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September 4, 2015

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. D. Christle, Board Secretary and Executive Director

Dear Mr. Christle:

RE: CENTRA GAS MANITOBA INC. ("CENTRA")
2015/16 COST OF GAS APPLICATION- PUBLIC VERSION OF INTERVENOR EVIDENCE

Centra is in receipt of the evidence of Mark Stauft on behalf of the Consumers Association of Canada (Manitoba). As requested by the Public Utilities Board of Manitoba, enclosed is a public version of Mr. Stauft's evidence that redacts commercially sensitive information.

Should you have any questions regarding this submission, please contact the writer at 204-360-3257 or Greg Barnlund at 204-360-5243.

Yours truly,

MANITOBA HYDRO LAW DIVISION

Per:

Brent A. Czarnecki
Barrister and Solicitor

MANITOBA PUBLIC UTILITIES BOARD

CENTRA GAS MANITOBA INC.
2015/16 COST OF GAS APPLICATION

EVIDENCE OF
MARK STAUFT
on behalf of
THE CONSUMERS ASSOCIATION OF CANADA (MANITOBA) INC.

Q. Please identify yourself and the party on whose behalf you appear, and briefly describe your qualifications.

A. My name is Mark Stauft and I am appearing on behalf of the Consumers Association of Canada (Manitoba) Inc. ("CAC"). I am a consultant in the field of utility regulation. I have filed evidence and appeared before the Board in a number of Centra Gas Manitoba Inc. ("Centra") proceedings related primarily to gas supply and transportation matters. A CV that describes my experience and qualifications is attached as Appendix A.

Q. Please explain the purpose of your testimony and identify the issues that you address.

A. On May 25, 2015 Centra filed its 2015/16 Cost of Gas application ("Application"). CAC asked me to review the Application and to provide it with my views on the reasonableness of certain of Centra's proposals.

To begin, I will briefly discuss two issues. The first is Centra's acquisition of [redacted] of NOVA Gas Transmission Ltd. ("NGTL") FT-D service to Empress, while the second is

Centra's report on potential asset management arrangements included as Appendix 7.3 in the Application. I have no serious disagreements with Centra's position on those issues.

The remainder of my testimony addresses Centra's response to the changes that have taken place in the Canadian natural gas market as a result of the National Energy Board's ("NEB") RH-003-2011 Decision. In that Decision the NEB effectively de-regulated tolls for short term transportation services on the TransCanada Mainline system ("Mainline"), with far-reaching consequences for all market participants.

I. ACQUISITION OF NGTL DELIVERY SERVICE

Q. Please explain the first issue that you identified.

A. Centra has traditionally purchased its Primary Gas supply at Empress, which is the interconnect between the NGTL and Mainline systems at the Alberta/Saskatchewan border. Centra has now [redacted] Centra says that it made that chang[redacted]

Q. Is that change reasonable in your view?

A. I have no reason to think that Centra's approach is unreasonable. [redacted]

[redacted]

[redacted] At this point I have no basis for saying that Centra's approach is unreasonable.

II. ASSET MANAGEMENT REPORT

Q. You also indicated that you have comments on Appendix 7.3, Centra's report on the merits of third party asset management arrangements. What is your response to Centra's position in that report?

A. In the past I have urged Centra to consider asset management approaches that might enable it to effectively increase its Capacity Management Revenue for the benefit of customers. The general objective of asset management is to optimize the utilization of fixed transportation and storage assets, usually through secondary market transactions of various kinds that capture for Centra the market value of assets that it temporarily does not need to meet its customers' requirements.

Centra has for many years undertaken asset management activities of various kinds, [redacted] the past, and in Appendix 7.3, Centra has resisted my suggestions that it seriously consider larger scale asset management arrangements under which a counterparty would be given control over all or most of Centra's asset portfolio.

It is clear that Centra has thought carefully about this issue and remains opposed to large-scale asset management transactions. In the end Centra is in a better position than I am to evaluate the value of potential asset management deals, and I recognize that in this area Centra's management ought to be given a certain degree of latitude.

I raise this issue here in order to acknowledge that, whatever Centra's views, large scale asset management arrangements are likely to be less feasible now, in the environment created by the RH-003-2011 Decision, than they were in the past. One factor, as explained in more detail in the remainder of my evidence, is that the short term transportation tools that an asset manager would have had available in the past to help optimize Centra's operations have essentially disappeared. The other factor is that, as also explained below, the new environment involves more pricing and operational uncertainty and risk for potential counterparties, which would tend to increase the cost of large-scale asset management arrangements and undermine their economic feasibility for all concerned.

