Winter 2013/14 Natural Gas Price Review

Prepared for:

Ontario Energy Board

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Winter 2013/14 Natural Gas Price Review

Glossary

Checkpoint balancing	A balancing requirement on Union Gas' direct purchase customers requiring a particular minimum balance to be in a customer's Banked Gas Account as of the Winter Checkpoint Date of February 28.
Dawn, Ontario	The major gas market and storage center serving southwestern Ontario
Eastern Canada	A division used to account for storage locations in Canada, including the areas east of the Saskatchewan-Manitoba border
Eastern U.S.	A division used to account for storage locations in the U.S., including the states of the U.S. east of the Mississippi River, but including IA, MO, and NE and excluding AL and MS
Empress	The point at the Alberta-Saskatchewan border where the TCPL Mainline begins
Enbridge	Enbridge Gas Distribution, the gas distribution utility serving much of Toronto and environs
FT	Firm Transportation of natural gas under utility tariff from a receipt point to a delivery point for a specified maximum capacity for a term over one year
HDD	Heating Degree Days, a measure equal to the number of degrees that a day's average temperature is below 18 degrees Celsius
IT	Interruptible Transportation of natural gas under utility tariff providing for curtailment for capacity and/or supply reasons, at the utility's option
LDC	Local Distribution Company, a retail gas distribution utility
QRAM	The Quarterly Rate Adjustment Mechanism that allows Ontario's gas distribution utilities to recover their gas supply costs via customer rates
STFT	Short-Term Firm Transportation for a term between 7 days up to one year, with less flexible terms than FT
STS	Storage Transportation Service allows for injections and withdrawals at storage locations, held in conjunction with an FT contract
TCPL	TransCanada Pipeline, which includes the Mainline
U.S. Region-East North Central	The U.S. states MI, OH, IN, IL, WI
U.S. Region-East South Central	The U.S. states KY, TN, AL, MS
U.S. Region-Middle Atlantic	The U.S. states NY, NJ , PA
U.S. Region-Mountain	The U.S. states MT, ID, WY, CO, UT, NV, AZ, NM
U.S. Region-New England	The U.S. states ME, VT, NH, MA, CT, RI
U.S. Region-Northeast	The U.S. states in the Middle Atlantic and New England
U.S. Region-Pacific	The U.S. states WA, OR, CA

U.S. Region-South Atlantic	The U.S. states WV, MD, DE, VA, NC, SC, GA FL
UDC	Unabsorbed Demand Charges, reflecting a utility's costs for unutilized firm transport capacity
Union Gas	Union Gas, Ltd., the gas distribution utility serving northern Ontario and parts of southwest Ontario

1. Executive Summary

The Ontario Energy Board (Board) engaged Navigant Consulting to analyze the gas market events of last winter, focusing on the variables and factors that affected Ontario natural gas supply, demand and prices over the Winter 2013/14 period, and to identify potential prospective issues relative to such factors affecting prices.

Extreme winter conditions associated with last winter's polar vortex[1] events elevated natural gas demand throughout the U.S. and Ontario to record levels. As a result of dramatically elevated natural gas demand levels that occurred over an extended period of time and over a widespread geographic area, spot natural gas prices were elevated across most market points of North America for at least some period of the winter. Prices at the Dawn market hub were elevated mostly during February, with a few spikes in January and some residual price elevation in early March. These market conditions also set the stage for additional factors that further exacerbated Ontario gas prices

There were many events unfolding in real time last winter as market participants made decisions on planning and acquiring supply. The most important event was the cold weather, which was widespread, persistent, and extreme. Hindsight allows all the information to be seen at once. Following are the main conclusions about last winter's gas prices and the various events that contributed to them:

- Extreme winter conditions elevated natural gas demand throughout the U.S. and Ontario to record levels, leading to a tight gas market and setting the stage for additional factors that exacerbated the winter's price behavior.
- Strong Midwest demand impacted gas prices at Dawn and incented increased storage withdrawals to meet Ontario demand.
- Large storage withdrawals early necessitated large spot purchases later (which happened to be at high prices) as continued cold conditions led to persistent high demand.
- "Checkpoint" balancing by Union direct purchase customers, although an annual occurrence, coincided last winter with the on-going need to meet persistent high demand, exacerbating prices.
- Increased interruptible transport tolls appear to have limited the competitiveness of Empress as an economic source of supply, leading incremental gas for Ontario to be drawn from the Midwest and Northeast, further exacerbating Dawn prices
- The necessary conditions for last winter's price scenario appear to be the coincidence in both the U.S. and Canada of early, widespread and persistent high demand (resulting from the macro weather conditions).
- It is not clear whether the same weather conditions would have led to the same price impacts had supply plan requirements called for more base storage or increased firm transportation, but more storage and increased firm transportation may have helped.
- Similarly, supply plan requirements leading to more conservative use of storage withdrawals (and thus more supply procurement early in the winter) would likely have helped.

[1] "Polar vortex" refers to a type of event, one of which occurred from December 2013 through April 2014, where there is a southward shift of the North Polar Vortex, which is a cyclonic wind pattern in the upper atmosphere in the North Pole region.

Navigant also reviewed the drivers of the Quarterly Rate Adjustment Mechanism (QRAM), the provinces's mechanism to allow gas distributors to recover their actual gas costs. As the QRAM relates to actual gas supply costs, the drivers of the QRAM are essentially the factors that influence a gas distribution company's actual gas costs. Such factors that could potentially be impacted by operational, managerial and regulatory policies, procedures, directives and decisions of a gas distribution company or its regulator include the following: weather assumption design day criteria, demand forecasts, firm transportation planning criteria, storage level planning, use of peaking supplies, and procurement mechanisms for incremental supply. Choices made with respect to these factors likely involve cost and risk trade-offs dependent on an entity's risk profile and the array of potential risks.

2. Explanation of 2013/2014 Winter Price Levels and Volatility-

a. Introduction

It is important to remember that the Ontario natural gas market is part of the larger, highly-integrated and interconnected North American natural gas market, which is distinct in the world for its efficiency and transparency that allow for a highly competitive market environment. As such, the market will largely drive the particular impacts of events such as a cold winter based on supply and demand. As supply resources and the infrastructure necessary to move new supplies to demand centers continue to develop, we would expect that market responses to cold weather events would evolve, as well.

Extreme winter conditions associated with last winter's polar vortex events elevated natural gas demand throughout the U.S. and Ontario to record levels. As a result of dramatically elevated natural gas demand levels that occurred over an extended period of time and over a widespread geographic area, spot natural gas prices were elevated across most market points of North America for at least some period of the winter. Prices at the Dawn market hub were elevated mostly during February, with a few spikes in January and some residual price elevation in early March. These market conditions also set the stage for additional factors that further exacerbated Ontario gas prices, as explained in Section 2.e.

The key price effect in Ontario was the sustained and increasing price trend that occurred in February. Due to the higher actual prices paid than were forecast, and larger than forecast purchased gas supplies by Ontario's major gas Local Distribution Companies (LDCs), Union Gas and Enbridge, substantial dollars were reflected in the LDC's Quarterly Rate Adjustment Mechanism (QRAM) filings for Q2 of 2014. The QRAM is a mechanism to allow for cost recovery of actual gas supply costs through the combination of a forecast-based rate and a true-up component to account for past variances between actual costs and recovered costs at then-existing forecast-based rates.

- Union's filings indicate a total of C$134 million in costs above existing rates during the November-March period last winter, due to C$76 million in higher prices on Union's planned purchases plus $58 million in higher prices on spot purchases to meet increased demand.[2]

- Enbridge's filings indicate a total of C$643 million in costs above existing rates during the November-March period last winter, due to higher prices on planned purchases and incremental spot purchases.[3]

b. Weather

Ontario

Last winter's weather was characterized by extreme, persistent, and widespread cold. Union Gas reported that its franchise area was the coldest since its records began in 1969, with weather that was 15.5%, 16.5% and 18.4% colder than normal in November, December and January, respectively.[4] FIGURE 1 shows heating degree day (HDD)[5] data for three large cities covering the range of Ontario's more populous areas that were colder than any of the prior 10 years, as follows:

- Toronto: 11% colder than 2010/11 (coldest there in prior 10 years),
- London: 10% colder than 2010/11 (coldest there in prior 10 years), and
- Ottawa: 9% colder than 2010/11 (coldest there in prior 10 years).

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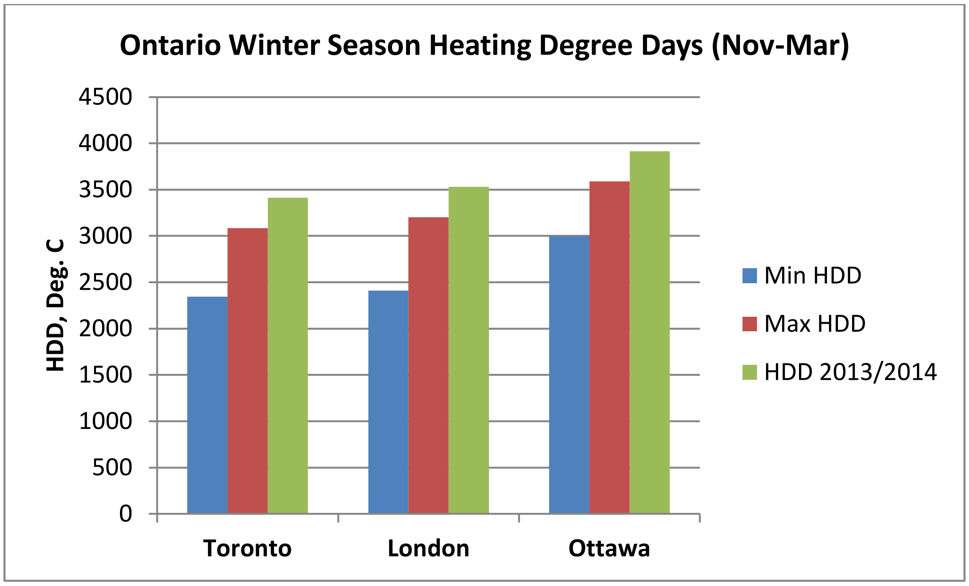
[2] See Union Gas Limited, April 1, 2014 QRAM Application (EB-2014-0050), Pre-Filed Evidence of Chris Shorts, Director, Gas Supply and Mary Evers, Manager, Gas Supply, (Tab 1, p.1), April 6, 2014.

[3] See Enbridge Gas Distribution Inc., Q2 2014 QRAM Application (EB-2014-0039), Gas Acquisition Costs Component of the Purchased Gas Variance Account, Ex. Q2-3, Tab 1, Schedule 2, p. 1 of 7), col. 6, items 8-12.

[4] Union QRAM filing, Tab 1, p. 15.

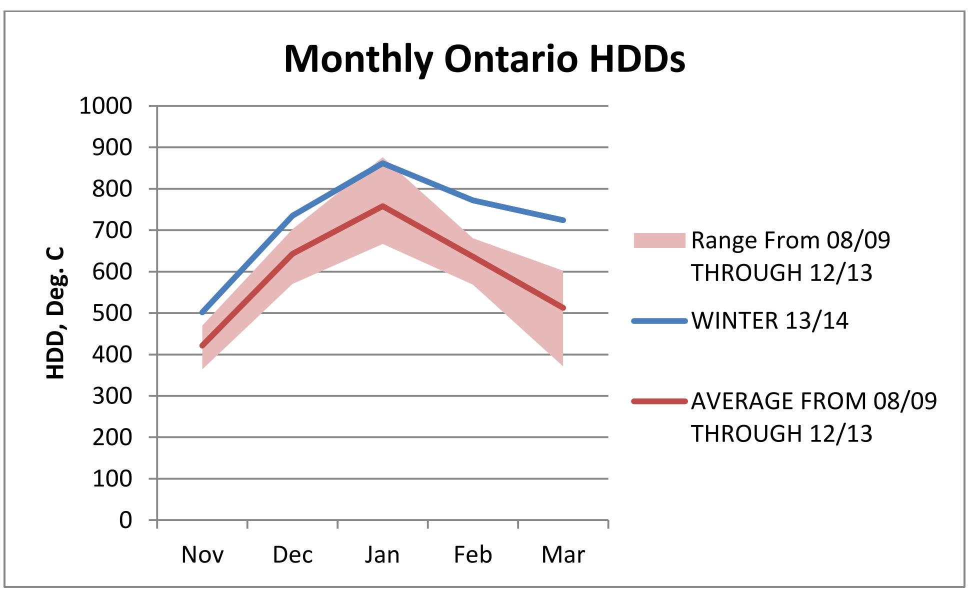
[5] Heating Degree Days is defined as the number of degrees by which a day's mean temperature was below 65 degrees Fahrenheit, or below 18.3 degrees Celsius. HDD's for a period of time is the sum of the HDD value for each day in the time period.



