PREFILED EVIDENCE OF THE ASSOCIATION OF POWER PRODUCERS OF ONTARIO

NATURAL GAS ELECTRICITY INTERFACE REVIEW

BOARD FILE NO. EB-2005-0551

MAY 1, 2006

Part 1 Introduction

The Ontario Government has made a strategic decision that for the medium term the majority of Ontario's need for new generation facilities (either to meet incremental demand or to replace retired facilities) will be satisfied by dispatchable gas-fired generation facilities. These facilities bring with them a unique set of characteristics which must be taken into accounting in crafting gas transportation, balancing and related services to meet their operational needs.

The Association of Power Producers of Ontario (APPrO) has actively participated throughout all phases of the Board's Natural Gas Forum process and has worked to coordinate the response of gas-fired generators throughout that process. As a result, for the purposes of this proceeding, APPrO's evidence represents a consensus on the needs of gas-fired generators in the Ontario marketplace and on proposals that meet those needs while at the same time improve the functioning of the wholesale gas market.

The Board's March 2005 Natural Gas Forum Report identified the growth in gas-fired power generation to be "the most important challenge affecting the natural gas sector in Ontario in the next few years." ["Natural Gas Regulation in Ontario: A Renewed Policy Framework", March 30, 2005, pp. 50-51.] Shortly after that report came out, the Board initiated the first phase of the Natural Gas Electricity Interface Review (NGEIR). The Board Staff report on the NGEIR, issued on November 21, 2005 established the groundwork for many of the issues to be addressed in this proceeding.

In its December 29, 2005 Notice of Proceeding, the Board stated that it would hold a generic hearing to determine whether it should order "new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other eligible customers) that contain the following:

1. More frequent nomination windows for distribution, storage and transportation as a new service for gas-fired generators (and other eligible customers).

2. Firm high deliverability from storage as a new service to gas-fired generators (and other eligible customers).

3. Greater operational flexibility in the provision of distribution services to gas-fired generators (and other eligible customers). This includes the removal of barriers to the inter-franchise movement of gas; the ability to redirect or acquire gas to a different delivery point on short notice; and the removal of unreasonable restrictions to the title transfer of gas in storage.

4. Gas storage and distribution as discrete new services to gas-fired generators (and other eligible customers)."

APPrO strongly supports this Board initiative. As more gas-fired generation capacity is constructed to supply intermediate and peaking requirements in the Ontario power market, the natural gas market must respond to power generators' need for greater operational flexibility. Power generators must be able to manage short-term variability in fuel requirements, and bridge the disconnect between the gas market, which is generally priced and scheduled on a daily basis, and the electricity market, which prices hourly, but dispatches domestic generation every five minutes. Gas utilities also require better information about upcoming changes in generators' gas consumption in order to operate their systems as efficiently as possible.

APPrO does not believe that it necessary or appropriate to establish new services or rates that would apply exclusively to power generators. Power generators exhibit a wide range of characteristics with respect to their location on the gas system, peak gas use, load factor and fuel management practices. Some power generation customers will continue to be satisfied with semi-bundled services that combine transmission, distribution, and storage features in the same package. Other generators need additional unbundled transmission and storage services to independently manage their fuel requirements.

Gas utilities need to implement new services, but must also make improvements to existing in-franchise and ex-franchise services. Standard transmission, distribution and storage services should incorporate the flexibility that customers need to effectively manage their gas supplies. Customers should not be required to purchase additional services to get access to essential service features, such as additional nomination windows or alternate receipt and delivery points. Tariff provisions that are barriers to the development of competitive markets for gas services, or impede the efficient and reliable operation of gas-fired generation should also be eliminated.

Ultimately, the best way to accommodate the expected growth in natural gas use for power generation is to ensure that power generators, and the producers and marketers who supply them, have access to open, transparent and liquid markets for the transportation and storage services they require. The Ontario gas utilities play a key role in the development of these markets, and their operations and services should meet or exceed the best practices in the natural gas industry.

Part 2 of this evidence provides the regulatory and operational context in which dispatchable gas-fired generators operate and within which any utility service offerings must be assessed.

Part 3 of the evidence sets out APPrO's proposals for the service offerings required by gas-fired generators.

Part 4 provides APPrO's response to the proposals made by Union Gas and Enbridge Gas Distribution.

PART 2: Dispatchable Gas-Fired Generators and Their Gas Transportation Needs

2.1 The Scheduling of Generators under the IESO Market Rules

Generally speaking, gas-fired generators fall into two categories: self-scheduling and dispatchable generators.

Historically, most gas-fired generators in Ontario have operated within the framework of power purchase agreements with the former Ontario Hydro (which have since been assumed by the Ontario Electricity Financial Corporation) under which the pricing is predetermined and generators produce relatively constant, predictable amounts of energy each day. Commonly referred to as non-utility generators or NUGs, the daily gas consumption patterns of these generators are predictable and relatively constant both during the day and from day-to-day. These plants by and large operate independently of dispatch instructions from the Independent Electricity System Operator ("IESO") and are known as self-scheduling generation facilities under the IESO Market Rules.

A second type of gas-fired generator is one that operates as a dispatchable generation facility under the IESO Market Rules. The Lennox, Brighton Beach and TransAlta Sarnia facilities are examples of existing gas-fired generators that are dispatchable generators. Most of the new gas-fired generation currently under development will also be dispatchable generation facilities. If a generator wishes to be considered for dispatch in a given day, the Market Rules require it to submit offers to provide energy, and optionally other physical services, for each hour for which it wishes to be considered. Generators are then dispatched in accordance with a ranking of economic merit determined by the IESO's algorithm.

Under the Market Rules, a dispatchable generation facility initially is expected to submit its offer data for each hour of a dispatch day by 11 a.m. on the day before the dispatch day (which starts at midnight) to enable the IESO to prepare the first pre-dispatch schedule by 12 noon on the pre-dispatch day. The Market Rules allow generators to revise the data for any dispatch hour without restriction up to two hours prior to that dispatch hour. Thereafter, the IESO must approve any variations in hourly dispatch data submitted by the generator.

After preparing its first pre-dispatch schedule, the IESO will update the pre-dispatch schedule each hour, taking account of changed forecasts, changed system capabilities and changed offers and bids. The IESO releases these revised pre-dispatch schedules to market participants as they are prepared. Throughout this process, the IESO provides each dispatchable generation facility with a pre-dispatch schedule for that particular facility.

The actual dispatch instructions issued by the IESO to a generator are based on real-time schedules prepared by the IESO. The Market Rules require the IESO to determine a real-time schedule for every 5-minute dispatch interval, two minutes before the dispatch interval to which it applies. Real time schedules use the same information for determining pre-dispatch schedules, updated to reflect the most recent valid dispatch data submitted by market participants, real-time system measurements and the most recent projections of demand and other information pertaining to the electricity system which relates to future periods of time. The Market Rules oblige the IESO to provide to a generator a real-time schedule for its facility "as soon as practical" but no later than the start of the dispatch interval to which it relates. A generator that fails to comply with the IESO's dispatch instructions is subject to sanctions under the Market Rules.

As can be seen, the process for scheduling generators under the Market Rules allows for changes in the pre-dispatch schedule from 12 noon on the day prior to the applicable dispatch interval to virtually the commencement of the actual dispatch interval. The IESO pre-dispatch scheduling process is designed for the greatest accuracy based on available information, but a variety of circumstances beyond the control of the IESO – changes in weather patterns, unexpected increases in load demand, unexpected lack of availability of generation units, contingencies on the transmission system - inevitably cause some variability between the initial dispatch schedules provided to a dispatchable generator and the real-time dispatch instructions that govern the generation facility's actual operation.

An additional uncertainty is also present. Although the IESO attempts to dispatch generation units in accordance with the economic merit of their offers, constraints on the transmission grid may prevent the dispatch of a generator whose offer would otherwise be accepted or may require the dispatch of a generator whose offer otherwise would not have resulted in its dispatch. These constrained-off/constrained-on situations are reflected in the pre-dispatch schedules, but may be subject to change in a non-transparent manner as system conditions change.

As a result of these factors, at the time the IESO publishes the initial pre-dispatch schedule at 12 noon on the day before the dispatch day, a generator cannot predict with certainty whether the pre-dispatch schedule for its facility will accurately reflect the schedule that governs its operations during a dispatch hour on the particular dispatch day.

2.2 Variability between Pre-Dispatch Schedules and Real-time Schedules

Variability between IESO pre-dispatch and real-time schedules is a reality of the current Ontario power market. The on-going initiatives by the IESO to develop a day-ahead market will not remove this variability, which will continue to be a challenge that generators will have to manage when operating their facilities.

The introduction of day ahead commitment processes, or of more comprehensive day ahead markets, will provide some benefits, but day ahead markets cannot relieve certain fundamental problems of variability. Day ahead market impacts can be considered from three perspectives: day ahead timing issues; day ahead market design issues; and variation issues.

2.2.1 Day ahead timing issues

Mismatches exist between day ahead concepts in gas and electricity industries. Day ahead electricity markets universally operate by calendar day (using either standard or daylight time) in the jurisdiction. By contrast, gas markets are co-ordinated across the continent with the gas settlement day running from 10 am to 10 am Eastern (prevailing clock time). As a result, the last 10 hours of every gas day, i.e., midnight to 10:00 a.m., see no benefit from any day ahead electricity market. In addition, the gas day ahead (for all gas trading purposes) is the previous business day, whereas the electricity day ahead is the previous calendar day. Consequently, the gas day ahead in respect of Sunday & Monday will always occur before the electricity day ahead.

2.2.2 Day Ahead Market design uncertainty

The IESO's 2004 Day Ahead Market design effort resulted in a concept that addressed physical generation unit commitment and financially binding energy purchase and sale arrangements. Many would consider that such physical unit commitment and financially binding trades for the bulk of the system load are essential features in order to provide any material benefit from the perspective of the gas-electricity interface. The 2004 design was not implemented for a number of reasons including systems complexity and cost. While the IESO remains committed to developing a practical Day Ahead Market, the design features are not yet established nor has a definitive timeline for completing the design and implementing a day ahead market been set. As a result, for the foreseeable future market participants will not be able to look with assurance to a prospective Day Ahead Market as materially addressing problems with the gas-electricity interface.

This summer, the IESO will be running a temporary Day Ahead Commitment Process ("DACP") which will commence in June and conclude at the end of November unless extended by the IESO's Board of Director. DACP will be a temporary reliability measure; it is not a market mechanism. DACP's performance will be assessed this fall in order to determine whether it should run again next year. Ontario generators selected to run in the DACP receive a guarantee that they will operate at minimum loading points for minimum run times based on each unit's technical requirements. Generators will still be subject to real-time dispatch variation for levels of output over and above the specified minimum loading point as well as for all intervals after the end of their minimum run time. The DACP therefore provides very limited mitigation of dispatch variation.

2.2.3 Variation issues

The existence of a day ahead electricity market will not eliminate the real-time variability of system load, available supply and weather and the occurrence of contingency events. Even with a day ahead market, the electricity system will always require real time dispatchability of generation to accommodate the following events:

- variation of actual load from forecast load;
- variation of actual wind and hydroelectric generation from forecast, and changes of water available for run-of-river hydraulic generation;
- failures of import and export transactions. (Under the Ontario Market Rules, intertie transactions are finalized one-hour ahead of real-time. If a scheduled import fails in real-time, the IESO must look to available domestic generation resources in order to make up the shortfall); and
- contingency events (failures of generation or transmission)

None of these conditions will be resolved in the day ahead electricity market.

It is expected that, in the absence of coal-fired generation gas fired generation will be relied upon to provide much of the real-time dispatchability to deal with these conditions, particularly during the 5 x 16 on-peak hours. Hydraulic generation may provide short term rapid response, but gas-fired generation is likely to be the tool of choice for sustained variation.

These different kinds of variability are discussed in more detail below.

(i) Variation of actual from forecast load

The IESO forecasts hourly Ontario demand as a basis for preparing its first pre-dispatch schedules the day ahead of the dispatch day. It subsequently updates these hourly forecasts in later pre-dispatch runs up to one hour ahead of real time. Actual system data is used as a basis for real time dispatch.

A very basic analysis has been performed of two major variations based on data provided by the IESO: the variation between the day-ahead and three-hours-ahead; and the variation between three-hours-ahead and actual. Data[1] has been used for the three year period from August 2002 to July 2005. Variation is analysed on an hourly and on a daily basis for all hours, after excluding anomalies. As can be seen from looking at the average daily cycle on Figure 1 chart, a pattern exists between the mean change from three-hours-ahead (T-3) forecast demand and the real time actual demand.

