Investigating Gas-Electric Market Alignment in Ontario

Final Report
Prepared for IESO
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Executive Summary

With the increasing reliance on natural gas-fired electricity generation in North America, the misalignment of North American natural gas market processes and the day-ahead scheduling processes of the electricity sector's Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) has surfaced. In the US, the Federal Energy Regulatory Commission directed both gas and power system operators to look at enhancements to processes to improve this alignment. The gas market responded with an amendment to its nomination process timelines. The power sector is responding with jurisdictional assessments of the alignment of their day-ahead processes to the gas market.

The IESO's own internal gas-electric review identified two potential issues: the sharing of non-public operational information between the IESO, pipelines and storage providers for promoting reliability and operational planning; and the alignment of the IESO's Day-Ahead Commitment Process (DACP) with the natural gas market timelines. This report examines the second issue, examining the interface of the natural gas market with the IESO's DACP, and how the misalignment of the two market processes affects both generators and the IESO system.

In Ontario, the main concerns resulting from the misalignment of gas and power markets hinge on the timing of both the IESO's DACP offer submission window and the timing of the unit commitment report. The misalignment of the calendar day commitment for electricity,12:00 am to 12:00 am Eastern Standard Time, versus the standard natural gas market day 10:00 am to 10:00 am Eastern Prevailing Time[1] adds further complexity to the alignment. In the current market environment, however, these concerns do not pose a significant risk to reliability of Ontario's electricity system.

Ontario is in a strong position to manage the challenges associated with market misalignment. The natural gas fleet in Ontario is relatively new in comparison with our neighbours, with much of the gas generation constructed within the last decade to prepare for the closure of the coal facilities. The 2005 Natural Gas Electricity Interface Review (NGEIR), managed by the OEB, allowed Ontario's natural gas pipeline operators and utilities to design and market specific services to meet the need for flexible, firm access to natural gas in parallel with the expansion of the fleet. These enhanced gas delivery and management (GD&M) services allow subscribing generators to balance the delivery of gas with the expected burn profile, utilizing pipeline capacity and natural gas storage.

Generators in Ontario can be divided into two general categories, those with GD&M services and those without. In general, those generators with enhanced services indicate there are only minimal challenges in managing the gas power market misalignment. Those generators without

[1] While the IESO remains in Eastern Standard Time year-round, the natural gas market defaults to prevailing time. Therefore, in the Daylight Savings Time season of March through November, the natural gas market day runs 09:00 am EST to 09:00 am EST. Further complicating the time conversion is the fact that the gas market typically communicates in Central Clock Time (CCT). For the purpose of this report, we have attempted to align the time zones for clarity, utilizing Eastern Prevailing Time (EPT). From March through November, EPT is one hour later than IESO's timelines in EST (10:00 EST = 11:00 EPT). From November through March, EPT is the same as EST (10:00 EST = 10:00 EPT).

such services have more of a challenge managing market alignment, particularly during periods of weather-based gas system constraints, where increased demand across the gas system brings both financial and operational uncertainty to generators without services to manage that uncertainty.

The financial implications of the misalignment of market timelines are more significant than the physical challenges. Much of the management of physical challenges relies on GD&M services, which vary in cost depending on a generator's size, location, and operating requirements. Whether a service is offered at a regulated, contracted or market price, the trend in GD&M service costs is increasing, with this increasing fee shared between consumers and generators. For some generators, the cost of these services is borne by the generator directly. For others, the costs are at least partially covered by payments from Generation Contracts[2], ultimately paid for by the ratepayer through the Global Adjustment. As a result, it is important for the IESO to consider these costs as well as physical and financial risks as it moves ahead with Market Renewal initiatives and develops new market initiatives around day-ahead and capacity markets.

[2] The term Generation Contracts refers to any and all type of contracts between Ontario's gas-fired generators and the IESO or OEFC, including legacy NUGs, re-contracted NUGs, CES-Style Contracts and Other Contract Structures.

Scope and Approach

Workbench was engaged by the IESO under RFP 88 to investigate the challenges and opportunities associated with the current alignment of the IESO's existing Day-Ahead Commitment Process (DACP) with the timeframes of the day-ahead gas market and gas nomination window. It is intended to bring together various perspectives within Ontario highlighting current opportunities, challenges and issues that exist. This report will also review recent developments and decisions made by neighbouring jurisdictions to address gas-electric alignment and discuss issues the IESO should consider in its work on future market development initiatives.

In order to perform the scope, Workbench approached three different groups of interviewees that have a role in the interaction between the DACP and the day-ahead gas market – generators, utilities and gas marketers or suppliers. Workbench assessed the appropriate interviewees based on specific parameters that would allow us to get a varied understanding of risks from the perspective of all three groups.

Generators were assessed and chosen based on a number of criteria including their geographical location, ensuring the pool of participants represented different gas distribution regions and different gas supply arrangements. Generators of varying size, contract structure and organization structure were included to ensure that risks and opportunities were sufficiently captured. Workbench interviewed the main gas distributors and gas transmission companies providing service to Ontario power generators. While the portion of natural gas load varied by delivery area, about 20% of the Ontario peak load was serving power generators. This is consistent with the 2014 Natural Gas Market Review Final Report prepared by Navigant Consulting for the Ontario Energy Board in December 2014. Marketers known to supply natural gas to Ontario-based gas generators as well as generation facilities in other markets were selected.

With these criteria, a target list of companies was developed. Workbench planned and implemented an outreach program approved by the IESO to engage target organizations in interviews. Interviewees were approached by phone and email and Workbench provided an information sheet to each of the interviews as well as a draft non-disclosure agreement to be executed at any participant's request. Meetings were held both in person and by phone.

Interviews were conducted with four gas utilities, three gas marketers and seven gas-fired generators. In the interviews Workbench discussed the physical and financial risks associated with market misalignments in the context of the IESO's DACP, ultimately distilling issues and capturing stakeholder perspectives on improvement opportunities.

This report is structured to ensure that specific responses will be confidential between Workbench and the respondent. Data and opinions have been sanitized to avoid attribution to any one facility or entity.

Background

Alignment of Gas and Power Markets in North America

With the increasing reliance on gas-fired electricity generation in North America in recent years, attention has been growing to the misalignment in market and scheduling processes between the North American Natural Gas Market and the individual Independent System Operators (ISOs) that operate electricity markets across the continent.

In Ontario, the Ontario Energy Board (OEB) completed a generic hearing known as the Natural Gas Electricity Interface Review (NGEIR) in 2005 with a decision released by the OEB in November 2006. This resulted in the development by natural gas utilities of high deliverability services that served to meet the variable nature of natural gas generation. The utilities designed the services to allow the generators to lock in a specific amount of variability in storage, balancing and transportation on firm contract, typically with medium- to long-terms (10+ years). The natural gas infrastructure supporting these services has the flexibility to manage the variable nature of generator consumption, but access to that flexibility is reserved for those generators that hold contracts for these natural gas services. For effective operation within the IESO market, generators were incented to purchase the system access. These high deliverability services are unique to Ontario, and rely on the well-developed gas infrastructure within the Province.

Other jurisdictions in North America have lagged in the development of generation-specific gas services, and have relied on alternative options to improve reliability of the gas fleet. Dual-fuel facilities are common in the US Northeast, whereby gas-fired generators may rely on on-site storage of a secondary fuel to operate in periods where natural gas is not available. During the winters of 2013 and 2014 when extreme weather hit North America, the misalignment between gas and power market scheduling mechanisms was highlighted. Gas supply was difficult to procure and firm transportation was maximized early, leaving generators across the continent unable to secure natural gas intra-day.

In response to these events and to ensure its gas generation fleet reliably supports the electrical grid, the US-based energy regulatory body Federal Energy Regulatory Commission ("FERC") undertook significant industry consultation to address the misalignment of markets, in addition to other initiatives. Through that engagement, discussed in the section of this document titled FERC Order 809, the North American Gas Market made several changes to improve its alignment with the general practices of the electrical system operators, as outlined below.

Alongside the changes happening in FERC jurisdictions, the IESO assessed its position and identified two components for further study – Information Sharing and DACP Alignment. To address the first item, Information Sharing, the IESO began a Stakeholder Engagement in 2015 to propose to the Ontario gas community some procedural changes that would allow the IESO to share generator operating schedules with natural gas utilities to identify reliability concerns. As a result of the complexity of gas service arrangements, the variability of schedules and the confidentiality of contract parameters, the existing situation was deemed to be sufficient. As per the original stakeholder engagement "After careful consideration of stakeholder feedback and concerns, the IESO acknowledges that, at this point in time, the current market rules place sufficient obligations on market participants to communicate any fuel supply limitations and enable the IESO to conduct reliable planning and operations" and the stakeholder engagement initiative was closed.

For the second component, the IESO has committed to identifying the impact of the market misalignments from the perspective of Ontario's gas generators, marketers and utilities, to better identify opportunities to amend its scheduling practices in the DACP. This report is within the scope of that approach.

FERC Order 809

In the United States, following comprehensive industry consultation the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rule Making ("NOPR") (RM14-2-000) in March 2014 "*as part of a series of orders, to revise its regulations at section 284.12 to better coordinate the scheduling of natural gas and electricity markets in light of increased reliance on natural gas for electric generation, as well as to provide additional flexibility to all shippers on interstate natural gas pipelines. The proposed revisions in this Notice of Proposed Rulemaking deal principally with revision of the operating day and scheduling practices used by interstate pipelines to schedule natural gas transportation service. These proposed revisions affect the business practices of the natural gas industry, which the industry has developed through the North American Energy Standards Board, and which the Commission has incorporated by reference into its regulations.*" The FERC provided the natural gas and electric industries six months to reach consensus on standards consistent with the FERC's guidance.