Source: Navigant/Aegent/Environment Canada

FIGURE 1: ONTARIO WINTER SEASON HEATING DEGREE DAYS

Confirming that last winter was persistently colder than normal in Ontario, FIGURE 2 shows that HDDs exceeded the prior 5-year maximum for virtually all of winter, with pronounced cold in February and early March. HDDs were 21.0% above average for the winter, starting the season at 19.2% above average during November and ending at 41.4% above average during March.



Source: Navigant/Aegent/Environment Canada

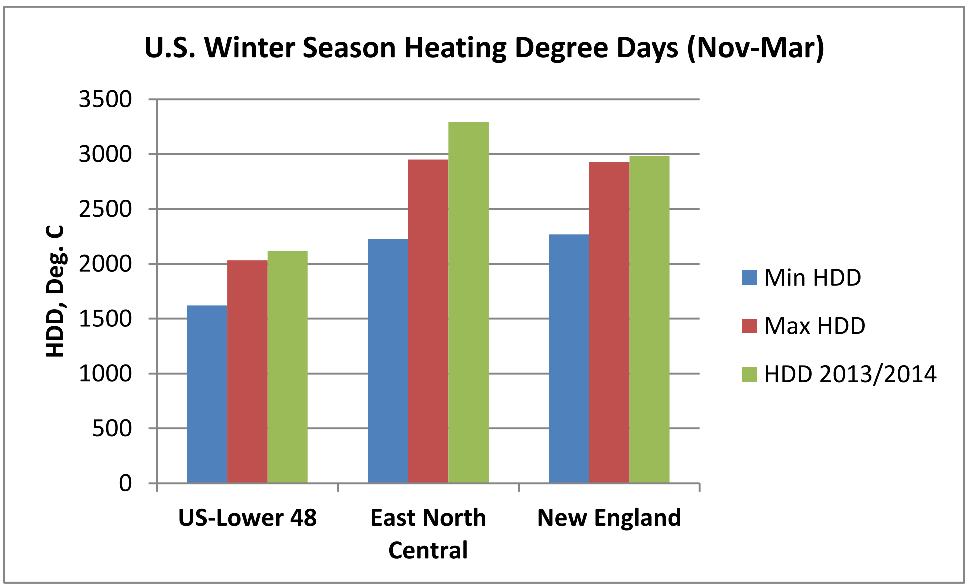
FIGURE 2: ONTARIO MONTHLY HEATING DEGREE DAYS

U.S.

In the U.S., the American Gas Association reported that last winter was the second coldest in 29 years across the U.S. as a whole, and that includes the fact that it was warmer than normal in the Pacific (composed of WA, OR and CA) and Mountain (composed of MT, ID, WY, CO, UT, NV, AZ and NM) regions that make up about one-third of the country.[6] The East North Central census region (ENC, composed of MI, OH, IN, IL, and WI) was the coldest in the 29 years reported. The East South Central (composed of KY, TN, AL and MS) and the South Atlantic (composed of WV, MD, DE, VA, NC, SC, GA and FL) regions were their second coldest, and New England (composed of ME, VT, NH, MA, CT and RI) and the Middle Atlantic (composed of NY, NJ and PA) were their third coldest in the 29 years.[7]

FIGURE 3 shows HDD data for three regions in comparison to the range for the prior 10 years, as follows:

- Lower 48: 4% colder than 2010/11 (coldest there in prior 10 years),
- East North Central: 12% colder than 2010/11 (coldest there in prior 10 years), and
- New England: 2% colder than 2004/05 (coldest there in prior 10 years).



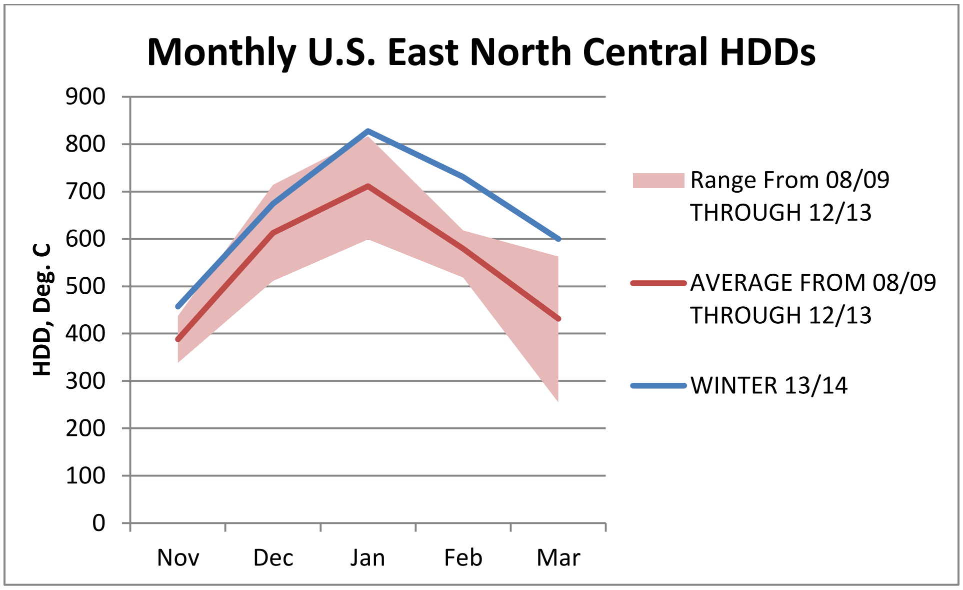
Source: Navigant/U.S. National Oceanic and Atmospheric Administration

FIGURE 3: U.S. WINTER SEASON HEATING DEGREE DAYS

As can be seen from FIGURE 4, the winter was persistently colder than normal in the U.S. In the East North Central region, where the more significant effects of the polar vortex were first felt, HDDs were 20.8% above average for the winter, starting the season at 17.8% above average during November and ending at 39.1% above average during March.

[6] "Promise Delivered: Planning, Preparation and Performance during the 2013-14 Winter Heating Season", American Gas Association, September 2014, Making the Statistical Case, p.9.

[7] Id.



Source: Navigant/U.S. National Oceanic and Atmospheric Administration

FIGURE 4: U.S. EAST NORTH CENTRAL MONTHLY HDDS

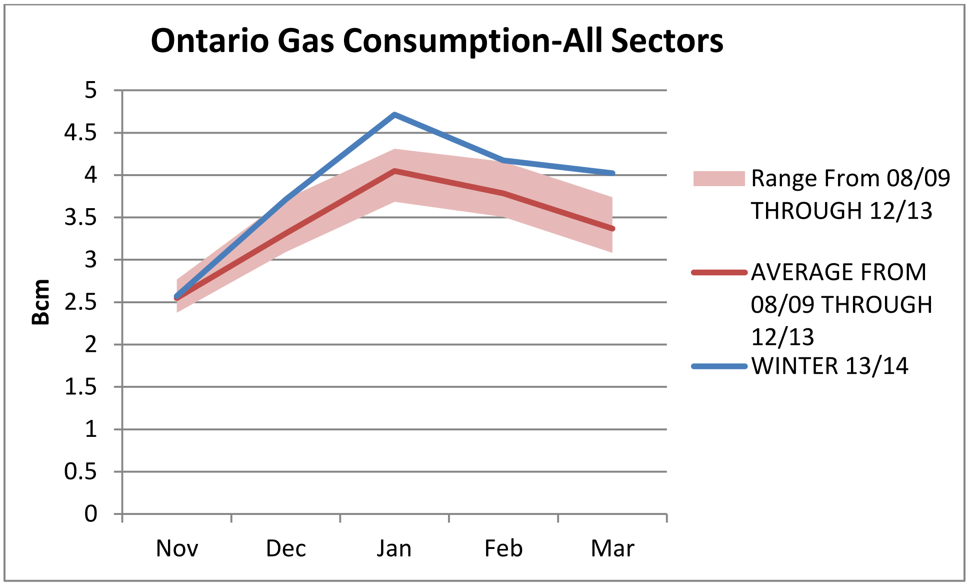
c. Demand

Ontario

In concert with the far-colder-than-normal weather data, natural gas demand was similarly noteworthy. Demand for the sum of residential, commercial and industrial customers and the electric generation sector, as well as for each sector individually, was above the 5-year average for each winter month, and particularly so as the winter progressed.

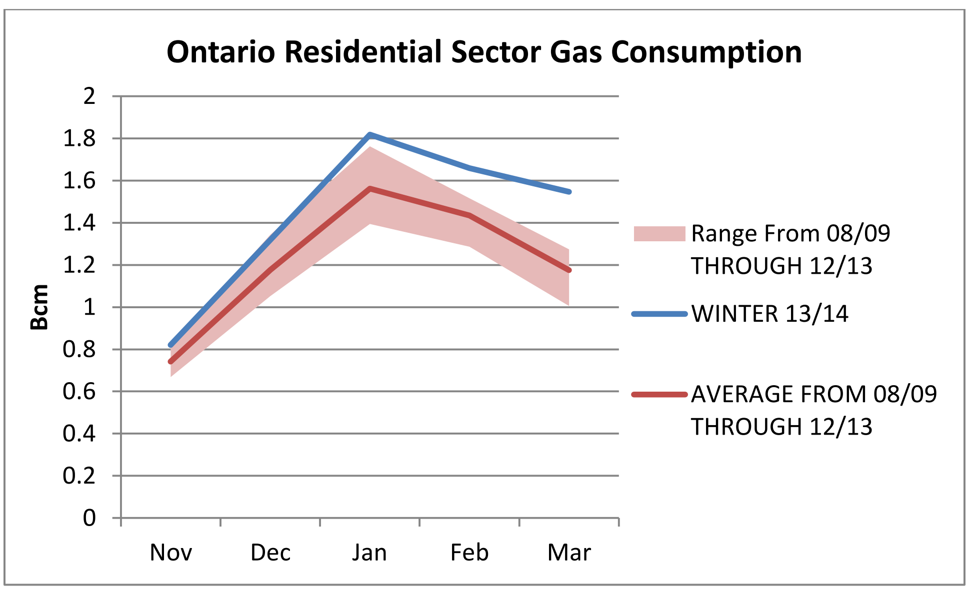
Total gas consumption was 12.5% higher than the season average for the prior five years, ranging from 0.9% greater in November to 19.3% greater in March. The residential sector was 17.6% higher than the season average, while the commercial sector was 19.4% higher and the industrial sector was 7.8% higher. The electric generation sector was 4% lower than the season average.[8] Demand trends can be seen in FIGURE 5 through FIGURE 9, and highlight the late winter season increases in residential and commercial sector consumption (versus historical averages) that correspond to the colder than average weather as shown in FIGURE 2, above.

