less transportation and supply to Empress. As a result, ConocoPhillips is responsible for balancing the daily nominations with supply within Alberta, in an environment where Centra's daily purchases are varying widely.

ICF believes that ConocoPhillips handles the daily volatility in natural gas purchases through an integrated approach using the entire ConocoPhillips portfolio of Alberta and North American assets and customer base. This approach may be available to other major marketers, but is not available to Centra or to small or mid-sized producers.

3.4.2 Balancing on the TransCanada System

The TCPL Mainline provides a certain level of balancing flexibility in its base tariff. The base tariff provides for daily variation between nominations and receipts of up to 2 percent of the nominations to the delivery area without incurring balancing penalties. Above 2 percent variation from nominations, TransCanada assesses balancing penalties ranging from 20 percent to 100 percent of the Mainline's Eastern Zone Toll (EZT). As the 100% load factor EZT has increased from $1.03/GJ in 2007 to $2.24/GJ in 2011 (interim toll effective March 1, 2011), the potential for Centra to incur higher TCPL balancing fees has also increased.

TCPL also offers a Parking and Loan service that allows daily balancing on an interruptible basis. The cost and availability of this service depends on market and Mainline operating conditions. As an interruptible service, the cost represents the lower bound on the cost of daily balancing above the flexibility provided in TransCanada's tariff service.

3.5 Delivered Service and Delivered Peaking Service

Centra currently has in place arrangements to purchase approximately one quarter (26.5 percent) of its design firm peak day requirement as a delivered service, where Centra has contracted with counterparties to deliver firm natural gas to the Centra citygate. 13.1 percent of the design firm peak day requirement (63,269 GJ/day) is met with baseload delivered service to the Centra citygate. Centra also contracts seasonally for an additional 64,380 GJ/day of peaking delivered service that can be called upon as required to provide additional coverage under very cold weather conditions. Peaking delivered service provides for 13.4% of Centra's design firm peak day requirements.

Centra has increased its reliance on delivered services to meet requirements in the last year. The 2009/2010 supply plan relied on delivered services for 17.5 percent of total peak day demand - 2.6% as baseload delivered service, and 14.9% as peaking delivered service. Fundamental to this shift is Centra's reduced reliance on firm capacity on the TransCanada pipeline system. As of November 1, 2010, TCPL firm service accounted for 28.5 percent of Centra's peak day requirements, down from over 40 percent in some prior gas years. Baseload delivered services have replaced most of this reduced TCPL capacity, while there has not been a fundamental change in Centra's use of peaking delivered services.

Peaking delivered service relies on other natural gas shippers on the TransCanada system willing to sell delivered natural gas at the Centra Citygate. These services are based on contracts between Centra and other parties that require the other party to deliver natural gas to Centra if and when called upon for up to a certain number of days over a specified period. This service allows Centra to meet peak period demands without holding additional capacity on TransCanada that is not used during most of the year.

3.6 Uncertainties Regarding Future Markets

The current Centra supply strategy, which relies on TCPL pipeline capacity and ANR natural gas storage capacity, along with associated pipeline capacity was developed and committed to during an historical period where TCPL pipeline capacity was relatively limited, and generally fully subscribed.

Since that time, changes in natural gas production patterns have had a fundamental impact on natural gas transmission patterns throughout North America. One of the largest changes has been the declining exports of natural gas from the WCSB on the TCPL Mainline system. This fundamental market shift changes the basic conditions impacting the Centra supply planning process.

3.6.1 Outlook for TransCanada

Almost all of the change in WCSB exports has been manifested in reduced pipeline flows on the TCPL Mainline. As the high cost option for moving natural gas east from the WCSB, TCPL has been the marginal transportation option out of the region, and pipeline flows on the TCPL Mainline generally have been declining since 2002. Pipeline flows from Empress for the 12 month period from July 2009 through June 2010 were 40 percent below peak flows from July 2002 through June 2003.

Most of the decline in flows has occurred in the last three years. Mainline flows during the 2010/2011 winter (November 2010 through March 2011) were more than 30 percent below flows for the 2007/2008 winter period. Natural gas flows east on the TransCanada system are not expected to return to historical levels for the foreseeable future.

Contracted Capacity

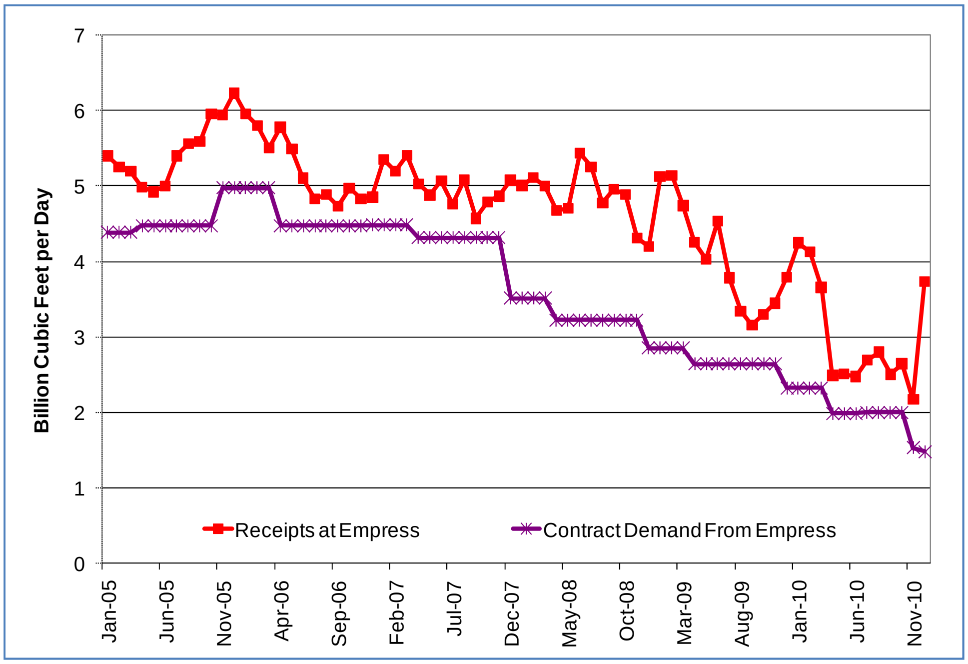
TCPL Mainline customers have responded to the decline in throughput and rising, uncompetitive tolls on the pipeline by turning back expiring pipeline capacity contracts. Contracted capacity at Empress has declined by about 65 percent since November of 2005, falling from about 5 Bcf/day to 1.5 Bcf/day in November 2010 (Figure 32).

3.6.2 Impact on TCPL Tolls

The decline in flows and contracted capacity on the TCPL Mainline system is placing significant upward pressure on pipeline tolls (See Figure 33). TransCanada has been able to reduce the net revenue requirement used to calculate tolls, but the decline has not been sufficient to offset the decrease in volumes. Thus the declining costs have been offset by more rapidly falling throughput and billing units over which fixed costs are spread, increasing the unit cost of transporting over TCPL.

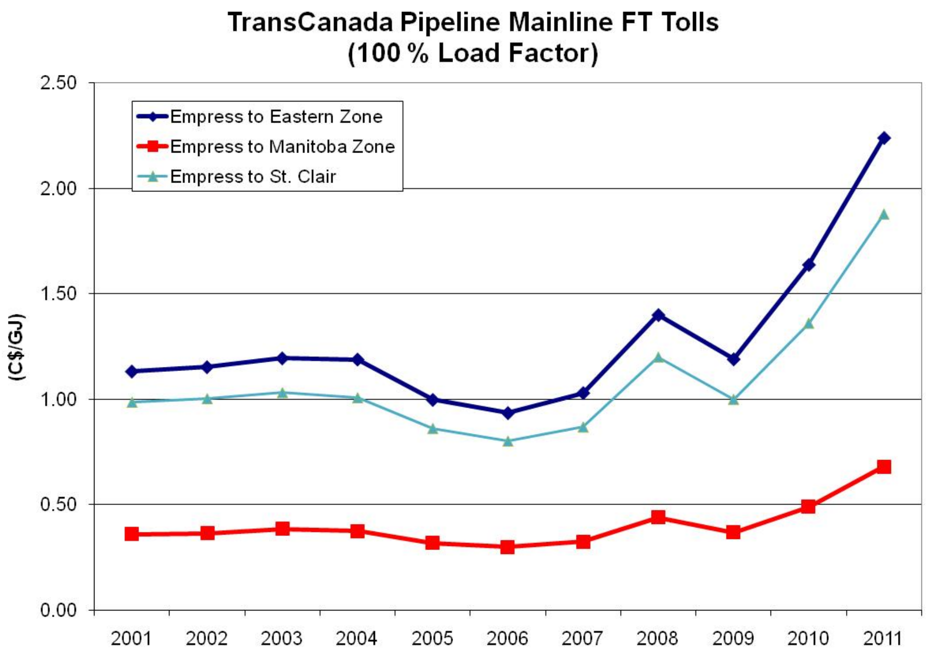
As of June 2011, the total cost of moving natural gas from the market center at AECO to the eastern zone, including tolls and fuel, on a firm service contract were about C$2.55/GJ, inclusive of fuel. Since 2006, 100 percent load factor costs including tolls and fuel have increased by about 150 percent for firm service transportation from Empress to the TCPL Eastern Zone.

Figure 32
TransCanada Mainline FT Contract Demand and Receipts at Empress (Bcf/day)



Source: (Flow Data) Lippman. Receipt at Empress Pipeline Interconnect. As of Feb 4, 2011. (Contract Demand from Empress) TransCanada. "2010 Index of Customers." Contract Demand Energy Archive.

Figure 33
TransCanada Pipeline Mainline FT Tolls, (100 % Load Factor, Excluding Fuel)



Source: TransCanada

As of June 2011, it seems likely that TCPL rates will continue to increase in the future. However, a settlement or regulatory solution could be reached leading to stable or declining rates. The lack of clarity with respect to regulatory and market conditions that will determine future TCPL rates makes it difficult to evaluate future costs of relying on TCPL assets. This issue is discussed in more detail in Section Four of this discussion paper.

3.6.3 Impact of Changes in Natural Gas Market Conditions on Centra Supply Planning

The change in market conditions on the TransCanada Pipeline results in several fundamental shifts in the planning environment for Centra:

1) TransCanada rates have increased substantially, and are expected to continue to rise over time, increasing the cost of the existing supply portfolio.

2) TransCanada pipeline capacity on forward haul capacity from Empress to the Centra citygate is currently unconstrained, and is expected to remain unconstrained for the foreseeable future. Hence the need to hold long term firm capacity on TransCanada may be reduced.

3) Availability of highly discounted backhaul capacity from ANR storage on Great Lakes Gas Transmission to Emerson and economic backhaul on TCPL from Emerson to the Centra Citygate may be declining, potentially resulting in increases in the cost of using ANR Storage in the future.

Overall, these changes tend to reduce the value of holding both TransCanada pipeline capacity and ANR storage capacity, while increasing the potential attractiveness of alternative sources of supply.

The availability of TCPL capacity, along with changes in market structure that have increased the importance of midstream natural gas marketers in the last ten years has resulted in the development of reliable delivered gas services that allow Centra to purchase natural gas at the Centra citygate on both a seasonal and peak day basis.

3.7 Impact of Liquids Extraction on AECO and Empress Market Prices

Centra purchases natural gas from the WCSB and transports the gas to the Centra service territory using its firm transportation capacity on the TCPL Mainline. Empress is downstream of AECO, and holding firm pipeline capacity on the NGTL Alberta system (Nova Gas Transmission Ltd.) from AECO to Empress currently costs about $0.19 per GJ on a 100 percent load factor basis. However, currently natural gas priced at Empress is below natural gas prices at AECO. This reflects an inversion of historical price relationships where typically, the price at Empress has been higher than the price at AECO. The change in price relationship is due to an increase in competition for natural gas liquids between liquids extraction facilities at Empress.
There are five liquids extraction plants at Empress that separate liquids from the natural gas stream that is being exported out of the province both through Empress onto the TCPL Mainline and through McNeil down Foothills Saskatchewan and Northern Border. There is currently significant excess processing capacity relative to exports out of Empress and McNeil.

As a result, these plants compete aggressively for unprocessed natural gas supplies. The processing plant economics are determined by the value of the liquids removed from the natural gas stream. As liquids prices have increased with crude oil prices, the processing plants have been willing to pay larger premiums for liquids-rich gas supply. The value of gas at Empress is reduced by the amount the extraction plants are willing to pay to “subsidize” the transport.

Future liquids premiums will depend on both the value of liquids, which will vary with crude oil prices, and the amount of excess processing capacity available at Empress. We anticipate that over time, the liquids premium will decrease, although we do not anticipate that the premium will return to historic levels.

It is also currently anticipated that TransCanada, the owner of the Alberta system, may file an application with the National Energy Board in 2011 to change the current liquids extraction model under the NGTL tariff which assigns liquids extraction rights to export shippers, potentially impacting the current AECO-Empress basis differential. The most likely implementation timeline associated with this application is November 2013.

(PAGE DELIBERATELY LEFT BLANK)

4
ISSUES AFFECTING TCPL

Throughput on the TransCanada Pipeline (TCPL) Mainline system has been declining with shippers shifting to short haul service and reducing long haul capacity contracts to obtain gas. The resulting rapid increase in tolls has undercut the competitiveness of the TCPL Mainline system, accelerating the decline in throughput.

The current situation regarding the competitiveness of the TCPL Mainline system and the resulting regulated tolls that may be charged over the next ten years is a vexing problem for Centra, for Manitoba, and for gas industry stakeholders across Canada. There are no apparent “silver bullet” approaches or policy alternatives that can prevent the impending crisis from having adverse effects on shippers, such as Centra, that have few and limited alternatives for the near term other than to continued to rely on transportation service utilizing delivery points on TCPL.

4.1 The Current Challenge

The term “crisis” is not used here lightly or as hyperbole. The conditions in the market present significant implications and challenges for the pipeline and for customers, with a large potential for negative consequences for gas consumers. It may be fortunate that these challenges are occurring at a time when gas commodity prices are relatively low. The implications, however, will extend beyond the current period of soft prices. These challenges have been building for a number of years. In the past few years, however, the pressures on the pipeline have accelerated. Shippers that have alternatives to renewing long haul capacity contracts that use the TCPL facilities on the western portion of the Mainline are replacing these contracts with short haul alternatives to access gas supplies from other producing basins rather than the Western Canadian Sedimentary Basin (WCSB).