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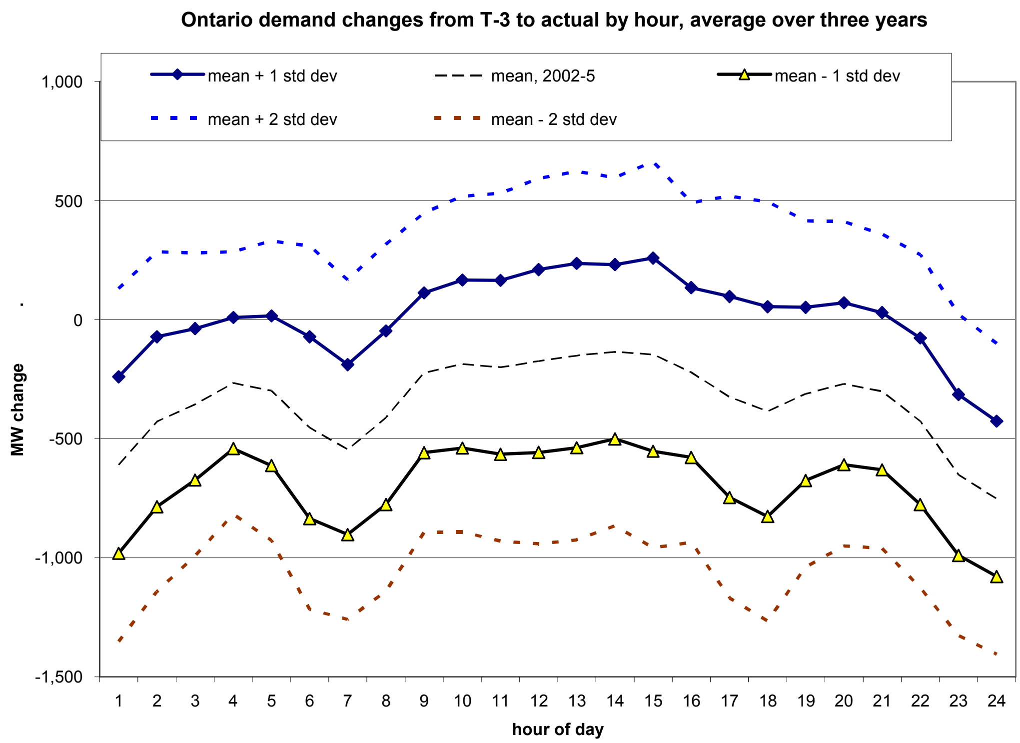
[1] The data sets used were

- Day ahead "hourly SSR demand" and "hourly Market demand" of which the hourly Market demand data was found to give the better match and so was used
- Three-hour-ahead and real time Ontario demand, which excludes any variability of exports

Figure 1


Ontario demand changes from T-3 to actual by hour, average over three years
mean + 1 std dev
mean, 2002-5
mean - 1 std dev
mean + 2 std dev
mean - 2 std dev
1,000
500
0
-500
-1,000
-1,500
MW change
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
hour of day

The results of the statistical analysis are summarised in Table 1:

Table 1: Variability in System Demand
(see footnote 1 for data definitions)

	Day-ahead to T-3	**T-3 to actual**	**Day-ahead to actual**
Mean hourly change	- 190 MW	- 343 MW	- 532 MW
Std. deviation in hourly change	800 MW	396 MW	856 MW
Std. deviation in hourly gas demand relative to forecast[2]	6,400 GJ/hr	3,200 GJ/hr	6,800 GJ/hr
Mean daily change	- 4,560 MWh	- 8,220 MWh	- 12,720 MWh
Std. deviation in daily change	11,230 MWh	4,040 MWh	12,200 MWh
Std. deviation in daily gas demand relative to forecast[3]	90,000 GJ	32,000 GJ	98,000 GJ

The changes shown in Table 1 arise from the demand forecasting alone.

This analysis indicates that maintenance of system reliability in the face of load forecast variation requires significant hourly flexibility in generation response (quantified by the standard deviation around the mean three-hour-ahead forecast error) regardless of individual generator considerations and the other compounding factors discussed below. In order to accommodate this

[2] Gas demand is calculated at an assumed 8 GJ/MWh to account for some inefficiency of variable operation.
[3] Assumes that gas is the marginal energy resource over the whole day.

variability 95% of the time, the gas system needs to provide the flexibility for generators to alter gas deliveries +/- two times the standard deviation, or +/- 6,400 GJ/hr. This flexibility is needed at all times in order to maintain electricity system reliability. While other technologies may accommodate some of this variability, the consistent pattern of variability throughout the day makes it likely that the maximum flexibility for gas-fired generation will be required for at least some of the time during the day.

This basic analysis shows that on a daily basis, the standard deviation in the short term change represents a total of 32,000 GJ/day. The provincial gas system would need to be able to accommodate some +/- 64,000 GJ/day of short notice (three hours) changes to gas deliveries, equivalent to the hourly variation sustained for ten hours.[4]

(ii) Variation of actual wind and hydroelectric generation from forecast

Given the recent addition of wind power to Ontario's resource mix, data is not yet available on the actual Ontario variability of total wind-generated output. However, if one assumes the potential for 2700 MW of wind generation, and an estimated variability of at least 25%, this would result in 675 MW of additional variability. At best this additional variability would not be correlated with load forecast variance. At worst, a drop in wind could cause both an increase in air conditioning load and a reduction in wind generation, with a significant compounding impact on the need for gas-fired generation to respond.

Hydroelectric generation in Ontario has limited storage capability. The operation of these plants is therefore dependant on the flow characteristics of water moving down the particular river. This can result in significant variability between day ahead forecasts and actual production levels for hydroelectric production.

(iii) Changes in import and export schedules, and failures of import and export transactions

The firmness of imports and exports becomes finally apparent to the IESO only as late as the two-hour-ahead pre-dispatch. This can materially impact the total market demand in a manner likely unrelated to variations in the Ontario demand and the wind generation output which are discussed above. This could impact the dispatch of generating facilities. The DACP that will operate this

[4] The unpredictable change required between day ahead and real time is two to three times the change arising in the last three hours, on both an hourly and daily basis.

summer will provide greater visibility of in-province generation resources in the day ahead and will provide incentives to importers to schedule their transactions in the day ahead. However, this does not apply to exporters and there is no requirement for day ahead participation by either importers or exporters.

It is important to remember that even after import and export transactions have been evaluated by the IESO from a market perspective, they may “fail” following communications with the other jurisdictions involved in the transactions. This problem has been discussed at some length in the reports of the Market Surveillance Panel. The DACP scheduling of imports may help to mitigate this in respect of imports that are scheduled in the day ahead.

(iv) Contingency events (failures of generation or transmission)

The electricity system is designed to be secure in the face of contingency events such as the failure of generation or transmission. In many instances, this requires that alternative generation be mobilised on short notice to satisfy system or local demand. In many such instances the IESO is likely to call on gas fired generation reserves to meet that demand.

(v) Combined impact – price based assessment

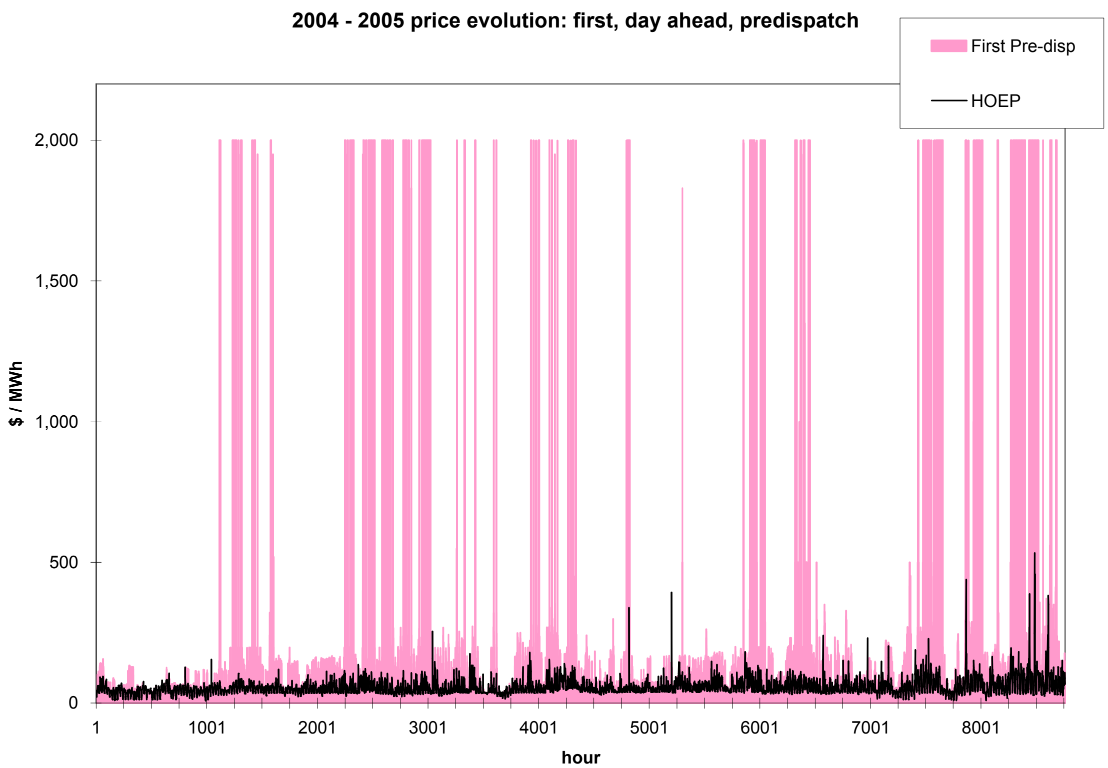
This evidence has identified in sections (i) to (iv) above certain underlying contributors to the variability and unpredictability of the demands placed by the system on gas-fired generators. Flexibility is required in the gas system to enable efficient response to these demands and to protect the interests of consumers.

It is also possible to approach the variability from the perspective of historical electricity market pricing information. In taking this approach it is necessary to recognise that in the absence of an actual day ahead market, it is not clear how representative the existing day ahead pre-dispatch information will be of any future day ahead market. (An actual day ahead market would provide different day ahead bidding incentives, etc.) Recognising this limitation, the historical data is still the only data set available to provide insight into the system parameters at this level of detail. APPrO therefore recommends this as a useful perspective to complement the above analysis of the causes of variability. In broad terms this price based assessment appears to show results quite consistent with that consideration of the factors that contribute to the variability

The analysis starts by taking the simple spark spread as a proxy for determining the optimum operations, i.e., if in any hour the price of electricity (HOEP) exceeds the Dawn index cost of fuel at an assumed heat rate, then the facility should run. While actual operation of generators is more complex, this proxy provides a reasonable basis for comparisons between perceptions in the day ahead, three hours ahead, and the actual outcome. Three charts have been prepared to show the results of the analysis.

Figure 2 compares day ahead pre-dispatch prices to the actual HOEP for the 12 month period from August, 2004 to July, 2005 (the x axis represents each hour in that 12 month period.) Note that it is the day ahead pricing results that would likely be most impacted by DACP or a day ahead market.

Figure 2



More detail is shown on Figure 3, which focuses on a one week period in January, 2005. This chart introduces the three-hour-ahead price for comparison, as well as the production fuel cost based on the Dawn gas index.