III. THE RH-003-2011 DECISION AND ITS AFTERMATH

1. Introduction

Q. With respect to the main issue addressed in your evidence, please explain the nature of that issue and the organization of your discussion of it.

A. Centra's supply and transportation portfolio can be thought of as consisting of or being associated with three main categories of supply. One is Primary Gas supply, [redacted] For these purposes I will often refer to Centra's facilities as the "MDA", or "Manitoba Delivery Area", which is the designation used by

TransCanada for the collection of points at which Centra takes delivery of gas from the Mainline. The second is Centra's storage infrastructure, [redacted]

The third is a residual category of what I would generally refer to as "downstream direct to load" purchases, meaning generally supply that is characterized as Supplemental Gas for rate-making purposes [redacted] For convenience I will often refer to these types of supply as simply "downstream supply". This category of supply arrangements is the focus of my evidence, recognizing that there is a certain amount of overlap amongst the three categories as I have described them.

The common element among the downstream supply sources that I am concerned about is that the acquisition costs of those supplies for Centra are closely connected with market prices [redacted]

[redacted]

[redacted]

[redacted]

Those high prices contributed to Centra accumulating a deficiency of over [redacted] in its various non-Primary Gas deferral accounts. The recovery of that deficiency is one of the issues in this case.

In my view it was almost inevitable that the RH-003-211 Decision would increase risks and costs for Centra and other market participants in one way or another, and it would be almost impossible for Centra and its customers to escape those effects entirely. Nevertheless, the question arises of whether Centra's response to that fundamental change in the structure of the market has been reasonable and appropriate.

Q. How is the remainder of this section of your evidence organized?

A. The remainder of this section is divided into three sub-sections.

Sub-section 2 describes the evolution of the market over the relevant time period. That includes descriptions of the pre-RH-003-2011 environment, the Decision itself, the market impact of the Decision, and the relevant market dynamics as they exist today.

Sub-section 3 discusses in general terms how Centra reacted to the RH-003-2011 Decision and the alternatives it should have considered. Centra's general approach seems to have been to maintain its pre-existing strategy as far as possible. [redacted] That sub-section includes a discussion of the benefits and costs of that alternative approach, and includes a quantitative analysis of one version of that alternative on a prospective basis, i.e. based on Centra's 2015/16 gas cost forecast.

Sub-section 4 addresses the 2013/14 PGVA deficiency, the extent to which Centra's response to RH-003-2011 contributed to it, and the reasonableness of that response. It includes a quantitative analysis of the impact of the alternative approach discussed in sub-section 3 based on Centra's actual 2013/14 experience rather than on Centra's current forecast.

2. Background - Evolution of the Market

Q. Please explain the background to this issue and the Emerson market that existed prior to RH-003-2011.

A. The Mainline system splits in the Winnipeg area, with one branch continuing east to Ontario, Quebec, and various export points, and the other going south to the U.S. border at Emerson. At Emerson the Mainline delivers to Viking Gas Transmission, which continues south to the ANR system in Wisconsin, and the larger Great Lakes Gas Transmission system. Great Lakes was originally built as a loop of the Mainline system, and it travels generally east through Michigan until it re-connects with the Mainline at St. Clair, Ontario. From St. Clair the Mainline connects to the large storage facility and market hub at Dawn, and indirectly to the more easterly parts of the Mainline.

Originally Great Lakes' primary customer was TransCanada itself, with some smaller U.S. LDC customers in the upper midwest. TransCanada used its Great Lakes capacity to deliver Canadian gas into southern Ontario under its FT service agreements with the large eastern Canadian distributors. The overall system was sized in the mid-1990's to meet a market requirement of close to 7 million GJ/d from Alberta to Manitoba, Eastern Canada, and various export points, including Emerson. Starting in the late 1990's throughputs on the Mainline started to decline, for various reasons. That trend has accelerated over the past several years with the development of large shale gas resources in the northeastern U.S. Those supplies displaced Canadian exports at Niagara and Iroquois, and have begun to displace Alberta gas from even domestic Canadian markets. Where close to 2.5 million GJ/d was once exported through Niagara/Chippawa, several hundred thousand GJ/d of U.S. gas now flows into southern Ontario through Niagara instead.