[8] Gas consumption for electric generation was estimated from IESO data for gas-fired generation (in MWh), using an estimated heat rate of 8.0 MMBtu per MWh. At that heat rate, the 2013 gas-fired electric generation of 17.3 TWh would require 139 million MMBtu, or approximately 3.93 Bcm of natural gas. With the residential/commercial/industrial gas consumption for 2013 totaling 26.56 Bcm, the natural gas consumption for electric generation represented about 13% of total Ontario gas consumption for the year. While this share is expected to grow in the future, it is currently as low as it is because the 17.3 TWh of gas-fired generation represents only 11% of total Ontario electric generation (despite gas-fired capacity being 29% of total installed electric generation equipment in Ontario).



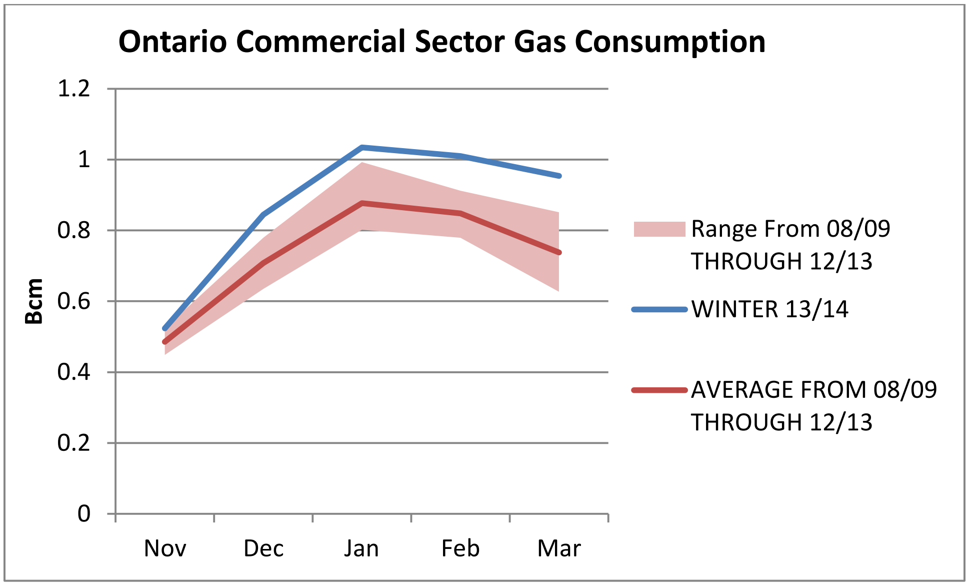
Source: Navigant/Statistics Canada

FIGURE 5: ONTARIO TOTAL GAS DEMAND



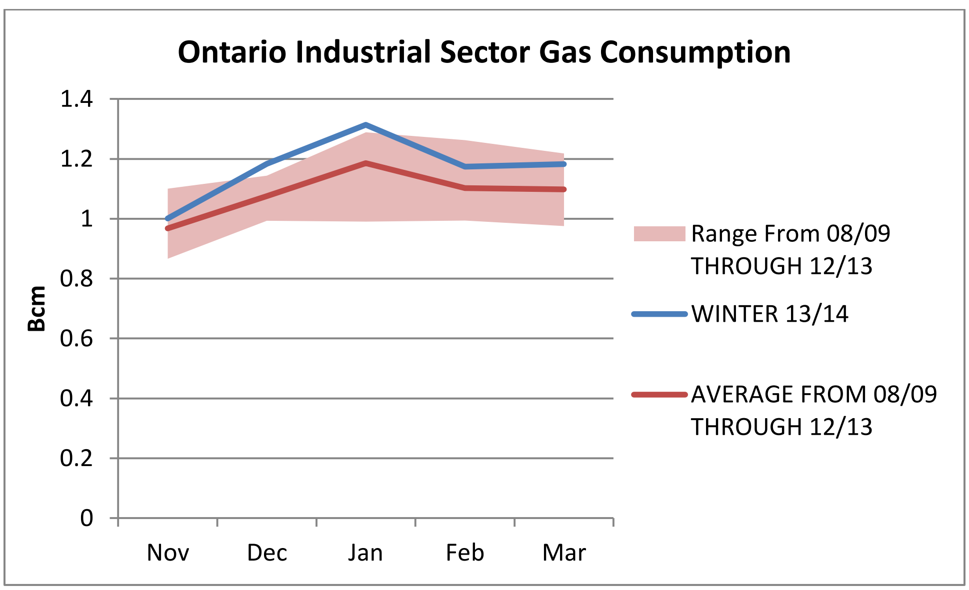
Source: Navigant/Statistics Canada

FIGURE 6: ONTARIO RESIDENTIAL GAS DEMAND



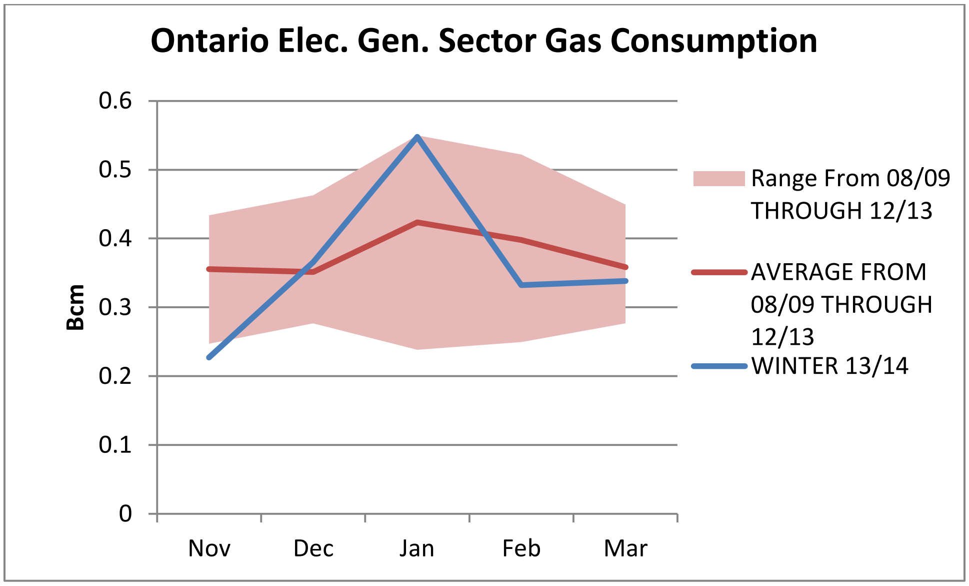
Source: Navigant/Statistics Canada

FIGURE 7: ONTARIO COMMERCIAL GAS DEMAND



Source: Navigant/Statistics Canada

FIGURE 8: ONTARIO INDUSTRIAL GAS DEMAND



Source: Navigant/Ontario Independent Electric System Operator

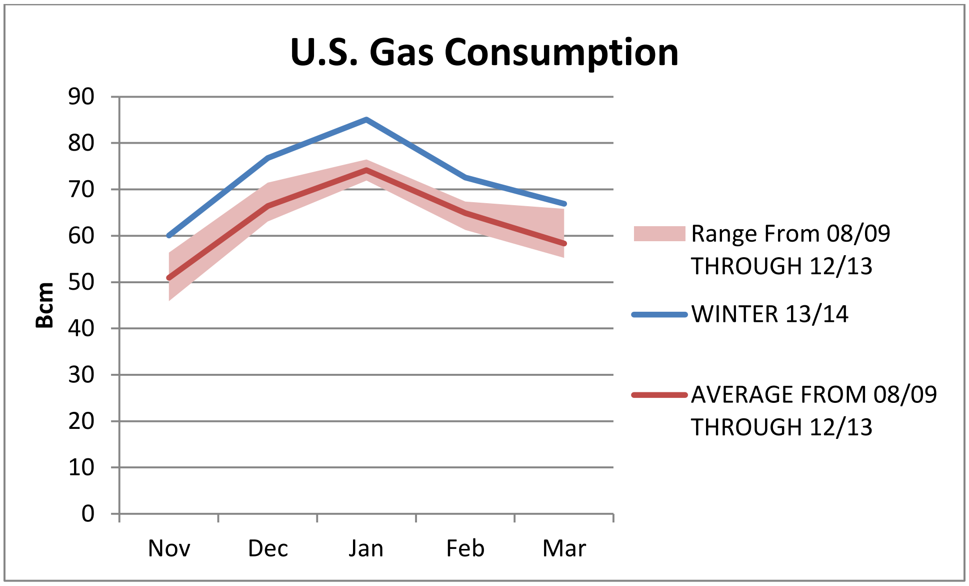
FIGURE 9: ONTARIO ELECTRIC GENERATION GAS DEMAND

Monthly total gas demands last winter exceeded the maximum monthly demands, over the prior five years from January through March, and was only 0.2% below the December maximum. The residential sector exceeded four of the five winter month maximums, and exceeded the monthly maximums for the season by an average of 6.5%. The commercial sector also exceeded four of the five winter month maximums, and exceeded the monthly maximums for the season by an average of 7.0%. Monthly industrial demands slightly exceeded prior maximums for December and January, but overall trailed the maximums for the season by about 2.7%. While industrial demand was still above average in February and March, unlike the residential and commercial sectors it did exhibit a decrease versus its trend above prior maximums, indicating some possible responsiveness to the increasing level of prices, as opposed to the more temperature-sensitive residential and commercial sectors. In addition, interruptible customers, who may lose service in extreme conditions, are generally drawn from the industrial sector.

A specific additional factor that influenced the market through its impacts on demand was the requirement of Union Gas direct purchase customers to meet a "checkpoint" balancing requirement at the end of February. This tariff-based requirement had the effect of increasing the demand in the spot market by a significant amount in a short period of time. The checkpoint balancing requirement will be discussed more in Section 2.e.

U.S.

Monthly demands were higher than the averages of the prior 5 years every month in the US, with the total gas consumption for the winter season being 14.8% higher than average. As can be seen in FIGURE 10, monthly demands each month last winter even exceeded the maximum monthly demands over the prior five years in every month, by an average of 6.9% above the prior monthly maximums.