Figure 3

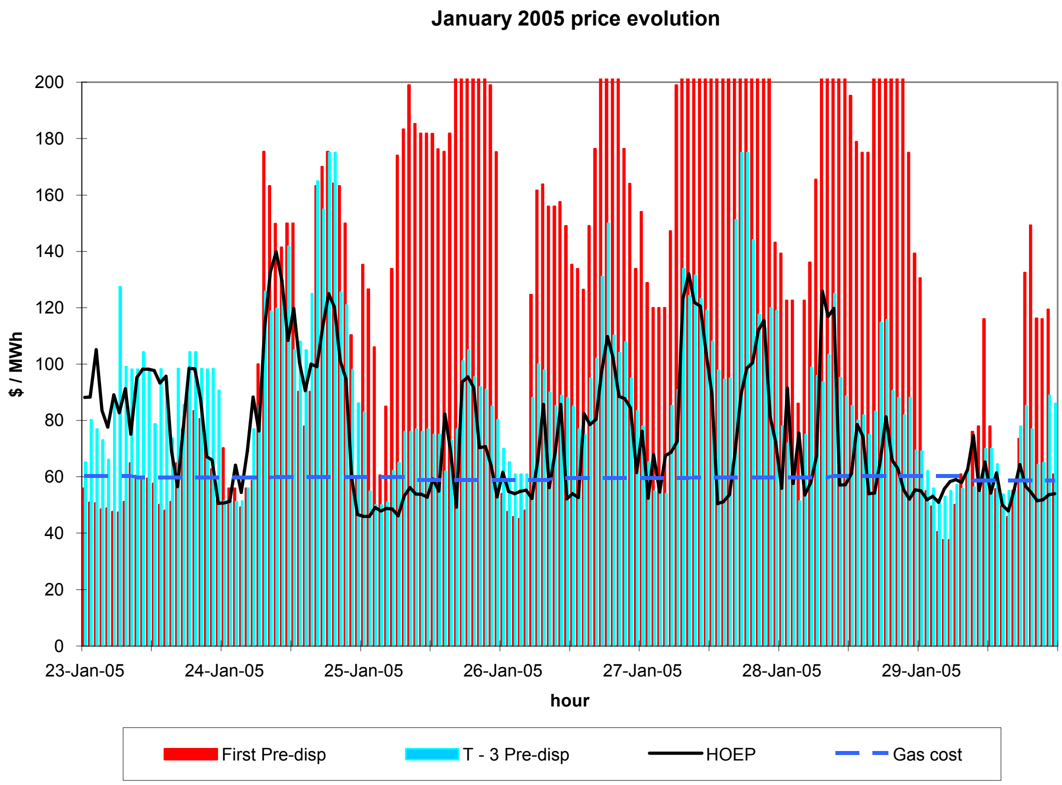
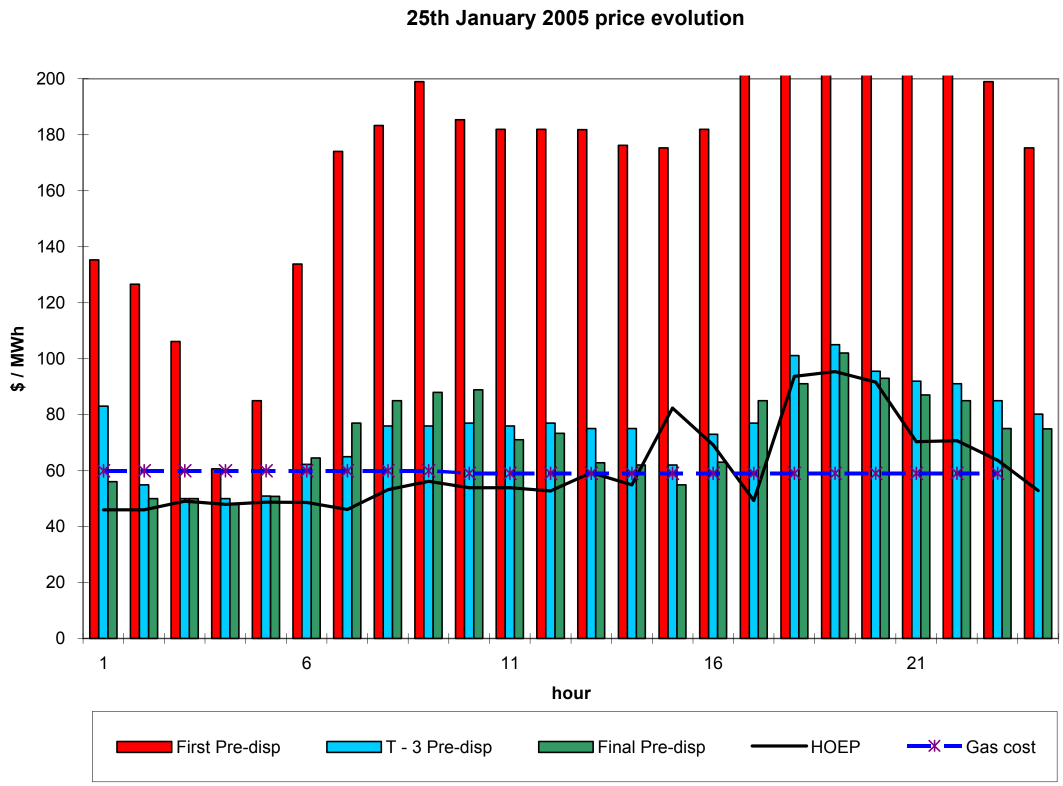


Figure 4 presents the data for a single day, January 25, 2005 and also adds the final (one-hour-ahead) pre-dispatch price for comparison.

Figure 4



The data for the day shown on Figure 4 clearly highlight the issues in question:

- From hours 2 to 6, in the day ahead dispatch appeared to be economic, but by three hours ahead it appeared uneconomic and actual operation would have been uneconomic;

- From hours 7 to 14, and again in hour 17, dispatch appeared economic in the day ahead and continued to be so in all pre-dispatch periods including the one hour day head. Real time dispatch, however, would have been uneconomic;

- In hour 15 it appeared in the final pre-dispatch that operation would be uneconomic, but in fact actual operation in real time would have been economic;

- In hour 16, and again in hours 18 to 23, all pre-dispatch signals correctly indicated economic operation in real time.

In total, the day ahead pre-dispatch signals indicated economic operation for 24 hours (100%), the three-hour-ahead pre-dispatch indicated economic operation for 20 hours (83%), and the actual real time operation would have been economic for 8 hours (33%). The status of the generator as economic or uneconomic to dispatch changed in 16 hours (67%) between day ahead and real time, of which 12 hours showed a change in the last three hours. (Charts are available to show how the pre-dispatch signals with respect to certain given dispatch hours have evolved over the period from the first day-ahead pre-dispatch schedule to the real time HOEP. These charts support, but do not materially add to, the data presented here.)

Over the full three year period from August, 2002 to July, 2005 , the analysis of all on-peak hours shows the following results:

(i) the day ahead indication was for economic operation of a hypothetical gas-fired generator in 84% of on-peak hours. The analysis shows that in 12% of those hours generation operation which was shown as economic in the day ahead schedule became uneconomic at three-hours-ahead. This was offset by 6% of on-peak hours in which day ahead uneconomic operations became economic at three-hours-ahead. Overall, this resulted in an indication at three-hours-ahead of economic operations for this hypothetical gas-fired generator in 78% of on-peak hours.

(ii) Between three-hours-ahead and real time, generation operations became uneconomic in an additional 26% of the on-peak hours, offset by uneconomic operations that became economic in real time in 3% of the on-peak hours. Real time economic operations of this hypothetical gas-fired generator were seen in 55% of on-peak hours.

(iii) Note that in 5% of on-peak hours, the change from day ahead to three-hours-ahead was reversed by real time. In total, therefore, the dispatch economics of this hypothetical gas-fired generator changed at least once in 42% of the on-peak hours. If one considered additional intervening pre-dispatch results, this percentage would further increase.

(iv) Given the likely impacts of the new gas fired generation on the total system supply curve, this assessment is not meant to suggest that all gas fired generation is going to be subject to dispatch over its full range with this frequency. Instead, the assessment confirms the strong impact of variations on the dispatch that will be required of gas fired generation when it operates close to the margin, irrespective of any day ahead market. The level of changed economics indicated in this price analysis appears in line with the analysis of system demand forecast changes set out above.

(vi) System variability and the need for gas-fired generator flexible responsiveness

In addition to the variability of dispatch that will continue to characterize the electricity market, even with the introduction of a day ahead market, it is very important to take into account the role that the responsiveness of gas-fired generation facilities will play as the province's power system shuts down existing coal facilities. As the IESO noted in its August, 2005 10-Year Outlook:

> Coal supply makes up a large part of Ontario's flexible generation, and it has traditionally been required to meet changing demand, to supply demand when other supply sources are unreliable, and to balance load and generation at all times. The specific operating characteristics of new generation will require changes to current practices in order to provide operating flexibility and sustained energy production capability as and when it is needed. (p. v)

In its Ontario Reliability Outlook, issued February 2006, the IESO again referenced the need for new supply to provide the operational capabilities currently provided by coal-fired units. With the retirement of Ontario's existing coal generation, dispatchable gas-fired generation will make an increasingly important contribution to system reliability and economic efficiency. Under these circumstances, there is a direct link between the flexibility of service offerings in the gas market and the reliability of the power grid. Inflexible gas service offerings increase the risk in the Ontario electricity system. Accordingly, it is necessary that dispatchable gas-fired generators have access to transportation and balancing services that will enable them to contribute to the required reliability of Ontario's electricity system.

2.3 The Key Operational Characteristics of Dispatchable Gas-Fired Generators

Since the decision of the Ontario Government in the late 1990's to restructure the province's electricity market, there have been three stages in the development of dispatchable gas-fired generation in the province.

First, early movers, such as TransAlta-Sarnia (2003) and Brighton Beach-Windsor (2004) constructed facilities that have come into operation since market opening.

Second, the Government's Clean Energy Supply RFP has given the green light for the construction of the Greenfield Energy Centre (Sarnia), the St. Clair Project (Sarnia), Greenfield South (Mississauga) and GTAA (Mississauga).

Third, in more recent months, the Ontario Power Authority, in accordance with ministerial directives, has enabled construction to proceed on Sithe Global Goreway (Brampton) and negotiations are underway to finalize an agreement with the Portlands Energy Centre (Toronto).

All of these gas-fired generation facilities share several features:

(i) they are **large-scale generation facilities** of 400 MW or greater, with the exception of Greenfield South and GTAA. They range in size from 99MW for the GTAA to the 1,005 MW Greenfield Energy Centre;

(ii) as a result of their size, these facilities will **consume large volumes of gas during each day**. Gas consumption for a 500 MW facility will be in the neighbourhood of 4,167 GJ/hr (100,000 GJ/day) if run for 24 hours;

(iii) these **facilities will not operate as baseload generators but as dispatchable mid-merit plants**. That is to say, these facilities will not operate at all hours during a day. It is anticipated that most of them will operate as mid-merit, intermediate facilities with an operating profile that will vary considerably on a seasonal and daily basis. It is unlikely that the facilities will operate for any significant times over weekends. As a result, the gas load profile of these facilities probably will result in load factors in the 40-50% range; and,

(iv) the Ontario power market is now characterized by dual summer and winter peaks. As a result, these facilities will **consume the largest volumes of gas during the summer and winter months** in response to IESO dispatch instructions.

2.4 The Impact of OPA Contracts on Facility Dispatch

The procurement contracts that the OPA is entering into with new gas-fired generators are designed not to alter the existing dynamic of the market driving the economic dispatch of generation plants. The contracts expose these generators to all the incentives of operating in the IESO real-time market, and if applicable the day ahead market. The CES contract calculates financial payments (whether support or revenue-sharing payments) using a model that deems the facility to operate when a certain relationship exists between the HOEP and day-ahead prices for gas at Dawn. Payments under the contract are independent of the facility's actual operation, but the payment structure tends to reinforce the incentive to be market-responsive.

Therefore, the facilities will operate as dispatchable generation facilities pursuant to dispatch instructions from the IESO and will continue to face the challenges in matching gas consumption with electricity dispatch instructions in order to minimize daily gas imbalances. Since the day-to-day dispatch of these new gas-fired generation facilities will be driven 100% by how the electricity market operates, it is critical that these plants have access to flexible gas transportation, balancing and related services from the utilities in order to optimize their dispatch and minimise the cost to the power system of reliable service.

2.5 The Key Need: Balancing Gas Volumes

The dispatch procedures under which generators operate in Ontario present challenges for their gas transportation arrangements: challenges that are very difficult to meet with the transportation and storage services presently offered by Ontario's gas utilities. The prevailing gas transportation standards applied by Union, EGDI and TCPL make it difficult for a dispatchable gas-fired generator to balance gas deliveries and gas consumption during a day in response to IESO dispatch instructions for several reasons:

(i) the opportunities to adjust gas nominations during the course of a gas day are limited to four windows;

(ii) only the initial 'timely' nomination window allows for the firm reservation of gas transportation capacity during a gas day;

(iii) the standard gas practice of treating gas flows as rateable over the course of a gas day is at odds with the highly variable requirements of a gas-fired generator for gas deliveries over the course of a gas day; and,

(iii) current tariffs impose significant penalties for the failure to balance deliveries and receipts by the end of a gas day.

In sum, the major gas transportation challenge faced by dispatchable gas-fired generators relates to the balancing of their daily withdrawals of volumes of gas from the pipeline system with the volumes of gas injected into the system.

A simple example, using Enbridge's current Rate 125, will illustrate the practical challenges faced by dispatchable gas-fired generators. Take a hypothetical 500 MW gas-fired generator located in Enbridge's CDA that has a contract demand 100,000 GJ of gas a day (4,167 GJ/hr). Assume that as a result of the IESO's pre-dispatch schedule issued at 12 noon on the pre-dispatch day (Monday), the generator forecasts that it will consume gas for 18 hours, or 75,000 GJ, over the course of the gas day (10 a.m. Tuesday to 10 a.m. Wednesday) and proceeds to nominate, at the timely nomination window (Monday, 1 p.m.) 75,000 GJ of gas for delivery over the gas day. Under this nomination, the rateable flow will effectively be 3,125 GJ/hr (75,000 GJ/24 hours) from 10 a.m. on Tuesday to 10 a.m. on Wednesday. Consider two scenarios:

(a) Supply Underrun: By 10:45 a.m. on Tuesday, the IESO has not dispatched the facility. The gas-fired generator believes it will not be dispatched for the remainder of the day. On the Intra-day 1 window, the generator reduces its nominations for the balance of the gas day. Nominations for the Intra-day 1 window are due by 11:00 a.m. Tuesday, with effective flow at 6 p.m. Tuesday. The remaining 16 hours of gas

(50,000 GJ = 3125 GJ * 16 hours) expected to be delivered from 6 p.m. Tuesday to 10 a.m. Wednesday can either be sent to storage, sold to a third party or diverted to another location. However, the 25,000 GJ for the first 8 hours of the gas day will be deemed to have flowed and will incur significant balancing penalties. For example, if gas is priced at $10/GJ, the lowest spot price on that day, the cost of the effective imbalance cash-out penalty with Enbridge would be $122,500 [25,000 GJ*(1.0-0.02)*($10/GJ*(1.0-0.5))]. With more nomination windows available, a generator would have had an opportunity to reduce the 25,000 GJ imbalance.

(b) Supply Overrun: At 10 a.m. on Tuesday, the IESO, responding to increased demands on the power system, issues revised dispatch instructions to the facility that will require it to increase its hourly consumption of gas over the day to 4,1617 GJ/hr, from 10:00 a.m. Tuesday to 10:00 a.m. Wednesday. The facility uses the Intra-day 1 window (Tuesday 11 a.m.) to increase its nominations from 75,000 GJ/day to 100,000 GJ/day. The additional volumes will only be available on an interruptible basis. If approval to increase the nomination is not granted, the plant will effectively draw 25,000 GJ of gas from the system that it did not deliver. The facility likely would face overrun charges at the end of that gas day. If gas is priced at $10/GJ, the highest spot price on that day, the cost of the effective cash out penalty would be $122,000 [25,000 GJ*(1.0-0.02)*$10/GJ*(1.5-1.0))].