For Centra and other captive shippers on the Western and Northern portion of the Mainline, the shift has significant direct implications in terms of gas transportation costs. With reduced contract support, the costs that are approved for recovery are supported by an ever smaller throughput volume. As the amount of capacity left stranded increases, the tolls calculated under the current regulatory methodology increases, making the transportation costs even larger and the transportation option even less competitive for those that have alternatives.

The increasing transportation cost also has a dynamic impact on the economics of gas exploration and production in the WCSB. The competitiveness of any source of gas is based upon the delivered cost of gas to the market. With increasing transportation costs, there is pressure on the “net back” price for gas production. All other things equal, the lower “net back” price at the wellhead reduces the amount of gas drilling activity and consequently reduces the volume of gas available to be transported on the pipeline.

Centra faces significant challenges due to uncertainty as well as the market fundamentals. ICF concludes that changes in the regulatory framework for TCPL alone are likely insufficient to provide a long term resolution to the management of gas supply costs. Without the development of competitive physical alternatives that significantly reduce the reliance on TCPL for the delivery of gas to Manitoba, Centra will have little control and little leverage in the marketplace. The identification and analysis of potential alternatives is a principle objective of the ICF analysis.

The discussion regarding an approach to the problem have focused on deferral of costs and adjustment of depreciation in order to attempt to restrain the increases in tolls that accompany reductions in contract and throughput volumes. While such mechanisms can reduce tolls in the near term, the effect of simply deferring cost recovery will only increase tolls in the longer term. Such proposals simply defer the crisis as they defer the costs in a hope that future events will alleviate the pressure on the pipeline. ***In ICF’s view, proposals of this sort do not present a long term solution. Moreover, modeling of the options lead ICF to conclude that at best, such proposals stabilize throughput at or near current levels, leaving significant capacity underutilized and stranded.***

It is important to recognize that the implications of the challenges presented to Centra by the issues facing the TCPL Mainline are problematic. First, it is likely that total gas transportation and storage costs will continue to increase over the next decade whatever Centra does. Alternatives that continue Centra’s reliance on TCPL service will continue to face the cost recovery issues and likely tolls that are higher than the average toll of the last three years. Alternatives that reduce the dependence on TCPL delivery services, by securing alternative physical connections, will incur costs either through direct investment in facilities or through contracting with alternative service providers who will need to construct, or convert and augment facilities to meet Centra’s requirements.

Second, it is unlikely that a permanent solution to the regulatory framework and toll methodology issues will be in place in the next few years. The current conditions have been building for a number of years and, even though there has been intense activity among the stakeholders, a clear path forward has not emerged. As a result, Centra will be faced with tremendous uncertainty during the period when decisions will have to be made regarding the transportation and storage portfolio required to maintain reliable service.

4.2 TCPL Rate Structure Sensitivities

The ICF Base Case assumes no changes in TCPL rate structure during the time frame of the analysis; TCPL tariffs are expected to remain constant at today’s levels throughout the analysis. This assumption reflects a median outcome in a case where the actual outcome is more likely to fall towards one of two extremes, either:

1) TCPL rates will reflect the recovery of the full cost of service, in which case TCPL rates will increase substantially for the next 3 to 5 years before stabilizing, reflecting projected declines in pipeline flows from the WCSB, or
2) TCPL will reach a restructuring agreement that substantially reduces rates from today's levels.

ICF evaluated the impact of these alternative outcomes by assessing TransCanada rate structure sensitivities around the basic gas market scenarios described in Section 2.3 of this report. The full cost of service sensitivity reflects an increase in TCPL rates to recover the full cost of service based on the estimated TCPL flows in the specified scenario. The discounting sensitivity reflects a stable tariff rate to the TransCanada Eastern Zone at well below today's tariff rates. The specific level of the discounted tariff reflects an assumption concerning the lower bound of feasibility. ICF believes this to be at about 50 percent of today's tariff rates.

As the volumes of gas transported on the TCPL Mainline from Empress to Ontario have declined, and as long-term firm long haul contracts have declined, the revenue requirement of TCPL has been recovered over lower volumes and billing determinates, resulting in significant upward movement in TCPL's tolls. The toll from Empress to the Eastern Zone has increased from $1.009 per GJ in 2000 to $1.64 per GJ in 2010, to the June 1, 2011 interim toll of $2.24 per GJ.

It is important to note that the 2010 toll of $1.64 per GJ was obtained only through deferrals of costs that TCPL plans to recover in future periods through deferral accounts. Without the deferral of approximately $85 million[9] in under-recovered revenue from 2009 in the calculated toll, the 2010 toll would have risen to $1.77 per GJ.

Moreover, there is a potential that tolls are likely to experience even further increases over the next several years. The increase in tolls is likely to continue to impact natural gas production in Western Canada, further reducing natural gas available for transport on the TCPL Mainline.

There is experience that demonstrates that TCPL toll competitiveness can lead to the investment in alternative transportation capacity. The Alliance Pipeline was built to provide an alternative transportation path for WCSB production, which at the time was receiving a "net back" price that was considerably below the price realized by producers and marketers in other locations. Once the Alliance Pipeline was completed, the "net back" price moved upwards, to values that were only 20 to 50 cents below the Chicago City gates.

In the future, increases in gas production from shale resources in Western Canada, notably British Columbia, offer an opportunity to supplement gas supplies on the TCPL

[9] TransCanada PipeLines Limited ("TransCanada") Application for Approval of 2010 Final Mainline Tolls.

Mainline. These projects, however, are contingent upon the relative attractiveness of transporting gas east via TCPL or moving gas to the Pacific Rim in the form of LNG.

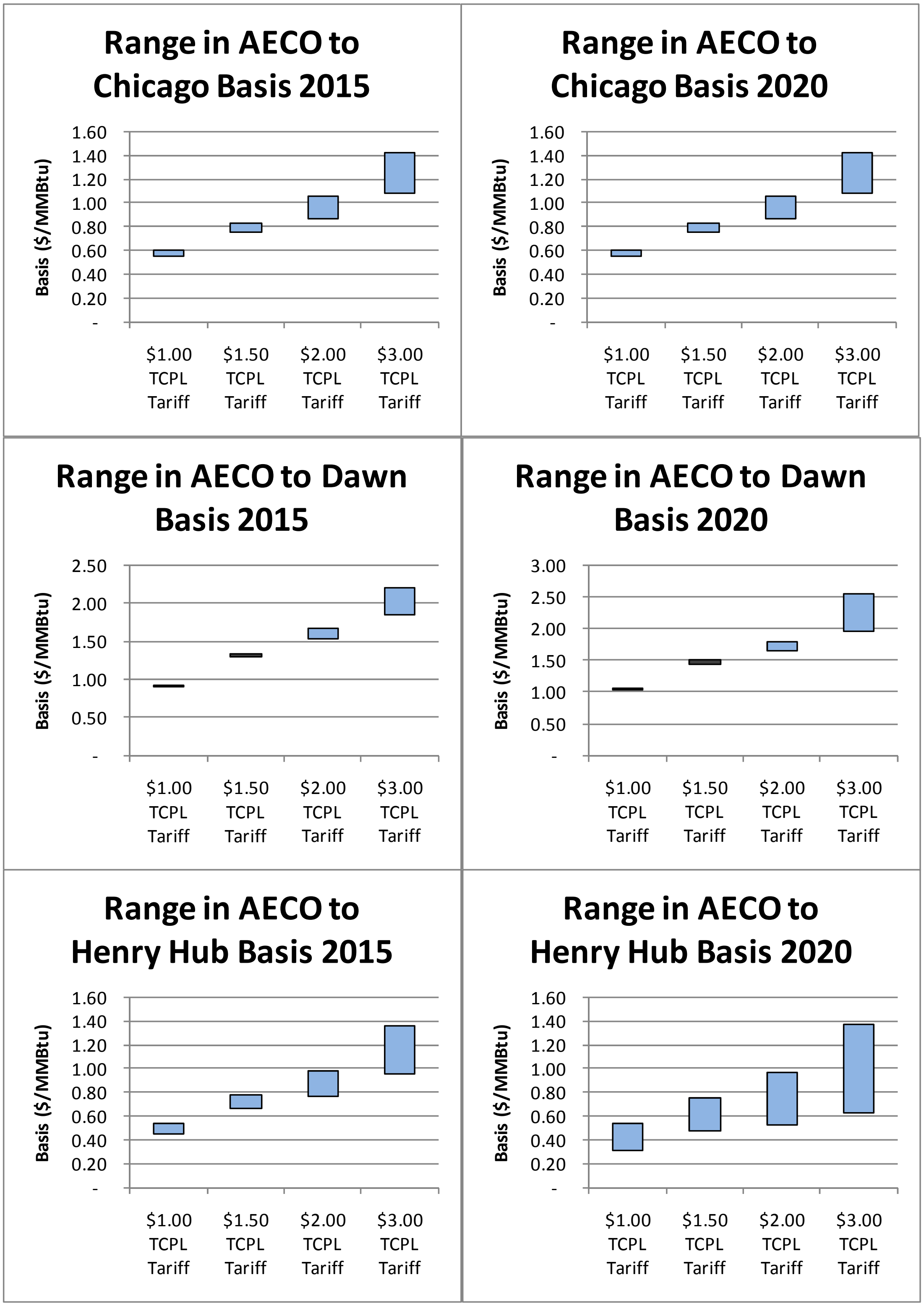
Production from these resources could effectively stabilize flows on the TCPL Mainline after 2013. At the meeting before the Ontario Energy Board, TCPL acknowledged that this gas would flow into Alberta; thereafter whether it flows through Empress or some other route is up in the air. However, the potential to substantially increase flows or return flows to pre-2009 levels are relatively small under the existing TCPL rates regime. Under the 2010 tolls, moving gas from BC to AECO/NIT added an additional $0.22 per GJ to the cost of transporting gas to market. Hence, the cost of moving BC shale gas to the TCPL Eastern Zone cost about $2.05 per GJ. In 2011 these costs have increased to $2.77 to move gas to the TCPL eastern zone.

Given the very high cost of moving natural gas to market on the TCPL Mainline, and the relatively low price of gas anticipated in the North American market for the next several years, the netback price to producers of moving gas west for sale to the Pacific Rim Countries as LNG will be higher than the netback to producers of moving gas east into the TCPL Mainline. Hence, much of the shale gas produced in the Horn River Basin will flow west to Kitimat LNG, and potentially other LNG facilities that may be developed in the future for export to the Pacific Rim.

The cost differential is at least partially related to a chicken/egg issue of the transportation costs of moving BC shale gas to markets outside the WCSB. If large volumes of shale gas are shipped on the TCPL Mainline, TCPL tolls could fall enough to make this the preferred option. However, TCPL tolls will not decline unless/until sufficient gas is shipped on the TCPL system to reduce tolls. Under the current TCPL regulatory framework, large volumes of shale gas must be committed to the TCPL system in order to have competitive tolls, but competitive tolls will be required first to attract the shale gas. There is also the risk that the longer it takes for TCPL to make its Mainline tolls competitive, the more difficult it may become to bring back to the Mainline shippers that may be undertaking long-term investments in other supply and transportation alternatives.

Figure 34 presents a summary of the results from the sensitivity analysis. The figure presents the range in projected basis values for AECO to Chicago, AECO to Dawn, and AECO to Henry Hub for the different market scenarios. Examination of these basis values illustrates the potential impact on natural gas basis costs between key market centers of different market scenarios over the potential range of future TCPL rates.

Figure 34
Impact of TCPL Rate Structure on Basis



The projected basis values shown in Figure 34 demonstrate the problem for Centra at this time. There is no certainty regarding the resolution to the TCPL toll issue. Moreover, there is not likely to be a complete resolution for several years at least. With the current level of uncertainty regarding future tolls and the influence of the tolls on the gas commodity cost at different locations, including AECO and all of the other alternative gas supply locations, a course of action that maintains the ability to adjust to future developments may be advisable. It is important to note, however, that flexibility has a cost. The approach that preserves the ability to adjust the portfolio according to developments in the market will have implications in the total cost of gas supply acquisition.

5
APPROACH TO SUPPLY PORTFOLIO OPTIMIZATION ANALYSIS

ICF has been retained to provide Centra with an objective analysis of the supply and infrastructure strategies available to the company in order to evaluate different options and assess alternative strategies for reliably meeting Centra customer requirements in the future. The assessment of the potential strategies is complicated by the volatility associated with future natural gas market conditions and the uncertainty inherent in the TransCanada rate structure and operating profile.

In order to assess the different strategies accounting for market uncertainty, ICF is conducting a two phase analysis. In the first phase, ICF has conducted a series of long term natural gas market forecasts to provide a realistic range of market scenarios that may be faced by Centra between 2013 and 2030. The scenarios and sensitivities form the core of the ICF analysis of natural gas market conditions for the Centra supply portfolio assessment. The scenarios have been described in Section Two of this report.

The different market scenarios provide important inputs into the probabilistic optimization process to be completed in Phase 2 of the ICF portfolio analysis. ICF is preparing an optimization analysis to evaluate the attractiveness of the alternative supply options to meet Centra requirements for each of the different market scenarios considered. ICF will use the deterministic model results from the scenario analysis to construct the likely distributions used in the optimization for variables such as gas prices, basis differentials, and Centra supply requirements and load profiles.

5.1 Factors Considered In Analysis

5.1.1 Quantitative Factors Considered in the Optimization Analysis

Factors being considered in the optimization analysis include:

- *Weather Volatility:* From year to year, the most important factor driving natural gas demand and natural gas portfolio costs is weather. While ICF cannot with accuracy forecast the weather for the analysis period, we can evaluate historical weather patterns to create a range and distribution for the expected weather. For the optimization analysis, ICF expects to evaluate the expected gas supply cost based on a range of different weather patterns based on historic weather data. The weather patterns reflect actual historical weather patterns from the period between April 1934 and March 2010. The use of multiple years of contiguous weather data is important in order to capture the full range of multi-year impacts of different storage costs and benefits when evaluating storage value.

- *Sendout Volatility*: The alternative weather patterns result in differences in sendout requirements for Centra customers, hence result in different storage utilization patterns and supply requirements. ICF estimates Centra customer natural gas requirements for each of the weather cases based on Centra projected relationships between heating degree days and sendout. For each case, the base case forecast of demand by customer class will be adjusted to reflect the impact on weather sensitive load of the difference between the heating degree days in the scenario relative to the heating degree days used in the Base Case.

- *Natural Gas Price Volatility*: The different weather scenarios also have a significant impact on national and local natural gas prices. For each weather case, the study will use the ICF Gas Market Model (GMM) to project North American natural gas prices for more than 120 key locations in North America, including AECO, Emerson, the MichCon citygate price, Henry Hub, Dawn, Chicago, and other market centers potentially accessible to Centra.