FERC had identified three major issues which they highlighted in Order 809, Section 11,

> *"(1) the difference between the standardized operating day of interstate natural gas pipelines and the operating days of electric utilities (including ISOs and RTOs);*
> *(2) the lack of coordination between the day-ahead process for nominating interstate natural gas pipeline transportation services and the day-ahead process for scheduling electric generators, particularly those in the ISOs and RTOs; and,*
> *(3) the lack of intraday nomination opportunities on interstate natural gas pipelines, which limits the ability of gas-fired electric generators, as well as other shippers, to revise their nominations during the operating day. Several conference participants stressed that, due to the difficult policy questions involved, they would need Commission policy guidance before they would be able move forward on coordination of the natural gas and electric industries existing scheduling practices."*

The FERC proposed three changes to gas pipeline operations in RM14-2-000:

- Change gas day from 9:00 am - 9:00 am CCT to 4:00 am – 4:00 am CCT (10:00 am EPT – 10:00 am EPT to 5:00 am EPT – 5:00 am EPT)
- Move timely deadline from 11:30 am CCT to 1:00 pm CCT (12:30 pm EPT to 2:00 pm EPT)
- Add a 3rd and 4th Intraday nomination window bringing the total number of North American Energy Standards Board (NAESB) nomination windows to 6

The response to NOPR was comprehensive and input was received from across the natural gas and electricity industries. The electricity industry generally supported the change as it would result in their operating cycle to be better contained within a single day, in particular the morning ramp. With the current gas day, they indicated the generators needed to hold back gas during the evening peak to reliably operate the next morning. They felt that moving the gas day forward to 4:00 am CCT (5:00 am EPT) would allow purchases in the timely market and would be more reliable as the morning ramp would be at the start of the gas day and generators would be better positioned to respond to evening peak. If gas supplies were exhausted, it would happen during the period of lower overnight demand when system is more stable.

The gas industry did not support a change to the gas day. They questioned if a change of time would affect generator reliability and noted that gas delivery issues were more related to the Northeast and not to other regions. They also cited safety concerns where field operations would be necessary with a 5:00 am EPT start. The noted bad weather conditions, fatigue, studies saying that critical decisions should not be made between 2:00 am and 6:00 am. They noted that preparations for gas day operations take place about three hours in advance.

The gas day is standard across North America and starts at 10:00 am EPT, that is during periods of daylight savings time, the gas day adjusts to compensate for the change in clock time. The effect of the single time is that as one moves from the east to the west, the gas day ends and begins at a different point of the morning electricity ramp; the further east you go, the greater the number of end of day gas hours that occur in the morning ramp and as a result, managing end of day gas volumes is more problematic.

FERC requested data from ISOs' and RTOs' to support the proposition on reliability of gas supply for gas generators in this end of gas day period. Section 66 of FERC Order 809 states,

> *"The Commission concludes that there is limited evidence to support the NOPR proposal to change the Gas Day. For example, in ISO-NE very few gas-fired generator de-rates due to fuel limitations had an ending time that coincided with the start of the next Gas Day at 9:00 am CCT in 2013 and 2014. In addition, in PJM, a majority of the fuel related gas-fired generator de-rates in 2014 and the vast majority of fuel-related gas-fired generator de-rates in 2013 were caused by a limited number of generating units. The Commission believes any conclusions that can be drawn from the PJM data are weakened by the idiosyncrasies of these units. Therefore, although gas-fired generator de-rates due to fuel limitations appear problematic in certain regions during certain times of the year, on balance, the Commission believes this does not warrant changing the nationwide Gas Day."*

FERC did adopt the change in the timely nomination time and added one intra-day nomination instead of the two they proposed. In Section 23, of FERC Order 809 they stated:

> "*Based on the record developed in this proceeding, the Commission is taking final action to address certain natural gas and electric industry coordination challenges resulting from the divergent interstate natural gas pipeline and electric utility scheduling practices. The Commission is revising its regulations to incorporate by reference the modified NAESB WGQ Business Practice Standards, which revise the standard nomination timeline for interstate natural gas pipelines*[34]*. These changes will revise the most liquid nomination cycle for scheduling natural gas transportation, the nationwide day-ahead Timely Nomination Cycle, so that the nomination deadline will be 1:00 pm CCT rather than 11:30 am CCT, and will include an additional intraday*

scheduling opportunity, as well as conforming other standards to these revisions……."

The revised nomination windows have been adopted by TransCanada PipeLines and Union Gas and are available to Ontario generators. The nomination windows represent a minimum requirement and do not preclude operators from offering services that increase nomination opportunities. The nomination windows are detailed in Table 4 of this document titled NAESB Nomination Cycle Timeline.

FERC also directed RTOs and ISOs under its jurisdiction to look at their scheduling practices to better align with the updated nomination times or provide the rationale for not needing to change. In particular, they were ordered in EL14-22-000, Section 19 to "….. *(1)make a filing that proposes tariff changes to adjust the time at which the results of its day-ahead energy market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination Cycles, respectively, to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations; or (2) show cause why such changes are not necessary…..*"

The revised nomination windows respond to the need of gas generator to have additional time to commit to gas purchases in the most liquid period of the day; the order to RTOs and ISOs requires that day-ahead electricity commitments be available to allow gas generators to make the required natural gas purchases. The additional evening nomination window provides the opportunity for gas generators to adjust deliveries to meet changes in production. In addition, FERC recognized that electricity generation is only a portion of a larger gas market and that the needs of other market participants needed to be considered.

Responses to FERC 809 by IESO's Neighbouring Jurisdictions

The responses of the IESO's neighbouring FERC-regulated ISO/RTOs to the direction ELI4-22-000, Section 19 Workbench reviewed the ISO/RTO organizations that most impact IESO operations. They include ISO-NE, NYISO, PJM and MISO. These organizations manage the electricity markets directly connected or once removed from the IESO controlled system.

ISO-NE and NYISO

The Independent System Operator of New England (ISO-NE) and New York Independent System Operator (NYISO) organization day-ahead market timelines corresponded with the new NAESB timelines and the FERC recognized that they were and continued to be compliant with the revised gas nomination timelines. Table 1 below shows the timelines association with day-ahead submissions and commitments in each jurisdiction.

Table 1 NYISO and ISO-NE Market Timelines

System Operator	Time for Bid Submission (EPT)	Time of Publication of Day-Ahead Bids (EPT)	Notification of Reliability Unit Assessment (EPT)
ISO-NE	10:00 am	1:30 pm	5:00 pm
NYISO	5:00 am	11:00 am	11:00 am

Table 1 (Sources: Table 1 – ISO and RTO Day-ahead Scheduling, FERC EL14-23-000, Order on Compliance Filing (issued November 19, 2015), Table 1 – ISO and RTO Day-ahead Scheduling, FERC EL14-26-000, Order on Compliance Filing (issued November 19, 2015)

PJM RTO

PJM's timelines were not in compliance with the new NAESB timelines. PJM proposed the revisions set out in the table below. The proposed changes were accepted by FERC on November 19, 2015 and became effective March 31, 2016. Interveners were generally supportive of the changes; however, there was some discussion of extending the close of the day-ahead market until 11:00 am EPT. PJM indicated that this would allow sufficient time for them to ensure clearance of the day-ahead market by 1:30 pm EPT publication. Their proposal does envision earlier publication where practicable. FERC found the timelines reasonable and consistent with their goal that the day-ahead market clear in advance of the Timely Nomination.

Table 2 PJM Market Timelines

Activity	Current	Revised
Close of PJM Day-Ahead Market	12:00 pm EPT	10:30 am EPT
Publication of Day-Ahead Market Results	4:00 pm EPT	1:30 pm EPT (or as soon as practicable thereafter, however PJM will not post the information earlier than 12:00 pm EPT)
Rebidding Period	4:00 pm to 6:00 pm EPT	Time between the Publication of Results of Day-ahead Energy Market (approx. 12:00 pm EPT to 1:30 pm EPT) until 2:15 pm EPT
Notification of Reliability Assessment Commitment	8:00 pm EPT	6:30 pm EPT

Table 2 (Source: Table 3 – PJM's Current and Proposed Day-ahead Schedule, FERC EL14-24-000, Order Accepting Proposed Tariff Records)

MISO

MISO's proposed changes did not comply and they set out reason they believe the times they were proposing would meet the intent of FERC Order 809. Their proposal was the result of a stakeholder engagement and ballot on preferred schedules. MISO's proposal and the position of the stakeholders was that they were satisfied with their ability to procure natural gas in the period leading up to the Evening Nomination. In Section 17 of EL14-25-000 Compliance filing the following was reported:

> *MISO states that Alternative 1, maintaining the status quo, was supported by most of MISO's stakeholders. MISO states that most MISO stakeholders did not favor Alternative 2, which involved moving up the day-ahead market trading deadline to 10:00 am EPT (9:00 am CCT) and the posting of MISO's day-ahead market results to 1:00 pm EPT (12:00 pm CCT), one hour before the revised Timely Nomination Cycle deadline. MISO explains that these stakeholders cited concerns relating to "seams management and greater price uncertainty, with associated uplifts." MISO states that stakeholders also indicated they have learned to manage the electric/natural gas markets timing issues that occur as a result of the status quo, and that stakeholders preferred that MISO allow natural gas trading to occur at the most liquid trading time, which would be encroached on if the day-ahead market trading deadline is moved to 10:00 am EPT (9:00 am CCT). MISO explains that given MISO's regional gas infrastructure and operations, MISO and its members have not experienced the gas scheduling challenges experienced in some of the other RTOs.*

Workbench notes that the MISO operating region is located in a region that is at the confluence of multiple pipelines originating in the US and Canada and is well served by natural gas storage, particularly in Michigan. It would be expected that the operating flexibility of this region would be greater than that available in ISO-NE, NYISO and PJM, which are located downstream of the Midwest's natural gas assets.