What these examples illustrate is that in order to meet their operational needs, dispatchable gas-fired generators require gas transportation services that enable them to adjust, frequently and in a timely manner, their calls on transportation services so that the generators (i) can respond to IESO dispatch instructions and (ii) end the gas day with minimal or no imbalances. To achieve this result, enhanced transportation services need to contain two key features:

(a) more nomination windows during each gas day in order to reduce the need to rely on balancing services to eliminate end-of-day imbalances; and

(b) more flexible balancing services, including storage deliverability, that permit generators to manage delivery/receipt imbalances on short notice.

The more flexible the gas transportation and balancing services offered by Ontario's gas utilities are, the easier it will be for the IESO, through its dispatch of generators, to maintain the reliability of the Ontario power grid.

It is also important to note that location is critical when considering the development of appropriate mechanisms to enable dispatchable gas-fired generators to manage their injections and withdrawals from the pipeline systems. The closer a generator is to storage and available pipeline capacity, the greater the flexibility the generator may enjoy in balancing delivery and consumption. Put another way, the balancing needs of a dispatchable gas-fired generator located west of Dawn near interprovincial or international pipelines will be quite different than those of a generator connected to TCPL's pipeline in Enbridge's CDA, those of a generator, such as Portlands Energy Centre, that is embedded deep in Enbridge's pipeline system, and those of a generator located in Enbridge's EDA. Each generator must operate in accordance with the same dispatch process contained in the IESO's Market Rules, but each faces unique challenges or opportunities in matching its daily gas consumption with its electricity dispatch instructions. As a result, any enhanced transportation and storage services offering solutions must be flexible enough to deal with these locational differences amongst generators. A "one size fits all" solution will not work.

2.6 The Basic Principles

2.6.1 The system reliability and economics benefits of improved gas transportation and balancing services

The Ontario Energy Board has correctly identified that improvements must be made in the interface between the natural gas and electricity markets. Enhancing gas transportation, balancing and related services for dispatchable gas-fired generators will influence positively both the reliability and the economics of the electricity system:

- The electricity system depends for reliability on generators capable of responding to continuous, short notice variations and contingencies. The gas-fired generators will require enhanced gas services in order to deliver such reliability benefits in any reasonably economic manner.

- Inflexibility of economical gas delivery creates inflexibility for generators in responding to changing demands and other circumstances. Such inflexibility will tend to drive the IESO to use resources that would not otherwise be economic when it needs to address variability. This creates a real cost to consumers.

2.6.2 Gas Services

Gas utilities bear the primary responsibility for developing the services that their dispatchable gas-fired generators customers need to respond to the instructions issued by the IESO. As this Board noted in its decision in the Greenfield Energy Centre Limited Partnership leave to construct application (RP-2005-0022), a primary consideration of the public interest with respect to services provided by utilities is that customers have access to the services they require.

The reality of the Ontario market place is that few third parties, including storage companies in Michigan, offer the type of balancing and storage services that dispatchable gas-fired generators require on an accessible, timely and cost-efficient basis. For example, as a practical matter, Michigan storage is not accessible to Ontario generators because of the lack of compatible transportation services on the Ontario side of the border.

So in order for gas-fired generators to meet the needs of their customers – the power consumers of Ontario – the gas utilities must provide their customers – the generators – with a suite of service options that will enable generators to operate in the Ontario power environment efficiently and effectively.

The gas-fired generators appreciate the work performed to date by Union, EGDI and TCPL to develop better transportation, balancing and related services. The new services and proposals for high deliverability storage and additional nomination windows are an improvement over existing services. However, the gas-fired generators believe that additional services or changes to the proposed services are necessary to ensure that dispatchable gas-fired generators can meet the growing electricity needs of Ontario.

The balance of this evidence seeks to (i) identify the particular services that generators require, (ii) propose those services that are required to enable generators to manage their gas supply requirements efficiently and effectively within the dispatch regime of the IESO and (iii) explain why the utilities' current and proposed services do not meet the generators' needs .

In putting forth its proposals, APPrO has been guided by the following key principles:

- utility services for generators should contribute to the economic efficiency of both the gas and electricity markets;
- such services should contribute to the reliability of Ontario's power system;
- fully unbundled services should be available to those generators who wish to contract for them; and,
- utility services for generators should contribute to the further development of a robust, competitive and transparent wholesale gas market in Ontario.

Part 3 APPrO Proposals

3.1 Introduction

APPrO is proposing specific changes to the gas transportation, storage, and related services offered by natural gas utilities under the jurisdiction of the Board. These service changes include:

1. Transmission-level service to in-franchise customers supplied directly from the utility's gas transmission mains, or served through a dedicated lateral to a third party pipeline.

2. Negotiated rates for firm transportation services to large end users, based on the special characteristics of the service or the customer's potential for bypass.

3. Utility storage services with higher deliverability at cost-based rates, but with incremental deliverability offered based on the utility's incremental costs.

4. Additional nomination windows and a shorter period between the time a nomination is due and the time the change goes into effect. Specifically, utilities should accept nomination changes each hour throughout the day, with changes becoming effective two hours later, or at the start of any later hour that the customer may specify.

5. Scheduling of transportation deliveries and receipts, and storage injections and withdrawals, at variable hourly rates.

6. The right to request alternate receipt and delivery points through the nomination process, with alternate points available on an interruptible basis whenever the capacity is operationally available.

7. "Firm all day" transportation and storage service as an option available to all customers.

8. Elimination of mandatory gas delivery obligations.

9. Additional services for imbalance management and intra-day trading, including: (a) combined nominations and imbalance accounts across multiple locations; (b) imbalance trading; (c) title transfers between utilities; and (d) title transfers between storage accounts.

10. Transportation and storage capacity offered on a pre-determined schedule and price indexes for market-based transactions.

11. A continuing review process to determine how well the services provided by the utilities meet the needs of gas-fired generators.

These proposed changes will directly benefit gas-fired power generators by improving their ability to manage their gas supply costs. However, these measures will also create direct and indirect benefits for energy consumers throughout Ontario:

- Other large gas users and marketers will be able to take advantage of the same improvements in gas delivery and storage services to better manage their gas supplies and reduce costs.

- Giving power generators the ability to manage fuel costs, and greater certainty about what these costs will be, will influence generators' bidding behavior, reducing the level and volatility of electricity prices. This is true both in terms of the short term energy price bids submitted to the IESO, and the long term capacity values bid to the Ontario Power Authority.

- Adding flexibility and transparency to gas utility services will promote competition for storage and balancing services and increase the efficiency of the Dawn Hub.

This section explains APPrO's proposals for improving the services provided by natural gas utilities in Ontario to meet the needs of gas-fired generators and other market participants.

3.2. Transmission-level service for in-franchise customers

APPrO Proposal 1

> **Utilities should be required to offer transmission-level services that exclude costs related to the distribution network. In the case of Union Gas, customers who cover the costs of any interconnection facilities and do not require additional balancing services from the utility should be able to operate using existing M12 or C1 transportation services, without contracting for additional distribution service from the utility.**

Customers should have access to all utility assets and services on an unbundled basis, and be able to purchase only the services they actually need. Complete and effective unbundling of utility services allows customers to reduce costs by directly managing their gas supply arrangements, and is necessary for the development of competitive markets for transportation, storage, and balancing services. At the same time, however, utilities should continue to offer bundled and semi-unbundled services, including services with no-notice features, for customers who do not have the capability or need to manage services on a fully disaggregated basis.

Many large customers, including gas-fired power generators, are served directly from transmission facilities or through a dedicated connection to a third-party pipeline operator such as TransCanada. Basic principles of cost-causation and fairness dictate that large customers supplied directly from transmission facilities should not be required to pay distribution-level costs, particularly when the additional costs associated with serving a customer through the distribution system are relatively large. According to evidence submitted by Union Gas in this proceeding, the Union average unit cost based rate associated with serving a customer off distribution main is more than three times the cost of serving a customer off transmission main (28.43 cents/m3/month for distribution compared to approximately 9.00 cents/m3/month for transmission). [UGL Undertaking 1]

Bundling distribution costs into transmission-level transportation services also creates incentives for bypass. If a large end user can avoid unnecessary gas distribution charges by building its own connection to the transmission network, the end user will have a financial incentive to bypass the utility, even if the utility's cost of providing service is lower than the end user's bypass cost. Functional unbundling of services will help bring rates into line with the cost of providing service, and reduce the incentive for bypass.

Union Gas does provide pure transmission-level transportation services under its M12 and C1 rate schedules. M12 is a cost-based service that is applicable to service between Dawn and Parkway or Kirkwall on Union's Dawn-Trafalgar system. The C1 Rate Schedule applies to transportation service on Union's other transmission facilities, and to transportation service between points within the Dawn Hub. Union Gas also has an M16 Rate Schedule that is used to transport gas for embedded third-party storage facilities.

Although the M12 and C1 services are mainly used by ex-franchise shippers, in-franchise customers can also contract for M12 and C1 service. For example, an in-franchise customer located east of Dawn with a Parkway delivery point under his T1 contract may choose to contract for M12 transportation service from Dawn to Parkway to take advantage of the greater liquidity of gas supplies and balancing services at the Dawn Hub. However, even if the customer is directly connected to the Union M12 transmission facilities, Union Gas does not allow gas to be delivered to the customer's meter using M12 transportation service, but requires this customer to also contract for additional transportation service under a separate rate schedule, such as T1.

Experience in Other Markets

Pacific Gas and Electric Company recently implemented a rate design change that created a transportation rate for large electric generators who are supplied through customer-owned laterals connected to the utility's "backbone" gas transmission system. Electric generator customers served through local transmission mains will continue to pay a different rate, and both transmission-level rate schedules are distinct from the utility's distribution-level services. In approving this change, the California Public Utilities Commission found that "the backbone level rate proposal aligns customers' rates with their cost of service by adhering to the principle that customers should not pay for services they do not receive, and achieves rates that reflect the costs that the customer imposes on the system." The Commission noted that the lower rate would help prevent bypass and establish cost based rates that more closely reflected market conditions. [Order Modifying and Denying Rehearing, Decision D0405061, June 1, 2004]

3.3. Negotiated Contracts

APPrO Proposal 2

> **Utilities should be allowed to negotiate rates for firm transportation and balancing based on differences in service quality or the customer's opportunity to bypass, as long as the revenue from the customer exceeds the incremental cost of providing service. Negotiated rates and terms of service should be filed with the Board prior to the commencement of service to demonstrate that the service will not be subsidized by other shippers and that the utility is not applying negotiated rates in a discriminatory manner.**

Utilities should have the ability to negotiate rates and terms and service for large end users under specific circumstances, and with appropriate safeguards against discriminatory treatment. Negotiated contracts may be necessary to meet a specific customer need or to compete with a bypass alternative. Negotiated rates can also be used to reduce financial risks for a large capital investment, such as an electric generating facility, by establishing a known rate over a specified period of time.

Experience in Other Markets

Many state and provincial utility commissions allow gas utilities to negotiate rates for transportation service provided to large end users. Michigan is one example. The Michigan Public Service Commission (MPSC) allows gas utilities to enter into special gas transportation contracts with negotiated rates and non-standard terms of service. In reviewing these contracts, the MPSC is primarily concerned that the negotiated agreement has no negative implications for other gas utility customers, either in terms of operations or rates. The utility is required to account for the negotiated contract as a separate rate class in its cost of service studies and must report revenues and volumes associated with the agreement separately in its annual report to the MPSC. The potential for bypass of the utility is one factor that the MPSC may consider in approving special gas transportation contracts. The MPSC has approved several special service contracts for service to gas-fired generators [see, for example, Order Approving Application for a special contract for gas transportation service between SEMCO Energy Gas Company and SEI Michigan LLC, Case No. U-12301, April 11, 2000].

The MPSC has also allowed gas-fired generators to construct bypass pipelines to connect directly with interstate transporters [see Order Approving Settlement Agreement, granting Mirant Wyandotte, LLC authority to construct and operate a natural gas pipeline to connect its proposed power plant to Panhandle Eastern, Case No. U-13387, January 31, 2001].

The Alberta Energy and Utilities Board (EUB) has determined that utilities should have the opportunity to implement innovative rates and services to compete with alternate suppliers and meet customer needs within the context of a postage stamp rate design. The criteria to be used in evaluating a proposal for a load retention rate include the requirement that the rate must exceed the long run incremental cost of service and provide a contribution to the system. [EUB Decision U97096, November 14, 1997]

3.4 High Deliverability Storage Service

APPrO Proposal 3

1. **Continue to make a base level of storage available to in-franchise customers at rolled-in, cost-based rates. The base level of storage that is made available to power generators should recognize that generators' need for storage is different from that of traditional space heating customers.**

2. **Give customers the option to increase storage deliverability by paying a rate that reflects the incremental cost of developing or acquiring storage capacity with higher deliverability. Costs associated with high deliverability storage would be tracked separately from the costs of storage with standard deliverability. The cost-based rate for purchasing additional storage deliverability would therefore change over time as additional high deliverability storage capacity is developed or acquired by the utility.**

3. **In-franchise customers should continue to have priority when additional storage capacity and deliverability are made available by utilities.**

The gas transmission and distribution services developed to serve Ontario markets have been built around the use of Dawn storage for balancing. All of the storage at Dawn is operated by Union Gas or Enbridge. It is therefore important that all in-franchise customers, including new gas-fired generators, have access to utility storage services at reasonable rates.