5.1.2 Other Criteria Considered

In addition to the specific criteria included in the optimization analysis, ICF is also evaluating the impact of other factors, including diversity and liquidity on the different portfolio options.

5.2 Impact of Uncertainty on Portfolio Optimization

While the optimization analysis takes into consideration the distribution of potential gas market outcomes, the analysis may not reach a definitive "Best Strategy" for Centra across all of the potential gas market outcomes. As a result, there may be value in delaying implementation of long term strategies until some of the uncertainty has been resolved, and a long term commitment regarding transportation may not be advisable given the uncertainty.

5.3 Analytical Tools

The analysis will utilize the results from two computer models. 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. GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices at more than 120 market centres throughout North America. The GMM has been widely used in the natural gas industry to evaluate North American and local natural gas markets, including demand, production, and natural gas prices.

The second model, the ICF *Gas Storage Valuation Model (GSVM)*, is an optimization model that utilizes the monthly gas prices projected by the GMM and a statistical characterization of daily prices. The statistical characterization is based upon historical price volatility, which is used to project the range and distribution of daily prices around the projected monthly average. Using this data and the variable cost assumptions for storage (injection charges, withdrawal charges, and fuel) and accounting for the time value of money, the model creates an optimal pattern of utilization for the storage capacity. This model has been extended for Centra to provide an optimized analysis of the different Centra portfolio options. The optimization minimizes the cost of different supply portfolios considering the distribution of changes in sendout and natural gas prices.

(PAGE DELIBERATELY LEFT BLANK)

6
POTENTIAL SUPPLY OPTIONS FOR CENTRA

Currently, most of the natural gas commodity purchased by Centra is sourced from the WCSB to the west of the Centra service territory, and is purchased from the AECO market center and received at Empress. During the summer, Alberta gas is purchased from AECO and shipped via the TransCanada Pipeline to the Centra citygates, and via TransCanada to Emerson, and then Great Lakes Gas Transmission and ANR to ANR storage in Michigan. During the winter, gas commodity delivered to Centra is largely sourced from two locations. The majority of gas consumed is purchased from AECO, and shipped via TransCanada to the Centra citygates. In addition, Centra withdraws gas from ANR storage, and, at least notionally, ships the gas from storage back to the Centra citygates.[10]

Centra also retains the potential to purchase baseload delivered services to Manitoba, seasonal natural gas supplies from the Mid-Continent and Gulf Coast along the southwest and southeast legs of the ANR pipeline system for delivery to Manitoba or injection into ANR storage in Michigan, and peaking supply as a delivered service at the Centra citygate.

One of the key questions faced by Centra is whether or not the current balance of Alberta, U.S. Midwest, and delivered services should be revised, and if so, where additional supplies should come from, and how the commodity should be delivered to the Centra service territory?

- Will current market conditions change in ways likely to change the desired mix of Alberta vs. non-Alberta supply options? Midwest supplies can be sourced from a variety of locations, including the U.S. Gulf Coast, Mid-Continent, or Rocky Mountains.
- Will new sources of supply, including Manitoba shale gas, and the U.S. Rocky Mountains (Williston Basin, Bakken Shale) develop in regions that would provide an economic alternative to Alberta supplies?

[10] Physical flow on the TransCanada system generally does not reverse during the winter, hence the natural gas withdrawn from Michigan storage does not flow back to Manitoba. Instead, the storage withdrawals allow displacement of natural gas. Gas moving east from Alberta on the TCPL system is delivered to the Centra citygates, and natural gas withdrawn from Michigan storage is delivered to other downstream customers.

6.1 Alternative Sources of Natural Gas Commodity

From a resource perspective, AECO represents the logical source for the majority of Centra purchases. The market is liquid, and expected to remain so. In addition, the price at AECO will be set by market prices downstream of Manitoba, adjusted for transportation basis. In a competitive gas transportation market, we would anticipate that AECO prices will remain lower than other existing sources of natural gas for direct delivery to Centra. However, the rate structure on the TransCanada system remains a significant issue, capable of skewing commodity market prices and impacting the delivered cost of WCSB gas in Manitoba. As a result, diversification of gas supply to minimize Centra's exposure to TCPL uncertainty represents an important consideration for the Centra supply strategy.

We anticipate that purchases at AECO will remain a primary source of natural gas in the future, due to the basic resource economics and location of this supply relative to the Centra service territory. As a result, AECO supply represents the default option against which other options will be evaluated.

In addition to purchases at AECO, we are aware of three potential sources of natural gas commodity upstream of the Centra service territory. These include:

1) WCSB production in Saskatchewan from existing and potential new sources.
2) Associated natural gas production in Manitoba.
3) Shale gas production in Manitoba.

We have also considered sources of gas supply in the U.S., including gas production from the U.S. Rocky Mountains, including the Williston Basin and Bakken Shales, Mid-Continent, Gulf Coast, and gas market purchases at Chicago and other Midwest market centers including the MichCon citygate and Dawn.

6.1.1 AECO, Empress and the Western Canadian Sedimentary Basin

Natural gas production in the Western Canadian Sedimentary Basin upstream of Empress includes production in Alberta and British Columbia. This source of supply represents about 20 percent of total North American natural gas supply. The largest market center in the region is the AECO market center. AECO is one of the most active and liquid market centers in North America. Centra accesses this market center via the TransCanada Mainline, and Alberta production provides the vast majority of natural gas consumed in Manitoba.

Pipeline Transportation Options

Currently, the TCPL Mainline is the only pipeline from the major producing regions in Alberta and Saskatchewan to serve the Centra service territory directly.

1) Alliance Pipeline

The Alliance Pipeline was built to provide a transportation path for WCSB production as an alternative to the TransCanada Mainline. Currently, Alliance operates as a bullet pipeline, transporting liquids rich gas[11] from northeast British Columbia and Alberta to the gas processing plant at Aux Sable, near Chicago (see Figure 35). The pipeline also picks up small amounts of Bakken shale gas in North Dakota.

The Alliance Pipeline has run at or near capacity since coming into service in 2000. However, in the last year, flows have declined by about 10 percent relative to historical levels. In addition, the 5-year renewal notice period on the 15 year contracts signed by the initial shippers has expired with only 8% of shippers having elected to extend their contracts beyond 2015. These indications of softness in the Alliance market reflect the larger issues of excess pipeline capacity from the WCSB into other downstream markets.

Alliance is considering a range of alternatives in response to the current market conditions, including the addition of new receipt and short-haul delivery services. However, in order to make any significant changes, Alliance needs to have an economic technical solution to enable the pipeline to deliver marketable, pipeline specification gas while keeping the natural gas liquids on the pipeline to the Aux Sable processing plant.

Historically, the gas commodity market on the Alliance pipeline has been substantially less liquid than the market at AECO. Fewer market participants routinely conduct business at that location and there is more variability in the depth of the market. With less liquidity, it would be more difficult – and likely more expensive – to manage variability in daily requirements through transaction on the Alliance Pipeline.

If Alliance can resolve technical issues associated with delivering pipeline specification gas, Alliance could potentially serve the Manitoba market. This could occur in one of several ways:

- Indirectly through an interconnect with TCPL near Regina.
- Directly into Manitoba with a new build to serve major markets such as Brandon and Winnipeg areas, or
- By connecting to TCPL in Manitoba to reach existing Centra meter stations off TCPL.

The interconnect with TCPL near Regina would require construction of a pipeline interconnect, but would not require major additional pipeline construction. The interconnect would provide Centra access to the natural gas supplies at Alliance Canadian Receipt Point, hence providing an additional source of supply, but would not fully reduce Centra dependence on TransCanada for natural gas deliveries.

The other two approaches would require new pipeline construction to reach Manitoba markets. Based on various pipeline projects ICF is familiar with, new pipeline construction can be estimated at $60,000 per diameter-inch-mile (i.e. $60,000 x diameter of pipe in inches x miles of pipe). We would anticipate construction of an 18

[11] "Liquids rich gas" refers to a gas stream that contains a higher quantity of natural gas liquids and non-methane hydrocarbons than is generally considered suitable for direct consumption without processing or blending.

inch to 24 inch pipeline[12], at a cost of between $1.0 and $1.5 million per mile. The investment costs would lead to a number of issues that would need to be resolved before proceeding with one of these options. These include:

- Cost of new construction and resulting toll into Manitoba
- Duplication of assets between Alliance and TCPL into Manitoba

At this time, it is not possible to compare full-path tolls due to the current uncertainty on both TCPL and Alliance

Another option for consideration would be to transport gas on Alliance to fill Michigan-area storage through its interconnections with other pipelines in the Chicago-Michigan region.

Figure 35
Alliance Pipeline

2) Northern Border Pipeline

Northern Border also transports WCSB gas to the US Midwest. It receives gas from TransCanada's Foothills Saskatchewan pipeline, which transports gas from the McNeil Alberta/Saskatchewan border point to Northern Border at the Saskatchewan/Montana

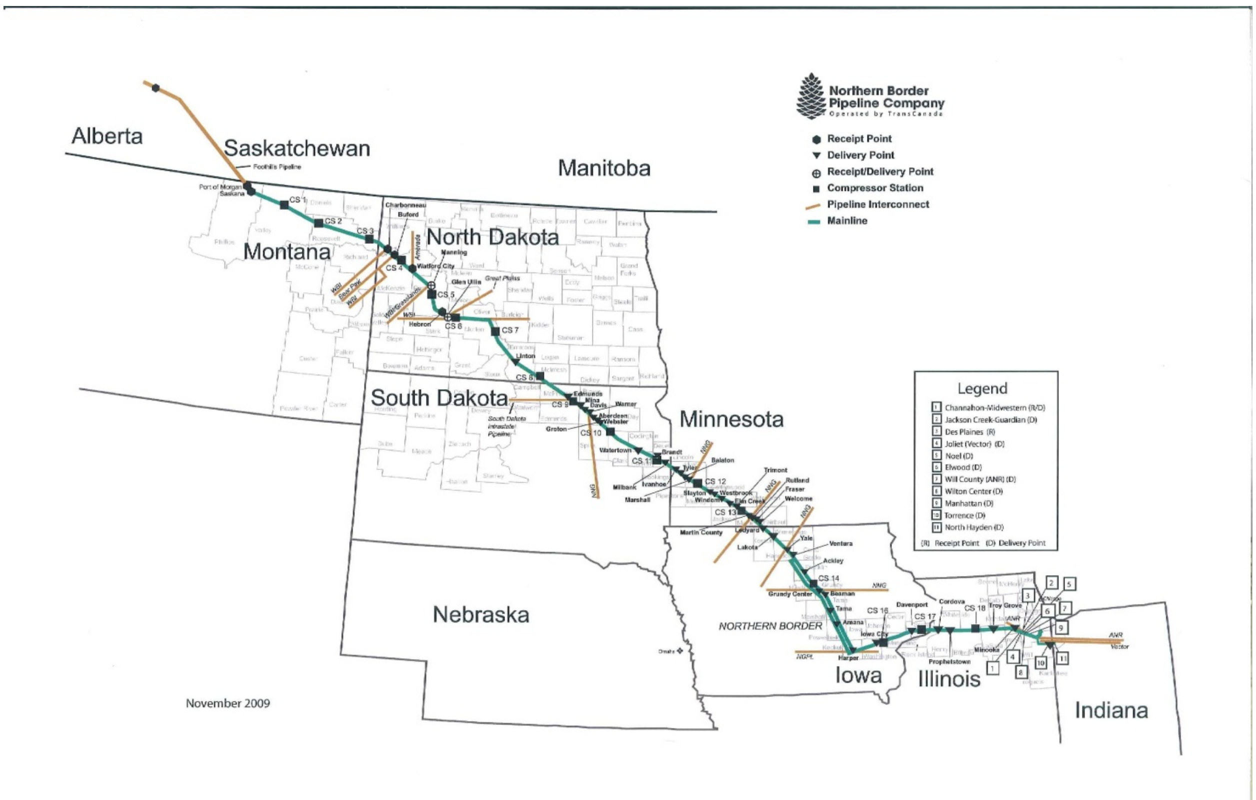
[12] The pipeline size and cost ranges are provided for illustrative purposes only. Actual pipeline expansion size and cost would be determined based on detailed engineering and market studies that have not been performed.

border. Northern Border also has receipt points in the Bakken shale region. Northern Border terminates in the Chicago area (Figure 36).

Gas transported on Northern Border cannot directly serve the Manitoba market. Interconnects with other pipelines would be required to transport Northern Border gas north and west to Manitoba, in total involving a minimum of five different pipelines from Alberta to Manitoba.

Gas transported on Northern Border could potentially be used to fill Michigan-area storage through its interconnections with other pipelines in the Chicago-Michigan region.

Figure 36
Northern Border Pipeline Map



6.1.2 Western Canadian Sedimentary Basin Downstream of Empress

There is a relatively well developed natural gas industry operating in the Western Canadian Sedimentary Basin in Saskatchewan, downstream of Empress. Currently, most of the natural gas produced is gathered by TransGas and becomes part of the TransGas Energy Pool, or TEP. The majority of the gas is either used locally within the TransGas Saskatchewan service territory, or moved onto the TCPL Mainline system in western Saskatchewan, or at one of several smaller receipt/delivery points further to the east.

The TEP hub is largely characterized by longer term deals rather than a liquid day market. Due to declining production and increased gas demand in the industrial and power generation sectors, the province of Saskatchewan has become a net importer of natural gas.

Pipeline Transportation Options

Currently, TransCanada provides the only viable pipeline transportation capacity to move Saskatchewan production to the Centra service territory. To transport TEP gas to TCPL, TransGas provides annual long-term firm transportation with renewal rights (minimum one-year term), while seasonal transportation is available as short-term firm transportation with no renewal rights (less than one-year term).

Purchase of Saskatchewan gas production for transportation on TCPL to the Centra service territory would potentially reduce transportation costs on the TransCanada system. However, all of the potential customers on the TransCanada system, including customers downstream of Centra would attempt to take advantage of the same reduction in transportation costs, and ICF believes that any potential advantages associated with purchasing Saskatchewan gas on a regular basis will be bid away in the competitive market if the gas is interconnected with the TransCanada system.

In the absence of an independent pipeline interconnection, ICF believes that the advantages of transacting at the AECO market hub are likely to offset any transportation cost savings that might be available from Saskatchewan purchases.

Gas produced in Saskatchewan could potentially provide a sustainable lower cost source of natural gas to Centra only if the gas could be delivered to the Centra service territory on a pipeline system not connected with TransCanada. TransGas could potentially provide this type of service to Centra.