MISO asserted that it had shown cause as to why posting day-ahead market results ahead of the Timely Nomination Cycle is not necessary. FERC disagreed and in Section 52 of EL14-25-000 stated:

> *We find that MISO's existing Tariff and its revised proposal are unjust and unreasonable insofar as they do not provide for the posting of MISO's day-ahead market results so that natural gas-fired generators will know their day-ahead commitments for the following electric operating day in time to submit nominations for natural gas pipeline capacity during the Timely Nomination Cycle. MISO's proposed day-ahead market results posting time of 2:00 pm EPT (1:00 pm CCT) is at the same time that nominations are due in the Timely Nomination Cycle such that gas-fired generators cannot know their commitments prior to submitting their nominations for pipeline transportation. As discussed below, we find that MISO has failed to show cause why this scheduling change is sufficient. We therefore will require MISO to submit a further compliance filing within 30 days of the date of issuance of this order that moves its posting of its day-ahead market results at least 30 minutes earlier than proposed to 1:30 pm EPT (12:30 pm CCT). We further find that MISO has failed to demonstrate that making this incremental change in its market results posting time will be unduly burdensome or disrupt its markets.*

FERC ordered MISO to adjust their scheduling timelines to be compliant with FERC 809. MISO made adjustment to effect this. The current, at the time this document was published, proposed and compliant timelines are provided in Table 3 below.

Table 3 MISO Current and Proposed Market Schedules

Event	Current	Proposed and Compliant
Day-Ahead Market Trading Deadline	11:00 am EPT (10:00 am CCT) (during period of the year not covered by Daylight Savings Time) 12:00 pm EPT (11:00 am CCT) (during period of the year covered by Daylight Savings Time)	11:00 am EPT (10:00 am CCT) ***Revised to:*** ***10:30 am EPT*** ***(9:30 am CCT)***
Day-Ahead Market Results Posting	3:00 pm EPT (2:00 pm CCT) (during period of the year not covered by Daylight Savings Time) 4:00 pm EPT (3:00 pm CCT) (during period of the year covered by Daylight Savings Time)	2:00 pm EPT (1:00 pm CCT) ***Revised to:*** ***1:30 pm EPT*** ***(12:30 pm CCT)***
Forward Reliability Assessment Commitment ("FRAC") Rebid Deadline	4:00 pm EPT (3:00 pm CCT) (during period of the year not covered by Daylight Savings Time) 5:00 pm EPT (4:00 pm CCT) (during period of the year covered by Daylight Savings Time)	3:00 pm EPT (2:00 pm CCT)
FRAC Notifications	8:00 pm EPT (7:00 pm CCT) (during period of the year not covered by Daylight Savings Time) 9:00 pm EPT (8:00 pm CCT) (during period of the year covered by Daylight Savings Time)	6:00 pm EPT (5:00 pm CCT)
Day-Ahead Market Schedules become effective	12:00 am EPT (11:00 pm CCT) (during period of the year not covered by Daylight Savings Time) 1:00 am EPT (12:00 am CCT) (during period of the year covered by Daylight Savings Time)	12:00 am EPT (11:00 pm CCT) (during period of the year not covered by Daylight Savings Time) 1:00 am EPT (12:00 am CCT) (during period of the year covered by Daylight Savings Time)

Table 3 (Source: FERC EL14-25-000, Order on Compliance Filing (issued December 17, 2015), FERC EL14-25-002 - Order on Compliance and Rehearing (issued March 31, 2016))

Ontario

While the IESO, as a Canadian entity, is not regulated by FERC, the interconnected nature of both the gas and power markets in North America ensures that Ontario is affected by FERC Order 809.

The material around the balancing of natural gas deliveries with electricity production that was considered in FERC Order 809 was also considered in the OEB's NGEIR hearings. In Ontario, NGEIR prompted the development of gas delivery and management services by the active Ontario pipeline operators, Union Gas, Enbridge and TransCanada PipeLines (TCPL) to respond to those needs.

For example, the scheduling hierarchy of nominations is different in Ontario than in other jurisdictions. In Ontario, in order to access firm transportation, TCPL offers two options: firm service and a newer firm-all-day service, developed in response to NGEIR. In Ontario, the default firm service is only guaranteed if nominated in the timely window. Once the timely nomination window passes, any remaining pipeline capacity may be committed to other shippers, including interruptible shippers, and once TCPL accepts an interruptible nomination, it becomes firm. As such, a generator that is not certain of its schedule ahead of the timely window is incented to purchase the enhanced firm-all-day service. This ensures a generator will have firm access to its natural gas at any point in the day, allowing it to balance gas flows with operation. In US jurisdictions, the default firm service may be available for nomination after the timely window, as interruptible nominations can be curtailed.

North American Gas Market

Natural gas supply in Ontario is integrated with the wider North American natural gas market: a vast network of interconnected pipelines spanning the continent. Gas is transported from production wells to market, where shippers can transact to purchase or sell natural gas. Market transaction points, or hubs, are generally created at the point of intersection of transportation pipelines, facilitating access to multiple sources of gas for trade.

Natural Gas Infrastructure in Ontario

Ontario's natural gas infrastructure is well developed. One of the largest market hubs in North America, the Dawn hub, is located in southwestern Ontario. Thirteen different pipelines converge at Dawn, ensuring a robust flow of natural gas to the region. It is a particularly liquid hub because the natural geology of the region has allowed for the development of significant natural gas storage infrastructure, bringing flexibility to both the supply and demand sides of natural gas transactions.

Similar to the electricity system, the natural gas system relies on both bulk transportation of natural gas from production to market and distribution of natural gas within a geographic distribution area. In Ontario, there are five Local Distribution Companies, or LDCs, that serve natural gas customers, operating separate franchise areas within the province, Union Gas and Enbridge are the primary distributors. Three smaller local LDCs serve the Kitchener, Kingston and Aylmer area. LDCs distribute the natural gas across a franchise area to the point where the gas is burned, the burner tip. Ontario's natural gas generators are typically supplied by one of the two primary LDCs, with a few notable exceptions.

TransCanada PipeLines operates the Canadian Mainline System ("Mainline"), the major pipeline that brings natural gas from the Western Supply Basin, a natural source of gas in Alberta, to Ontario and the eastern markets. Several Non-Utility Generators ("NUGs") in the north were originally designed and built to supply power to the TCPL Mainline, and remain directly connected to that transportation pipeline. In addition, two of Ontario's generators in the Sarnia area, Greenfield Energy Centre[3] and the Green Electron Power Project[4] applied to the Ontario Energy Board ("OEB") for, and received, the right to bypass the LDC (Union Gas) and connect the plant directly to a US-based pipeline, Vector Pipelines.

Figure 1 illustrates the distribution franchise areas across Ontario.

[3] OEB Decision and Order for Greenfield Energy Centre LP: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/472299/view/dec_order_Greenfield_20150402.PDF

[4] OEB Decision and Order for Greenfield South Power Corporation: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/472299/view/dec_order_Greenfield_20150402.PDF

Figure 1 TransCanada Mainline and Distribution Franchises in Ontario

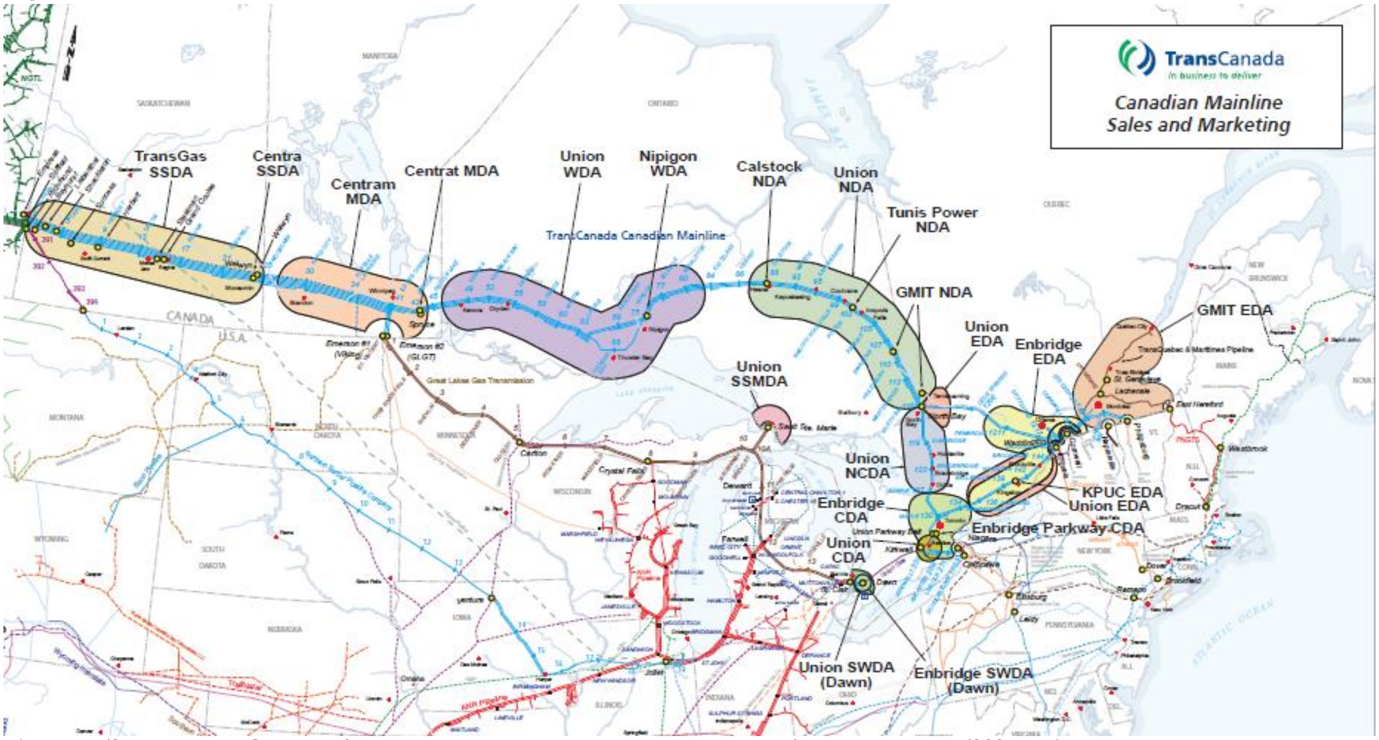


Figure 1 (Source: TransCanada Informational Postings at www.transcanada.com/customerexpress/892.html)