Union Gas and Enbridge currently make storage service available to in-franchise customers who take service under unbundled or semi-unbundled rate schedules at cost-based rates. The maximum amount of storage capacity the customer is able to purchase at cost-based rates will be determined using the "aggregate excess" methodology. This storage service has a standard deliverability (withdrawal and injection) of 1.2%, and is subject to ratchets.

Union Gas and Enbridge both charge, or propose to charge, market-based rates for storage service sold to in-franchise customers when that storage service has deliverability greater than 1.2 percent.

There is wide recognition that power generators will need storage services with deliverability that is higher than the standard utility storage services currently provide:

> There was a consensus among industry experts that generators are likely to require higher deliverability from storage since generators will have two seasonal peaks (summer and winter) and will likely be required to switch on their plants and operate on relatively short notice. [Board Staff Report, EB-2005-0306, November 21, 2005, pp. 31-32.]

> To be able to balance the power generation load, the issue of how quickly gas can be injected or withdrawn will be more important than the amount of space…. [Enbridge Evidence, Exhibit B, Tab 3, Schedule 1, Page 5]

There is considerable difficulty in understanding how the current market for higher deliverability storage works because of the lack of transparency or price discoverability. This poses a planning challenge for gas-fired generators.

Moreover, under the current proposals of the Ontario utilities, it is not clear how generators will obtain access to the storage services they need in the future, and what this service will cost.

3.5. Additional Nomination Windows

APPrO Proposal 4

> **After the completion of the Timely nomination cycle, which ends at 5:30 PM Eastern Time when day-ahead scheduling information is received by shippers, customers should have the ability to submit nominations each hour, prior to and during the applicable gas day. The new nomination will become effective two hours later, or at the start of any later hour that the customer may specify. Customers may request that nomination changes become effective sooner, and the utility will use reasonable efforts to accommodate these requests. For instance, this shorter period could apply to a request to increase or decrease the rate of injection or withdrawal from the utility's own storage service, which does not require confirmation from another transporter. In all events, the nomination change will not go into effect unless it is confirmed by the upstream and downstream transporter or storage operator, as required.**

Example:

A power generator determines at mid-day on Wednesday that additional gas will be needed for the Wednesday gas day. Under this proposal, if the generator submits a revised nomination by 1:00 PM, the change in flow will be effective at 3:00 PM. If the generator decides to increase supply by withdrawing gas from a Union Gas storage service, or borrowing gas from Union under a Hub Services account, Union Gas may be able to implement the change earlier, in which case the change in gas flow could become effective at 2:00 PM. If the generator is bringing in additional supply from an upstream pipeline, and the upstream supplier cannot confirm the change until 4:00 PM, under this proposal the generator would be able submit a nomination at 1:00 PM with an effective time of 4:00 PM. By contrast, the minimum standard developed by NAESB would require the generator to wait until the Intra-day 2 nomination cycle at 6:00 PM, in which case the nomination change would not be effective until 10:00 PM.

Gas-fired power plants often have consumption characteristics that are very different from those of other large gas consumers. Power generators may consume natural gas at a relatively high hourly rate during certain hours of the day, but consume little or no gas during the rest of the day. Power generators also need to adjust their consumption during the course of the day in response to short-term changes in the power market. This results in a variable hourly load pattern determined by both predictable and unpredictable factors.

The differences between the nomination and scheduling practices in the natural gas market and the dispatch practices in the electricity market are well documented. The natural gas industry is based on transactions over a standard gas day, which begins at 10:00 AM in the Eastern time zone. Spot market trading for the day occurs during the morning of the previous day, and timely nominations for gas transportation must be submitted to the transporter before 12:30 PM. Shippers subsequently have few opportunities to adjust their nominations.

The challenge facing power generators is even greater during the weekend because the 72 hour period from 10:00 AM Saturday to 10:00 AM Tuesday (the Saturday, Sunday, and Monday gas days) are traded as a single block. This makes it virtually impossible to accurately schedule gas supply for a plant that shuts down for the weekend and needs to start up early on Monday morning, even if the plant dispatch schedule is known well ahead of time.

Gas nominations involve three different parameters:

1. The frequency with which the transporter will accept nominations for service (i.e. the number of nomination windows);

2. The length of time between the time the nomination is accepted and the time the nomination becomes effective; and

3. Whether the nomination must be a daily number, or the transporter allows the customer to nominate a different quantity for each individual hour.

The standard nomination process established by the North American Energy Standards Board (NAESB) includes four nomination windows—two before the start of the gas day and two intra-day nominations. Each nomination becomes effective between four and twenty-one hours after the nomination deadline. Day-ahead nominations become effective at the start of the gas day at 10:00 AM. Intra-day nominations must be submitted by 11:00 AM to go into effect at 6:00 PM for the Intra-day 1 nomination cycle, and be submitted by 6:00 PM to be effective at 10:00 PM for the Intra-day 2 nomination cycle.

NAESB Nomination Schedule

Wednesday Gas Day (10:00 Wed to 10:00 Thurs Eastern Time)

Cycle	Nomination Deadline	Effective Time	Elapsed Hours	Remaining Hours
Timely	12:30 Tues	10:00 Wed (21.5 hours later)	0	24
Evening	19:00 Tues	10:00 Wed (15 hours later)	0	24
Intra-day 1	11:00 Wed	18:00 Wed (7 hours later)	8	16
Intra-day 2	18:00 Wed	22:00 Wed (4 hours later)	12	12

With only the four NAESB windows, there is no way for a shipper to accurately align gas deliveries with consumption when the change in gas use occurs at any other time other than 10:00 AM, 6:00 PM, or 10:00 PM. For example, a gas-fired generator cannot schedule gas to start operations at 7:00 AM to match the beginning of the peak period in the electric market. The generator would either need to over-deliver gas during the night, or under-deliver gas until the start of the next gas day at 10:00 AM.

Over the course of the gas day, gas is deemed to flow at a constant hourly rate. When a shipper nominates a quantity of gas for delivery on the next gas day, the rate of delivery is calculated as 1/24 of the daily rate over each hour, even if the customer knows that the gas will only be consumed during certain hours of the day. This means that even if the generator is able to predict his hourly consumption with absolute certainty, the current nomination system results in imbalances between the assumed rate of delivery and actual consumption.

Finally, gas flows scheduled in earlier nomination periods cannot be reversed. For example, if a generator who had previously scheduled gas to operate finds out after 7:00 PM that the plant will not be running the next day, the earliest time that he can change his nomination is during the nomination window that closes on 11:00 AM for an effective time of 6:00 PM. By that time one-third of the daily quantity of gas will have been delivered. There is no way for the generator to avoid an imbalance between his supply and his actual consumption, even if he knew at least 12 hours before the start of the gas day that his consumption would be zero.

TransCanada and the Ontario gas utilities have recognized that the four NAESB windows are inadequate, and have implemented four additional nomination windows for shippers using the TransCanada's STS service and Union's M12 service [Enbridge Evidence, Exhibit B, Tab 1, Schedule 1, Page 7]. In its evidence Enbridge discusses the limitations of managing supplies even with the eight STS windows, particularly when consumption changes occur late in the gas day [Exhibit B, Tab 1, Schedule 1, Page 8].

Experience in Other Markets

The four NAESB nomination cycles are a minimum standard for pipeline and storage operators in North America. However, it is very common for companies to allow customers to nominate changes in service outside these four windows for customers contracting for basic firm and interruptible services. In some cases the pipeline or storage operator will specify additional windows during which it will commit to accept nominations on a "firm" basis. In other cases the tariff allows the company to waive the nomination deadlines, or accept out-of-cycle nominations on a best efforts basis. Other pipelines may not have explicit language in their tariffs, but will work with shippers and point operators to adjust flows outside the NAESB windows when these requests can be accommodated.

Texas Eastern Transmission Company is an example of a major interstate pipeline that provides nomination flexibility beyond the minimum NAESB standard. Section 4.1 of the General Terms and Conditions of Texas Eastern's FERC Gas Tariff allows a shipper to submit an intra-day nomination at any time after the timely nomination deadline, but only obligates the pipeline to completely reschedule its system during the four NAESB windows. Panhandle Eastern's tariff allows the company to waive nomination deadlines if operating conditions permit.

Other pipelines offer greater scheduling flexibility on a firm basis to customers who contract for enhanced services. In the case of Vector Pipeline, customers using the FT-H Hourly Firm Transportation Service or the

Management of Balancing Agreement Service can schedule intra-day changes with one hour notice. Customers of ANR Pipeline's FTS-3 service can initiate or terminate flows at any time with a minimum two hours notice.

Examples of tariff provisions that allow for nomination flexibility greater than the NAESB minimum can be found in Exhibit A.

3.6 Non-Uniform Rates of Flow

APPrO Proposal 5

1. **Utilities should allow customers to schedule non-uniform hourly quantities for all in-franchise transportation services and both in-franchise and ex-franchise storage and park and loan services.**

2. **Union Gas should add variable hourly receipts and deliveries as an option to its C1, M12, and M16 transportation services. Customers should incur no additional charges as long as hourly receipts and deliveries are in balance within a reasonable tolerance. Any additional charge to reflect intra-day balancing costs should be determined at a cost-based rate.**

Transactions in the natural gas industry are typically based on daily quantities with equal hourly rates of flow. Even with intra-day nominations, natural gas is assumed to flow at constant rate before and after the nomination change goes into effect. This is not how gas is actually consumed. Residential and commercial heating loads can vary considerably over the course of a day. The growth of gas-fired power generation, while not creating the problem, has highlighted a mismatch between gas accounting assumptions and operational reality that has always existed. Power generators need both additional nomination flexibility and non-uniform flow rights to avoid daily imbalances on the gas utility system (see example in Exhibit B).

To address this issue, many transporters and storage operators have implemented services that provide for non-uniform hourly rates of flow. These features may be incorporated into existing firm and interruptible services, or offered as new services. Although there are many variations, there are two basic types of hourly transportation services: (a) services where the transporter receives gas on a daily basis and redelivers the gas at different hourly rates, up to the shipper's maximum hourly entitlement, and (b) services where both the receipt and delivery of gas vary hourly, and receipts and deliveries are balanced each hour. Both types of service are most often used to transport gas from an upstream supply or balancing point, such as a pipeline interconnection or storage hub, to an end-use delivery meter. However, hourly services can also be used to deliver gas into a downstream transporter, if that transporter offers compatible hourly services on its system.

Pipelines connected to Union Gas currently offer, or have proposed, hourly transportation services:

Vector Pipeline

Vector Pipeline has an hourly firm transportation service (FT-H) for deliveries to on-system customers with dedicated delivery meters. Vector also offers a Management of Balancing Agreement (MBA) service that is also applicable to service between pipeline and storage interconnection points. The MBA service, which allows nomination changes on one hour notice, could be used to balance hourly receipts and deliveries between Michigan storage and the Dawn Hub.

Bluewater Gas Storage

Bluewater Gas Storage has the ability to deliver or receive gas at variable hourly rates through Vector Pipeline or at its interconnection with Union Gas. In a letter filed with the Board in this proceeding, Bluewater states that it is "currently able to offer many of the proposed services that gas-fired generators require such as more frequent nominations, high deliverability service, and access to alternate receipt and delivery points directly into Union's franchise territory."[Bluewater letter dated January 27, 2006]. Bluewater is developing a new Interruptible Hourly Balancing Service, which it expects to file with the Federal Energy Regulatory Commission next month.

TransCanada Pipelines

TransCanada's proposed FT-SN service would allow shippers to nominate receipts and deliveries on an hourly schedule, and change nominations with 15 minutes notice.

The usefulness of these services to customers in Ontario depends on the development of compatible services on the Union Gas system. As the operator of the Dawn Hub and the Dawn-to-Trafalgar transmission system, Union Gas must be both a provider of services and a facilitator of services offered by third party transportation and storage providers. Services with hourly scheduling flexibility are critical to the development of a market for storage and balancing services at the Dawn Hub.

3.7. Alternate Receipt and Delivery Points

APPrO Proposal 6

> **Union Gas and Enbridge should give customers access to alternate receipt and delivery points through the nomination process. For the most part, this would simply streamline the implementation of rights that the customers already have under their contracts. In the case of point-to-point transportation services such as Union's C1 and M16 services, customers should have the same access to alternate receipt and delivery points as long as the capacity is available and the customer agrees to pay any difference in the applicable charges, including differences in fuel.**

Without the flexibility to adjust gas deliveries to keep up with changes in gas requirements, it is difficult for gas-fired generators to manage their gas supplies to avoid imbalances between deliveries and consumption. One way to manage imbalances is to inject or withdraw gas from underground storage. This is the basic premise behind the bundled and semi-unbundled transportation services that Union Gas and Enbridge have traditionally offered. Given the size and variability of power generation loads, however, storage should not be expected to absorb all potential imbalances, and consumers need to have other tools, in addition to storage, to help prevent large imbalances from occurring.