6.1.3 Manitoba Natural Gas Production

Currently, while there is oil exploration, development and production activity in Manitoba, there is no directed natural gas production in the province. In 2008, the province produced 9 million barrels of oil and had no marketed gas production.[13] During that same year, there were approximately 230 oil wells completed and no gas well completions. The last reported year with a gas well completion was 1999. A total of only 5 gas well completions have been reported in the province.

While there is no directed natural gas production in the province, there are two potential sources of natural gas in Manitoba that could provide a long term local source of gas supply for Centra.

---

[13] CAPP Statistical Handbook, 2010

1) There is a modest amount of associated natural gas produced along with oil. Currently, there is no infrastructure to process the gas and to deliver it within the Manitoba market. Much of the associated natural gas is currently being flared or vented.
2) Recent developments in shale gas completion technology have opened up new oil and gas plays in many areas of North America. Manitoba has some potential shale resources, opening the potential for Centra to displace more distant sources of natural gas if the Manitoba shales can be economically developed.

Local natural gas production would have the primary benefit to Centra of reducing its reliance on the TCPL Mainline to deliver gas to Manitoba, and thus reducing its exposure to TCPL transportation tolls. Ancillary benefits to the province of Manitoba would include royalties on sales of domestic gas production, local economic development, and a solution to the squandering of an existing energy resource in the associated gas that is currently flared or vented.

Associated Gas Production

In 2007, an estimated 0.8 Bcf (2.25 Mmcf/day) of natural gas was produced in association with crude oil production in Southwestern Manitoba.[14] About 28% of the associated gas was conserved, 38% was flared, 16.3% was vented and the remaining 17.7% was used as fuel on-site. To date, there has been almost no available market for the natural gas other than limited on-site usage.[15]

The oil industry is expanding rapidly in Manitoba; an aggressive drilling program is underway, stimulated by current high oil prices and a favourable royalty regime in Manitoba. The Manitoba government's Petroleum Branch is currently forecasting 550 new oil wells to be drilled in the Province in 2011, following 510 new wells that were drilled in 2010. Manitoba oil production in 2010 reached 11.6 million barrels.

In 2010, the Petroleum Branch estimated annual associated gas production in Manitoba at 1.4 Bcf (3.83 Mmcf/day) from approximately 100 oil batteries in southwest Manitoba. The estimate of associated gas includes all present gases, so the amount of pipeline quality methane that could ultimately be sold to Centra after processing would be less than this estimated volume.

We understand that industry is evaluating a range of potential solutions to gas flaring and venting, including construction of new processing plants, construction of pipelines

[14] "*World Bank Global Gas Flaring Reduction – Private Public Partnership Implementation Plan for Canadian Regulatory Authorities*", June 2008, Page 7.

[15] At least one pipeline has been built to ship associated gas from an oil battery in Manitoba into Saskatchewan to minimize flaring. The Pierson Pipeline was built to transport raw natural gas produced from an oil treater battery near Pierson, Manitoba to be gathered into a compressor in Saskatchewan for shipment via pipeline to the Nottingham Gas Plant in Saskatchewan. The source for the gas is the solution gas produced from the oil treater.

to transport the gas to other jurisdictions, and the use of the associated gas on site to generate power for oil batteries.

There are currently no gas processing facilities in Manitoba that can deliver pipeline quality gas (i.e. gas that meets the specifications of LDCs and the TCPL Mainline). One midstream operator has indicated that the cost of constructing a processing plant that can deliver pipeline quality gas would be approximately $30 million. Centra's pipeline infrastructure in the southwest corner of Manitoba is currently insufficient to accept significant amounts of any potentially available natural gas in this part of the province.

Given the potential growth but limited current volumes of associated gas production in Manitoba, we understand that Centra will continue to monitor industry developments and maintain dialogue with industry participants to identify any future opportunities.

Shale Gas Production

The outlook for natural gas in North America has undergone a fundamental revision in the past two years due to technological and resource evaluation advances allowing large scale production of natural gas from shale resources. There are large shale beds in Manitoba that could potentially lead to natural gas production in the province. The main interval of interest for gas production in Manitoba is the Upper Cretaceous, which contains organic shale and interbedded siltstone with some stated potential for biogenic gas production. Also of interest is the older Devonian Three Forks /Mississippian Bakken oil play, the development of which is underway with horizontal wells, resulting in crude oil and associated gas production.

Figure 37 shows the CSUG (Canadian Society for Unconventional Gas) play outlines for the "Colorado Group" which is the Upper Cretaceous shallow biogenic gas play and "Jurassic and Paleozoic" which includes the Bakken oil play. Both of these are shown to extend somewhat into Manitoba.

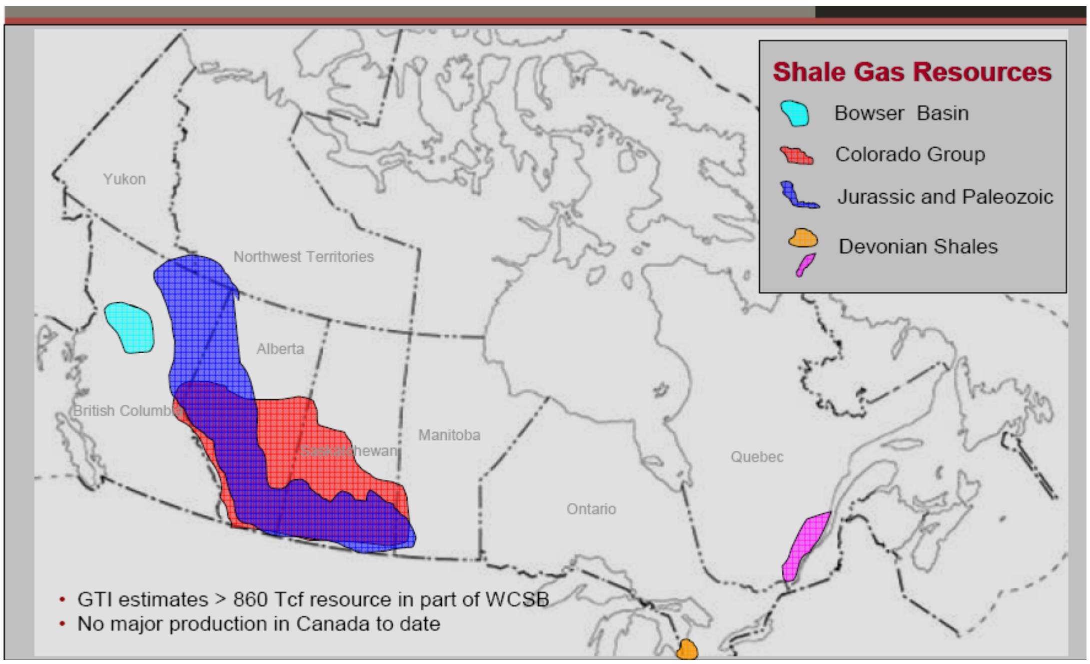
Upper Cretaceous Shale and Siltstone Gas Play

The Upper Cretaceous section is productive in Alberta and Saskatchewan in the Medicine Hat Field area. The majority of the productive area is in Alberta, with an extension into western Saskatchewan. This is a large gas field characterized by long life, shallow low productivity "tight" gas wells. The gas is dry and of biogenic origin. Several other fields in the Williston Basin, including in Montana, produce shallow biogenic gas from the Cretaceous. The Canadian deposits have been extensively drilled by thousands of wells in recent decades, although drilling activity declined precipitously in 2009 and has not rebounded. In 2008 there were 1,166 gas well completions in Saskatchewan. The number of completions declined to 182 in 2009.

While the Upper Cretaceous is a regionally extensive gas accumulation, the role of geologic structure is poorly understood in Manitoba. Mapping of organic content, thermal maturity, depth, and thickness, which are the standard shale gas analysis parameters, are not currently available. Such information is typically sought by industry to assess the potential productivity of a shale formation.

The Manitoba Geological Survey (MGS) is currently conducting research into Manitoba's shale gas potential. We understand that Centra is monitoring this research to help determine the potential for economic shale gas production in Manitoba.

Figure 37
2008 CSUG Map of Shale Gas Plays in Western Canada



Overview of Devonian-Mississippian Bakken-Three Forks Shale Oil Play

The Bakken oil play is very active in the Williston Basin of North Dakota and Montana. Approximately 120 rigs are currently active in the play. This is a "mature oil shale" play characterized by horizontal drilling and completion methods. Current oil production is approximately 250,000 barrels per day and gas production is about 0.235 Bcf per day. Most of the production growth has occurred within the past five years or so, and most of the current growth is in North Dakota. The play was assessed by the U.S. Geological Survey as having the potential for 3.64 billion barrels of recoverable oil, 1.85 Tcf of natural gas, and 0.15 billion barrels of natural gas liquids. [16]

The Bakken-Three Forks interval extends into Saskatchewan and Manitoba. The eastern part of the Bakken play in the U.S. Williston Basin, which is the area closest to Manitoba, was assessed at 4 million barrels of oil. The Bakken-Three Forks in Manitoba has seen significant horizontal oil development over the last seven years, contributing to the growth of associated gas volumes in Manitoba.

[16] U.S. Geological Survey, 2008, "Assessment of Undiscovered Oil Resources in the Devonian-Mississippian Bakken Formation, Williston Basin Province, Montana and North Dakota," USGS Fact Sheet 2008- 3021.

6.1.4 U.S. Rocky Mountains

The U.S. Rocky Mountain region is a large and growing source of natural gas serving demand in the Rocky mountain region, as well as exporting gas to the U.S. West Coast and to the U.S. Midwest. Currently, the Rocky Mountain region is producing about 12 Bcf per day of natural gas, which is expected to grow to over 17 Bcf per day by 2030.

The Rockies currently represent one of the lower cost sources of natural gas in North America, as well as representing the major source of natural gas physically closest to Manitoba after the WCSB. However, there is very little pipeline infrastructure capable of moving Rockies gas directly into Manitoba. There are two potential options for moving Rocky Mountain gas to Manitoba.

1) The Williston Basin Interstate Pipeline is connected to the TransGas system at the Saskatchewan border.
2) The Bison Pipeline could be extended from its interconnect with Northern Border to bring Rockies gas to Emerson.

Other pipeline options would require significant backhaul from higher value markets. While these options are unlikely to be economic as a source of direct-to-load supply, when combined with storage they may be economic. These options include pipeline deliveries into Michigan storage, with deliveries to Manitoba via backhaul through Emerson.

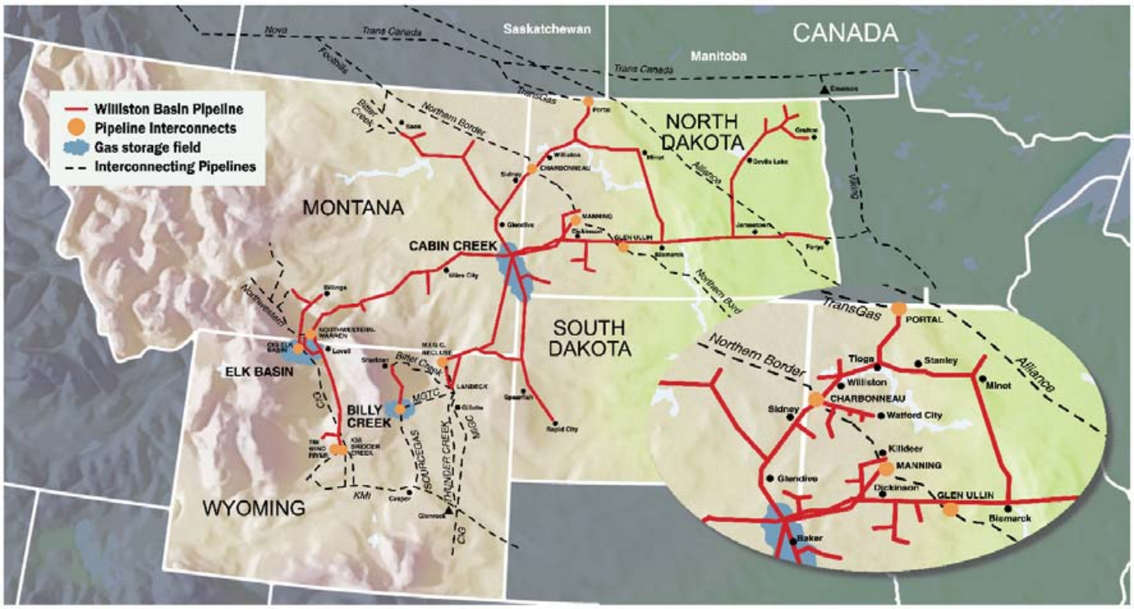
1) Williston Basin Interstate Pipeline:

The Williston Basin Interstate Pipeline (WBIP) currently is used primarily to serve U.S. LDC's in the upper Midwest and Rocky Mountain states. The pipeline is connected to the Wyoming supply basins, and currently receives about 100,000 GJ/day of Bakken shale gas, which primarily flows to storage and Northern Border. The pipeline is connected to three storage fields operated in aggregate. These storage fields include the Baker field, which has very large capacity with very low deliverability.

WBIP is connected to the TransGas system with an 8" line at Portal on the North Dakota/Saskatchewan border. This interconnect historically transports sporadic supply south from Saskatchewan into North Dakota. ICF understands that TransGas is building a 10" pipeline in southeast Saskatchewan that could potentially accommodate gas imports from Portal onto its system of up to 20,000 GJ/day should Portal be modified to receive U.S. gas. New or modified compression would likely be required to accommodate exports of natural gas from North Dakota into Saskatchewan.

The east end of WBIP in North Dakota approaches relatively close to Emerson (Figure 38). However, the WBIP system is constrained east of Bismarck with no expansion potential. Also, there is no interconnect between WBIP and Viking Gas Transmission, precluding a Viking backhaul to Emerson.