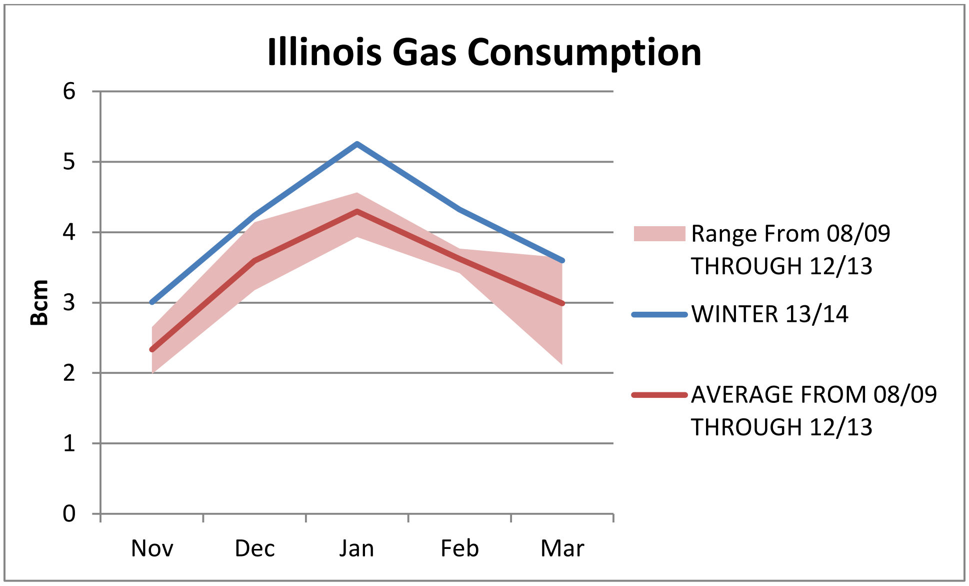


Source: Navigant/U.S. Energy Information Administration

FIGURE 10: U.S. GAS DEMAND

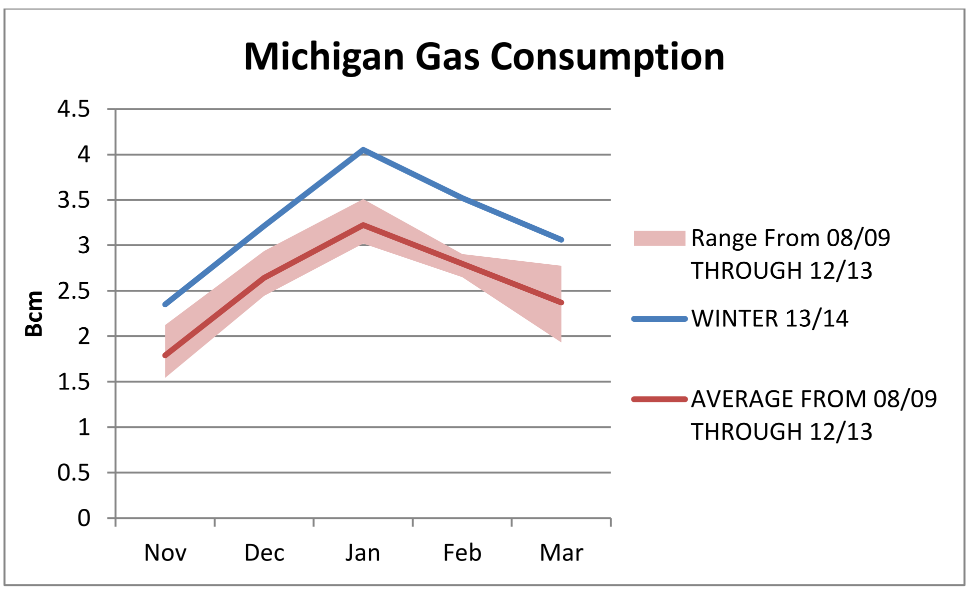
To complete the picture of U.S. demand with a focus on markets close to Ontario, we look briefly at Illinois (home to the Chicago market hub) and Michigan (directly tied in to Ontario infrastructure at Sarnia and Windsor). Illinois and Michigan had particularly strong demands, as shown in FIGURE 11 and FIGURE 12. Illinois monthly demands exceeded the averages of the prior 5 years every month, with the seasonal total gas consumptions being 21.3% above average and the highest percent increase being 29% above average in November. Michigan monthly demands exceeded the averages of the 5 prior years every month, with the seasonal total gas consumptions being 26.2% above average and the highest percent increase being 31.1% above average in November.

Illinois monthly demands exceeded the maximum monthly demands in four out of five months over the prior five years, by an average of 8.9% above the prior monthly maximums. For Michigan, the monthly demands exceeded the prior 5-year monthly maximums every month of the season, by an average of 13.3%.



Source: Navigant/U.S. Energy Information Administration

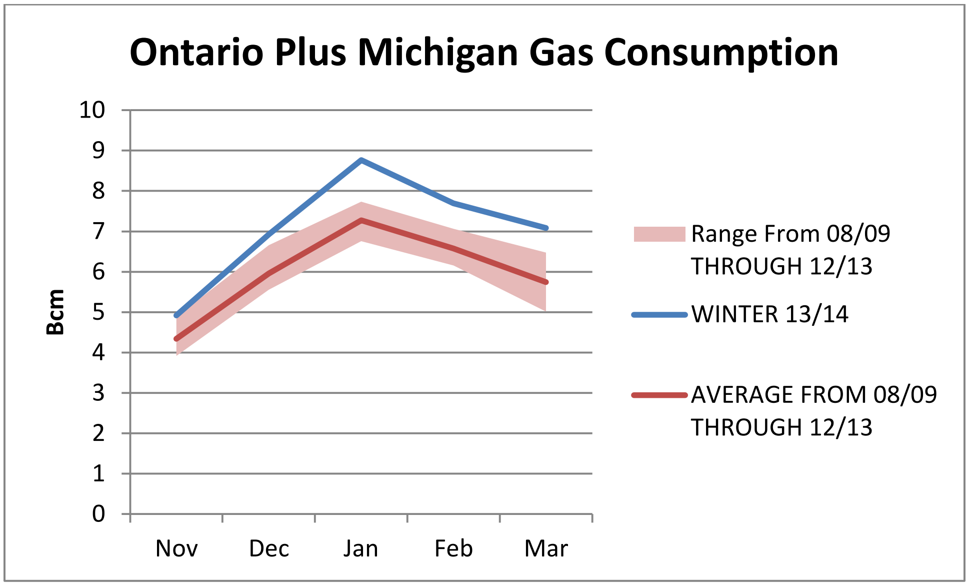
FIGURE 11: ILLINOIS GAS DEMAND



Source: Navigant/U.S. Energy Information Administration

FIGURE 12: MICHIGAN GAS DEMAND

Looking at combined Michigan and Ontario demand raises the Ontario seasonal demand percentages from 12.5% above average to 18.4% above average (for the combined demands), and maximum monthly demands from 2.0% above prior 5-year maximums to 7.2% above prior 5-year maximums, as can be seen in FIGURE 13. Looking at the combined loads for the interconnected Michigan and Ontario markets shows how the high early season demand in Michigan could have strengthened perceived demand in Ontario at that time

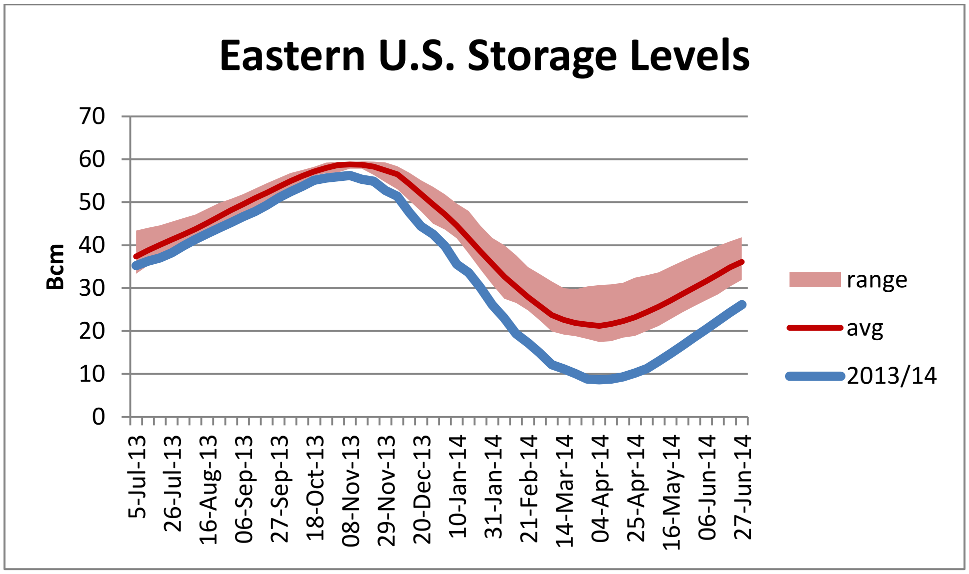


Source: Navigant/U.S. Energy Information Administration/Statistics Canada

FIGURE 13: ONTARIO PLUS MICHIGAN GAS DEMAND

d. Supply

As early winter season impacts were felt in the U.S. before Canada, we will briefly summarize the Eastern U.S. storage conditions. As shown in FIGURE 14, storage levels were already below the bottom of the prior 5-year range in October after an injection season (i.e. additions into storage) that appears to have been a bit behind average and to have started to flag a bit early. At the start of November, inventories were at 95% of average levels for the time, perhaps as a reaction to several recent warmer winters. By the end of December, much-higher-than normal gas demands had already dropped Eastern U.S. storage levels to 14% below normal levels for the time, at 73% of the average November 1 inventory level (i.e. 42.5 Bcm) versus 84% of the average level (i.e. 49.5 Bcm). The continuing and increasingly cold weather kept up the much-higher-than-normal gas demands into January and then through the rest of the winter, leading to Eastern U.S. storage levels at the end of January being 28% below average levels for the time, at 44% versus 61% of the average November 1 inventory level. These figures are summarized in TABLE 1.



Source: Navigant/U.S. Energy Information Administration

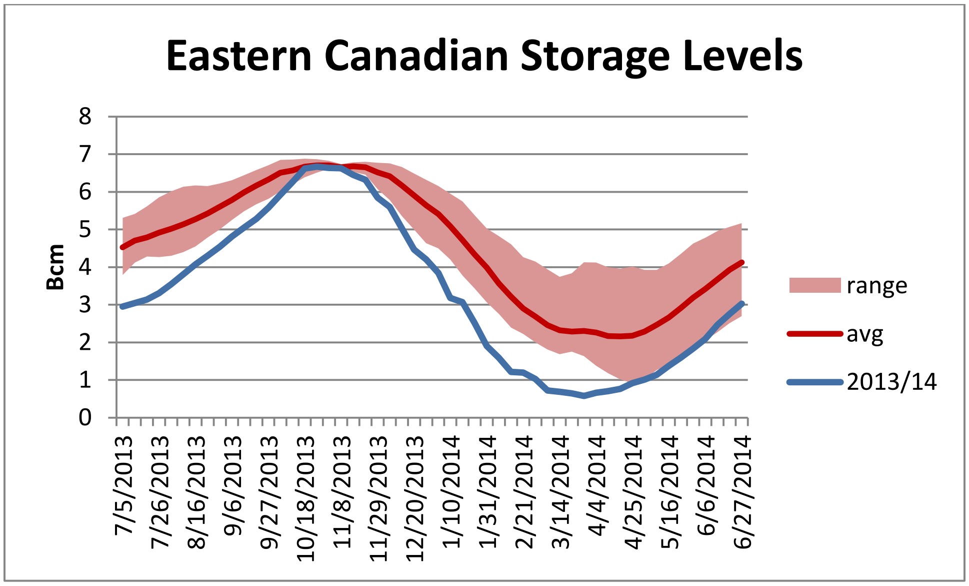
FIGURE 14: EASTERN U.S. GAS STORAGE LEVELS

TABLE 1: SUMMARY OF MONTHLY U.S. GAS STORAGE ACTIVITY AND METRICS

Date	Average Storage Level (Bcm)	2013/14 Storage Level (Bcm)	Average Withdrawal for Month (Bcm)	2013/14 Withdrawal for Month (Bcm)	2013/14 withdrawals as percent of normal withdrawals	Avg. Year Percent of Avg. Nov. 1	2013/14 Percent of Avg. Nov 1
11/1/2013	58.6	55.9				100%	95%
11/29/2013	57.4	52.7	1.2	3.2	265%	98%	90%
12/27/2013	49.5	42.5	8.0	10.2	128%	84%	73%
1/31/2014	35.6	26.1	13.9	16.5	118%	61%	44%
2/28/2014	25.8	14.9	9.7	11.2	115%	44%	25%
3/28/2014	21.5	8.8	4.3	6.1	141%	37%	15%

Source: Navigant/U.S. Energy Information Administration

Eastern Canadian storage inventories quickly dropped even farther below average during the winter, as shown in FIGURE 15. By the end of December, much-higher-than normal gas demands had already dropped Eastern Canadian storage levels to 26% below average levels for the time, at 63% of the average November 1 inventory level (i.e. 4.2 Bcm) versus 84% of the average level (i.e. 5.6 Bcm), as presented in TABLE 2.