Shipper imbalances can often be reduced or avoided if the shipper is able to bring on additional supplies or divert gas to a different delivery point on short notice. This may involve a short-term purchase or sale of gas, or the use of off-system storage or load balancing services. Shippers should be able to make these types of adjustments using their existing transportation service, without the need to purchase additional services from the utility. Shippers should also have an expectation that the use of an alternate receipt of delivery point will be approved promptly as long as the transaction will not affect the services being provided to other customers, or create other operational problems for the utility.

In its evidence, Union Gas describes the balancing services that it offers to in-franchise customers to allow them to redirect gas supplies to or from the Union Gas system as follows:

> In the event a T1, R20, R100 or R25 customer's consumption is unexpectedly reduced with the gas day, the gas may be injected

> into storage, the customer may request authorization to redirect gas to a HUB account, or may suspend receipts by Union in order to sell to a third party….
>
> In the event a U7 customer's consumption is unexpectedly reduced within the gas day, they have the flexibility to nominate the remainder of the day's receipts into their U7 storage account (up to contract parameters), to nominate to redirect gas to a HUB account, or to suspend gas receipts in order to sell to a third party,
>
> In the event consumption unexpectedly exceeds original supply arrangements, all customers can request to bring in incremental supply. [Tab 3, pp. 30-31]

Union Gas provides additional information in Appendix B, which in turn references the Union Gas website at www.uniongas.com/business/unionline/balancingtypes.asp. These additional materials describe the barriers to implementing the changes Union Gas describes, particularly when these changes need to be put into effect at short notice:

1. The balancing options described by Union Gas generally require the shipper to request prior approval from the utility. Approval of transactions is at the sole discretion of Union Gas.

2. Union's authorization process is a manual procedure that adds to the time needed to complete transactions in the day-ahead market, and makes it impossible to execute short-term transactions in the intra-day market. The Union Gas webpage cited in Appendix B has the following notice in bold type at the top of the page: **"Balancing transaction requests submitted via Unionline require a 24-hour turnaround time and requests submitted via fax or e-mail require a 72-hour turnaround time. All transactions must be fully executed before the transaction can flow."**

3. Union Gas may impose restrictions on the use of the redirected gas by the receiving party (e.g. gas must be consumed outside the Union Gas franchise area).

Experience in Other Markets

Access to secondary receipt and delivery points is a standard feature of the services offered by FERC-regulated pipelines. In Order 636, FERC required pipelines to allow firm shippers to use any receipt or delivery point within the same zone as a secondary point. In the case of systems with postage stamp rates, this means that all points on the system are available on a secondary basis at no additional cost. Shippers have access to points outside the shipper's rate zone or primary transportation path if the shipper pays any difference in the applicable rates.

In Canada, TransCanada's diversion and alternate receipt point procedures serve a similar purpose.

3.8. Firm All Day Transportation and Storage Services

APPrO Proposal 7

> **Firm customers should have the ability to reserve transportation capacity or deliverability as an option under all in-franchise and ex-franchise firm transportation and storage services. "Firm all day" services may be priced at a premium to the standard service, but only if a premium or surcharge is required to compensate utility firm customers for interruptible service credits that they would otherwise receive.**

Under the scheduling protocol used by Union Gas and TransCanada, unless firm service that is nominated during the first nomination cycle, which closes 21½ hours before the start of the gas day, that service does not have priority over previously-scheduled interruptible service for purposes of scheduling. This "no bump" policy creates a problem for power generators who need to bring on additional gas, or redirect an existing supply of gas, after the first nomination window, since the pipeline capacity or storage deliverability that the customer is paying for under its firm service agreement may not be available.

This issue affects nominated transportation and storage services, but does not affect no-notice services such as Union Gas T1 service, which already is "firm all day." For example, no matter how late in the day an imbalance occurs, the entire imbalance is credited or debited from the customer's bundled T1 storage service, as long as the total imbalance quantity is not greater than the customer's daily deliverability entitlement, and the customer either has the gas in storage to withdraw or sufficient space available to accommodate the injection. If the customer needed to balance intra-day using an unbundled storage service, he would have the risk that the withdrawal or injection deliverability would not be available because of earlier interruptible storage transactions.

Experience in Other Markets

This problem is less severe on U.S. pipelines, which generally allow firm services to bump interruptible services through the Evening Nomination cycle. Nonetheless, the potential inability of firm customers to acquire service intra-day was been identified by NAESB as an area of concern for power generators. The

NAESB Gas-Electric Interdependency Committee recently considered the possibility of adding an additional nomination cycle with bumping rights "to provide more flexibility to shippers, including power generators, with firm transportation rights such that they can nominate for natural gas supporting their market clearing times." Although the NAESB committee was unable to develop a specific proposal, the committee's report to the Federal Energy Regulatory Commission noted that "technological advances make additional nomination cycles and changing the 'no bump' cycle to later in the day potential feasible solutions." ["NAESB Final Report on the Efforts of the Gas-Electric Interdependency Committee", FERC Docket No. RM05-28, February 24, 2006]

3.9. Mandatory Gas Delivery Requirements

APPrO Proposal 8

1. **The Obligated DCQ is incompatible with the economic dispatch of gas-fired power generation and should be eliminated immediately for all new customers.**

2. **Union Gas should be directed to phase out the Obligated DCQ for existing customers as early as possible.**

Power generators need to control the timing of gas purchases to avoid unnecessary price risks. To operate profitably, generators need to realize a positive margin between the sales price of electricity and their variable cost of operation, the biggest component of which is the delivered cost of fuel. For plants operating under the Ontario Power Authority's Clean Energy Supply contract, payments are based on the hourly Ontario energy price (HOEP) and the daily Dawn index price for the hours during which the plant is assumed to dispatch economically. This increases the importance to the generator of purchasing gas at a price that is as close as possible to the current day's market.

The "Obligated DCQ" requirement on the Union Gas system forces a gas-fired generator to purchase and deliver to Union Gas a specific quantity of gas, even on days when the plant is not operating. This creates a mismatch between the market price of gas when the plant operates and the generator's actual gas costs, increasing the generator's financial risk. The Obligated DCQ also creates a physical gas imbalance that can only by managed using Union Gas storage.

Last year Union Gas began telling prospective power generation customers that it would no longer require an Obligated DCQ for new customers located west of Dawn. However, Union Gas said that it will continue to require an Obligated DCQ for new customers located east of Dawn, and maintain the Obligated DCQ requirement for existing transportation customers. The level of Obligated DCQ is negotiated on a customer-by-customer basis, and is subject to the discretion of Union Gas. Union Gas may temporarily waive the Obligated DCQ requirement, but this is also subject to Union's discretion. There do not appear to be any publicly-available or Board-approved guidelines concerning the level of Obligated DCQ that Union Gas can require, or the conditions under which request to waive the Obligated DCQ will be approved or rejected.

The cost of the Obligated DCQ requirement for a gas-fired generator can be illustrated by a simple example. If a generator has an Obligated DCQ of 50,000

GJ/day and this requirement is enforced on just 10 days (not necessarily consecutive) when the plant is not dispatched to generate electricity, the generator will end up purchasing an additional 500,000 GJ. If this is a winter month, this gas will be credited to the generator's Union storage account, but it is unlikely that the generator will have access to sufficient interruptible storage deliverability to withdraw all of this gas before the end of the winter heating season. If the market price for gas falls $3.00 per GJ between the time the gas purchased and the time the gas is withdrawn, the generator will incur a loss of $1,500,000 (50,000 GJ x 10 days x $3.00/GJ).

3.10. Additional Services to Manage Imbalances and Facilitate Intra-day Trades

APPrO Proposal 9

> **Additional services are needed to give gas-fired generators and other end users additional opportunities to manage imbalances and reduce their dependence on utility storage and balancing. These are detailed below.**

(a) Combined service for multiple plants

Generators may have multiple plants served by the same utility, or a single fuel manager may manage service for multiple customers. These entities could achieve efficiencies by managing the gas supply for these plants as a single pool. Combining services reduces the number of individual nominations and allows imbalances to be netted across multiple delivery locations.

Union Gas already allows contracts to be combined if the ownership is the same. This should be extended to non-affiliated shippers with common fuel management.

(b) Imbalance trading

Imbalance trading allows shippers to net out positive and negative imbalances between themselves to avoid penalties and cash-outs. This is a standard feature on U.S. pipelines, and should be adopted by Ontario utilities.

(c) Title transfer between utilities

Union Gas and Enbridge should allow transfers of gas between the utilities at common points, such as Dawn and Parkway.

(d) Title transfer to gas in storage

Title transfers between storage customers are a common feature of utility and non-utility storage services throughout North America. As an example, Washington 10 Storage's tariff includes the following language:

> Transporter or any Shipper receiving storage service from Transporter shall be entitled to transfer, in-field, any of its storage Gas to another Shipper or to Transporter pursuant to a

valid request for an in-field transfer. Transporter may restrict such transfer when the transfer would result in an increase in Transporter's service obligations, and such transfer would in Transporter's reasonable judgment impair Transporter's ability to meet all of its other service obligations of equal or higher priority. [Section 30.12]

Union Gas and Enbridge should implement similar provisions for their storage services. Title transfer rules must balance customers' need for greater transactional flexibility with the utility's need to provide the contracted level of service to all firm customers, but should not be unnecessarily restrictive.

3.11. Transparency Concerning the Availability and Cost of Utility Services

APPrO Proposal 10

1. **Utilities should be required to offer transportation and storage services on a defined schedule that is publicly available and subject to review by the Board.**

2. **The principal commercial terms of all transportation and storage transactions done at market-based rates should be available to the public within 30 days of the date the transaction is executed, whether or not the service has actually been completed. If it is determined to be necessary, this information may be released without identifying the counter party, or multiple transactions may be summarized as an aggregate quantity and weighted average index price.**

3. **With respect to Issue III on the Board's list of issues for this proceeding, APPrO recommends that potential customers should only need to bid a premium over the cost-based rate if the utility, despite its best efforts, is unable to construct sufficient capacity and other options to allocate capacity fail. However, in no event should premiums be collected by the utility unless the expansion is actually over-subscribed.**

It is currently impossible to predict when Ontario utilities will make transportation and storage services available to the market. This creates unnecessary uncertainty about whether or not additional transportation or storage capacity will be available when it is required, and increases the risks associated with developing new gas-fired generating capacity.

The market is also affected by a lack of information about the prices at which market-based services have been sold into the market. Without proper price signals, market participants are less likely to make efficient choices.

3.12. Recommendation for On-going Review

APPrO Proposal 11

> **The Board should establish a process to review how well services are meeting the needs of gas-fired generators in 2008, when many of the new generation facilities will be in service.**

The development of new utility services is an ongoing process, as is the evolution of the electricity market. In response to the Board's direction, Union Gas and Enbridge have proposed new services that will be put in place over the next two years. APPrO has also proposed new services. Whatever new services end up being approved by the Board, it is important to ensure that these services meet the intended needs. Therefore, the Board should establish a process to review these services in 2008, by which time many of the new gas-fired generators that have been proposed for the province are expected to be in full operation.

3.13. Summary Of Recommendations

General Principles

A. Utility services should be made available on a fully unbundled basis. Customers should be able to purchase only the services they need, and not be required to pay for services or facilities they do not use.

B. Utilities should offer generic services with wide applicability, and let customers decide how these services will be used. Narrowly-defined services designed for specific applications or market groups restrict customer choice and may be anti-competitive.

C. Penalty provisions should only be as high as is required to create the proper incentives. Utilities should not assess penalties for actions that do not affect service to other shippers or create other system costs ("no harm, no foul").

D. Utilities should be allowed to charge market-rates only when there is an open and competitive market for the service

Specific Proposals

1. Utilities should provide transmission-level services to customers who do not use the utility's distribution mains.

2. Utility should be allowed to negotiate rates and terms of service to reflect specific circumstances, provided that there are no negative effects on existing utility customers.

3. Utilities should continue to make a base level of storage available to in-franchise customers at rolled-in cost-based rates. Additional storage deliverability should be made available to customers at a cost-based rate that reflects the incremental cost of developing or acquiring storage with higher deliverability.

4. Utilities should allow nomination changes to be submitted each hour, with changes effective within two hours after the nomination deadline, or at the start of any later hour that the customer may specify.

5. Utilities should allow customers to nominate non-uniform hourly rates of flow for all services.

6. Customers should have access to alternate receipt and delivery points, both day-ahead and intra-day, through the nomination process.

7. Firm customers should have the option to reserve transportation capacity or storage deliverability throughout the day.

8. Union Gas should eliminate the Obligated DCQ requirement for all customers.

9. Utilities should provide additional services to allow customers to avoid imbalances, including imbalance trading, in-storage title transfers, combined nominations for multiple plants, and greater ability to move gas between utilities.

10. The procedures by which utilities offer transportation and storage capacity and the prices charged for market-based service must be made more transparent and predictable.

11. A review process is needed to determine how well the services provided by the utilities meet the needs of gas-fired generators.

PART 4. COMMENTS ON UNION GAS AND ENBRIDGE PROPOSALS

Union Gas and Enbridge filed evidence in this proceeding on March 20, 2006. This evidence was the subject of a technical conference held on April 5-6, 2006. The purpose of this section is to provide APPrO's comments on the Union Gas and Enbridge proposals, and to compare those proposals to the APPrO recommendations presented above.