Figure 38
Williston Basin Pipeline System



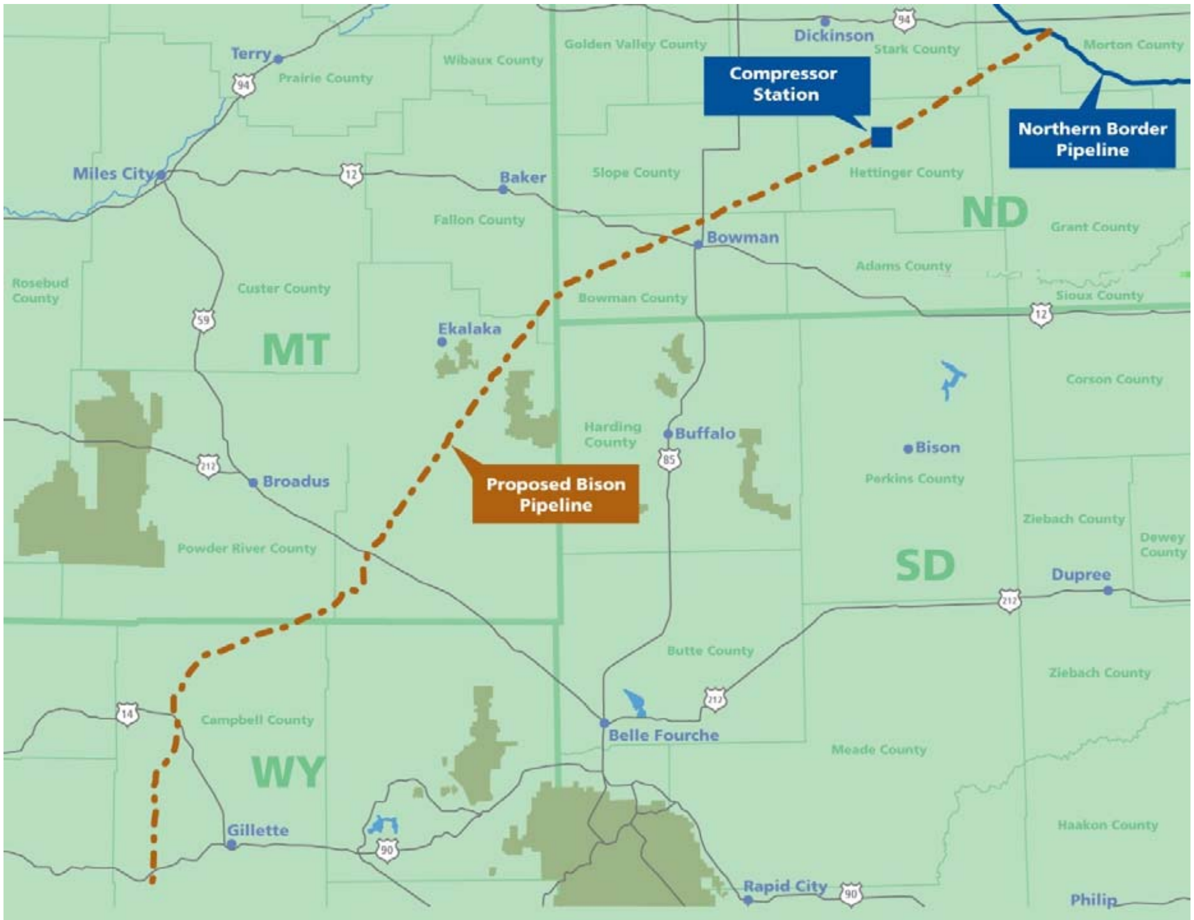
WBIP could potentially provide access to a limited volume of Rocky Mountain natural gas supplies. The option would partially reduce exposure to TCPL rate uncertainty, although TCPL transportation would still be required from a TransGas-TCPL interconnect in Saskatchewan to the Manitoba market. The new 10" line being constructed by TransGas is not contemplated to interconnect with TCPL.

2) Bison Pipeline

The Bison Pipeline is an interstate natural gas pipeline designed to transport gas from the Powder River Basin in Wyoming to the Midwest market (Figure 39). The Bison Pipeline is wholly owned by an indirect subsidiary of TransCanada.

The first section of the pipeline consists of approximately 302 miles of 30-inch-diameter natural gas pipeline and related pipeline system facilities that extend northeastward from the Dead Horse Region near Gillette, Wyoming, through southeastern Montana and southwestern North Dakota where it interconnects with Northern Border Pipeline Company's (Northern Border) system near Northern Border's Compressor Station No. 6 in Morton County, North Dakota. When approved by the U.S. FERC in 2010, the pipeline was projected to cost US$609 million. This section of the pipeline was completed and brought into service in January 2011.

Figure 39
Bison Pipeline System



Bison's design capacity is approximately 477 million cubic feet per day with potential expandability of up to approximately 1 billion cubic feet per day. During the first four full months of operation (February through May, 2012), the Bison pipeline has been flowing at about 75 percent of capacity. Future development plans include the expansion and extension of the Bison pipeline into the U.S. Rockies basin, and potential interconnect with the Baker Storage complex.

TransCanada has discussed a 245-mile extension of the Bison Pipeline from the Northern Border Pipeline to Emerson, which would provide Centra access to Wyoming gas and Bakken shale receipts. Gas transported on Bison would be delivered to Centra via backhaul on TCPL from Emerson to the Centra service territory.

Twenty-year commitments may be sought from shippers in order to make the Bison extension to Emerson a reality. Currently, there is insufficient shipper interest to proceed with this extension.

6.1.5 U.S. Gulf Coast and Mid-Continent

Centra currently maintains access to the U.S. Mid Continent and Gulf Coast producing regions as an option for meeting a small part of total supply requirements. Centra holds capacity on ANR Southeast capable of transporting gas sourced from Louisiana and the Gulf Coast into ANR storage during the summer, as well as capacity on ANR Southwest that is capable of transporting gas sourced from Oklahoma to ANR storage in summer and to GLGT for backhaul to Manitoba in winter.

The U.S. Mid-Continent supply regions remain a vibrant and growing source of natural gas. ICF is projecting total production from this region to increase by more than 25 percent, from 9263 BCF per year in 2010 to 11,777 Bcf per year in 2020 due to growth in shale gas production in the Barnett, Eagle Ford, and other shale basins.

ICF does not project similar growth for Gulf Coast production. We anticipate that production will decline over time for most of the Gulf Coast producing regions. However, the Gulf Coast is expected to remain a critical component of the natural gas pipeline transportation system. As pipeline capacity from this region into market areas becomes available due to the decline in production, we anticipate construction of additional pipeline capacity from the Mid-Continent and other producing regions into the Gulf Coast area to take advantage of existing pipeline infrastructure. The growth in natural gas interconnects with other producing regions should ensure that this region remains a major market center and potential source of natural gas supply.

ICF is also projecting relatively modest growth in pipeline utilization in the pipeline corridors from these producing regions into the U.S. Midwest, and to Michigan-area storage. This gas would be available to Centra via backhaul pipeline capacity on ANR, Great Lakes, and TransCanada. As a result, ICF expects gas supply sourced from these regions to remain viable supply options for Centra for the foreseeable future.

The relationship between commodity prices in the US, and commodity prices in Alberta, is not a critical issue for Centra supply purchased for direct consumption in Manitoba, since the cost of Alberta commodity delivered to Manitoba from Alberta should generally be lower than the cost of natural gas commodity delivered to Manitoba via backhaul from the U.S. If commodity prices in U.S. markets fall to the point where Centra is consistently able to purchase and transport commodity to Emerson, and then backhaul the gas to the Centra Citygate at a cost lower than purchase and transport from AECO, other shippers on the TransCanada Mainline are likely to bid up the cost of the U.S. supply and transportation capacity to Emerson to match the cost of gas delivered to Emerson on the TCPL system. Prices of delivered gas on the TransCanada system west of Emerson should generally be lower than prices of delivered gas at Emerson or east of Emerson.

However, changes in the relative price of gas between AECO and the U.S. supply regions can have a significant impact on the relative cost of natural gas injected into Michigan-area storage. Currently, approximately two-thirds of the gas Centra injects into ANR Michigan storage is gas supply purchased in Alberta. The cost of purchased gas in Alberta plus the incremental cost of transportation to ANR storage typically has been less than the cost of gas purchased in the U.S. and transported to ANR storage. However, this has been true primarily due to the relatively large gas cost advantage in Alberta relative to other sources that has existed during most periods. A shift in the delivered to storage price of natural gas sourced in Alberta relative to other U.S. sources could change the economics of natural gas delivered to Michigan-area storage.

6.1.6 Major Midwest Natural Gas Market Centers

Chicago, Dawn, and Michigan are major market centers that are located downstream from the Centra service territory. The attractiveness of these market centers depends on the relative price of the commodity, and the reliability, flexibility, and price of the transportation options back to Centra. Dawn and Chicago are highly liquid markets with significant daily transaction volumes and parties. The MichCon citygate is a growing market with sufficient liquidity to conduct transactions.

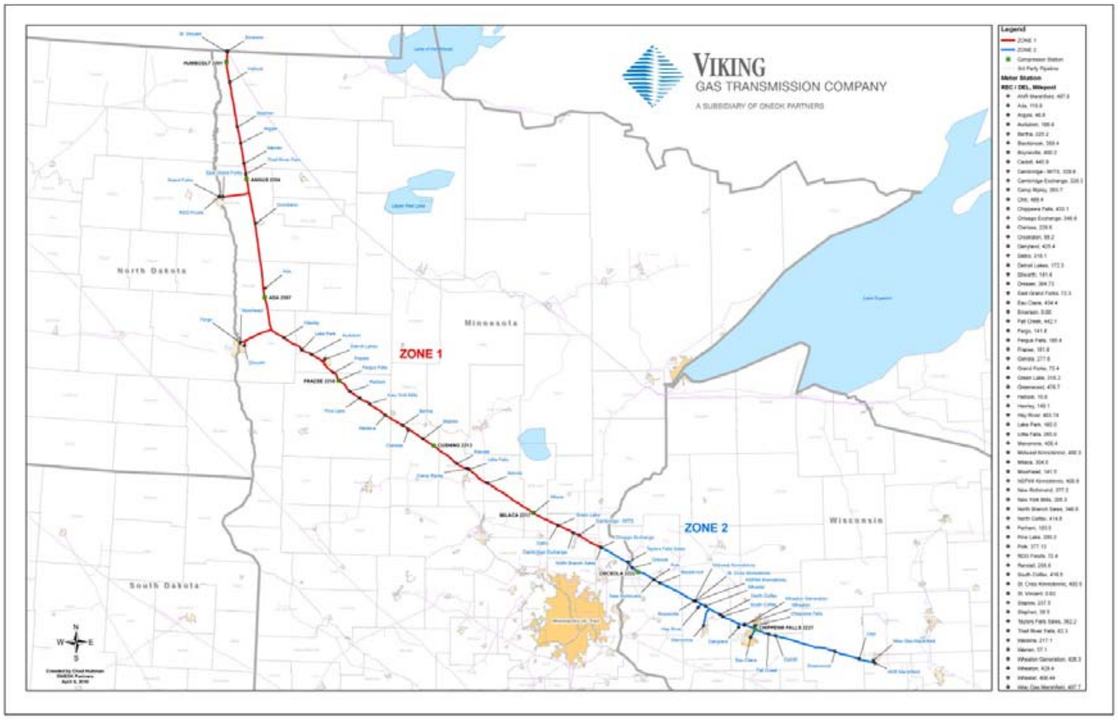
Any of these three markets could be utilized to purchase natural gas for injection into Michigan or Ontario storage, or for winter natural gas purchases, depending on the relative cost relationships. In the past, the cost of gas at these points, plus the cost of moving gas back to the Centra citygate has made these points relatively uneconomic. With the increasing cost of forward haul pipeline capacity on TransCanada, however, these points are worth considering to determine if they might represent a lower cost option for meeting Centra gas requirements relative to purchases from the WCSB.

A number of pipelines operate in the U.S. upper Midwest that may allow Centra to access natural gas at Chicago, Dawn, and the MichCon citygate in Michigan. ANR Pipeline and Great Lakes Gas Transmission (GLGT) could transport Chicago gas to Emerson. Dawn gas could be backhauled on GLGT to Emerson or via a TCPL Mainline backhaul to Manitoba. MichCon gas could be accessed via GLGT to Emerson. Transportation services could also potentially be provided by Viking Gas Transmission and Northern Natural Gas Pipeline.

1) Viking Gas Transmission

Viking Gas Transmission is a 24" pipeline that transports Canadian gas southeast from Emerson into Minnesota and Wisconsin, terminating at Marshfield (see Figure 40). Viking is largely used to serve Minnesota and Wisconsin LDC supply requirements. Receipt capacity at Emerson is about 500 Mmcf/day, and delivery capacity at Marshfield in Wisconsin is about 300 Mmcf/day, where Viking interconnects with ANR. Viking could potentially provide access to Chicago gas via ANR and a notional backhaul to Emerson. Viking also interconnects with Northern Natural Gas Pipeline near Minneapolis-St. Paul.

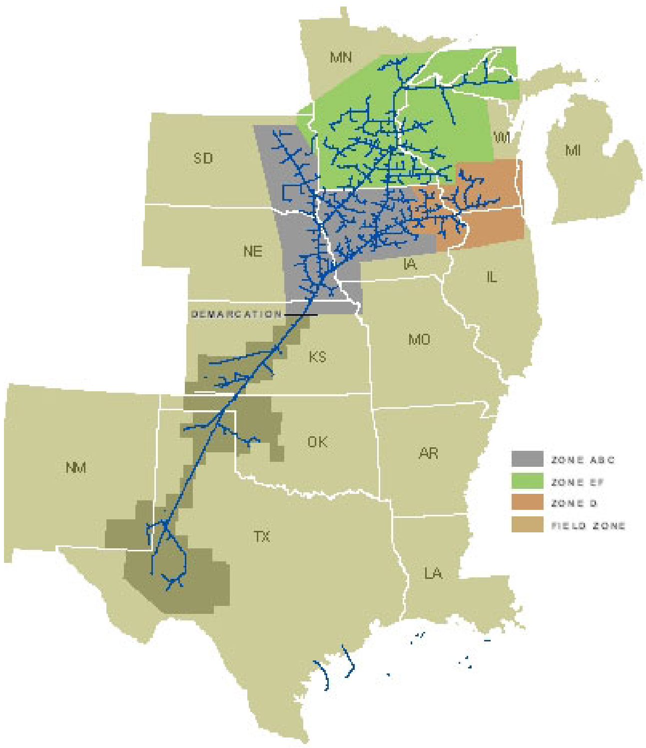
Figure 40
Viking Gas Transmission



2) Northern Natural Gas Pipeline

Northern Natural Gas (NNG) is a major U.S. pipeline that extends from Texas into Minnesota, Wisconsin, and the Michigan upper peninsula (see Figure 41). NNG interconnects with Northern Border at the Ventura hub in northern Iowa. Ventura is a trading hub of moderate liquidity. The price of traded gas at Ventura is influenced by WCSB and Rockies gas prices via Northern Border and Mid-continent gas prices via NNG. Ventura gas could potentially be transported north on NNG to the NNG-Viking interconnect Chisago near the Twin Cities, and backhauled on Viking to Emerson. NNG also has interconnects with GLGT in Minnesota and Michigan.