Source: Navigant/Enerdata

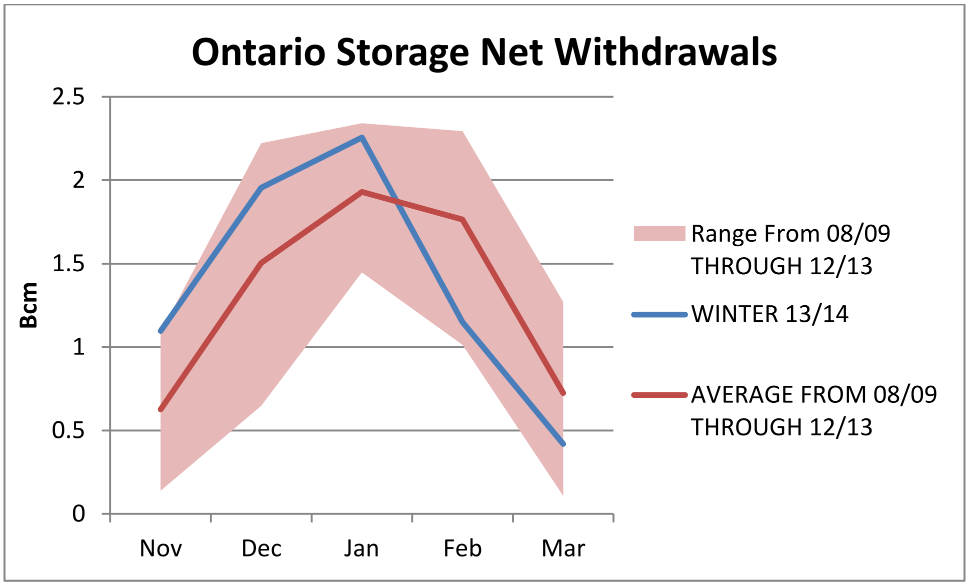
FIGURE 15: EASTERN CANADIAN GAS STORAGE LEVELS

TABLE 2: SUMMARY OF EASTERN CANADIAN MONTHLY GAS STORAGE ACTIVITY AND METRICS

Date	Average Storage Level (Bcm)	2013/14 Storage Level (Bcm)	Average Withdrawal for Month (Bcm)	2013/14 Withdrawal for Month (Bcm)	2013/14 withdrawals as percent of normal withdrawals	Avg. Year Percent of Avg. Nov. 1	2013/14 Percent of Avg. Nov 1
11/1/2013	6.7	6.6				100%	99%
11/29/2013	6.5	5.8	0.2	0.8	427%	97%	87%
12/27/2013	5.6	4.2	0.9	1.6	188%	84%	63%
1/31/2014	4.0	1.9	1.7	2.3	139%	59%	28%
2/28/2014	2.7	1.0	1.3	0.9	68%	40%	15%
3/28/2014	2.3	0.6	0.4	0.4	115%	34%	9%

Source: Navigant/Enerdata

Net storage withdrawals in Eastern Canada in November through January were well above normal, exceeding the average withdrawals, for those months (totaling 2.7 Bcm) by 2.0 Bcm, or 74%. After three months of heavy decreases in storage inventories, levels were less than half of average for the time (at 28% versus 59% of average inventories at the start of November), and were not sufficient for storage to effectively meet continued high demands in February. Due to the low storage inventories, February net withdrawals were less than 70% of normal for the month (as shown in FIGURE 16), despite the fact that Ontario gas demand in February was 13.5% above normal.

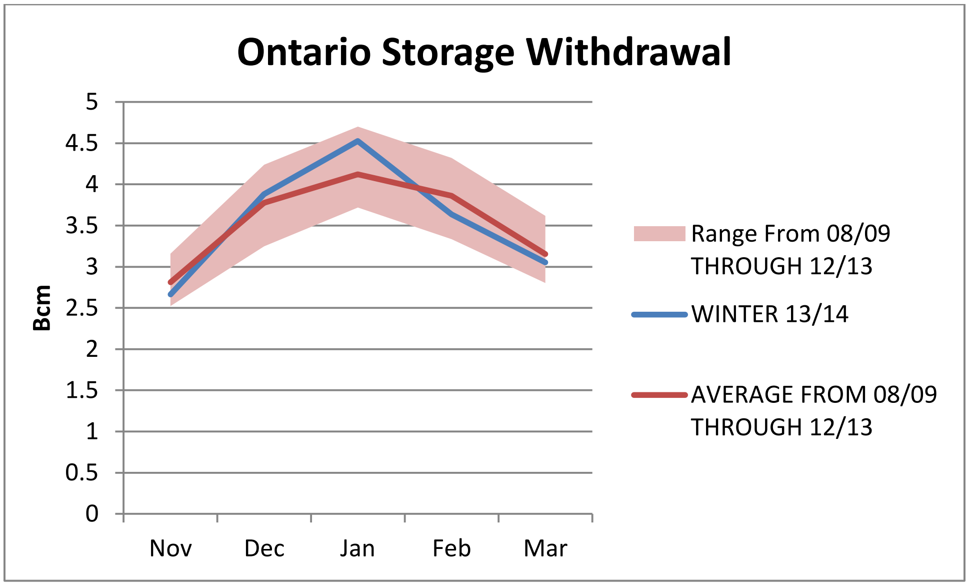


Source: Navigant/Statistics Canada

FIGURE 16: ONTARIO STORAGE WITHDRAWALS (NET)

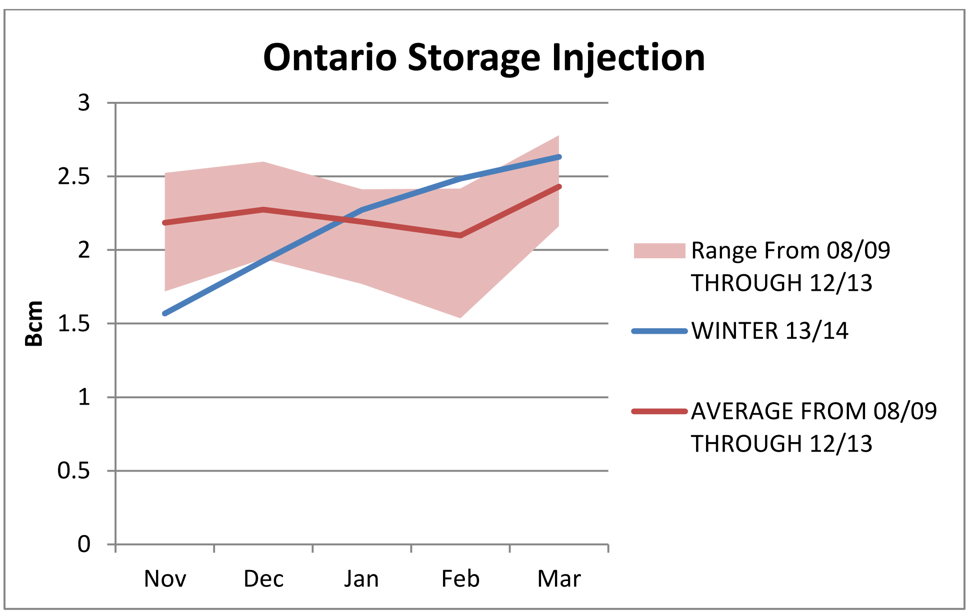
Looking at withdrawals from storage and injections into storage separately, data shows that the November and December withdrawals were about average (shown in FIGURE 17), but that injections were below average (shown in FIGURE 18), resulting in large net withdrawals. These successive large net withdrawals, combined with a large withdrawal in January, led to the steep and continued drop in overall storage inventories as the cold winter conditions persisted.[9]

[9] Note that the storage inventories shown in FIGURE 15 and TABLE 2 reflect total physical inventory levels, which should be heavily driven by LDC actions, but not entirely driven to the extent that LDC contractual rights to storage are less than overall storage rights.



Source: Navigant/Statistics Canada

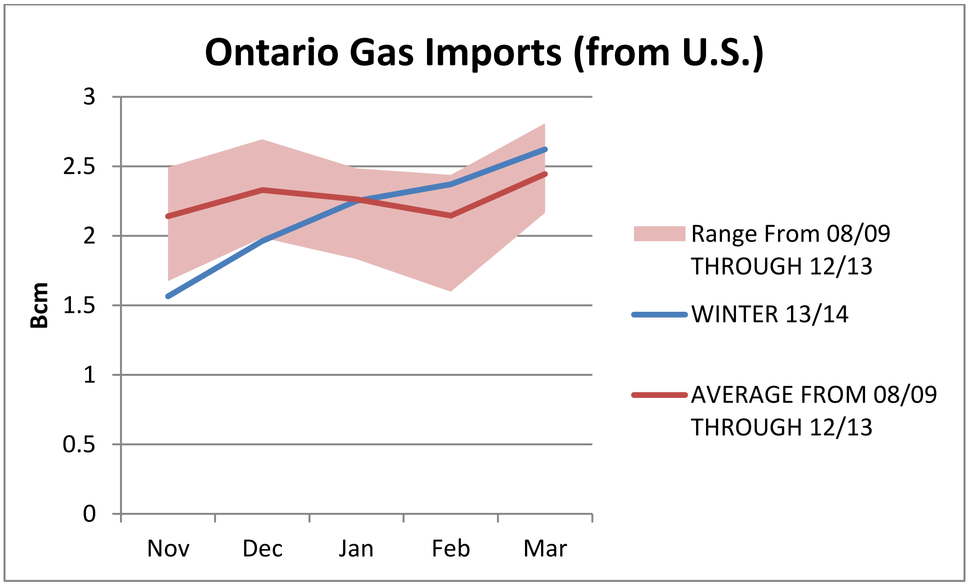
FIGURE 17: ONTARIO STORAGE WITHDRAWALS



Source: Navigant/Statistics Canada

FIGURE 18: ONTARIO STORAGE INJECTIONS

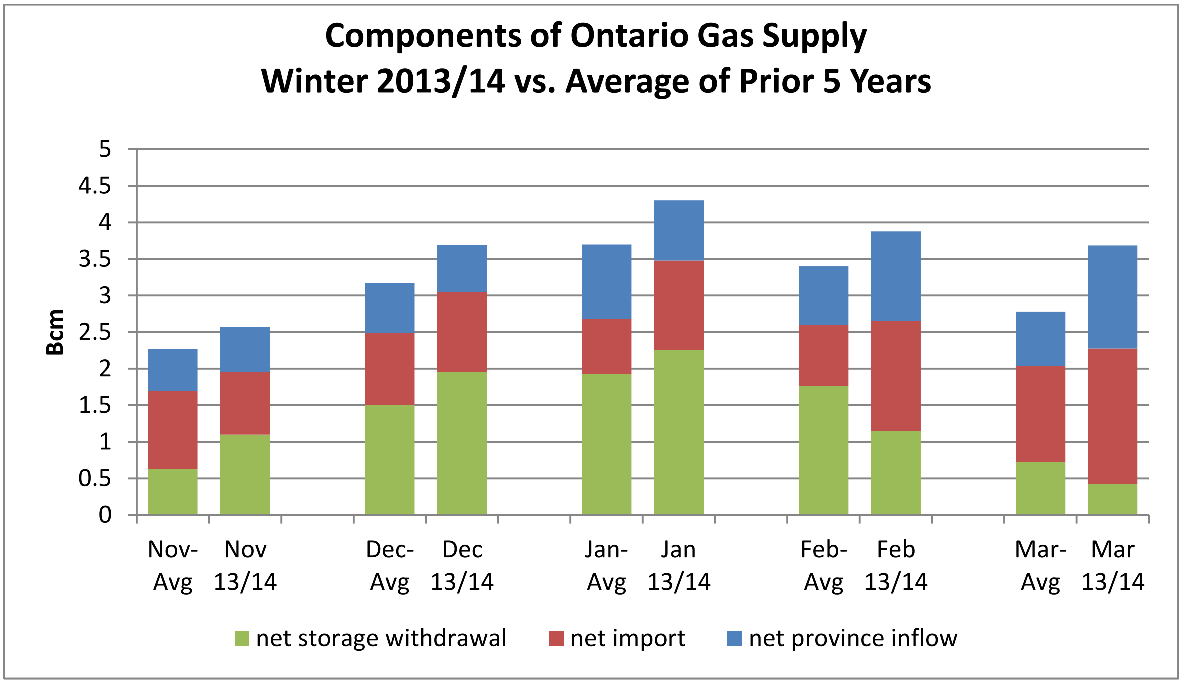
Consistent with net Eastern Canadian storage withdrawals being large early in the winter (as the main source of supply to meet demands) is FIGURE 19 showing imports of gas into Ontario from the U.S. being well below normal in November and December, and only returning to average levels in January.