In Figure 1, the Canadian Mainline Pipeline is illustrated bringing natural gas from Alberta across northern Ontario and into the eastern markets. Each of the distribution franchise areas within Ontario is marked. The main distribution franchise areas that serve Ontario's generating fleet include:

- Union SWDA & CDA (Southwest and Central Delivery Areas) covering southwestern Ontario, from the Michigan border to the GTA
- Union NDA (Northern Delivery Area) in northeastern Ontario
- Union EDA (Eastern Delivery Area) in eastern Ontario, from the GTA to the Quebec border
- Enbridge CDA (Central Delivery Area) covering the Greater Toronto Area
- Enbridge EDA (Eastern Delivery Area) covering Ottawa and its surrounding areas
- Specific delivery points for the northern NUGs from the TCPL Mainline:
    - Nipigon WDA for Nipigon GS
    - Tunis Power NDA for Tunis GS

The figure also demonstrates the array of pipelines in the northeastern US, bringing gas from the Marcellus and Utica shale gas zones to market.

In Figure 2, the major market hubs in Ontario are visible as points of intersection of multiple pipelines, in particular Dawn, Parkway, Iroquois and Niagara points.

Figure 2 Ontario Distribution Areas and Transaction Hubs

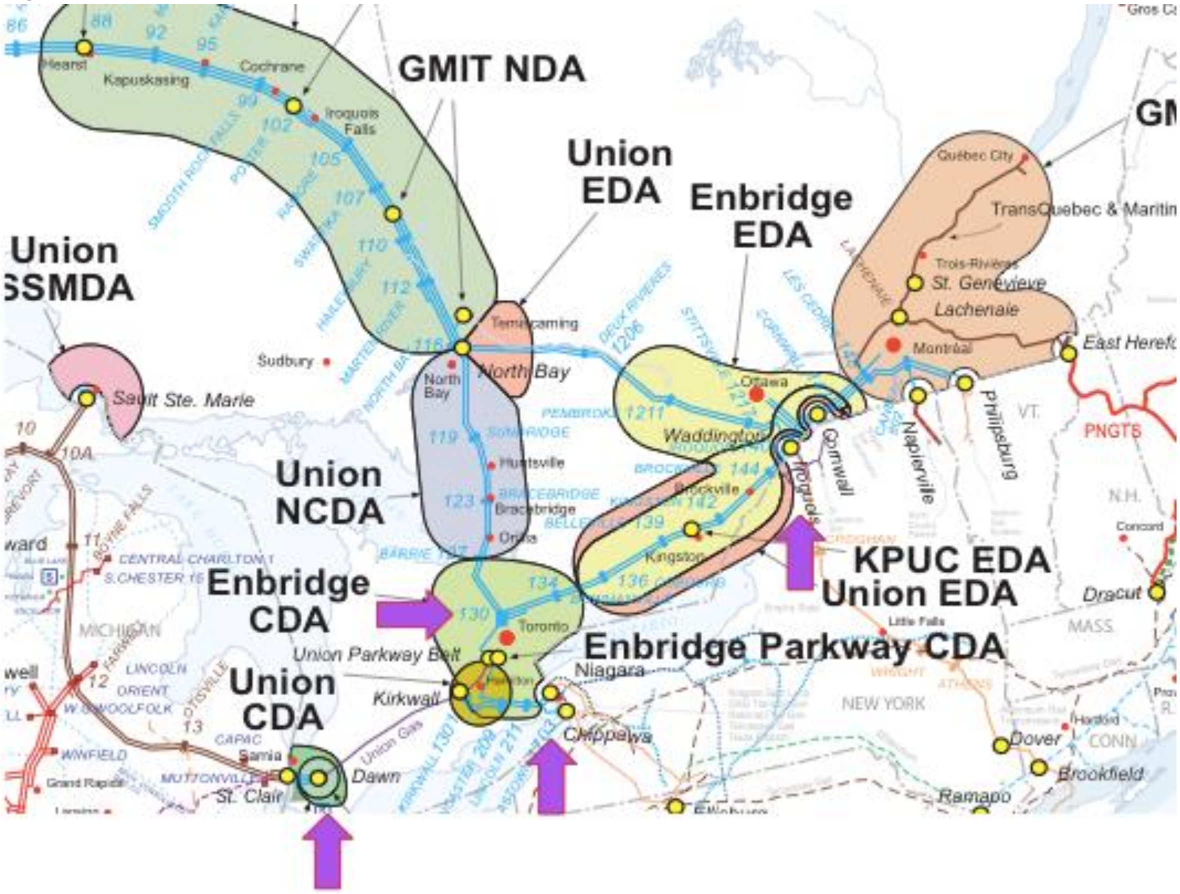


Figure 2 (Source: TransCanada Informational Postings www.transcanada.com/customerexpress/892.html)

Transaction Alignment within the Natural Gas Market

To ensure seamless integration of transactions across intersecting pipelines, transactions are standardized across jurisdictions. The North American Energy Standards Board ("NAESB"), has served to develop standards for market interactions on the wholesale and retail side of natural gas. NAESB successfully developed the schedule of trading windows in North America, commonly referred to as the NAESB windows, which are used by all active participants in the natural gas market in Ontario. NAESB windows are utilized not only for the purchase and sale of natural gas, but also to schedule flows along pipeline pathways, allowing intersecting pipelines to align flows. The scheduling of gas flows is typically referred to as the nomination process. A gas nomination is an instruction to the pipeline operator, storage operator or LDC that a participant is buying, selling, shipping along a pathway, withdrawing from or injecting into storage, or delivering gas to burn.

Prior to FERC Order 809, there were four NAESB nomination windows for a gas day, which spans two calendar days, running from 10:00 am EPT to 10:00 am EPT. In response to FERC Order 809, NAESB introduced a fifth window and amended the timelines of the existing windows. Table 4 below compares the pre-FERC 809 windows with the current windows, implemented on April 1, 2016.

Table 4: NAESB Nomination Cycle Timelines

Nomination Window	Pre-FERC 809 NAESB Standard		Current NAESB Standard	
	Nomination Deadline	Hours of Gas Flow Affected	Nomination Deadline	Hours of Gas Flow Affected
Timely	12:30 EPT pm (day-ahead)	**24**	2:00 EPT pm (day-ahead)	**24**
Evening	7:00 pm EPT (day-ahead)	**24**	7:00 pm EPT (day-ahead)	**24**
Intraday 1 (ID1)	11:00 EPT am (same day)	**16**	11:00 am EPT (same day)	**19**
Intraday 2 (ID2)	6:00 EPT pm (same day	**12**	3:30 pm EPT (same day)	**15**
Intraday 3 (ID3)	N/A	**N/A**	8:00 pm EPT (same day)	**11**

Table 4 (Source: FERC Docket No. RM14-2-000;Order No. 809)

Gas Commodity Transactions

For Ontario's gas generators, natural gas can be purchased or sold at the time of the NAESB transaction windows at either a transaction hub (Dawn, Iroquois, Niagara, Parkway, etc.) or at its distribution area. A natural gas commodity transaction involves a volume (MMBtu), a price (usually in USD), a term (daily, monthly, annual or as agreed), and a transaction point (hub or distribution area). Gas is purchased either from a natural gas marketer with whom a generator has a counterparty contract or from the distributor itself, under a Distribution Sales Service agreement[5]. Gas is deemed to flow in equal hourly volumes across the remaining period of the gas day from when it is transacted.

Gas marketers serve the Ontario market by providing access to natural gas commodity at a variety of transaction hubs, the most common of which is Dawn. Marketers typically manage a portfolio of transportation and storage assets across North America, moving gas across pipeline pathways to supply market demand. To supply gas at Dawn, a marketer may perform trades with other marketers at Dawn or upstream of Dawn, may transport gas from other hubs or locations to Dawn, or may utilize a Dawn-based storage account.

Most transactions transpire in advance of the first day-ahead NAESB nomination window, the Timely Window, so that nominations are submitted ahead of the 14:00 EPT deadline (recently changed from 12:30 EPT). Natural gas transactions can either be fixed price where the buyer and seller agree on a fixed price, or index-based where the price paid is based on the weighted average price of fixed price transactions at that hub in that window that are filtered through the Natural Gas Exchange service (NGX). Marketers typically transact for index-based transactions in a limited window, between 09:00 – 09:30 EPT of the day ahead of the gas flow. Timely fixed price transactions typically occur throughout the morning such that the actual settled index price can be reasonably estimated by 12:00 EPT. These timelines allow gas marketers to manage a portfolio of transactions ahead of the Timely Window ensuring transactions are supported by upstream nominations.

[5] Rates for Distribution Sales Service are fixed on a quarterly basis or otherwise, as determined by the OEB's rate regulation process. Sales Service is typically applicable only to small facilities, and is unlikely to be subscribed to by gas generators that are IESO market participants.

Gas Transportation Transactions

Whether an Ontario generator chooses to buy its gas at a transaction hub or at its distribution area is driven by its ability to move gas from that transaction point to the plant. Gas purchased at a transaction point will require the generator to procure transportation from the transaction point to its distribution area. Transportation can be reserved long term by contracting with the pipeline operator(s) along the desired path, or reserved on a term basis by transacting with a transportation reseller or marketer (secondary market). Gas marketers may hold transportation contracts across Ontario pathways, and may be able to offer either transportation service on a daily basis, or delivered gas to a distribution area along its reservation pathway. The reservation of pipeline transportation capacity is integral to ensuring gas can be delivered to the generator. As such, Ontario's gas utilities have developed firm natural gas transportation services that ensure capacity is reserved on the pipeline at all times.