Figure 41
Northern Natural Gas Pipeline Map



3) Great Lakes Gas Transmission

Great Lakes Gas Transmission (GLGT) is a 2.2 Bcf/day pipeline that connects Canadian gas received from TCPL at Emerson to U.S. Midwest markets. Centra has used GLGT since 1993 to notionally backhaul gas withdrawals from Michigan storage to Emerson for further backhaul on TCPL to the Manitoba market. The rate paid by Centra for this large-capacity winter transportation has been at a significant discount to the maximum rate allowed under GLGT's tariff, which has made a Michigan storage portfolio cost-effective and viable. The continued availability of significantly discounted transportation from Michigan to Emerson on GLGT is therefore a key consideration with respect to the future viability of a Michigan storage portfolio for Centra.

There are a number of current areas of uncertainty related to GLGT that are relevant to Centra.

1) *Declining forward-haul shipments of gas on GLGT and GLGT dependence on TCPL*. Rising tolls on TCPL negatively impact GLGT in two ways: 1. Shippers move less gas on TCPL to Emerson for receipt and transport by GLGT; 2. Declining use of TCPL long-haul transportation from the WCSB by eastern shippers in favour of short-haul paths results in less contracting by the TCPL

Mainline on GLGT. (TCPL transports gas on GLGT to serve TCPL long-haul shippers in southern Ontario and eastern Canada, a practice referred to by TCPL as TBO - "transportation by others"). The impact of declining physical flows from Emerson has resulted in GLGT physically reversing flows to east-to-west from west-to-east on portions of its pipeline in order to serve certain delivery points on its system. Should this practice become the norm on GLGT, it raises the possibility of fuel charges on transportation to Emerson (notional backhaul does not normally attract fuel charges). Declining flows on GLGT could also have implications for future GLGT rate applications.

2) *Availability and pricing of backhaul capacity to Emerson on GLGT*. TCPL is not only a major forward-haul shipper on GLGT, but has in recent years contracted for significant backhaul capacity to Emerson. As a result, there have been periods in recent years in which GLGT has been sold out of backhaul capacity, while TCPL has effectively established the market price for GLGT backhaul to Emerson. Given the current uncertainty on TCPL, its future use of GLGT to transport gas in either direction and the resulting impact on market prices sought by GLGT for transportation capacity is likewise uncertain.

3) *Upcoming GLGT rate case*. As a result of a settlement reached with GLGT shippers in 2010, GLGT is required to file a rate case before FERC no later than November 1, 2013. GLGT has not provided any indication as to when the application will be filed, or the magnitude of any rate increases or decreases that may be sought. While this presents further GLGT rate uncertainty for Centra, U.S. pipelines generally have the latitude to enter into transportation contracts with shippers for a discounted or negotiated rate that can provide the shipper with fixed, known rates for the duration of a contract.

6.2 Role of Natural Gas Storage

Natural gas storage fills a major role in Centra's natural gas supply strategy. Currently, Centra holds 15,509,323 GJ of ANR storage capacity in Michigan, which is used to meet 208,591 GJ of peak day requirements, or about 43 percent of peak day requirements. Centra also utilizes ANR storage to meet from 25 to 35 percent of winter gas requirements and 15 to 25 percent of annual gas requirements, depending on weather and storage withdrawal patterns.

Natural gas storage fills a number of critical roles for the utility:

1) Gas storage minimizes costs on the TransCanada pipeline system for additional winter pipeline capacity.

2) Gas storage improves Centra's purchase and transportation load factors for Western Canadian supply to over 80%, compared to a Manitoba sales load factor of slightly greater than 30%.

3) Natural gas storage allows Centra to utilize normal seasonal differences in commodity prices to minimize and hedge annual gas purchase costs.

4) Gas storage mitigates rate volatility for customers when gas purchased at varying prices for storage injection is withdrawn at a single unit storage gas cost.
5) Natural gas storage provides additional daily gas supply flexibility to balance nominated supply to weather-driven demand fluctuations in winter through utilization of TCPL's Storage Transportation Service (STS), which includes access to the intra-day 5:00 a.m. CCT nomination cycle for the last four hours of the gas day. This late-night nomination window enables Centra to minimize its load balancing charges on TCPL.
6) Storage allows Centra to minimize open market purchases and reliance on swing services on high demand days when prices typically are highest.
7) Access to storage gas provides increased security of supply during periods of limited supply liquidity and when physical commodity markets are closed.
8) Depending on where it is located, storage may facilitate supply diversity by providing access to gas supplies from remote gas markets to fill storage that could not otherwise be readily incorporated into Centra's daily supply plan for the Manitoba load.

Remote storage (storage that is not located in the LDC's service territory) is generally used to improve the overall pipeline load factor of the capacity held by the LDC. Remote storage can also be utilized to provide a load balancing service. The 5:00 a.m. TCPL STS nomination cycle currently utilized by Centra, and that ANR and GLGT coordinate to, is an example of a mechanism that enables Centra to use remote ANR storage for both pipeline load factor improvement and load balancing.

The alternative is to hold large-capacity remote storage for pipeline load factor improvement and small-capacity high-deliverability storage close to the load for load balancing and to serve peaking requirements.

The existing ANR storage and related transportation contracts expire at the end of March 2013. The expiration of the existing contracts provides Centra with an opportunity to reassess the location and volumes of future storage services. The assessment includes a review of the level of storage capacity, deliverability, and ability to cycle the storage capacity more than once each season. Determining the appropriate amount and location of natural gas storage is a key element of the Centra supply portfolio review; should Centra hold additional storage capacity to reduce exposure to rising and volatile costs on TCPL? Or reduce storage capacity in order to reduce long-term cost commitments? Should Centra change storage providers, or storage locations?

6.2.1 The Relationship Between Storage Capacity, Deliverability, Cyclability, and Seasonality

Capacity, deliverability, and cyclability are elements of a storage service that cannot be considered in isolation. Take Centra's current ANR storage service as an example. The deliverability of Centra's storage service (net of withdrawal fuel) is 208,591 GJ/day, providing for what is known as a "74-day service" (15.5 million GJ or 15.5 PJ capacity divided by 208,591 GJ/day). In other words, Centra could completely withdraw and deplete its storage gas in 74 days. Centra could potentially opt for higher deliverability - for example, a 60-day service for deliverability of about 258,000 GJ/day. While Centra would have to consider obvious factors such as the cost of increased storage deliverability and the availability and cost of associated transportation capacity to accommodate higher deliverability, Centra would also have to consider that higher deliverability may also mean that Centra would deplete its storage more quickly during a cold winter, potentially leaving Centra without storage gas in the latter part of winter. Centra's current ANR storage service is seasonal (rather than annual), meaning that storage gas cannot be injected in winter (or withdrawn in summer), thus precluding Centra from refilling storage in winter through its contractual ANR storage injection point. Centra may be able to fill storage during the winter through inventory transfers with other ANR storage holders that are willing to sell their own inventory of gas, yet this would provide no operational benefit to Centra as Centra's current storage service with ANR is "single-cycle storage" (i.e. has cyclability of 1.0), meaning Centra is only entitled to withdraw gas up to its maximum storage quantity (MSQ) of 15.5 PJ in any one winter season. To address these issues related to higher deliverability storage, Centra could opt for greater storage capacity, or for annual storage with increased cyclability (for example, 1.2) thus allowing withdrawals greater than its MSQ (e.g. 15.5 PJ x 1.2 = 18.6 PJ) and allowing for winter injections (and summer withdrawals) to prevent depletion of storage.

Greater storage capacity, higher deliverability, increased cyclability, and annual (rather than seasonal) storage can each be expected to come at a higher price. However, an LDC may be able to hold less storage capacity if it can be matched with higher deliverability and cyclability with the ability to inject into storage in winter. The relationship of these factors and their impact on costs, operations, and reliability will be evaluated in consideration of storage options.

6.2.2 Transportation of Storage Gas and TCPL Storage Transportation Service

Storage options cannot be considered in isolation of the transportation capacity required to ship the optimal levels of gas to and from storage for injection and withdrawal. A significant question for any LDC is the degree to which transportation is held from a supply basin or liquid trading hub to the storage operator's injection point versus relying on purchases of gas from the market at the storage operator's injection point for injection by the LDC.

The nature of available transportation services also influences how an LDC can nominate gas withdrawals from storage. TCPL's Storage Transportation Service (STS) features a late intra-day nomination cycle at 5:00 a.m. CCT for the last four hours of the gas day that is used by Centra for load balancing to mitigate TCPL charges for imbalances between daily nominated supply and daily gas consumption in the MDA and SSDA.

STS is an annual service that provides for transportation of gas for both storage injections and withdrawals. Monthly demand charges are based on the contractual injection demand if the storage facility is located downstream of the LDC's delivery area, or on the contractual withdrawal demand if the storage facility is located upstream of the LDC's delivery area. Currently, Centra's contracted storage capacity and STS injection and withdrawal point (Emerson) are located downstream of its delivery areas.

TCPL's STS is currently Centra's primary load balancing tool in the winter storage withdrawal months. In the absence of STS, TCPL Short-Term Firm Transportation (STFT) could potentially be used for withdrawal of storage gas. STFT does not feature nomination cycles later than Intra-Day Two (ID2), which must be nominated to TCPL by 5:00 p.m. CCT for 9:00 p.m. flow - that is, for the last twelve hours of the gas day. With respect to contract renewal rights, STS contracts must be held in conjunction with annual TCPL FT contracts and have associated renewal rights, while STFT contracts can only be held for less than one year and do not have renewal rights.

6.2.3 Term of Storage Arrangements

As the gas storage market has evolved over the last decade, very long term arrangements, such as Centra's current twenty-year contracts, have become much less common. As marketers have established a significant presence in the storage market, short-term storage services of a year or even less have become more commonplace.

While shorter terms have also become typical for LDCs in some locations, LDCs remain concerned with the ability to renew contracts for storage upon expiration. With an obligation to serve a customer base on the system, LDCs often contract for longer terms than marketers. LDC system requirements have ongoing needs to address seasonal and peak day requirements that will exist for decades to come which storage addresses. For an LDC, determining factors for the appropriate term will include current opportunities in storage markets at the time contracts are negotiated and the tightness in the market that is expected to develop at or near the expiration of the proposed contract.

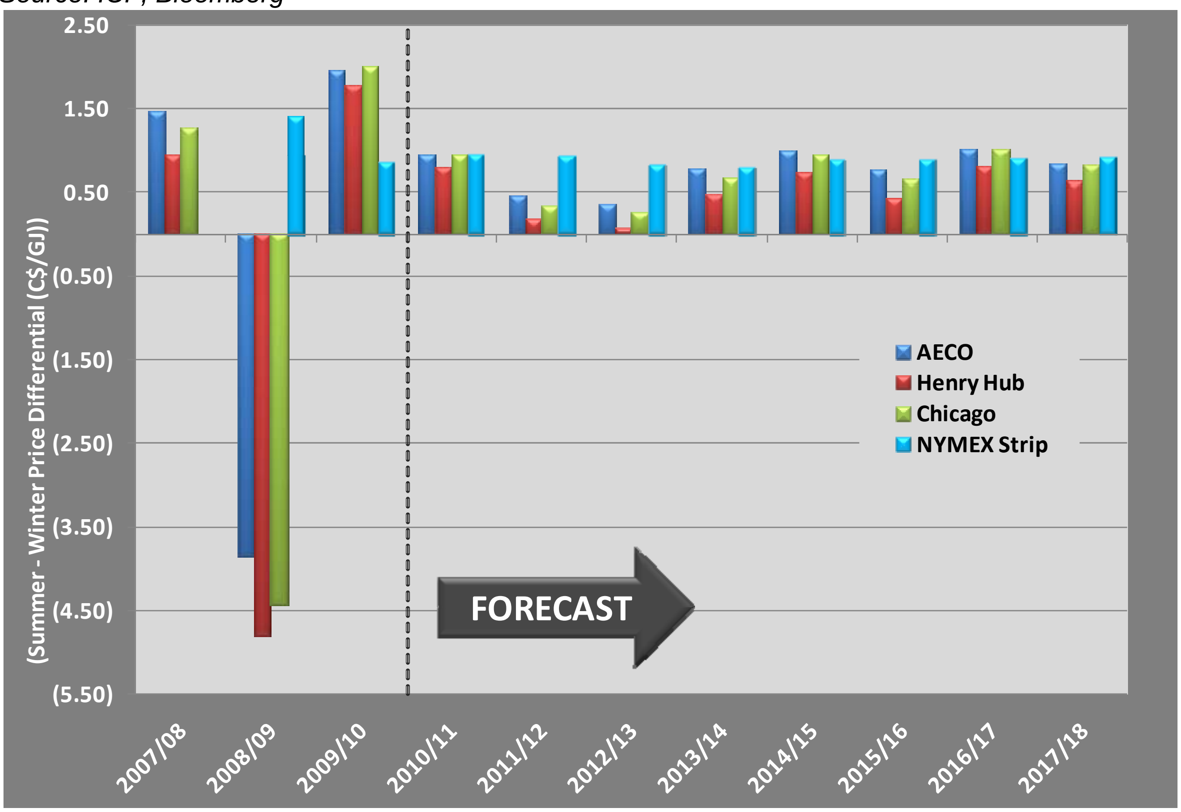
6.2.4 Storage Value

In the recent natural gas market, the price difference between winter and summer has begun to decline (the 2008/2009 winter, when storage premiums visited negative territory, was brought about by a declining economy, which pushed demand below anticipated levels). As storage markets stabilize, and end-of-winter inventories return to more traditional levels, near- and mid-term storage values are projected to remain depressed. ICF's forecast of the price difference between the average summer injection period price (May – September), and the winter withdrawal period price (December – February) for the next few years is shown in Figure 42. For the 2008/09 period, this value was negative since gas prices declined between the 2008 summer injection season, and the 2008/09 withdrawal season. The 2009/10 withdrawal season saw a rebound in storage values, but values fell again in the 2010/11 season. ICF expects the actual natural gas differential to fall again in the 2011/2012 winter and to remain relatively low through the 2012/13 season before starting to rebound.

Note that, as shown by the NYMEX values in the figure, the natural gas market is still expecting a significant seasonal price spread through the 2011/12 winter. The storage values that market participants are willing to pay are determined by market expectations, and the ability to hedge seasonal prices, hence the immediate value of storage is determined more by the NYMEX future strip rather than actual prices. The NYMEX strip behavior tends to change based on experience with actual prices, hence lags the actual market.

Figure 42
Seasonal Arbitrage Value of Natural Gas Storage

Source: ICF, Bloomberg[17]



6.3 Natural Gas Storage Options

The following storage options are being considered as part of the Centra portfolio review:

---

[17] NYMEX represents value of Henry Hub futures strip. The 2008/09 value is based on the April 2008 strip. Later values are calculated from the November 2010 strip.