Source: Navigant/Statistics Canada

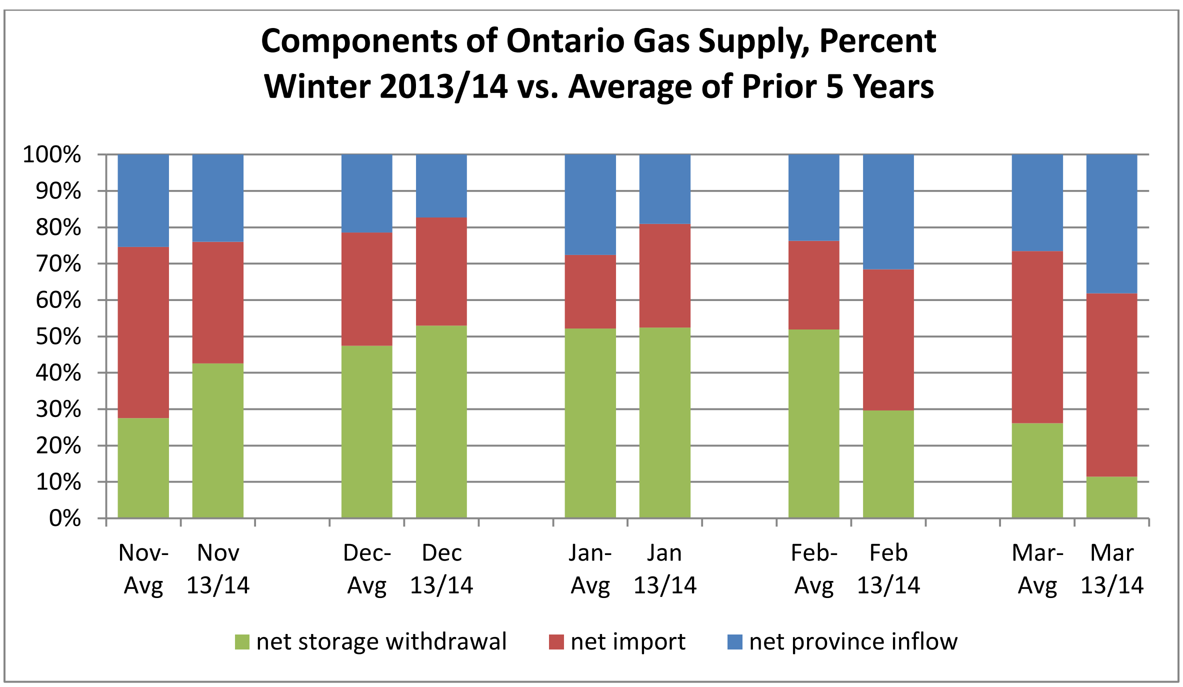
FIGURE 19: ONTARIO IMPORTS (FROM U.S.)

In order to meet a large demand in February, without sufficient gas in local storage, LDCs had to meet their gas demand requirements through additional procurement. As indicated to us by Enbridge, with storage down and their long-haul transportation (from the U.S. or Canada) already filled, they had to buy at Dawn. The data indicates that gas imports into Ontario from the U.S. continued to increase beyond average levels at this time, as can be seen in FIGURE 19, above. FIGURE 20 summarizes the components of gas supply for Ontario last winter versus the average of the prior five years. As can be seen, the total volume of purchases, composed of net imports from the U.S. plus the inflow from Alberta net of outflow to Quebec, but not including storage withdrawals, in February was significantly greater than average, at about 2.7Bcmversus 1.6Bcm. FIGURE 21 shows the components of gas supply for Ontario on a percentage basis.



Source: Navigant/Statistics Canada

FIGURE 20: COMPONENTS OF ONTARIO GAS SUPPLY

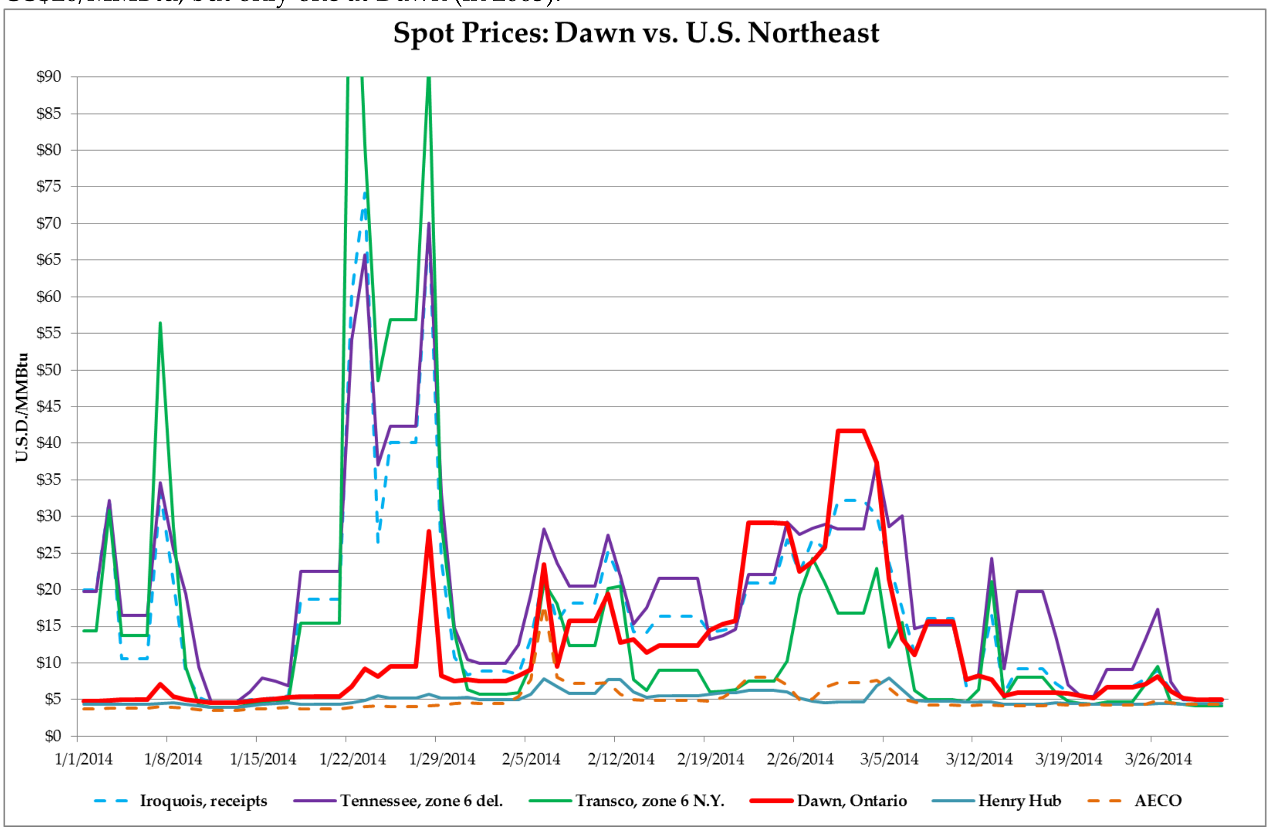


Source: Navigant/Statistics Canada

FIGURE 21: COMPONENTS OF ONTARIO GAS SUPPLY-PERCENT

e. Price Behavior

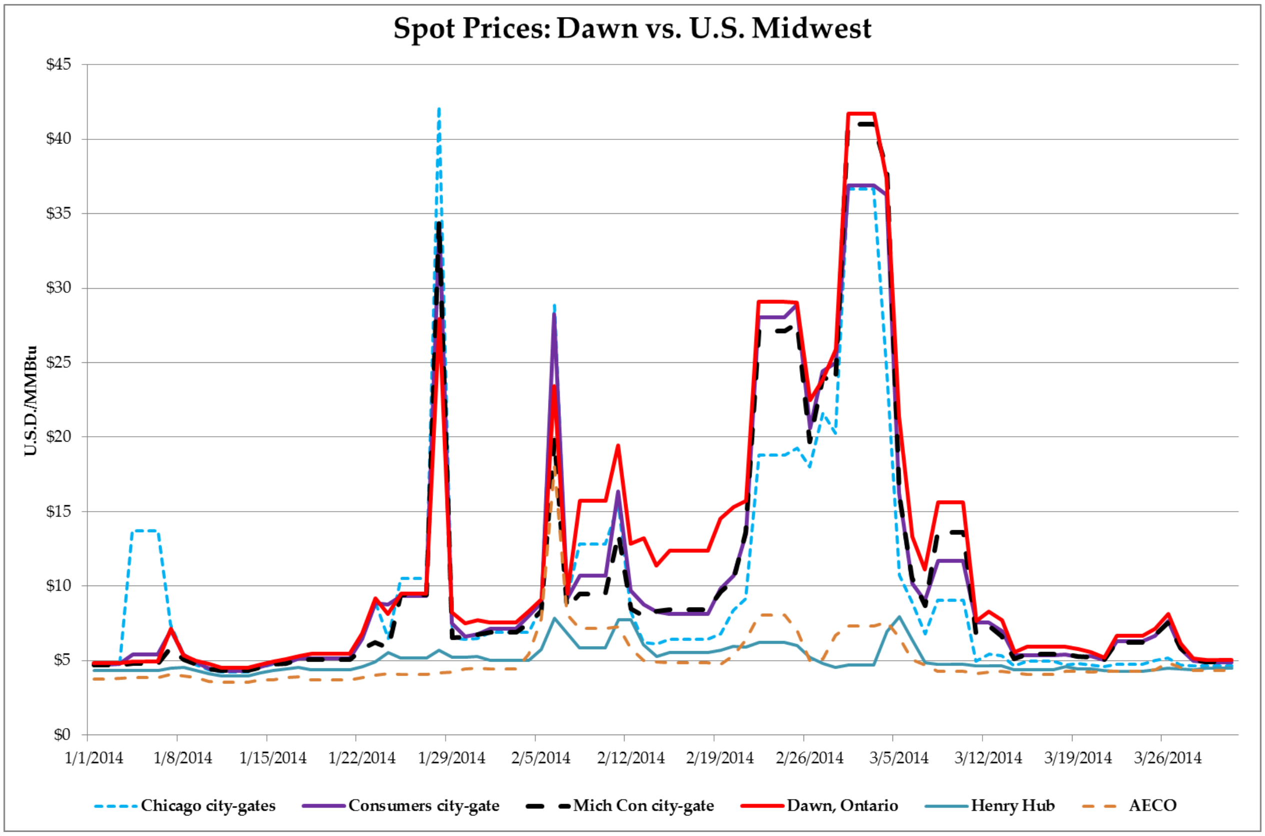
Spot prices were elevated across most market points of North America for at least some period of the winter. The Northeast, as usual, experienced the largest price spikes in the U.S.. As indicated in FIGURE 22, prices in New York reached over US$120/MMBtu in late January, while the Dawn price spike at about that time (the first of the winter, on January 28) was to just under US$30/MMBtu. Regarding volatile market behavior indicative of peak day type events, it is a relatively normal occurrence in the Northeast (although usually with prices not going much above US$40/MMBtu), and much less normal at Dawn. In the prior 16 years going back through 1998, there were eight events where Northeast gas prices reached US$20/MMBtu, but only one at Dawn (in 2003).