Standard firm transportation contracts allow shippers who nominate gas in the timely window to reserve transportation on a firm basis only in the Timely window. The pipeline operator(s) may interrupt transactions in subsequent NAESB windows. As such, commodity purchased from marketers in subsequent NAESB windows who are relying on interruptible transportation to meet the transaction may also be interrupted.

Because of the reliance of Ontario's gas generation fleet on firm access to natural gas throughout the day, the natural gas utilities worked together to design and implement a collection of Gas Delivery and Management ("GD&M") Services to enhance access to firm gas intraday. These services include enhancements to firm transportation, increased deliverability into and out of storage accounts with firm access, and a number of balancing services that assist generators in balancing the equal-hourly-flow gas purchases with the actual burn profile of a dispatchable generating facility. These GD&M Services are discussed in more detail below.

Gas Distribution Agreements

Within a Gas Distribution Franchise Area, a regulated utility, or LDC, is the possessor and distributor of natural gas. Natural gas that is delivered to a franchise area becomes the responsibility of the LDC to deliver to its customer(s). An LDC is notified of natural gas arriving in its zone by a nomination submitted by its customer. The LDC receives gas on behalf of its customer and distributes that gas across its distribution pipeline network to the customer's burner tip in accordance with that nomination. The robustness of the distribution network within each Delivery Area varies across Ontario.

In Union's South franchise area that spans from the US border in southwestern Ontario to the GTA, there is significant natural gas infrastructure supporting residential, commercial, industrial and generation customers. Ontario's generators represent about 10% of the gas load in that zone, according to Union Gas. Generators in this distribution area have access to firm distribution contracts with no nomination service, allowing Union Gas to manage the variability of flow across its area.

In Enbridge's Central Delivery Area (CDA), where generators represent 6-8% of the utility's distribution network, generators that are connected to the TCPL Mainline via a dedicated pipeline have no distribution network from which to draw. The distribution of natural gas to the generator must match what is being transported upstream on the TCPL Mainline. Where a generator is connected to the robust distribution network in the Toronto area, i.e. Portlands Energy Centre, the distribution agreement offers some balancing flexibility. If the generator uses more or less gas than it transported to the CDA, the distribution network has sufficient natural gas movement to balance those deliveries.

Gas Distribution Agreements vary by utility and by customer need. Utilities offer a variety of firm distribution and interruptible distribution options, with rates that vary by, among other things, the flexibility of balancing service, contract demand, commodity supply arrangements, and capacity factor. Rates are regulated by the OEB for Union Gas and Enbridge.

Gas Delivery and Management Services

Each of the pipeline owners and utilities active in Ontario has responded to the needs of Ontario's gas generation fleet with optional services that enhance the ability to access natural gas and adjust the flows of natural gas across a gas day.

Gas Delivery: Transportation

While standard firm transportation and distribution contracts support firm access to pipeline capacity along a specific path in the Timely window, pipeline operators and utilities in Ontario have developed add-on services that allow shippers to reserve firm pipeline capacity beyond the Timely window.

Firm-all-day services ensure that generators that have not nominated natural gas ahead of the Timely nomination window (14:00 EPT) will still have firm access to transport natural gas thereafter. Services offer additional nomination windows beyond the 5 NAESB windows, allowing generators to adjust the flow of gas from a transaction point or from a storage account to the distribution area across the course of a day.

Firm transportation contracts, standard and enhanced, are contracted on a fixed demand basis. A firm transportation customer reserves a maximum daily and maximum hourly volume on the pipeline path, and pays a fixed rate for that reserved capacity whether or not it moves gas.

The cost of these contracts varies by distance of the reserved capacity and by volume of capacity. Generators further from a transaction point may need to reserve transportation capacity on multiple pipeline paths from more than one gas pipeline operator. In Ontario, as most natural gas transactions occur at the Dawn hub, the cost of transportation increases with the distance from Dawn.

Gas Management: Storage and Balancing

In addition to purchasing and flowing natural gas, Ontario's generators need to balance the difference between the purchased gas and the burned gas. The operation of gas generators in Ontario is not flat, that is, gas will not be consumed in the equal hourly volumes in which it flows. The gas burn profile of a gas generator in Ontario is directly dependent on its real time operating schedule in the IESO market, whether or not its operation is scheduled in the day-ahead. Generators have access to balancing options from a number of locations along a transportation path, from purchasing a storage account at the Dawn hub, to purchasing a balancing service along a pipeline (eg. TCPL Short Notice Balancing Service) to an associated balancing account embedded within the Distribution Agreement with the LDC.

At the Dawn hub, both Union Gas and Enbridge offer a variety of storage services, with a spectrum of firm vs. interruptible access. With the Union Gas storage service, customers can access enhanced deliverability storage, with firm injection and withdrawal rights across a full gas day, and higher volume deliverability than the standard. In Ontario, a number of gas generators have contracted for this High Deliverability Storage Service. Below is an excerpt from Union Gas's Index of Storage Customers showing that a number of large Ontario gas generators that operate outside of the Union South distribution area hold long term contracts for High Deliverability Storage (HDS).

Table 5: Excerpt from Union Gas Index of Storage Customers

Customer Name	Contract Identifier	Maximum Storage Quantity (GJ)	Start Date	End Date	Maximum Firm Daily Withdrawal Quantity (GJ)	Maximum Firm Daily Injection Quantity (GJ)	Receipt Point	Delivery Point	Affiliate
Thorold CoGen L.P. by its General Partner Northland Power Thorold Cogen GP Inc.	BHDS001	170,000	01-Nov-08	31-Mar-19	44,000	44,000	Dawn	Dawn	N
Goreway Station Partnership by its managing partner Goreway Power Station Holdings ULC	BHDS002	600,000	01-Jul-08	31-Oct-28	128,000	128,000	Dawn	Dawn	N
Greenfield Energy Centre LP	BHDS003	211,011	01-May-08	31-Oct-18	42,202	42,202	Dawn	Dawn	N
Portlands Energy Centre L.P. ,by its General Partner, Portlands Energy Centre Inc.	HDS007	500,000	01-Jan-09	31-Mar-19	40,000	40,000	Dawn	Dawn	N
York Energy Centre LP	HDS008	175,000	01-Apr-12	31-Oct-22	87,654	87,654	Dawn	Dawn	N

Table 5 (Source: Union Gas Storage and Transportation Index of Customers https://www.uniongas.com/~/media/storage-transportation/infopostings/indexofcustomers/Storage_Holders.pdf?la=en)

As with transportation service, purchasing enhanced deliverability storage accounts involves fixed demand-based pricing, where the storage capacity and deliverability is reserved for the customer up to its contracted values, regardless of usage. The higher the volume contracted, the higher the cost.

Additional balancing services, including Union Gas' Downstream Pipeline Balancing Service and TCPL's Short Notice Balancing Service, allow generators to adjust the flow rate of natural gas between transportation paths, improving the alignment of gas flows with the expected gas burn profile. These services, and others, are offered as add-on services to an existing storage or transportation account with either Union Gas or TCPL.

Once natural gas has flowed from the transportation path to the distribution pipeline network, balancing options are limited by the flexibility of the LDC and as such, may be interruptible. In Union EDA, for example, customers with Rate 20 Distribution Agreements are provided with a Customer Balancing Service ("CBS"), with balancing capacity related to the distribution service volume. Access to the CBS may be interrupted in tight conditions where the utilization of the service may affect the reliability of the distribution area.

Operation of Gas-Fired Generators in IESO Market

Currently, Ontario has 9,942 Megawatts of gas-fired generation capacity, accounting for 28% of overall installed capacity. This capacity is dispersed across the province, with varying technologies, sizes and owner-operators. The development of Ontario's gas generating fleet has relied on generation contracts, or power purchase agreements, between the facility owner/operator and the Ontario government, by way of one of its agencies.

Generation Contracts

There are a variety of generation contract structures that are in place in Ontario. In general terms, the contracts can be divided into: Legacy NUGs, Re-contracted NUGs, CES-Style Contracts and Other Contract Structures.

Legacy NUG contracts remain in place between the OEFC and some NUG facilities. These contracts were designed and developed before deregulation of Ontario's electricity market and therefore, are structured in a way that does not require market responsive operation. Legacy NUGs are self-scheduling facilities, and as such do not need to participate in DACP other than to submit their forecasted schedule for the following day. There is no commitment nor are they tied to the operation that comes out of the DACP scheduling engine. As a result, these facilities can plan ahead when and how they operate, consuming gas in a predictable way and eliminating any risk and therefore any requirement for balancing services.

A number of NUG contracts that were due for expiry in recent years were re-contracted with new contract structures and are held by the IESO. These re-contracted facilities are required to be dispatchable, and are therefore responsive to IESO market signals. The contracts are structured to support peak period operation, that is, business days from 07:00 am to 11:00 pm EPT (5x16 operation) with a requirement to offer in the DACP. In general terms, re-contracted NUG facilities are of an older vintage (pre-2002), and therefore can be expected to operate at less efficient heat rates than newer facilities built post-deregulation. These facilities may operate at a lower capacity factor than the newer cohort of gas generators in Ontario. The interaction between contract parameters and actual operation is limited, allowing generators some flexibility in the management of their fuel supply, specifically, a lesser need for firm-all-day access to natural gas. With lower capacity factors and more flexible commercial terms in contracts, re-contracted NUG facilities are not expected to hold long-term firm-all-day GD&M services. Further, as these NUGs were constructed under a different market scheme to operate as baseload, many are built in areas where natural gas infrastructure is limited: far from Dawn. It may be more practical at low capacity factors, to utilize the secondary market to deliver gas to the facility's gas distribution area than to hold firm transportation directly.