The result has been large amounts of excess capacity on the Mainline, especially in the western section, the line running south to Emerson, and in northern Ontario. Flows from Empress are now commonly in the range of 2.5 million GJ/d or less, compared to a current system capacity of around 6 million GJ/d. Over time TransCanada has been forced to give up most of its Great Lakes capacity, and that system is now used independently by marketers and LDCs to move Canadian gas into Dawn through St. Clair and to U.S. markets. By 2011 there were no FT contracts from Empress to Emerson. Gas continued to flow on that route using IT service, but at levels well below the available capacity of over 3 million GJ/d.

IT service on the Mainline has for many years been made available through a bidding process. Prior to the RH-003-2011 Decision the floor price for bids for IT on any path was fixed in the Mainline tariff at 110% of the daily equivalent FT toll for that path. For points like Emerson, or for that matter the MDA, where there is ample excess pipeline capacity, that floor was almost always the effective IT toll. Because there was enough available capacity to meet any conceivable demand, no shipper needed to bid above the floor, and essentially all IT nominations were accepted. The only real risk with using IT service was the possibility of curtailment in the event of physical upset on the pipeline. In fact by 2011 much of the flow through Emerson was generated by marketers using IT service in conjunction with the FT-RAM feature of the FT service held by the large eastern LDC's.

The result was that market prices for gas at Emerson were consistently and predictably at or below a level that reflected the prevailing Empress price plus the daily FT toll to Emerson.

During that period Emerson was a logical source of supply for Centra. It could theoretically have purchased gas at Emerson and shipped it to the MDA for a modest Mainline toll, although likely the more efficient approach would be to purchase the gas as a delivered service at a price that reflected the supplier's opportunity cost of the Emerson market price.

Q. How did the RH-003-2011 Decision change that structure?

A. One thing the NEB did in the RH-003-2011 Decision was eliminate the FT-RAM feature of FT service. Although the operational details are complicated, the practical effect of FT-RAM was to enable FT shippers to bank unutilized FT capacity over a month and utilize or sell it in aggregated form when doing so was most advantageous. The loss of that feature reduced the ability of FT shippers, including Centra, to manage their firm capacity and effectively market their excess capacity in the secondary market.

The more significant change was that the NEB decided to allow TransCanada itself to set the bid floor for IT service at any level TransCanada chooses, and to set the bid floor for the short term firm "STFT" service at any level at or above the daily FT toll. Although IT and STFT tolls are still subject to the regulatory requirement for a bidding process, the economic effect has been to deregulate IT and STFT tolls completely. For any given path, for example Empress/Emerson, TransCanada can set the bid floor at \$0.05/GJ, \$0.60/GJ, \$2.00/GJ, or \$25.00/GJ, and that will be the price of the service.

Q. What is your understanding of the NEB's reasons for taking that step?

A. The RH-003-2011 proceeding was convened to consider a number of TransCanada proposals that were designed to address, according to TransCanada, the continuing erosion of Mainline throughput and FT contract levels and the resulting escalation of tolls. There was much discussion at the hearing of "Armageddon scenarios" where tolls became uneconomic, forcing throughput down even further, increasing tolls again, and so on in a "death spiral".

In the end the NEB rejected most of TransCanada's proposals, including schemes to shift significant Mainline costs to, for example, captive NGTL producer-shippers who have no connection to the Mainline. Instead the NEB imposed an entirely new toll model under which it fixed Mainline tolls at what it concluded was a "competitive" level for a five-year period, with TransCanada supposedly at risk for any revenue shortfall at the end of the period. Associated with that, although not a logically necessary part of it, was the deregulation of IT and STFT tolls. The logic appears to be that if TransCanada is to be exposed to earnings risk in relation to essentially arbitrary, non-cost-based tolls, it is necessary to give it "tools" to maximize its revenue. Deregulation of short term tolls was one of those tools, and indeed the most important one. The NEB appeared to take the position that customers in general have no entitlement to short term tolls that are just and reasonable in any traditional sense, i.e. being cost-based, as long as they have available to them the alternative "recourse" of regulated FT services. Thus, if Centra, for example, does not like the IT toll offered for service to the MDA, even if it only needs the service for one day, it is free to sign up for regulated FT service for an entire year instead.

Q. Did the concept of effective competition constraining unregulated IT tolls to a reasonable level enter into the NEB's reasoning?