Source: Navigant/Platts

FIGURE 22: SPOT PRICES: DAWN VS. U.S. NORTHEAST

The particular January 28 price spike at Dawn can be put into context by looking at the relationships between Dawn prices and prices in the U.S. Midwest. FIGURE 23 shows the same Dawn price series, but compared to citygate prices at Chicago and in Michigan. What can be seen is that on the same day there were also price spikes at the U.S. Midwest citygates, but reaching higher, to above US$30 and US$40 per MMBtu, which was counter to the historical relationship to Dawn. There was a similar, but more modest, Chicago price spike event in early January, from the 4th to 6th. These events may relate to anecdotal information from Union Gas that competition for Dawn gas from the Chicago market could have had a role in driving early season Ontario demand to be met in large part from storage rather than from purchases. The fact that the spikes were larger in the U.S. Midwest than at Dawn would seem to indicate that the dynamic originated in the U.S., with some attenuated affect in Ontario.



Source: Navigant/Platts

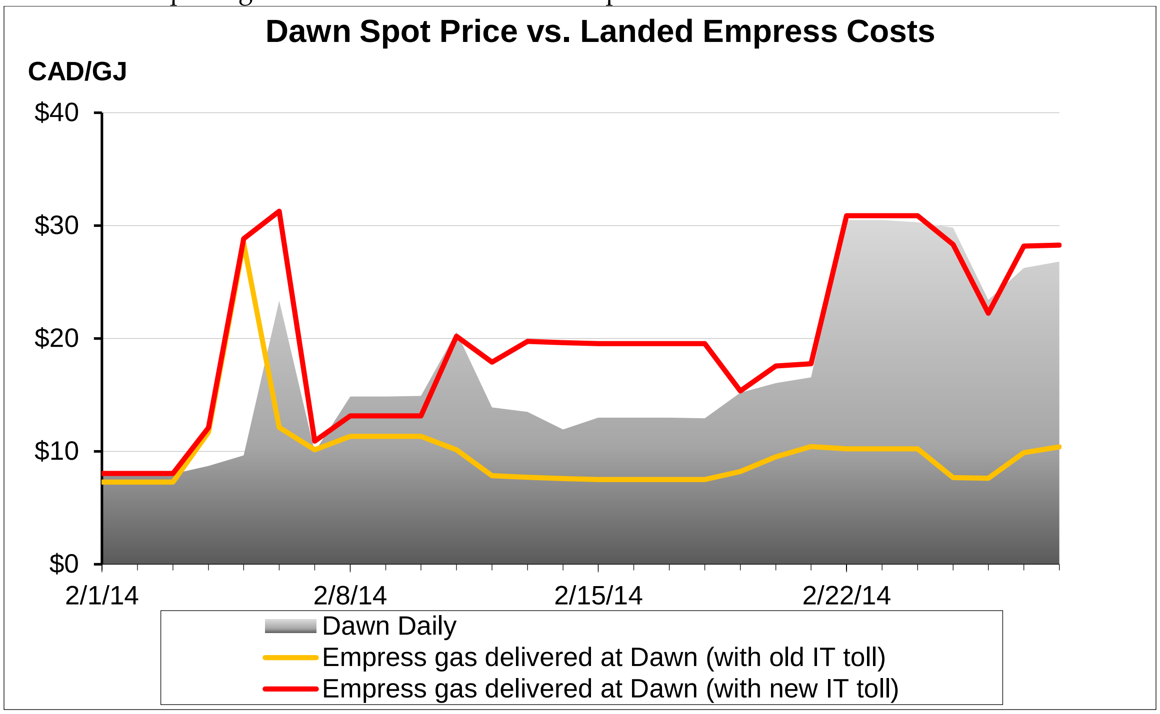
FIGURE 23: SPOT PRICES: DAWN VS. U.S. MIDWEST

Perhaps the most interesting developments with regard to Dawn prices occurred in February, which saw a relatively steady increase in price level over the course of the month from under US$8/MMBtu to over US$40/MMBtu on March 1. Factors that contributed to these price levels include those already outlined, such as the persistence of widespread cold weather creating record gas demands, and large cumulative storage withdrawals during November through January leading to lower gas inventories in storage and thus to greater spot purchases in February, as well as several additional items.

The first additional factor relates to the rates set by TransCanada PipeLine (TCPL) to move gas from Empress to Dawn on TCPL. Winter 2013/14 was the first in which TCPL had the ability to set interruptible (IT) and short-term firm transportation (STFT) tolls at their discretion, pursuant to the NEB's decision in TransCanada's application to restructure its Mainline ratemaking.[10] The NEB decision included changes to the IT/STFT rate structure as a way for TCPL to improve cost recovery on its Mainline by incentivizing the purchase of long term firm transportation (FT) versus IT/STFT. By

[10] RH-003-2011, Application for Business and Services Restructuring Proposal and 2012 & 2013 Mainline Final Tolls.

increasing the minimum IT/STFT bid toll, TCPL effectively increased the cost of incremental gas from Alberta in Ontario. As shown in FIGURE 24, with respect to February, the landed price of Empress gas at Dawn, based on the new higher IT tolls with a bid floor that averaged C$11.97/GJ, was at or above the actual Dawn prices on all but five days in the month. On the other hand, assuming the prior level of IT toll bid floor of C$2.08/GJ, the landed price of Empress gas at Dawn would have been below the actual Dawn prices on all but three days in the month. The higher IT tolls meant that spot Empress gas was uneconomic in the Dawn market, with other supplies on the margin, as prices were ultimately higher than what Empress gas would have cost under the prior bid floor.

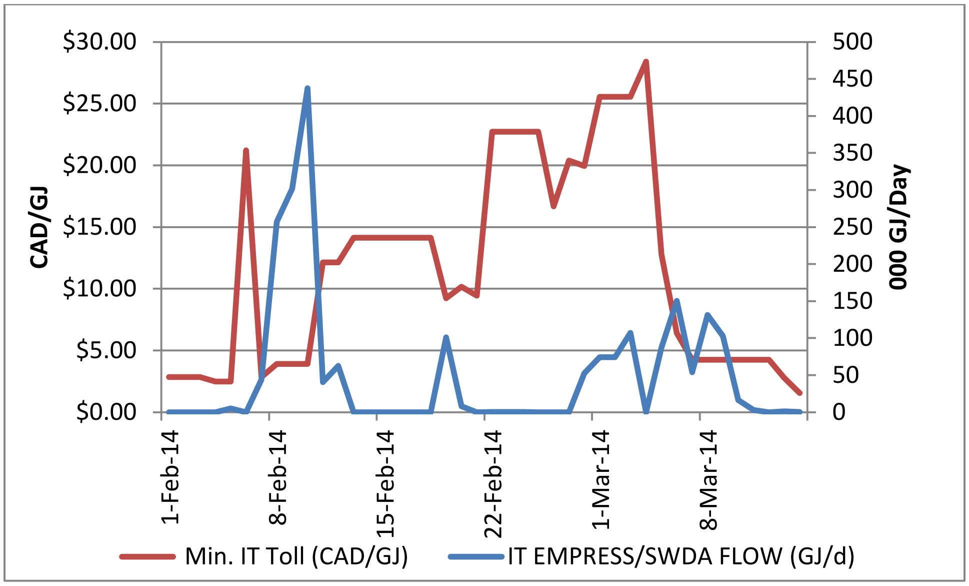


Source: Aegent/CGPR/TCPL

FIGURE 24: SPOT PRICES: DAWN VS. LANDED EMPRESS @ TCPL IT MIN BID

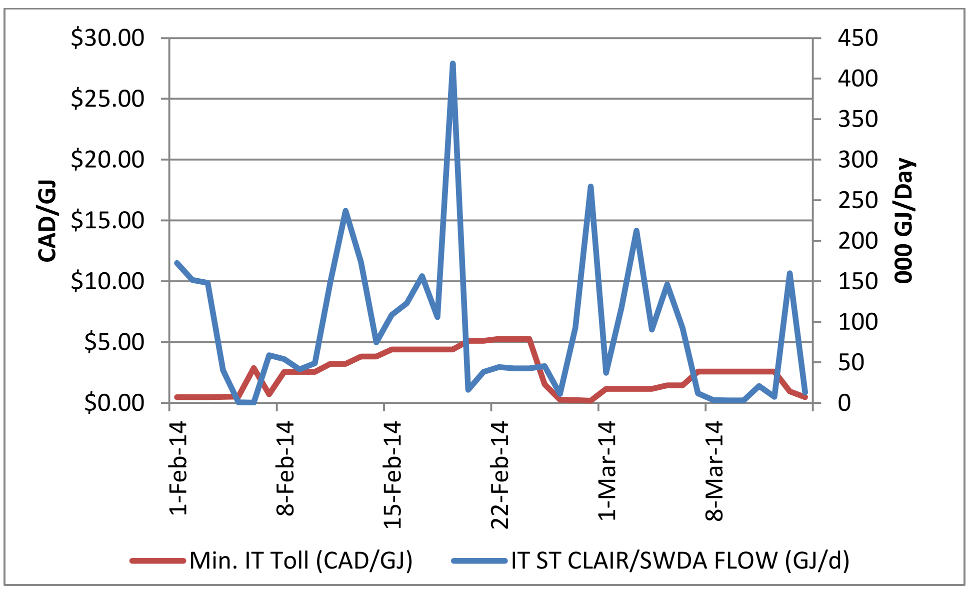
FIGURE 25 illustrates the impact of the IT tolls by highlighting that IT flows from Empress to Dawn occurred on a limited number of days during the period from February 1 through March 15, with 21 days having flows of zero or less than 1,000 GJ. The minimum bid set for the IT toll from Empress averaged C$11.65/GJ during this period, and only 2.1 PJ flowed. For comparison,

FIGURE 26 shows that IT flows from St. Clair to Dawn over the same period were 3.8 PJ, with flows over 1,000 GJ occurring on all but two days. The average IT bid toll on the St. Clair to Dawn path was only C$2.44/GJ. The resulting economic limitations (due to transport costs) on sourcing incremental gas supply from Empress meant that more expensive gas would need to be obtained, effectively raising prices at Dawn.



Source: Aegent/TCPL

FIGURE 25: FLOWS (IT) FROM EMPRESS VS. MIN. IT TOLL



Source: Aegent/TCPL

FIGURE 26: FLOWS (IT) FROM ST. CLAIR VS. MIN. IT TOLL

The second additional factor impacting prices relates to the "checkpoint" balancing requirement on Union Gas' direct purchase customers. Under Schedule 2 to Union's Southern Bundled T service, a Banked Gas Account is required, reflecting the cumulative balance between a customer's receipt of

Union-distributed gas and the customer's deliveries of gas to Union. A positive balance means the customer has delivered more gas to Union than has been distributed to the customer by Union. A customer's contract will contain a Winter Checkpoint Quantity (and an analogous Fall Checkpoint Quantity) that represents the minimum balance that must be in its Banked Gas Account as of the Winter Checkpoint Date (February 28). The amount of additional gas that a customer may need to deliver to Union by February 28 will vary according to its existing Bank Gas Account balance.

While Schedule 2 to Union's Bundled T service says that a customer is "expected to take balancing actions early in the winter to ensure that the BGA balance is not less than the Winter Checkpoint Quantity as of the Winter Checkpoint Date", we understand from Union that many customers will have built up significant shortfalls in their Banked Gas Accounts relative to their checkpoint quantities. The result of these customers delaying their balancing obligations all the way until the February 28 checkpoint date was to have large volumes of demand entering the market in a concentrated time period. Such demand bubbles can be expected to contribute to price volatility and, in an extremely tight market, we would expect the effect would be even more pronounced. Last winter, the market was indeed already tight, and the checkpoint balancing demand likely raised prices even higher at the end of February.

f. Conclusions—What Happened and Why

As outlined in the previous sections, there were many events unfolding in real time last winter. The most important event was the cold weather, which was widespread, persistent, and extreme. Hindsight allows all the information to be seen at once. In reality, the future is never known, although it is constantly forecasted and evaluated. It is presumed that an LDC's supply planning parameters (such as the LDC's assumed design day demand or its storage deliverability target) have been set to allow the LDC to reliably and efficiently meet expected demand. As noted by the Board, gas supply plans are "based on the amount of gas that would be expected to be needed to address the normal range of demand."[11] As unexpected events occur, such as last winter's cold, then the system is challenged. While planning necessarily involves trade-offs between the cost of mitigating risks and the potential cost impacts of the risks themselves, the nature of risk makes it highly unlikely that all risk can be mitigated at reasonable costs.