These comments are based on the Union Gas and Enbridge evidence, as supplemented by the information provided at the conference and in subsequent undertaking responses. Enbridge recently filed evidence on to its Rate 300 services, which also includes additional information concerning the services proposed in its March 20 filing. In addition, the new ex-franchise services proposed by Union Gas are specifically intended to match up with TransCanada's proposed FT-SN service. An application for the FT-SN service has not yet been filed with the National Energy Board, but such a filing may be made shortly. Given the information that has only recently become available, and the fact that additional relevant information may be forthcoming, APPrO retains the right to supplement this evidence at a later stage of this proceeding.

4.1 Union Gas Proposals

In-Franchise Services

Union Gas states that its existing rate schedules for in-franchise services "currently provide all the flexibility required in the Board's directive for the NGEIR."[Tab 3, p. 1] The only change that Union Gas is proposing is to replace the two block declining demand charge for its T1 firm transportation service to a four step block demand rate. Union Gas states that this change will better align rates with the cost of providing service, and make the utility's in-franchise transportation services more robust against bypass.

Ex-Franchise Services

Union Gas is proposing four new services for ex-franchise customers. These services are intended to match up with TransCanada's proposed FT-SN service to meet the needs of new gas-fired generators located in the Enbridge franchise area.

(a) F24-T

The F24-T is an optional service that would add two separate features—reserved firm capacity and additional nomination windows—to Union's standard transportation service. Union is proposing to offer F24-T service as a "bolt on" to service under the M12 Rate Schedule, which means that this enhanced service would only be available for service between Dawn and Parkway.

Union states that only 500,000 GJ per day of F24-T service will be made available, with a starting date of November 1, 2007. Shippers in the 2007 expansion will be given first priority to contract for this service.

Union Gas proposes to offer F24-T customers ten nomination windows: the four NAESB windows, three of the four existing STS windows, and three new windows. All of the new windows have a two hour interval between the nomination deadline and the effective time.

Union Gas Proposed F24-T and F24-S Nomination Schedule
Wednesday Gas Day (10:00 Wed to 10:00 Thurs Eastern Time)

Nomination Cycle	Nomination Deadline	Effective Time	Elapsed Hours	Remaining Hours	Comment
Timely	12:30 Tues	10:00 Wed	0	24	NAESB
Evening	19:00 Tues	10:00 Wed	0	24	NAESB
10:00	10:00 Wed	12:00 Wed	2	22	Existing STS
14:00	14:00 Wed	16:00 Wed	6	18	New
Intra-day 1	11:00 Wed	18:00 Wed	8	16	NAESB
16:00	16:00 Wed	18:00 Wed	8	16	New
Intra-day 2	18:00 Wed	22:00 Wed	12	12	NAESB
23:00	23:00 Wed	02:00 Thurs	16	8	Existing STS
04:00	04:00 Thurs	06:00 Thurs	20	4	Existing STS
06:00	06:00 Thurs	0:800 Thurs	22	2	New

Union Gas proposes to charge a cost-based rate for F24-T that is based on the estimated costs of providing ten nomination cycles and reserved capacity for 250,000 GJ per day of M12 service. The costs include over $1 million of information systems improvements, compressor maintenance costs, and ten additional full-time employees. F24-T shippers will not be eligible for credits from the S&T deferral account.

(b) F24-S

The F24-S service is the storage counter-part of the F24-T service. This service also includes two separate features: reserved firm space and deliverability and the same ten nomination windows as Union has proposed for F24-T service. F24-S service is a "bolt-on" to market-based storage service provided under Rate Schedule C1.

Union states that there are no additional costs of providing this service once the utility implements F24-T.(Tab 4, p. 36)

Union states that it may need to purchase additional services or develop additional assets to be able to provide F24-T service, depending on the market demand.(Tab 4, p. 37)

Union proposes to charge a market-based rate for F24-S service.

(c) UPBS - Upstream Pipeline Balancing Service

UPBS combines the receipt of gas at an average hourly rate at Dawn with redelivery at Parkway at non-uniform hourly nominated by shipper. Gas will be redelivered at Parkway over no fewer than 12 hours. Union says that this service would allow a power generator to receive gas into Parkway during the hours that the generator actually intended to operate.

UPBS is a "bolt-on" to M12 service. UPBS can be used either with or without the F24-T service.

Union estimates that the capital costs to modify its gas management systems to allow it to offer both UPBS and DPBS (see below) are approximately $3.85 million.

The service would be offered at a market-based rate under the existing C1 rate schedule.

(d) DPBS – Downstream Pipeline Balancing Service

DPBS is a firm short-notice park and loan service at Parkway. The base service would allow a shipper to park or borrow the equivalent of two times the maximum hourly flow rate under the shipper's M12 transportation contract. Union states that it would also negotiate different service parameters.

Union Gas would confirm the availability of gas at Parkway to TransCanada and Enbridge every fifteen minutes. Union says that this service, used in conjunction with TransCanada's proposed FT-SN service, would allow a gas-fired generator served by Enbridge to start up operations at short notice.

DPBS is a "bolt-on" to M12 service. DPBS can be used either with or without the F24-T service.

The service would be offered at a market-based rate under the existing C1 rate schedule.

4.2. APPrO's Comments on the Union Gas Proposals

In-Franchise Services

In presenting its T1 rate redesign proposal, Union Gas acknowledges that there is a strong relationship between cost of service and the facilities used to serve the customer. However, instead of proposing a separate service or a rate within T1 that is based only on transmission costs, Union proposes to adjust the T1 (and U7) rates to come closer to this result. APPrO's proposal, to develop separate rates for transmission-level service and allow negotiated rates for firm service, would more clearly align rates with cost responsibility and provide greater protection against bypass.

Obligated DCQ

In response to questions concerning Union's policy to waive the Obligated DCQ requirement for new customers located west of Dawn, but not for new customers located east of Dawn or for its existing customers, Union Gas stated that the Obligated DCQ was implemented in the late 1980s when customers began purchasing gas supplies directly to account for physical conditions that existed at that time. Union Gas did not explain the rationale for applying this requirement to new customers, or why a condition related to the transition from system supply to direct purchase arrangements continues to be justified, other to indicate that it was looking into the issue. Union Gas should be required eliminate the Obligated DCQ as APPrO has recommended.

High Deliverability Storage

In stark contrast to Enbridge's filing, Union Gas did not provide any specific information about how much and what kind of high deliverability storage service Union Gas would be able to provide, and what that service would cost. Union should offer high deliverability service at cost based rates following the principles outlined by APPrO.

Nomination Flexibility

Union's proposal to implement ten nomination windows only applies to the F24-T and F24-S services, and only if Union decides to go forward with F24-T. Even if F24-T is implemented, all in-franchise services and most ex-franchise services will still be limited to the minimum NAESB standard of four nomination windows.

The ten windows proposed by Union Gas do not meet power generators' needs. For example, the Union Gas proposal leaves a long gap between the 7:00 PM Evening Cycle and the 10:00 AM nomination, which does not become effective 12:00 PM, at which time two hours of the gas day have already past. In addition to the need for more opportunities to change nominations before the start of the gas day, power generators are also interested in a having nomination that becomes effective at the start of the electric day at 24:00. APPrO's proposal to require nominations each hour would address these concerns and would create greater consistency between Union and interconnecting pipelines.

Union Gas has stated that it can add nomination windows if there is a consensus as to the windows that are needed. Union Gas has indicated that there would be little or no cost to increasing the number of windows. It is also not clear what the constraints are that would prevent Union from applying the additional nomination windows to all M12 contracts and to other transportation services. The APPrO proposal is the consensus proposal of the Ontario generator community and should be implemented as soon as possible.

Union's F24-S proposal would extend the F24-T windows and the reservation of capacity feature to C1 storage service. Union did not indicate that there is any restriction on the amount of F24-S service that it can provide. Union has also provided no justification for why additional nomination windows cannot be offered independently of the reservation of capacity feature. There appears to be no reason why Union Gas would need to recover any additional revenue to increase the number of nomination windows for all storage services. Since there is no shortage of supply and no "market" for additional storage windows on Union Gas storage, there is no basis for Union Gas to charge market-based rates to increase the number of available nomination windows under its existing storage services. Union Gas should implement additional nomination windows for storage to implement the APPrO consensus proposal.

Hourly Services

Union's proposed UPBS service is very similar to hourly delivery services offered by natural gas pipelines in the U.S. However, the minimum delivery period of twelve hours is more restrictive than other services, and does not meet the requirements of generators, who may operate over fewer than twelve hours over the gas day. Nor does it meet the short-term flexibility needed to maintain electricity system reliability, as described in Part 2 above. Under ANR Pipeline's FTS-3 service, for example, a shipper can take delivery of its daily contract quantity in as little as four hours.

Union's proposal to charge market-based rates for this service is not consistent with the pricing of these services in other jurisdictions. U.S. interstate pipelines with similar non-uniform delivery services must offer these services at cost-based rates.

In addition to a cost-based UPBS service, Union should be required to offer an hourly transportation service that provides for non-uniform flows for both receipts and deliveries. This service could be paired with storage, hourly park and loan service, or upstream deliveries at Dawn to create the same flexible deliveries at Parkway as Union Gas proposes to offer with UPBS. Allowing third parties to deliver gas to Union Gas at non-uniform rates at Dawn, and having Union Gas redeliver the gas on the same schedule at Parkway, would create competition for the services shippers will require to match up with TransCanada's proposed FT-SN service. Under the services proposed by Union Gas, Union will be the only party able to offer these services from Dawn.

The DPBS service has been described as an hourly park and loan service at Parkway. In response to a question from APPrO, Union Gas could not explain why the same type of firm hourly park and loan service could not be provided at the Dawn Hub.

In-Storage Title Transfers

Union Gas should offer in-storage title transfers in line with the APPrO proposal. This should apply both to in-franchise services and C1 storage services.

4.3. Enbridge Proposals

(a) Enbridge Rate 125

The Rate 125 is designed for large end users that are served from Enbridge's extra high pressure transmission system or through a direct connection with a third party transporter such as TransCanada. Enbridge proposes to set the Rate 125 transportation charge based on the cost of providing transmission-level service.

(b) Enbridge Rate 316

Enbridge proposes to develop incremental high deliverability storage that would be available to both in-franchise and ex-franchise customers at market-based rates under Rate Schedule 316. Enbridge states that it can create up to 2 Bcf of 10 percent deliverability using the existing Tecumseh storage assets, and that all of this storage could be available in 2008.

(c) Enhanced Title Transfer

Enbridge has proposed a new enhanced title transfer service (ETT) to allow gas to be moved between utilities at Dawn. The implementation of the ETT service depends on other utilities developing compatible services.

(d) In-Storage Title Transfer

Enbridge proposes that in-storage title transfers be allowed, but only for services with identical service parameters or conditions.

4.4. APPrO's Comments on the Enbridge Proposals

(a) In-Franchise Transportation Services

Enbridge's Rate 125 service proposal incorporates several of the principles and features that that APPrO has endorsed:

- The transportation rate is based on the cost of the transmission-level facilities that are used to provide the service.
- A balancing service is bundled with the transportation service, but the customer is only required to pay for balancing to the extent that it is actually used.
- Enbridge proposes to allow nominations for multiple Rate 125 contracts to be combined.
- Enbridge proposes nomination flexibility to fully match upstream service providers.

Nonetheless, APPrO has the following comments and concerns related to Enbridge's Rate 125 proposal:

- The minimum daily quantity required to be eligible for service under Rate Schedule 125 is too high. At 600,000 m3 per day, this service does not take into account the needs of smaller generators which otherwise have the same service needs.
- Enbridge states that the customer's Maximum Contract Imbalance (MCI) "may be less than or equal to the customer's [contract demand], based on the Company's assessment." The MCI is an important term of service, and should be determined on basis of an objective set of criteria and the customer's physical contract demand.
- The conditions under which Enbridge would declare an OFO day, whether OFOs will be localized or system-wide, and the utility's obligation to lift OFOs as soon as conditions warrant, all must be clearly defined.
- Enbridge has not demonstrated that its cashout penalties are reasonable.

Finally, in its evidence to date, Enbridge has suggested that Rate 125 customers may not be able to take advantage of TransCanada's proposed FT-SN service if that service requires point-to-point delivery. If TransCanada's proposal contains such a requirement, Enbridge must work to put in place arrangements that will enable its customers (both customers with direct connections to TransCanada and customers embedded in the Enbridge system) to subscribe to the TransCanada FT-SN service.

(b) High Deliverability Storage

APPrO supports the development of additional high deliverability storage in the province. In the absence of a liquid competitive market, however, it is APPrO's position that utility storage must be sold at cost-based rates. Enbridge's proposal to auction off a relatively limited quantity of high deliverability storage to the highest bidder is problematic. In particular, although Enbridge proposes to develop new storage to meet the needs of gas-fired generators, Enbridge provides no assurance that this storage would actually be available for the market these facilities are intended to serve.

- There is nothing preventing a large marketing company from buying up all of the available high deliverability service to serve market outside the Enbridge franchise or outside Canada.

- There is no protection against a single entity acquiring all of the storage capacity offered and using its resulting market power to resell services at a higher price.