1. Alberta storage
2. Saskatchewan storage
3. Manitoba storage development
4. Williston Basin Interstate Pipeline storage
5. Northern Natural Gas Pipeline storage
6. Michigan storage
7. Ontario storage
8. Virtual storage
9. No storage

6.3.1 Alberta Storage

There is significant natural gas storage capacity in the province of Alberta. Niska owns and operates 135 Bcf of storage capacity in two facilities in Alberta (the AECO Hub). Since 2006, Niska has added 41.3 Bcf of gas storage capacity through expansions. TransCanada Gas Storage owns or controls more than 130 Bcf of gas storage in Alberta. Although the TransCanada Gas Storage facilities are not physically located at AECO, the company provides storage injection and withdrawal services at AECO.

Because Alberta gas storage is located upstream of Empress, utilization of Alberta storage would not reduce the need for capacity on the TransCanada system to meet peak loads; in fact, it would increase winter transportation requirements on the TCPL Mainline and the Alberta System (NGTL) by 208,591 GJ/day assuming the same storage deliverability Centra has today with ANR storage combined with GLGT and TCPL STS transportation.

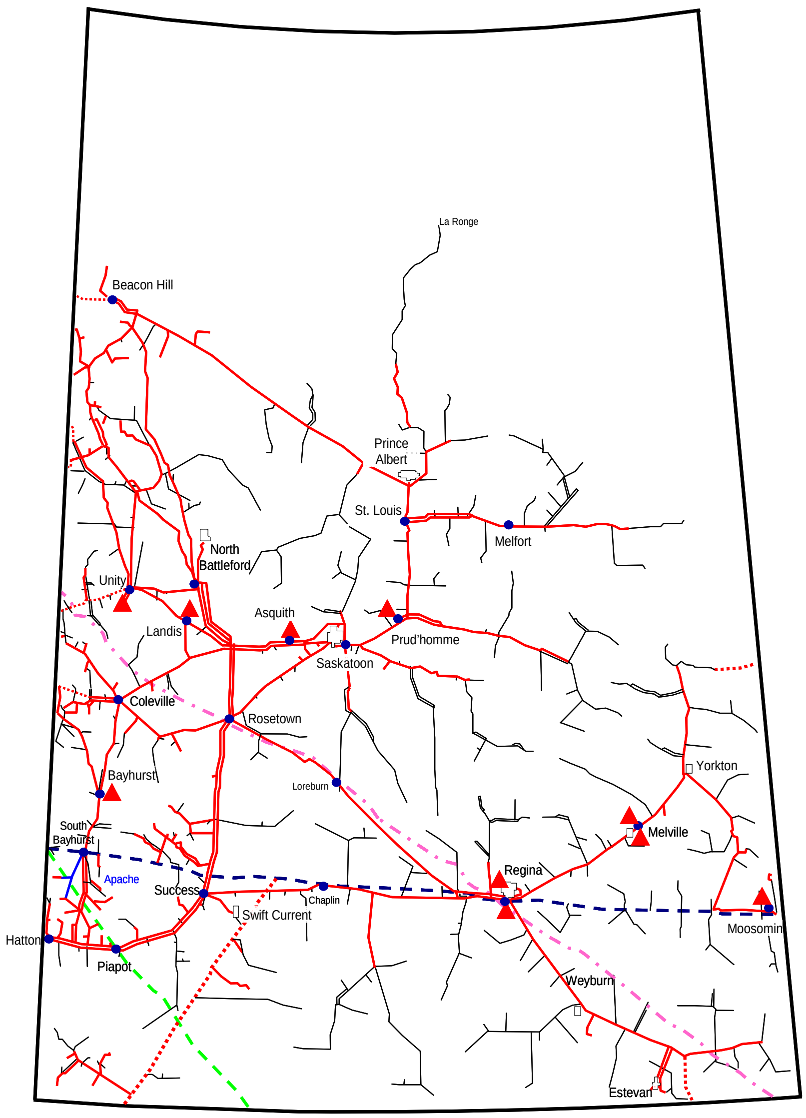
6.3.2 Saskatchewan Storage

TransGas, a subsidiary of SaskEnergy, is a major storage operator in the province of Saskatchewan. TransGas currently operates 46 PJ of storage, and is expanding to 50 PJ, all of which is subscribed. TransGas provides storage services to the SaskEnergy LDC, and sells storage services to other market participants.

Although TransGas has numerous dispersed storage facilities in the province, it offers non-site-specific storage services centered around its Bayhurst facility in western Saskatchewan and the TransGas Energy Pool (TEP), with charges based on storage capacity and deliverability. Gas can be injected into TransGas storage by delivering gas to the TransGas transmission system (for example, at Empress or Bayhurst). The shipper must pay TransGas receipt transportation on injections, using long-term firm (LTF) transportation (one-year minimum term with renewal rights), short-term firm (STF) transportation (less than one-year term with no renewal rights), or interruptible transportation. Alternatively, the shipper can buy gas at the notional TEP hub, which can be deemed injected into storage upon purchase, thus avoiding receipt transportation charges. In either case, the shipper must pay TransGas delivery transportation charges (using LTF, STF, or interruptible delivery transportation, which have the same rates and features as receipt transportation) upon withdrawal of storage gas, which is generally delivered to the TransGas interconnect with TCPL at Bayhurst, slightly east of Empress. Under this model, Centra would need to hold capacity downstream of the storage withdrawal point on TCPL over a relatively long distance (Bayhurst to Manitoba).

TransGas storage withdrawals closer to the Manitoba border would improve the economics of Saskatchewan storage by reducing the distance of transportation downstream of storage that would need to be held on TCPL. In this case, other issues would need to be considered such as TransGas delivery capacity in eastern Saskatchewan and the likely requirement to hold year-round LTF delivery transportation (and LTF receipt transportation if shipping AECO gas) when only seasonal delivery transportation of gas withdrawals may be required. Figure 43 below shows the locations of storage in Saskatchewan.

Figure 43
Storage in Saskatchewan



6.3.3 Potential Manitoba Storage Development

We understand that Centra is actively investigating specific storage development opportunities in Manitoba. The opportunities range from storage sites that could be of similar capacity to Centra's current storage service, to much smaller storage sites that could form one element of a Centra storage portfolio.

Should Manitoba storage development prove to be technically and economically feasible, a Manitoba storage facility would not likely be operational for a number of years beyond 2013, particularly if it were to be a large-capacity storage facility.

Depending on the capacity and deliverability, Manitoba storage could provide a number of benefits to Centra. However, there are also risks and timing issues associated with the development of Manitoba storage. Benefits and risks include:

1) ***Increased operational flexibility to manage weather-driven load swings through the ability to utilize annual storage***

Manitoba storage may provide the operational flexibility to inject and withdraw gas at any time of the year, thus providing the ability to increase baseload gas purchases while minimizing swing gas purchases and the need for peaking arrangements. This would be accomplished intra-day by injecting into Manitoba storage when long baseload gas that was scheduled direct-to-load, and withdrawing gas from Manitoba storage when short gas to serve the load, rather than nominating swing gas (up or down) through a supply contract. While annual storage (storage that allows injections and withdrawals at any time of the year, unlike Centra's current seasonal storage arrangements) may be available from remote storage operators, the ability to both inject and withdraw gas on any day would be limited by the transportation required between Manitoba and remote storage and the ability to get intra-day nominations approved on multiple pipelines. For example, under Centra's current storage arrangements, Centra would need to hold additional transportation between Manitoba and Michigan on three different pipelines to accommodate use of annual storage; and, as Centra would need to nominate to or from storage as late as the Intra-day Two (ID2) nomination cycle to respond to weather-driven load swings, Centra would be at risk of having nominations rejected on any of three different pipelines. Manitoba storage could therefore provide a new way for Centra to manage its considerable load swings, and reduce its reliance on swing gas contracts and peaking arrangements. It could be particularly beneficial in shoulder months such as April and October when Centra currently does not have access to storage and related transportation, yet there can be significant market requirements during colder than normal weather. While Centra has thus far been able to contract for swing service economically, there is the potential risk that cost-effective swing services may become more difficult to obtain in the future.

2) Reduction in TCPL Mainline capacity and reduction or elimination of US storage and transportation portfolio

Manitoba storage could result in the need for less TCPL Mainline capacity. Between Alberta and Manitoba, Centra may be able to reduce its capacity requirements by contracting largely or exclusively for baseload requirements to the load and storage, while contracting for little or no Alberta-to-Manitoba capacity to accommodate swing requirements. Rather, the "swing" requirements would be met via Manitoba storage withdrawals, with pipeline capacity only required for the short distance from Manitoba storage to the Manitoba load. The current paths of Alberta-to-Manitoba-to-Emerson and Emerson-to-Manitoba pipeline capacity for remote storage injections and withdrawals (reflected in Centra's current TCPL FT and STS contracts) could potentially be reduced or eliminated. Centra's U.S. storage and transportation portfolio could similarly be reduced or eliminated.

3) Reduced exposure to market uncertainty

Manitoba storage, by potentially reducing reliance on physical assets outside of Manitoba, may reduce Centra's exposure to general market uncertainty, particularly with respect to TCPL and GLGT (see section four for a discussion of TCPL issues, and section 6.1.6 for a discussion of the issues facing GLGT). Given the greater ability to rely on baseload supplies into Manitoba storage with the concurrent ability to rely on Centra-controlled storage withdrawals at any time of the year, Centra could increase its reliance on delivered services from marketers (both into storage and to the load), without need for consideration of the relative cost-effectiveness of particular physical supply sources and transportation paths at a given point in time. This would reduce the requirement to hold long-term transportation capacity from a particular region (e.g. TCPL to access WCSB gas versus a U.S. portfolio to access U.S. gas via Emerson). A reduction in long-term, long-haul transportation commitments would reduce Centra's exposure to changing market conditions; market circumstances would dictate the most cost-effective delivered gas supply to Manitoba.

4) Facilitate local market development

Manitoba storage may operationally facilitate acquisition and ultimately the growth of local production. Local production may be of relatively small volumes and sporadic (low load factor), making it challenging to accommodate into an LDC's daily supply plan. Local storage could effectively act as a "hub" that could accommodate varying daily volumes of local supply without impacting the LDC's daily supply plan to serve the load.

5) Risks of Manitoba storage development

All storage development projects have risks from a geological and engineering perspective; these are typically managed by modeling the performance of a storage facility under a range of assumptions and having contingency plans for the associated range of outcomes. There may also be uncertainty regarding how existing surface and mineral rights may impact a potential storage project with respect to costs and development time. Storage development projects may also have to address regulatory risk and public acceptance risk, particularly in jurisdictions that do not already have storage facilities. Reliance on a single storage field may also present risk compared to non-site-specific storage offered by large storage operators that may be able to pool multiple storage fields to meet the non-coincident requirements of numerous storage customers.

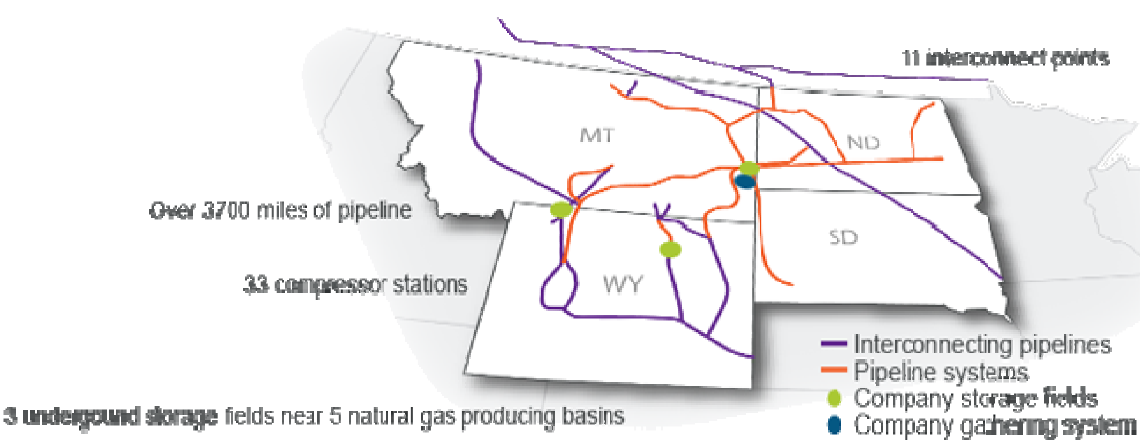
6) Timing Considerations of Manitoba storage development

The development of any technically and economically feasible Manitoba storage facility would likely take several years; as such, it is not anticipated that any such facility or facilities would figure significantly in Centra's portfolio for a number of years after 2013. Given the current uncertainty in the market, particularly with respect to TCPL, GLGT, emerging supply sources, and the demand for and value of storage in the marketplace, a prudent approach would be to continue to investigate Manitoba storage to gather sufficient information to position Centra to make a "go" or "no go" decision on Manitoba storage development under the appropriate market conditions.

6.3.4 Williston Basin

The Williston Basin Interstate Pipeline Co. (WBIP) is located in North and South Dakota, Montana, and Wyoming. It has access to supply as well as system storage. There are three storage fields on WBIP's system, which are operated in aggregate. These include the Baker field, which has very large capacity with very low deliverability. WBIP interconnects with Northern Border pipeline. Wyoming gas could conceivably be used to fill WBIP storage, with storage withdrawals flowing onto Northern Border and backhauled to Empress for delivery to Manitoba on the TCPL Mainline. Significant transportation, including on TCPL, would be required to accommodate WBIP storage withdrawals for the long distance to Manitoba on this path. A map of the WBIP is shown below as Figure 44.

Figure 44
Williston Basin Pipeline Map with Interconnections



6.3.5 Northern Natural Gas Pipeline Storage

As discussed in section 6.1.6, Northern Natural Gas (NNG) is a major U.S. pipeline that extends from Texas into Minnesota, Wisconsin, and the Michigan upper peninsula. (See Figure 41). NNG also operates 59 Bcf of firm storage services from its system, which has been sold out since 1997. Of the 59 Bcf, 53 Bcf is offered at cost-of-service rates, and 6 Bcf at market rates.

NNG storage could potentially be filled with purchases at the Ventura hub in Iowa, or with Canadian gas transported to NNG storage in Iowa. Storage withdrawals could potentially flow onto Viking or GLGT for backhaul.

6.3.6 Michigan Storage

The options for Michigan storage include renewing or modifying the current arrangements with ANR Pipeline in 2013 or replacing part or all of these with other arrangements from other storage providers including DTE/MichCon and Bluewater storage.