It should be remembered that while there were significant price impacts, both LDCs followed their supply plans, and neither curtailed any firm service. Following are the main conclusions about last winter's gas prices:

- Extreme winter conditions elevated natural gas demand throughout the U.S. and Ontario to record levels, leading to a tight gas market and setting the stage for additional factors that exacerbated the winter's price behavior.
- Strong Midwest demand impacted gas prices at Dawn and incented increased storage withdrawals to meet Ontario demand.
- Large storage withdrawals early necessitated large spot purchases later (which happened to be at high prices) as continued cold conditions led to persistent high demand.

[11] See Decision and Order of May 22, 2014 in EB-2014-0039, Enbridge's Q2 2014 QRAM application, p. 6.

- "Checkpoint" balancing by Union direct purchase customers, although an annual occurrence, coincided last winter with the on-going need to meet persistent high demand, exacerbating prices.
- Increased interruptible transport tolls appear to have limited the competitiveness of Empress as an economic source of supply, leading incremental gas for Ontario to be drawn from the Midwest and Northeast, further exacerbating Dawn prices
- The necessary conditions for last winter's price scenario appear to be the coincidence in both the U.S. and Canada of early, widespread and persistent high demand (resulting from the macro weather conditions).
- It is not clear whether the same weather conditions would have led to the same price impacts had supply plan requirements called for more base storage or increased firm transportation, but more storage and increased firm transportation may have helped.
- Similarly, supply plan requirements leading to more conservative use of storage withdrawals (and thus more supply procurement early in the winter) would likely have helped.

3. QRAM Discussion

a. Overview

The Quarterly Rate Adjustment Mechanism (QRAM) is a cost recovery mechanism to allow gas distributors to recover their actual gas costs since those costs can (and will) differ from whatever was assumed in order to set the distributor's rates. The purpose of the QRAM is to allow for the collection of actual costs by gas distributors in a way that provides a balance between price stability and market price sensitivity. The QRAM operates based on a 12-month price forecast that is updated quarterly, plus a true-up account (Purchase Gas Variance Account) to track the variances between actual costs and recovered costs at the existing forecast-based rates. The forecast price is computed each quarter based on a "21-day strip" that "represents the simple average of future market prices, as reported by various media and other services, over a 21-day period for a basket of pricing periods, pricing points, and pricing indices that reflects [a company's] gas purchase arrangements, both actual and anticipated, during the 12 months subsequent to the 21-day period."[12] The true-up rate rider is computed each quarter to provide for recovery of Purchase Gas Variance Account balances, plus any historical variance in collections of the PGVA rider. Cost recovery is achieved by collection of the forecast component (i.e. base rates) and the true-up component (i.e. Purchase Gas Variance Account rider), assessed against a customer's monthly gas volume.

b. Drivers

As the QRAM is a mechanism to allow for cost recovery of actual gas supply costs (through the forecast-based rates and the true-up based rate riders), the factors influencing the QRAM are essentially the factors that influence an LDC's actual gas costs. Conceptually, the various factors could be grouped into two broad categories: 1) those that are more independent, and may not generally be within an LDC's (or its regulator's) specific realm of control (although they may manage their responses to these factors), and 2) those that could potentially be more directly impacted by the operational, managerial and regulatory policies, procedures, directives and decisions of the LDC or its regulator.

[12] See Appendix A to Enbridge Q2 2014 QRAM Application (EB-2014-0039), Ex. Q2-1, Tab 2, Schedule 1, Appendix A, pp. 1-2.

- The more independent factors would include the following types of events that can impact the gas market and thus an entity like an LDC:

    1. weather
    2. outages
    3. gas supply development
    4. interstate pipeline development
    5. gas demand growth
    6. economic or business cycles
    7. world events

- Other factors that could potentially be more directly influenced by an LDC or its regulator are well-represented by an LDC's supply planning parameters, as outlined below.

c. Supply Planning Parameters

As the potentially controllable drivers of an LDC's costs and its QRAM, its supply planning parameters should be of interest from policy and commercial perspectives.

i. weather assumptions

Weather assumptions (i.e. how far away from normal weather could a season reasonably be, and what is "normal") are important because they help drive the range of potential weather outcomes that would need to be planned for.

- Union: proposed switch (for 2013) to 20-year declining trend from 55/45 blend of 30-year average and 20-year declining trend; Union reports this is the same as current Enbridge method

ii. design day criteria

Design day criteria help determine what the peak day demand assumption will be. A colder design day will require additional supply planning measures, which could range from additional storage or transportation (high fixed costs) to additional peaking resources (high variable costs).

- Union North: coldest observed day in each of six delivery areas
- Union South: 44 HDD DegC
- Enbridge: 1-in-5 forecast with log-normal (settled after an earlier request to increase from 1-in-5 to 1-in-10 with log-normal), which comes to 41 HDD DegC.

iii. demand forecast

Assumptions such as no migration between utility gas sales service and direct purchase (DP) service customers could lead to the need for increased incremental supply with possible market impacts. The demand forecasting itself is likely less controversial.

- Union: no migration during year between DP and sales service customers
- Union: actual winter 13/14 migration was 25,000 DP customers returning to sales service, leading to 1.8 PJ of incremental supply needed, (Union Gas Q2 2014 QRAM, Tab 1, p.8).

iv. firm transportation planning criteria

The decision to purchase annual firm transportation is important because it creates a fixed cost obligation that could prove stranded, but could also result in a much mitigated result in the case of high demand.

- Union South: firm transport capacity set at average daily quantity, used at 100% load factor
- Union North: firm transport capacity set at design day, which leaves 10.4 PJ of unused capacity on lower demand days, i.e. Unabsorbed Demand Charges (2013 Test Year)
- Union: Short-term firm and interruptible transport are not within the supply plan
- Union: holds contracts for diversified supply
- Enbridge: has displaced STFT with FT
- Enbridge: forecasts C$17.2M in UDC for 2014 (EB-2012-0459, Ex. D1, Tab 2, Sch. 1, p.6)
- Enbridge: notes that even with additional UDC, total costs could be less depending on the relative rates of different transport service options, and thus recoverability rules on UDC could impede decisions that would lower costs (see EB-2012-0459, Ex. D1, Tab 2, Sch. 1, p. 14).

v. storage level planning

Storage operating regimes are another large cost-risk trade-off, whose importance is evidenced by this last winter. Storage withdrawal rights are a related parameter.

- Union: full on Nov 1, empty by March 31 (w/ "normal" weather)
- Union: able to meet design day until February 28 ("maximum deliverability")
- Enbridge: able to meet design day until January 31 ("multi-peak")
- Union: 15.0 PJ of TCPL STS withdrawals
- Union: uses Aggregate Excess Storage Method based on normal year to determine base storage requirement

vi. use of peaking supplies

Contracted peaking supplies allow demand not met by specifically planned volumes to be met by contractual purchase option rights

- Union: none forecasted for 2013/14
- EGD plans same level for 2013 as 2014, but will meet with more TCPL FT since planning for STFT is too uncertain with regulatory changes

vii. procurement mechanisms for incremental supply (spot vs. forward market purchases)

Regimes that allow or can accommodate month-ahead purchases are likely to benefit from lower and less volatile prices that those limited to incremental purchasing in the daily or intra-month spot markets

- Union: month-ahead Dawn supply per Gas Procurement Policy and Procedures, see Union QRAM Tab 1, pp. 16-18
- Enbridge: "exposure to daily/intra-month market pricing is driven by plan requirement to manage purchases to meet projected demand and storage deliverability targets" (QRAM, Ex. I, Tab 2, Schedule 1, pg. 3)

viii. Other forecast assumptions

The supply planning process needs to incorporate assumptions on certain variables.

- Assumed transportation tolls are those in effect at the time of forecast.
- Commodity price forecast used is the same as in QRAM process.

d. Commentary

i. Cost and risk trade-offs of relevant gas supply planning parameters

A recurring theme regarding supply planning is the idea that certain risk mitigation measures may have high fixed costs, but low average costs in the event that a risk actually develops. Products with demand charges, such as firm transportation, fall into this category, and would be the preferred option when a risk actually develops. If the risk does not develop, then these products would likely end up costing more than an alternative product with low fixed costs but high average costs in the event that a risk actually develops. Using hindsight to evaluate the "winning" strategy may be interesting, but shouldn't guide future decision making. Having a clear understanding of an entity's risk profile, and the considerations driving that risk profile, is critical to structuring an appropriate risk strategy. Examples of cost-risk trade-offs abound in the supply planning function[13], and include such things as the following:

- Colder design day would increase storage deliverability targets and levels of firm transport, which would cost more but mitigate risks in the event of a colder winter
- Less planned use of peaking services would increase storage deliverability targets and levels of firm transport, which would cost more but mitigate risks in the event of a colder winter
- Higher storage deliverability requirement may cost more, but it also reduces exposure to market pricing

[13] See, e.g., the Board's Decision and Interim Order in EB-2014-0039 (Enbridge Q2 2014 QRAM application), where the Board "acknowledge[d] the differences in the gas purchase options available to Union and those available to Enbridge." The Board noted that differences in Union's and Enbridge's gas supply plans included storage inventory and heating degree day levels, use of peaking service contracts, and balancing requirements for direct purchase customers.

ii. Likely persistence of identified price drivers

Regarding the weather, it should be remembered that predictions are inherently risky and cannot be made with anything approaching certainty. That being said, it would seem that it would not be improbable for Ontario to have another winter with early, persistent or extreme cold. The likelihood of having a winter with all three attributes would be lower, and the likelihood of having a winter with early, persistent and extreme cold, and that is also occurring over a widespread geographic region, lower still. It would be speculative to suggest anything further. It is not apparent what other phenomenon could result in such large, widespread, and persistent gas demand increases.

If the Board seeks to affect commercial decisions (e.g. storage management, transportation tolling, customer balancing) by market participants acting within the terms of their supply plans, the Board could potentially make changes to the gas supply plans or planning parameters.

iii. New or emerging factors that could influence QRAM drivers and prices

There are several on-going trends in North America that we see as key factors in the evolution of market dynamics. The two primary, interrelated trends are the further development of shale gas resources, and the associated expansion of the gas pipeline network to help bring shale gas supplies to markets. Since Ontario, and in particular the Dawn Hub, is a significant market that is well-located with respect to the key shale region in the U.S. Appalachian Basin, the likelihood of Ontario benefitting from a strengthening of supply seems good.

Other potential factors are likely less relevant, but nevertheless could include such trends as changing weather or weather patterns, perhaps as connected to climate change (e.g. impacts hydroelectric availability on electric generation gas demand).

iv. Areas for the Board's consideration

We understand the Board is already involved in many of the factors noted in this review by virtue of its role in reviewing and approving the LDC supply plans. An analysis of the cost and risk trade-offs associated with different decisions regarding these factors could be an area of interest for the Board, bearing in mind that the nature of risk makes it highly unlikely that all risk can be mitigated at reasonable costs.

An additional potential area for consideration is maintaining an on-going awareness of the evolution of supply and demand at Dawn in the near to medium term. As we understand the LDCs to be planning on procuring more gas at Dawn, while on the supply side there are analogous industry moves to increase access at Dawn to developing supplies, we would expect the Dawn supply-demand balance to be an important topic with respect to regulated gas supply for Ontario.