The third contract structure is the Clean Energy Contracts (CES), Accelerated Clean Energy Contracts (ACES) or Early Mover Clean Energy Contracts (EMCES) held between a generator and the IESO. These contracts are structured to incentivize twenty-four-hour reliable and flexible operation in response to market needs. The contract structure supports dispatchable operation and participation in both the DACP and the IESO's Real Time market. Generators with CES-style contracts have requirements to maintain availability to the IESO grid. In general terms, whether negotiated or bid, CES-style contracts may include some payment to account for fixed costs associated with firm gas services for transportation, storage and balancing services that facilitate operation as a dispatchable generator.

Other generation contracts, including CHP, are active in Ontario. For the most part, the parameters of these contracts do not yield distinct operating structures from those discussed above.

IESO Day-Ahead Commitment Process

The IESO DACP requires facilities to submit offers into the IESO market between 6:00 am and 10:00 am EST for the following calendar day, the 24-hour period between 12:00 am and 12:00 am EST. The Day-Ahead Commitment Engine (DACE) runs up to three passes to optimize energy and operating reserve through determining the least-cost security-constrained solution based on all of the bids and offers submitted.[6]

The first pass is the commitment pass which determines the initial set of committed Day-Ahead Production Cost Guarantee (DA-PCG) eligible generator facilities and imports required to satisfy average hourly forecast demand. It then runs a reliability pass, which commits additional DA-PCG-eligible generators, imports or reductions to dispatchable load or exports to satisfy peak hourly forecast demand. Lastly, the scheduling Pass calculates day-ahead constrained schedules for all resources based on average hourly forecast demand.

The resulting day-ahead schedule for a generator, published no later than 3:00 pm EST[7], can be for any number of hours across the day greater than its minimum generation block run time and for any output from its minimum loading point up to maximum capacity offered. Within that schedule, the IESO commits the generator to its Minimum Loading Point (MLP), which may be lower than its published day-ahead schedule. Committed generators must act to ensure the fuel is nominated and delivered to meet the committed schedule.

[6] IESO Market Manual 9.0: Day-Ahead Commitment Process Overview

[7] The day-ahead schedule deadline of 03:00 pm EST translates to reports published at 4:00 pm EPT from March through November. This is 2 hours behind the new timely nomination deadline in the daylight savings time period, and one hour behind in the remainder of the year.

Discussion of Findings

Participation in the DACP and the Alignment of the Electricity and Gas Markets

Dispatchable gas-fired generators are required to submit energy offers into the IESO's DACP that represent the cost of starting a resource, the cost of holding a resource at a speed-no-load, the resource's incremental cost of energy, and the maximum available energy that the resource can produce on an hourly basis. The cost element within each part of the offer is directly dependent on the cost of the generator's fuel in that hour. The maximum available energy component in the offers is directly dependent on equipment condition and ambient temperature. Each of these components requires some element of speculation on behalf of the submitting generator as a result of market timing misalignment.

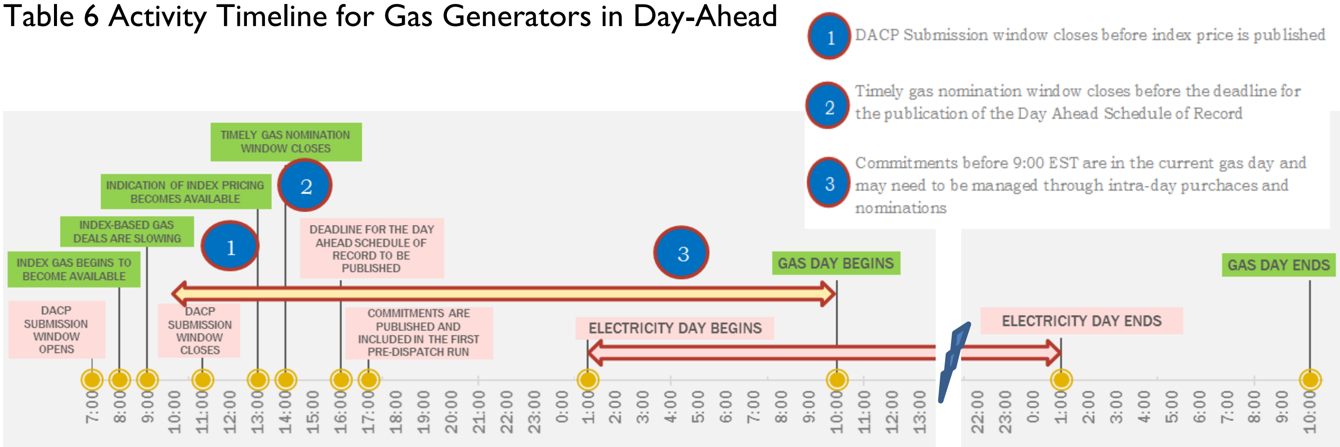
There are three main issues associated with differences in timing between the natural gas market and the IESO DACP process:

1. Generators must submit offers to the DACP before the natural gas index price is settled. While the trading window is active prior to the DACP offer submission deadline of 10:00 am EST[8], the index price of natural gas isn't typically settled until the close of the timely nomination window, recently changed to 2:00 pm EPT.
2. Generators must make decisions to purchase and nominate gas before the IESO has published a day-ahead schedule or commitment report. A generator must determine whether or not to purchase day-ahead gas in the trading window. This decision is typically made on the basis of the generator's operational expectation, independent of the DACP, and needs to be made in alignment with a gas market trading window. To procure gas at an index-based cost, transactions are made when the gas market is actively trading, typically between 8:45 am – 9:15 am EPT.
3. The difference in the 24 hours of the gas day and electricity commitment day results in generators relying on intra-day gas nominations to support a committed schedule in the period from 12:00 am to 10:00 am EST.

These activities and decisions are made by generators according to the timeline described in Table 6 below.

[8] The DACP offer deadline of 10:00 am EST translates to a deadline of 11:00 am EPT from March through November.

Table 6 Activity Timeline for Gas Generators in Day-Ahead



TIME (EST)	TIME (EPT)*	ACTION	Details
6:00	7:00	DACP Submission Window Opens	Four hour window to submit DACP offers opens
7:45	8:45	Index gas begins to become available	Most index gas deals start to become available
8:15	9:15	Index-based gas deals are slowing	Most index gas deals are done and move to fixed price gas
10:00	11:00	DACP Submission Window Closes	Four hour window to submit DACP offers closes
12:00	13:00	Indication of Index pricing becomes available	Prices begins to settle
13:00	14:00	Timely Gas Nomination Window Closes	Capacity access must be nominated in timely window
15:00	16:00	Deadline for the Day Ahead Schedule of Record to be published	Indication of day ahead operations becomes available
15:07	16:07	Commitments are published	Finalization of any day ahead commitments

Table 6[9]

Gas Utility and Marketer Perspective

Gas utilities and marketers operate independently of the power market, and all those interviewed clearly stated that gas generation in Ontario represents only a portion of their business and as such, the IESO's DACP scheduling has little to no impact on their physical or financial business.

Gas utilities and pipeline operators suggest that the timing misalignment between the IESO's DACP and the gas market nomination timelines has no implication on reliability of service. Through the NGEIR engagement, utilities developed GD&M services to meet generators' needs without the restricted timelines of the standard NAESB windows. The utilities interviewed agree that generators who have contracted for firm service will receive firm service.

Gas marketers, or commodity suppliers, convey little interest in the timing of the IESO's scheduling mechanisms. Gas generators transact with marketers on the same timelines as other gas counterparties, both in the Timely and Intra-day transaction pools. Marketers are indifferent as to whether generators are purchasing fuel for a day-ahead commitment, for a real-time schedule, for balancing of storage accounts or to trade with another counterparty. Those interviewed were clear: the IESO's DACP has no direct impact on their business.

[9] The timeline in Table 6 is built to demonstrate the effective times during Daylight Savings period, March through November, where EPT is one hour later than EST. Electricity market times are illustrated in EST and gas market times in EPT. During the winter season, from November through March, EST and EPT are aligned.

Generator Perspective

Generators interviewed acknowledge that time is taken to assess market conditions and predict operational schedules independently of the IESO's DACP. Without a pre-DACP market signal from the IESO, facilities operating in Ontario develop internal tools and assumptions to drive the market assessment and may come to different conclusions, considering current system conditions, supply mix, weather and operating reserve market expectations. For many generators, this assessment feeds into a generator's hourly operational forecast, which is typically done at hourly granularity for a period greater than 24 hours to account for the difference in the 24-hour period of the Gas Day versus the Power Day[10]. The resulting operational forecast is independent of the IESO's DACP. Generators communicated that operational forecasts developed independently provide a stronger indication of operation in the IESO market than does the IESO's DACP. As a result, natural gas transactions are driven more by a generator's internal operating forecast than by relying on a day-ahead commitment from the IESO. A better alignment of DACP scheduling with the gas market would be unlikely to impact this assessment for most generators.

In general terms, the gas-fired generators interviewed expressed the opinion that that the IESO's Day-Ahead Commitment Process does not serve as an indicator of a generator's next-day operation. Generators indicate that a majority of their operation is scheduled in the IESO's real time market. This is by design, as the DACP is intended to ensure that sufficient resources are committed in the day-ahead to meet only the Ontario demand. As intermediate resources, gas generators may not be required to meet the Ontario demand in the day-ahead; instead, they may be scheduled to meet market demand in real time, once exports are scheduled. Exports are not typically part of the DACP, as the risk of incurring an export failure penalty coupled with a lack of financial assurance for day-ahead schedules keeps those exports from committing in the day-ahead.