1) ANR Storage

ANR operates over 250 Bcf of FERC-regulated storage capacity in Michigan. Centra currently contracts for 15.5 PJ of capacity with deliverability of 208,591 GJ/day and an injection rate of up to 88,625 GJ/day. Centra delivers some gas into ANR storage from the Midwest and Gulf Coast on ANR, and some from the WCSB, via Emerson, Great Lakes and into the ANR system. Storage gas is redelivered via backhaul over Great Lakes to Emerson (See Figures 30 and 31 for the flows). Although ANR does not currently have additional storage capacity available, certain service attributes could potentially be modified, such as increasing winter deliverability or converting a portion of the existing seasonal storage to annual storage matched with summer transportation capacity from Michigan to Emerson on GLGT. The upstream transportation used to fill ANR storage could also be modified with respect to path and capacity, including consideration of the optimal mix of Canadian and U.S.-sourced gas and the potential to acquire gas at the ANR storage injection point.

2) DTE and MichCon Storage

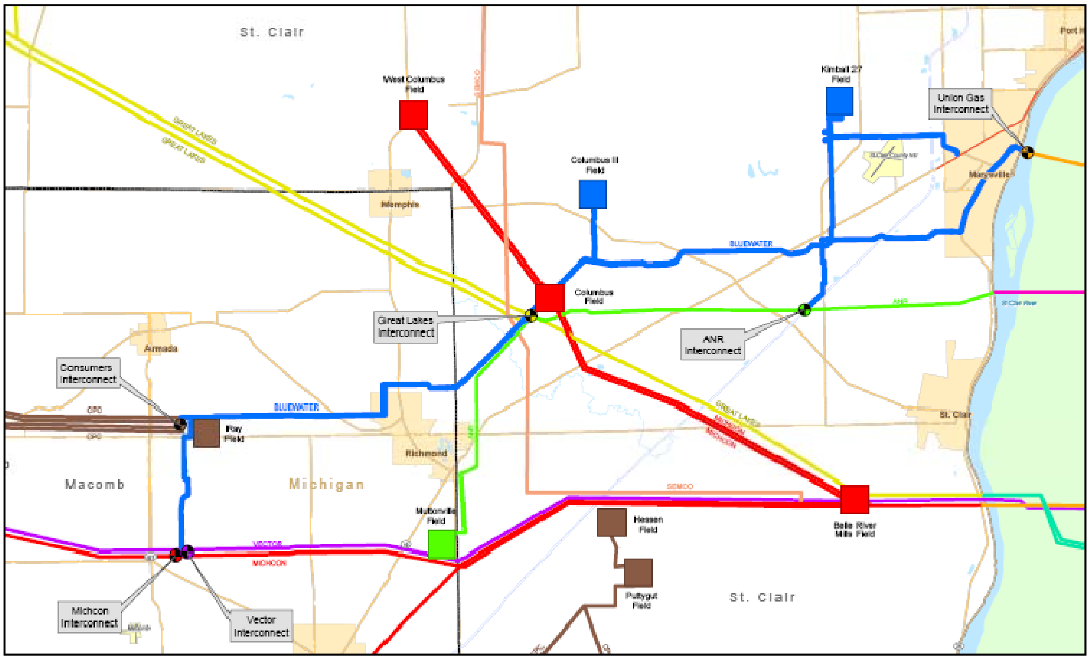
DTE Energy and its subsidiary MichCon operate over 220 Bcf of storage capacity in Michigan. Unlike ANR storage which is largely offered under its FERC-regulated tariff rates, DTE and MichCon offer storage services at market-based rates. MichCon is also a major LDC in Michigan, and reserves a portion of its storage to serve its 1.2 million utility customers. MichCon has interconnections with most of the major pipelines in the Michigan area, including Vector, GLGT, ANR, Union, and DTE’s Washington 10 storage complex (See Figure 45). MichCon storage could potentially be filled using these interconnecting pipelines, or through buying gas at the MichCon hub that would effectively be deemed in storage. Under their market-based rates, DTE and MichCon have considerable flexibility in providing negotiated, customized storage services. It currently appears that DTE and MichCon will have storage capacity available in 2013.

Figure 45
DTE and MichCon Gas Storage Facilities

3) Bluewater Gas Storage

The Bluewater Gas Storage facilities are located in eastern Michigan, where the Bluewater complex has 29 Bcf of working gas capacity. Bluewater has interconnections with Union Gas (Ontario), Vector, MichCon, ANR, and GLGT (Bluewater can receive gas from but not deliver to GLGT) (See Figure 46). The storage and transportation services are at market-based, negotiated rates. Bluewater is an indirect subsidiary of Plains All American Pipeline, L.P.

Figure 46
Bluewater Storage and Pipeline Interconnections



6.3.7 Ontario Storage

Ontario storage is accessible by Centra via backhaul on the TCPL Mainline, or via interconnections of Ontario storage operators into Michigan to transport gas on GLGT to Emerson. In the past, Ontario storage typically has not been economic relative to Michigan storage due to additional costs associated with transporting gas to and from Ontario storage.

However, given the significant growth in liquidity at the Union Dawn hub, gas could be acquired at Dawn for immediate injection into Union Gas storage, thus reducing or eliminating the need to hold upstream pipeline capacity to fill storage. For storage withdrawals, a TCPL Mainline backhaul from the Union Gas interconnect with TCPL at Parkway (near Toronto) to Manitoba could be utilized, requiring a long distance of transportation on TCPL. An alternative route would be to ship Dawn storage gas to GLGT in Michigan for transport to Emerson.

The Dawn Gateway Pipeline is a proposed pipeline that would connect the Dawn hub to MichCon's Belle River, an interconnect of MichCon, Vector, and GLGT in eastern Michigan. The pipeline is a joint partnership between DTE (parent of MichCon) and Spectra Energy (parent of Union) with a planned in-service date of November 2011 or November 2012, with initial capacity of 360,000 Dth/day that can be expanded. Although largely conceived to transport Michigan gas to Dawn, Dawn Gateway could potentially be used to transport gas from Dawn to GLGT via the Belle River interconnect.

6.3.8 Virtual Storage Services

The increasing importance of major natural gas marketers that hold a variety of natural gas midstream assets in different locations has enabled these types of companies to offer services that mimic storage and pipeline services, often at lower costs than a physical capacity solution. These companies use a combination of upstream and downstream assets, and upstream and downstream sources of supply and customers to optimize the value of the physical assets that they hold. These companies may be able to craft a service that mimics ANR storage, with deliveries at a specified point such as Emerson or the Centra citygate, at a cost lower than Centra could contract for directly. Should such a service be operationally viable, Centra will need to assess the value of the service against any risks that may be inherent in the service. While Centra may not want to rely too heavily on virtual services where Centra does not directly control the physical assets behind the service, the potential cost savings could be sufficient to justify contracting for this type of service for a portion of the Centra supply portfolio.

6.3.9 The No-Storage Portfolio

Earlier in this report (section 6.2), we identified eight roles that storage may play in an LDC's portfolio and specifically Centra's portfolio. With no storage, all of these benefits to Centra's portfolio would be lost. With the flexibility to nominate anywhere from 0 to 208,591 GJ/day, storage currently provides Centra with its largest tool to manage its considerable day-to-day and intra-day load variability in the winter months. Eliminating storage would suggest reliance on TCPL's STFT service from Empress to Manitoba in the five winter months, matched with the ability to acquire up to an additional 208,591 GJ/day (plus TCPL fuel) at Empress to serve the Manitoba market with the same capacity that is currently served by storage. At the current TCPL tolls, this amount of STFT capacity would cost about $21.4 million over a five-month period; at 2010 toll levels, the cost would be about $15.4 million.

In addition to this transportation cost uncertainty, Centra's balancing fees would be expected to increase without access to the STS 5 a.m. nomination cycle, which Centra currently uses for load balancing. TCPL balancing fees are charged as a percentage of the Mainline's Eastern Zone toll. Prior to the implementation of late-night STS nomination cycles, Centra experienced annual balancing fees of up to approximately $2 million per year at a time when the Eastern Zone toll level was less than half of what it is today. Centra's balancing fees in recent years have been in the order of $200,000 per year.

Along with the potential for considerably higher balancing fees due to the unavailability of the STS, Centra would need to acquire significantly more supply in the daily market (whether through swing contracts or daily open market purchases) throughout the winter to meet Manitoba market requirements, particularly on the coldest days of the winter - up to an additional 208,591 GJ/day to replicate Centra's current storage portfolio. Cost-effective swing services that provide full optionality to nominate gas supplies higher or lower at intra-day nomination cycles including at ID2 on weekends and holidays when markets are closed would be required for Centra to balance on the pipeline. (We note that weekends and holidays comprise approximately 30% of the days in a year. Even on regular business days, market liquidity drops significantly late in the afternoon at the ID2 nomination cycle.) If such increased volumes of swing services are not economically available, Centra would either have to accept increased commodity costs for swing services, or turn to daily open-market purchases in which Centra would be hard-pressed to meet its market requirements and would almost certainly face a significant increase in pipeline balancing fees.

6.4 Natural Gas Peaking Options

Perhaps the key characteristic of the Centra load is the extreme, short duration peaks in sendout requirements created by weather. Centra's peak sendout requirements are much higher than annual average load, resulting in the need for large amounts of capacity that may be used only a few days per year. While pipeline capacity and natural gas storage can be used to meet peaks in demand, utilities also use a variety of other options specifically designed to meet peak requirements on a few days each year.

Centra currently meets these peak requirements using ANR storage capacity in Michigan, as well as peaking services purchased from other customers on the TransCanada pipeline system. In addition to the storage options, which are described earlier in this report, and the existing peaking services contracted for by Centra, we have identified two other potential options for consideration. While our initial review suggests that the costs for these options will not be competitive with the existing peaking services available to Centra, the uncertainty related to the existing services dependent on the TransCanada Pipeline suggests that these options be kept on the table for consideration. These two new options include an LNG facility, and conversion of TCPL pipeline capacity to high deliverability storage. The three peaking service options are reviewed below.

6.4.1 Delivered Service

Peaking delivered service relies on other natural gas shippers on the TransCanada system willing to sell delivered natural gas at the Centra Citygate. These services are based on contracts between Centra and other parties that require the other party to deliver natural gas to Centra if and when called upon for up to a certain number of days over a specified period. This service allows Centra to meet peak period demands without holding additional capacity on TransCanada that is not used during most of the year.

The delivered service contracts typically are short term, and are dependent on the availability of TCPL capacity held by other parties. Given the changes in the TransCanada customer base, ICF is somewhat concerned about the availability and cost of future peaking service. If the amount of capacity under contract on TransCanada continues to decline over time, we would expect the opportunities to purchase peaking services will also decline, driving up costs for this type of option.

The cost of the service should be set primarily by the opportunity cost to the shipper, plus a premium to compensate the seller for accepting the contract performance risk of providing the firm delivery service. The opportunity cost to the shipper depends on a variety of factors including pipeline capacity holdings on TransCanada, storage capacity in different markets, and types of customers served.

Given the almost certain availability of excess pipeline capacity from the liquid market point at AECO, however, the risk associated with availability is likely to remain modest. Hence ICF anticipates that delivered peaking service will remain the cheapest option for reliably meeting peak period requirements for the foreseeable future. However, peaking service does not allow Centra to take advantage of the time arbitrage opportunities associated with natural gas storage, that is, purchasing gas at lower prices during off peak periods for use during peak periods when prices typically are significantly higher.

6.4.2 Liquefied Natural Gas Peaking Plant

An LNG liquefaction and peaking plant would provide a viable source of peaking capacity for the Centra system. The concept has been widely proven by LDC's in both the U.S. and Canada, as a means to minimize requirements for pipeline capacity to meet peak period loads. This issue with LNG is primarily one of cost.

Centra has not conducted the detailed engineering studies needed to fully evaluate the economics of an LNG peaking plant. Based on a review of costs of other recently built facilities, the annualized costs of an LNG facility likely would be more than competitive compared to low load factor use of annual TCPL FT capacity. However, the costs are not competitive with STFT capacity, or the peaking services currently available to and utilized by Centra.

6.4.3 TCPL Pipeline Capacity Conversion to High Deliverability Storage

One potential option for using underutilized pipeline capacity on the TransCanada pipeline system would be to convert a section to high deliverability storage. This storage capacity would hold only a few days of natural gas in storage, and would be ideally suited for a peak shaving application.

This option would entail isolating a link of existing TCPL pipe near the Centra citygate for use as storage. While the specific amount of pipeline that could be incorporated into the storage asset will depend on a physical assessment of the available pipe and compression capacity, a 500 kilometer section of 36 inch pipe could hold an estimated 320 Mmcf of deliverable natural gas, with a peak hourly deliverability of about 40 Mmcf, and a peak daily deliverability of about 160 Mmcf/day[18] (roughly 170,000 GJ/day).

This storage option could potentially be structured as a tariff service provided by TransCanada. While this option should be technically feasible, the economics of the

[18] Storage space increases in a linear relationship to the length of the pipeline used for storage. Peak hourly deliverability does not increase with the length of the pipeline used for storage, however additional pipe will increase the number of hours that peak deliverability can be maintained.

project are uncertain. Converting existing pipeline capacity to storage likely will require an increase in pressure rating for the pipe, which could require significant incremental investment to ensure pipeline integrity.

6.5 Other Portfolio Matters - WTS

The Western Transportation Service ("WTS"), first introduced in May 2000, was designed to allow Centra's end-use customers to purchase their Primary Gas supplies directly from third party broker/marketers other than the utility at contractually agreed-upon prices. Primary Gas is defined as those natural gas supplies that would otherwise be purchased by Centra under its Western Canadian commodity supply agreement(s) and transported on the TransCanada Mainline from the Alberta/Saskatchewan border to its Manitoba distribution system. From the inception of the WTS up until the present time, Primary Gas has made up the vast majority of the natural gas consumed by customers each year, typically greater than 90%.

Supplemental Gas on the other hand, are those supplies, over and above available Primary Gas supplies, required to fully serve customers' natural gas requirements. Supplemental Gas typically makes up a small percentage of the natural gas consumed by customers each year, normally less than 10%. Under the WTS Centra retains sole responsibility for serving customers' Supplemental Gas requirements.

If the results of Centra's comprehensive supply, storage and transportation portfolio review were to indicate that a greater diversification of supply basins, or purchasing the majority of its natural gas requirements from a basin other than the Western Canadian Sedimentary Basin is desirable, this could require changes to the nature and structure of how third-party natural gas marketers serve customers' commodity requirements in the Manitoba market under the WTS.

Submitted By:

ICF INTERNATIONAL

9300 Lee Highway

Fairfax, VA 22031

USA

(703) 218-2758

Contacts:

Bruce Henning

Michael Sloan

June 2011