- There is no provision for Enbridge customers who enter the market after 2008 to have access to high deliverability storage, since Enbridge does not expect to be able to offer additional high deliverability storage from its existing Tecumseh storage complex.

To address these concerns, APPrO's proposes that high deliverability storage be sold at an incremental cost-based rate, and that priority be given to in-franchise customers before this service is offered to the market.

(c) Hourly Services

Enbridge states that it will match the nomination provisions of any upstream transporter in providing distribution services. Enbridge should also match the nomination provisions of any downstream transporter when it is providing storage services. This would include greater frequency in nomination windows and acceptance of nominations with non-uniform hourly quantities.

(d) Enhanced Title Transfer

APPrO proposes that title transfers be allowed at other points, in addition to Dawn.

(e) In-Storage Title Transfer

The Enbridge proposal is more flexible than the Union Gas proposal, but more restrictive than the APPrO proposal. Utilities should allow in-storage title transfers unless there is a reason to expect that the transfer will affect services to other customers or cause operational harm to the system.

Exhibit A

NATURAL GAS PIPELINES AND STORAGE FACILITIES WITH FLEXIBLE NOMINATION PROVISIONS

(a) Texas Eastern Transmission

General Terms and Conditions

Section 4.1(B)(3): Nomination Procedure for Other Firm Services

> "In the event Customer does not submit a timely nomination or desires to alter a timely nomination, Customer shall have the right to submit an intra-day nomination to revise Customer's scheduled quantities, Point(s) of Receipt, and/or Point(s) of Delivery on a prospective basis prior to the end of the delivery day; provided, however, that such nomination shall be processed after timely nominations have been scheduled. Such intra-day nomination shall, subject to Section 17 and 4.1(J)(1) of the General Terms and Conditions, be implemented by Pipeline to the extend and only to the extent that Pipeline is able to confirm the receipt and delivery of such gas at the Point(s) of Receipt and Point(s) of Delivery and only if the scheduling of such intra-day nomination will not require the Systematic Rescheduling of Pipeline's capacity among previously scheduled service agreements in order to provide capacity for said intra-day nomination."

Section 4.1(F): Minimum NAESB Nomination Standards

> "In the event the more flexible nomination procedures set forth in Sections 4.1(A), (B), (C), and (D) above are inapplicable for any reason, nominations shall be submitted and processed in accordance with the minimum standards set forth in this Section 4.1(F)." [Goes on to describe the four standard NAESB cycles]

(b) Panhandle Eastern

General Terms and Conditions

Section 8.2(c)

"Panhandle may waive any part of the notice requirements … upon request, if operating conditions permit such waiver. Shipper shall notify Panhandle immediately of any unexpected changes in volumes tendered for receipt or delivery, whether or not such notice conforms to the times set out herein."

(c) Vector Pipeline

Management of Balancing Agreement Service

Section 2.7(b)

When Balancing Customer requires a change in the quantity of deliveries during a part of any Day, Balancing Customer and Balancing Provider will notify Transporter by direct phone contact with Transporter personnel no less than one (1) hour prior to the time requested for the change of (i) the time when such change in deliveries shall take place, (ii) the amount of deliveries requested, and (ii) the duration in hours of the requested change. Balancing Customer will confirm the request via fax within one (1) hour.

FT-H Hourly Firm Transportation Service

Section 2.7

"In addition to the nomination timeline provisions of Section 5.2 of the GT&C, Shipper may nominate to Transporter, by direct telephone contact at least one (1) hour prior to the actual gas flow at the Point(s) of Delivery, service under this Toll Schedule. Upon Transporter's verbal acceptance of the nomination, Shipper shall confirm the nomination via fax within thirty (30) minutes. At no time shall transporter be required to provide service under this Toll Schedule until Transporter has received appropriate confirmation from the upstream and downstream operators at the respective Receipt Point(s) and Delivery Point(s)."

<u>(d) ANR Pipeline</u>

FTS-3 Firm Transportation Service

Section 4: Short Notice Start-up and Shut-down

> "In addition to the nomination and scheduling procedures set forth in Section 6 of the General Terms and Conditions, Shipper may elect the right to start-up and shut-down service hereunder only upon providing Transporter with two (2) Hour(s) telephone notification or, subject to operational conditions, a shorter period of notice. After such telephone notification by the Shipper, and subsequent verification by the Transporter, Shipper shall also be required to provide a nomination consistent with Section 6 of the General Terms and Conditions."

Exhibit B

ELECTRIC GENERATOR DISPATCH EXAMPLE

Assumptions

- 500 MW combined-cycle power plant consumes 4,000 GJ/hour
- Plant expects to operate during the 16 peak electric hours (7:00 AM to 11:00 PM) on Wednesday and Thursday.
- Scheduled supply for the Wednesday gas day is 4,000 GJ x 16 hours = 64,000 GJ
- The fuel manager finds out at 4:15 AM on Thursday that the plant will not recommence operations at 7:00 AM as originally planned.

Case 1: NAESB Minimum Nomination Standard

- By the time the change in power dispatch becomes known, there are no remaining nomination windows for the Wednesday gas day.
- The plant has a daily imbalance of 12,000 GJ with the utility (19% of the scheduled quantity)

Case 2: Hourly Nominations

- Under the APPrO proposal, the fuel manager is able to submit a nomination change at 5:00 AM to reduce deliveries to the utility to zero, effective at 7:00 AM.
- Because supply is delivered to the utility ratably over the gas day and nomination changes are only effective prospectively, the plant still has a daily imbalance of 4,000 GJ (7% of the revised scheduled quantity).

Case 3: Hourly Nominations and Hourly Quantities

- During the day-ahead nomination process, the plant is able to schedule deliveries to the utility at an hourly schedule that matches the plant's expected gas consumption.

- As in Case 2, the fuel manager submits a nomination change by 5:00 AM to be effective 7:00 AM, reducing deliveries to the utility to zero.

- The daily imbalance is zero.

CASE 1: NAESB MINIMUM NOMINATION STANDARD

NAESB Deadlines	Hour Ending	Day	Expected Consumption	Gas Supply Scheduled	Actual Consumption	Imbalance
Timely Nomination	13:00	Tues				
	14:00	Tues				
	15:00	Tues				
	16:00	Tues				
	17:00	Tues				
	18:00	Tues				
Evening Nomination	19:00	Tues				
	20:00	Tues				
	21:00	Tues				
	22:00	Tues				
	23:00	Tues				
	24:00	Tues				
	1:00	Wed				
	2:00	Wed				
	3:00	Wed				
	4:00	Wed				
	5:00	Wed				
	6:00	Wed				
	7:00	Wed				
	8:00	Wed				
	9:00	Wed				
	10:00	Wed				
Intra-day 1	11:00	Wed	4,000	2,667	4,000	
	12:00	Wed	4,000	2,667	4,000	
	13:00	Wed	4,000	2,667	4,000	
	14:00	Wed	4,000	2,667	4,000	
	15:00	Wed	4,000	2,667	4,000	
	16:00	Wed	4,000	2,667	4,000	
	17:00	Wed	4,000	2,667	4,000	
Intra-day 2	18:00	Wed	4,000	2,667	4,000	
	19:00	Wed	4,000	2,667	4,000	
	20:00	Wed	4,000	2,667	4,000	
	21:00	Wed	4,000	2,667	4,000	
	22:00	Wed	4,000	2,667	4,000	
	23:00	Wed	4,000	2,667	4,000	
	24:00	Wed	0	2,667	0	
	1:00	Thurs	0	2,667	0	
	2:00	Thurs	0	2,667	0	
	3:00	Thurs	0	2,667	0	
	4:00	Thurs	0	2,667	0	
	5:00	Thurs	0	2,667	0	
	6:00	Thurs	0	2,667	0	
	7:00	Thurs	0	2,667	0	
	8:00	Thurs	4,000	2,667	0	
	9:00	Thurs	4,000	2,667	0	
	10:00	Thurs	4,000	2,667	0	
Gas Day Totals (GJ)			**64,000**	**64,000**	**52,000**	**12,000**

CASE 2: HOURLY NOMINATIONS

Proposed Deadlines	Hour Ending	Day	Expected Consumption	Gas Supply Scheduled	Actual Consumption	Imbalance
Timely Nomination	13:00	Tues				
	14:00	Tues				
	15:00	Tues				
	16:00	Tues				
	17:00	Tues				
	18:00	Tues				
Revised Nomination	19:00	Tues				
Revised Nomination	20:00	Tues				
Revised Nomination	21:00	Tues				
Revised Nomination	22:00	Tues				
Revised Nomination	23:00	Tues				
Revised Nomination	24:00	Tues				
Revised Nomination	1:00	Wed				
Revised Nomination	2:00	Wed				
Revised Nomination	3:00	Wed				
Revised Nomination	4:00	Wed				
Revised Nomination	5:00	Wed				
Revised Nomination	6:00	Wed				
Revised Nomination	7:00	Wed				
Revised Nomination	8:00	Wed				
Revised Nomination	9:00	Wed				
Revised Nomination	10:00	Wed				
Revised Nomination	11:00	Wed	4,000	2,667	4,000	
Revised Nomination	12:00	Wed	4,000	2,667	4,000	
Revised Nomination	13:00	Wed	4,000	2,667	4,000	
Revised Nomination	14:00	Wed	4,000	2,667	4,000	
Revised Nomination	15:00	Wed	4,000	2,667	4,000	
Revised Nomination	16:00	Wed	4,000	2,667	4,000	
Revised Nomination	17:00	Wed	4,000	2,667	4,000	
Revised Nomination	18:00	Wed	4,000	2,667	4,000	
Revised Nomination	19:00	Wed	4,000	2,667	4,000	
Revised Nomination	20:00	Wed	4,000	2,667	4,000	
Revised Nomination	21:00	Wed	4,000	2,667	4,000	
Revised Nomination	22:00	Wed	4,000	2,667	4,000	
Revised Nomination	23:00	Wed	4,000	2,667	4,000	
Revised Nomination	24:00	Wed	0	2,667	0	
Revised Nomination	1:00	Thurs	0	2,667	0	
Revised Nomination	2:00	Thurs	0	2,667	0	
Revised Nomination	3:00	Thurs	0	2,667	0	
Revised Nomination	4:00	Thurs	0	2,667	0	
Revised Nomination	5:00	Thurs	0	2,667	0	
Revised Nomination	6:00	Thurs	0	2,667	0	
Revised Nomination	7:00	Thurs	0	2,667	0	
Revised Nomination	8:00	Thurs	4,000	0	0	
	9:00	Thurs	4,000	0	0	
	10:00	Thurs	4,000	0	0	
Gas Day Totals (GJ)			**64,000**	**56,000**	**52,000**	**4,000**

CASE 3: HOURLY NOMINATIONS AND HOURLY QUANTITIES

Proposed Deadlines	Hour Ending	Day	Expected Consumption	Gas Supply Scheduled	Actual Consumption	Imbalance
Timely Nomination	13:00	Tues				
	14:00	Tues				
	15:00	Tues				
	16:00	Tues				
	17:00	Tues				
	18:00	Tues				
Revised Nomination	19:00	Tues				
Revised Nomination	20:00	Tues				
Revised Nomination	21:00	Tues				
Revised Nomination	22:00	Tues				
Revised Nomination	23:00	Tues				
Revised Nomination	24:00	Tues				
Revised Nomination	1:00	Wed				
Revised Nomination	2:00	Wed				
Revised Nomination	3:00	Wed				
Revised Nomination	4:00	Wed				
Revised Nomination	5:00	Wed				
Revised Nomination	6:00	Wed				
Revised Nomination	7:00	Wed				
Revised Nomination	8:00	Wed				
Revised Nomination	9:00	Wed				
Revised Nomination	10:00	Wed				
Revised Nomination	11:00	Wed	4,000	4,000	4,000	
Revised Nomination	12:00	Wed	4,000	4,000	4,000	
Revised Nomination	13:00	Wed	4,000	4,000	4,000	
Revised Nomination	14:00	Wed	4,000	4,000	4,000	
Revised Nomination	15:00	Wed	4,000	4,000	4,000	
Revised Nomination	16:00	Wed	4,000	4,000	4,000	
Revised Nomination	17:00	Wed	4,000	4,000	4,000	
Revised Nomination	18:00	Wed	4,000	4,000	4,000	
Revised Nomination	19:00	Wed	4,000	4,000	4,000	
Revised Nomination	20:00	Wed	4,000	4,000	4,000	
Revised Nomination	21:00	Wed	4,000	4,000	4,000	
Revised Nomination	22:00	Wed	4,000	4,000	4,000	
Revised Nomination	23:00	Wed	4,000	4,000	4,000	
Revised Nomination	24:00	Wed	0	0	0	
Revised Nomination	1:00	Thurs	0	0	0	
Revised Nomination	2:00	Thurs	0	0	0	
Revised Nomination	3:00	Thurs	0	0	0	
Revised Nomination	4:00	Thurs	0	0	0	
Revised Nomination	5:00	Thurs	0	0	0	
Revised Nomination	6:00	Thurs	0	0	0	
Revised Nomination	7:00	Thurs	0	0	0	
Revised Nomination	8:00	Thurs	4,000	0	0	
	9:00	Thurs	4,000	0	0	
	10:00	Thurs	4,000	0	0	
Gas Day Totals (GJ)			**64,000**	**52,000**	**52,000**	**0**