In other jurisdictions, the day-ahead scheduling is market-based. Generators that are active in other markets suggest that the market-based day-ahead solutions that operate in other jurisdictions are perceived to provide more reliable schedules for short- and long-term planning, creating investor confidence.

The feedback received from interviewed generators made clear that the impact of the misalignment of natural gas and power markets in Ontario is different, depending specifically on the ability of generators to access GD&M services. The feedback from generators is split into two general categories:

A. Category A is used to describe large combined- or simple-cycle gas generators with generation contracts that provide for the long-term contracting for firm gas transportation and storage services, enabling the generator to deliver firm gas outside of the timely window, typically CES-style contracts.
B. Category B is used to describe those combined- or simple-cycle gas-fired generators with generation contracts that provide for fixed cost recovery excluding the cost of

[10] The standard Gas Day runs from 10:00 am – 10:00 am EPT. The DACP commits facilities over a calendar day from 12:00 am – 12:00 am EST.

long-term contracting of GD&M services, typically re-contracted NUG-style contracts. Category B generators may rely on the secondary market, some combination of firm and interruptible service, just interruptible service or have a secondary fuel type to support operation.

Financial Implications of Gas Electric Market Misalignment

Financial implications of the misalignment of the gas market with the IESO's DACP affect both the IESO and the gas generation fleet. Gas generators are afforded some protection from natural gas price volatility and from fuel supply issues through mechanisms in generation contracts. These protections come with a cost that is borne in part by the ratepayer, either through the market price of energy or the global adjustment. Generators themselves bear the risk of their real time decisions, where DACP offers may not align with true operating costs, or where true operating costs do not align with generation contract parameters.

Generator Financial Risk

The most common financial risk to gas generators offering into the day-ahead commitment process is the uncertainty of the fuel cost at the time DACP offers are submitted. Whether a generator is procuring index-based gas prior to the settlement of the index value, or is waiting for a commitment before procuring fixed-price gas in a subsequent window, the fuel cost offered into DACP very likely varies from the actual cost of fuel burned to generate. The financial risks to both Category A and Category B generators are be directly related to the misalignment of the gas and power markets in Ontario.

Category A Generators

Most Category A generators in the Ontario market procure natural gas based on internal operating forecasts ahead of the DACP submissions. Because most of the generation contracts tie Ontario generators to the Dawn-based index price, Category A generators submit DACP offers based on an estimated index price. In most circumstances, the stability of Dawn index pricing does not create a high financial risk and the generators are able to estimate the commodity cost for input into their offers somewhat accurately. However, in tight market conditions as experienced during the Polar Vortex winters of 2013 and 2014, the natural gas price can trade with much volatility, and estimates made ahead of the 10:00 EST deadline may vary significantly from the ultimate index price. Category A generators know this risk, and have expressed comfort in their risk mitigation.

Overall, the financial implications of the misalignment in the current market are minimal for generators in Category A. The risks are known and managed through the GD&M services and existing market programs. For generators in this group holding CES contracts, the risk policy and management of contract risk can affect operational behavior in both the day-ahead and real-time markets. The contracts assume participation in the market based on the Dawn Day-Ahead Index price and any assumed market revenue is calculated using costs based on this commodity cost.

Specific company risk profiles can influence participation in the DACP. A generator with a conservative risk profile may deem the cost risk of misalignment too high in some market conditions. Offers may reflect a risk premium that aligns with the facility's risk profile, resulting in a lower likelihood of obtaining a commitment. Once the gas price is settled and the cost of operation more certain, this generator can amend offers to participate in the real time market.

In some market conditions, the value of the natural gas transportation and storage assets held by a Category A generator may exceed the expected value of the facility's generation. A Category A generator may contemplate selling, on a permanent or temporary basis, some of its firm natural gas transportation and storage assets in the secondary natural gas market. The secondary market is available to assist asset holders in extracting value when the asset is underused. If an enhanced deliverability product is sold, the full value of that service may not pass on to the buyer as a result of specific metering requirements associated with the contracted delivery points.

For a generator, selling or assigning all or a portion of a contracted asset creates value by relieving it of fixed costs. However, it reduces their flexibility and may increase operating cost in the energy market. A generator could also release capacity back to the pipeline which is similar to the permanent sale; however, the pipeline may choose not to maintain the capacity.

With the secondary market sale, the capacity remains available but is held by another counterparty. To regain access to this capacity, the generator needs to compete. This leads to increased cost in the energy market as the fixed cost essentially becomes a variable cost. Access to this capacity needs to take place during the timely window for certainty of supply. This is the result of TCPL's no bump interruptible services.

A generator can also participate in the interruptible transportation market. TCPL currently sets floor prices for this transport that are indicative of the secondary markets. Access to interruptible transportation needs to take place in the timely window; however, once accepted it is firm for the next gas day.

The increased cost of these supply approaches may be included in the DACP offers.

Category B Generators

For generators in Category B, the financial implications of the misalignment are somewhat different. While the challenges in estimating a gas price are similar, these generators typically do not subscribe to firm-all-day transportation services, and may not hold storage accounts. These facilities may rely on the secondary market to deliver natural gas. In the timely nomination window, the cost of fuel procured from the secondary market may be estimated with some accuracy in most market conditions. In subsequent nomination windows, as less liquidity exists in the market and upstream arrangements may be less firm, the cost of both commodity and interruptible transportation may be more difficult to estimate.

Generators in Category B, with less access to firm services intra-day, need to rely more heavily on their operational forecasts. With the DACP commitment published after the timely window, natural gas is nominated almost exclusively in Intra-day nomination windows. Category B generators may rely on the secondary market for commodity and transportation. While gas marketers agree that natural gas is almost always available in the intra-day window, the price of that must be estimated ahead of the DACP offer submission. Where generators in Category B receive a commitment for the period preceding 10:00 am EPT, limited NAESB windows are available for purchasing or nominating from a balancing account. The fewer windows there are to manage gas, the less flexibility there is, which may in turn increase the fuel cost for that portion of the schedule. The fixed price cost of gas purchased intra-day and the cost of obtaining IT transport services could be higher than offered.

The financial implications and risks for generators in Category B are also more pronounced in periods where natural gas pipelines operate near physical limits. Typically occurring during cold winter weather or contingencies somewhere on the pipeline system, the pipeline limitations result in curtailment of interruptible service, making the estimation of delivered gas prices more challenging and riskier. Gas utilities may impose a curtailment on customers with interruptible service. Curtailment can be declared at any time, sometimes with as little as four hours' notice. A Category B generator with interruptible service may incur significant financial penalties to honour a DACP commitment that was granted in advance of the curtailment call. Operating during curtailment requires generators to find other sources of gas, purchase more expensive transportation or incur stricter balancing penalties. These all translate into financial risks for operation that cannot be managed ahead of the DACP submission window.

Financial Risk to Market: Cost of Electricity

The energy cost embedded in a gas generators' offers flows through to the IESO market, and ultimately the Ontario ratepayer through HOEP or market uplifts. The market, therefore, takes on the financial risk of a committed generator's offers exceeding its actual operating cost. Whether the energy cost reflects a conservative index estimate, a risk premium or a longer start period than is actualized, this increased cost is paid to a non-quick start generator under the Production Cost Guarantee program.

Further, where a gas-fired generator does not obtain a commitment from the IESO's DACP, it may still operate in real time. The different scheduling mechanisms utilized by the IESO in its DACP scheduling engine versus its real time scheduling processes embed the risk of scheduling resources in real time that may not represent the most efficient resource on an all-in cost basis.

Consideration must be given to the fact that the flexible GD&M services that are utilized by generators to manage the misalignment of gas and power markets in Ontario are backed by generation contracts ultimately paid by the ratepayer through Global Adjustment.

Physical Implications of Gas Electric Market Misalignment

The IESO's DACP is a reliability commitment program. Essential to that reliability is the assurance that generation offers submitted into the DACP represent the true physical capability of the offered resource. Generators agree that their offered energy is reflective of their ability to produce electricity. Gas utilities resolutely agree that the services and infrastructure are in place to support the reliable physical supply of natural gas not only in the day-ahead timeframe, but also in real-time. Gas marketers agree that if commodity is available, a marketer can get that commodity to market, wherever and whenever that market may be.

A physical supply interruption in Ontario can come in one of two ways: an inability to procure commodity or an interruption in the transportation or distribution of that commodity to the generating facility.

From a physical flow perspective, the timing of the IESO's DACP process and its resulting commitment schedules leads to generators potentially receiving commitments that cover two gas days. To support a committed schedule in any hour prior to 10:00 am EPT, operational gas must be secured in an Intra-Day nomination window. For commitment schedules after 10:00 am EPT, operational gas can be secured for the day-ahead.

However, the IESO's current DACP schedule commits generators at 3:00 pm EST, 1-2 hours after the NAESB Timely Nomination Window closes for the next day, and 25-26 hours after the NAESB Timely Nomination Window closes for the current gas day. As a result, the DACP schedule requires generators to make a determination of their operating schedule two days ahead. Generators interviewed acknowledge that in participating in the IESO's DACP, time is taken to assess market conditions and predict operational schedules independently of the program. This assessment is done daily on a rolling 24-hour basis to account for the difference in the 24-hour period of the Gas Day versus the Power Day.

This misalignment in market timing has the ability to introduce physical implications to both gas-fired generators and the IESO system, if not managed.

Physical Risk to Generators

Stakeholders perceive the risk of natural gas generation not meeting a physical DACP commitment as minimal in the current market environment, regardless of the misalignment of the IESO DACP and the North American Natural Gas Market. A physical interruption in natural gas supply has, can and will happen, but the impact of such an interruption on generators is perceived to be minimal.[11]

None of the stakeholders interviewed for this engagement perceived there to be a risk of an inability to procure natural gas commodity to meet a DACP commitment in typical gas market

[11] A physical interruption of natural gas such as a force majeure event that is outside the control of the pipeline or utility (e.g., a pipeline rupture). In such an event the pipeline or utility will provide service to the extent capacity remains available. The allocation of this capacity will be to firm service holders in proportion to their contract capacity, interruptible services are curtailed prior to any firm interruption.

conditions. Most of the natural gas burned by Ontario's gas fleet is sourced at the Dawn hub, which, as an intersection of multiple pipelines and storage pools, is one of the most liquid trading hubs in North America. Even in extreme weather conditions, marketers agree that gas can be purchased, though the price will vary.

Category A Generators

On the transportation and distribution side, the implication of the misalignment of gas and power markets is more visible. Generators with firm GD&M services, those in Category A described above, can ensure gas is delivered to their facility on a firm basis to meet any DACP obligation. Because these services are not reliant on the Timely nomination window, the fact that nominations may not be in place ahead of the IESO's commitment being communicated does not impact the ability to deliver gas.

A Category A generator has physical risk only where its host LDC or upstream pipeline operator imposes flow limits on its customers. For example, the transmission companies noted that their systems have hourly consumption constraints and that during periods that their system is operating at capacity they would enforce these limits. The hourly volume must be no more than 5% of the daily volume under standard firm transportation contracts. If under-nominated, generators cannot "draft" or pull line pack gas from the distributor or transmission systems as this would negatively impact other gas system customers.

In a number of Distribution Agreements, LDCs hold the right to reduce or stop the physical flow of gas from the utility to the generator's burner tip if that generator is using more gas than it is delivering, therefore putting the distribution system at risk. Were this to occur, the generator might incur some impact on its equipment and may have a forced outage or a forced derate. Distributors agree that flow control is a last resort option, and there is a very low likelihood of its utilization.

Category B Generators

For generators in Category B that do not hold firm GD&M services, transportation or distribution service may be interrupted either as a result of a nomination in a non-firm window or of an interruptible service. These generators, however, have developed comfort in their natural gas delivery options. Pipeline operators and LDCs communicate the availability of interruptible transportation and distribution services publicly, and that information has proven to be reliable. Information on interruptions is often available on a day-ahead basis, in advance of a generator's DACP submission. Where an interruption is anticipated, Category B generators may look to the secondary natural gas market or a secondary fuel source to support operation.

A physical supply interruption in natural gas may, at worst, lead to a forced outage or forced derate of either a Category A or Category B generating facility. For a generator, the risk of an outage is financial: it loses its opportunity to earn market revenue and/or its revenue deviates from its generation contract revenue assumptions. While there is an embedded financial risk on generators, the reality is that generators have very little physical risk.

Physical Risk to Market: IESO Grid Reliability

The IESO holds the reliability risk around physical gas availability. While the financial implications of the gas and power market alignments weigh more heavily on the generators, the physical implications of the gas market alignment issues weigh more heavily on the IESO.

In terms of natural gas supply interruptions, where a gas generator's supply or transportation is curtailed, that generator may not be available to the IESO. Where that information is known ahead of the DACP offer submission, the IESO will see the generator's unavailability reflected in offers. If the situation becomes known after the DACP window, the IESO will see it reflected in outage or derate submissions. To maintain grid reliability, the IESO may need to schedule another resource to meet Ontario's demand where one or more gas resources becomes unavailable as a result of physical fuel limitations.

These physical risks of the gas and electric power misalignments are minimal, overall, to both the IESO and the generation community. The impact of this misalignment is heavily mitigated by GD&M services. However, this may not remain the case.

The IESO supply picture has evolved into a baseload-heavy balance, with nuclear, hydro-electric and renewable generation meeting much of Ontario's demand. Natural gas-fired generation has seen a reduction in capacity factor. In parallel, the fixed cost of holding GD&M services may change as natural gas pipeline conditions evolve. For example, TCPL's Energy East Project proposes to reduce transportation capacity to meet only that capacity under firm contracts. This may put upward pressure on the market price of that firm transportation. In combination, these factors may result in some generators reducing their subscriptions to firm GD&M services, ultimately deciding to increase their risk of physical supply availability in exchange for a reduction in fixed operating costs.

In the longer term, generation contracts are set to expire starting in the 2020's. As the IESO market evolves, generators will need to consider participating in a new market environment without these generation contracts. With the high fixed costs and relatively long terms (5-10 years) of GD&M service agreements, strictly merchant generators may not have the revenue certainty or investor confidence to contract directly for service. In order to ensure the reliable supply of electricity from the gas-fired generators, an evolved IESO market must consider mechanisms to ensure a continued reliable, flexible supply of natural gas.

Additional Comments from Interviewed Stakeholders

During the course of this engagement, interviewed stakeholders provided a number of perspectives on potential improvements to the IESO's DACP process. Many comments received applied to elements of the DACP that are unrelated to the misalignment of gas and power markets in Ontario, and as such, are outside of the scope of this report. The comments below represent the perspectives of stakeholders on the market misalignment challenges, and how they may be addressed by IESO.

Current Management of Market Misalignment in DACP by Generators

Many generators, both Category A and Category B, are satisfied that they have developed processes that allow them to manage the financial and physical risks associated with the misalignment of natural gas market and IESO DACP timeframes in Ontario.

In terms of reliability and physical ability to operate in the IESO market, interviewed stakeholders agree that there is a minimal risk of DACP-participating generators receiving a commitment from the DACP that is not achievable in real time. Participating generators have varying gas procurement, delivery and management scenarios, and none perceived a significant risk of missing a commitment. Ontario's gas-fired generators understand the risks and opportunities embedded in their gas and generation contracts, and how to manage these risks while maintaining compliance with the IESO Market Rules. A generator's operational capability is understood fully and best only by that generator, as arrangements may be in place that are invisible to the generator's distributor, its upstream transportation counterparty, its storage asset counterparty, its gas marketer and the IESO.

Generators have learned to manage the risks associated with the misalignment of gas and power markets under normal operating conditions. NGIER and the resulting gas services provide generators with the tools to manage most of the financial and physical risk exposure to generators, either through direct gas service contracts or secondary market arrangements. The IESO's cost guarantee programs, in their current forms, serve to further mitigate operating risk in both the day-ahead and real time timeframes.

Improving Market Signals Ahead of DACP

Interviewed generators suggest that understanding the IESO's reliability need ahead of the offer submission will allow all participating facilities to better predict operating schedules for the day-ahead, improving decisions for the procurement and scheduling of natural gas. In particular, seeing a better indicator of operating reserve constraints and export conditions would add value to the market assessment performed by gas-fired generators ahead of the DACP offer submission window.

The DACP solves the joint optimization of energy and operating reserve in the day-ahead timeframe resulting in gas-fired generators receiving commitments in periods where energy alone may not have provoked a commitment. Where generators have a better indication of this possibility or have some element of cost commitment on OR schedules, they can make better decisions in the gas transaction and nomination windows ahead of receiving a schedule. To meet the IESO's reliability needs for OR and the impact on gas generators' gas purchase and nomination decisions for a jointly optimized schedule, a future DAM will need to provide clear market information and price commitments for both energy and OR.

Amendments in Commitment Timing

Interviewed stakeholders are aware of the timing misalignments between the gas and power markets, and proposed three potential timing amendments.

Delay of Offer Submission Deadline

Some generators suggested that the IESO delay the offer submission window until the gas market price indicators are stronger.
This proposal may not be practical, given that:

a) Gas generators, particularly those in Category A, noted comfort in the management of the price risk in normal operating conditions. It is only in periods of extreme weather where the financial risk is of concern.
b) There is an understanding that the IESO's DACP engine requires time to run. Delaying the offer submission window may affect the publication timeline, which was clearly a priority for generators.

In Ontario's neighbouring jurisdictions, the submission timeline for bids and offers in the day-ahead timeframe is generally aligned with the IESO. NYISO has a 10:30 EPT deadline, as will both PJM and MISO, once the amendments promised under FERC Order 809 are implemented. ISO-NE requires offers in at 05:00 EPT, well ahead of the IESO's timeframe.

Acceleration of Commitment Publication

Almost unanimously, interviewed generators suggested accelerating the commitment publication timeline to allow generators to nominate within the firm timely nomination windows, i.e. ahead of 14:00 EPT (13:00 EST in Daylight Savings period, 14:00 EST in non-Daylight Savings period). Generators interviewed noted that the IESO's Day-Ahead Scheduled Energy reports are often published early, but participants are hesitant to make commitments to support the schedule until the commitment report is published. It was noted that an acceleration of the DACP scheduling period may impact the IESO's ability to forecast the next-day conditions. It is a priority to stakeholders that the IESO aim to preserve the reliability of the forecast in an accelerated DACP window. In Ontario's neighbouring jurisdictions, this timeline has become standard. PJM, MISO and NYISO publish schedules by 13:30 EPT (12:30 EST in Daylight Savings period, 13:30 EST in non-Daylight Savings period. ISO-NE has accelerated even further, with a publication timeline of 11:00 EPT.

Changing the DACP Commitment Period

One further suggestion from stakeholders is to investigate the possibility of aligning the IESO commitment period with the North American Gas Market, that is to 10:00 am -10:00 am EPT. This would eliminate the issue of issuing commitments that cross two gas days and the risks associated with procuring intra-day gas to meet the morning ramp commitments. While the effect on other non-gas DACP participants, including the IESO itself, is unclear, some stakeholders requested the IESO consider the possibility when looking ahead at new day-ahead initiatives. None of the neighbouring jurisdictions have made this amendment.

Recommendations for Future Initiatives

In considering changes in market mechanisms, the firm, reliable access to natural gas commodity will be an important consideration both for gas-fired generators and the IESO. More reliable day-ahead schedules, if published ahead of gas nomination timelines, may allow facilities to operate reliably with lower fixed costs associated with subscriptions to firm intraday services, bringing cost efficiency to both a potential capacity auction and market operation.