A. Not in any organized way, although the NEB seemed to believe that competition would somehow limit the IT tolls TransCanada could profitably charge. In most situations where there is a proposal to deregulate prices for a traditionally regulated service a market power analysis is undertaken. The objective of such a study is to determine whether price regulation is actually unnecessary, in the sense that even without it there is sufficient competition in the relevant market to constrain prices to a roughly cost-based competitive level. The NEB conducted no such analysis, and it is clear that the Mainline, especially in the domestic market, would utterly fail any conventional version of a market power test.

It is likely true that at some export points TransCanada faces competition in a sense, in the form of U.S. gas transported on U.S. pipelines to markets that are also indirectly served by the Mainline. The Mainline's export delivery points are not, however, points at which conventional direct pipeline competition occurs.

It is also the case that TransCanada's unregulated IT service faces competition from Mainline FT shippers paying regulated rates. This is important for the analysis of the Emerson market and is discussed further below. The diversion feature of the FT service, which allows FT shippers to divert their gas to alternative upstream and downstream delivery points, facilitates that kind of competition. In the RH-001-2013 proceeding TransCanada proposed to consolidate and enhance its market power in the short term transportation market by eliminating downstream diversions from the FT service. Fortunately, the NEB rejected that idea.

Q. What happened when the RH-003-2011 Decision was implemented in July 2013?

A. TransCanada immediately increased the bid floors for IT and STFT at most points, especially domestic points, to multiples of the regulated toll. Those services were thus effectively eliminated from the domestic market.

At Emerson, which was the main point at which gas was flowing under IT service, TransCanada quickly increased the IT toll by about $0.60/GJ, effectively doubling it to around $1.20/GJ. Because that happened in the summer, when downstream demand was low, Emerson prices increased somewhat but the main effect was to immediately drive Alberta supply prices down by roughly the amount of the Emerson IT toll increase. Alberta producers were unhappy with that result.

As the summer and fall of 2013 progressed, the main effect of deregulated IT prices was to trigger an explosion of FT contracting. By November TransCanada had contracted well over 1.5 million GJ/d of FT service, as I recall more than doubling its system-wide FT contract levels. At Emerson alone FT contracts went from zero to over 600,000 GJ/d. All of that Emerson FT service was contracted for by marketers whose business involves selling gas under mostly short term arrangements at Emerson or points downstream of Emerson. As far as I am aware no LDCs subscribed for new FT service to Emerson, although the eastern domestic LDCs contracted for large amounts of new FT to their service areas.

Q. Please explain in more detail the nature of the competition between FT shippers and unregulated Mainline IT service, in particular as it affects the gas market at Emerson.

A. In a situation where there is no FT service to a point, as was the case at Emerson in July 2013, the IT price set by TransCanada normally establishes the "differential" for the path in question. The differential is the difference in the market price of gas between the delivery point, here Emerson, and the receipt point, Empress. It is essentially a measure of the market value of the transportation path. When TransCanada increased the Empress/Emerson IT price by $0.60/GJ in early July 2013 the Empress/Emerson commodity price differential had to expand by that amount. Otherwise, no shipper would buy the IT service at the new higher toll and no gas would flow. As it happened, because it was July and producers were more eager to sell their gas than downstream customers were to buy it, the differential was increased by Alberta prices being driven down. During the winter, when there is more need for the gas downstream and less urgency to find customers in the producing area, one would expect the differential to expand primarily as a result of prices at Emerson increasing.

That situation changes when there are FT shippers on the same path. By the winter of 2013/14 there was over 600,000 GJ/d of FT service on the Empress/Emerson path, all held by marketers. In that situation, as long as the total demand at Emerson is less than the FT contract level, commodity prices at Emerson will be set by competition amongst the FT shippers and downstream customers. There will be no market for TransCanada IT service, and it will make no difference what IT toll the pipeline sets. In that situation, in fact, there may be a tendency for Emerson prices to fall, and differentials to contract, to a point where differentials do not recover the full FT toll. That will happen if FT shippers bid the price down in order to keep their capacity full so that they can recover their fixed costs.

The situation is entirely different, however, if downstream market demand exceeds the FT contract level. In that case the IT service will be the marginal supply. Its cost, plus the cost of gas at Empress, will be the marginal cost of Emerson supply, which sets the market price. In that scenario all of the FT shippers will fully utilize their service, and they will all be able to charge a price for gas at Emerson that reflects the cost of gas at Empress plus the IT toll set by TransCanada. If the IT toll is $10.00/GJ, and the market price of gas at Empress is $3.00/GJ, the Emerson market price for all buyers and sellers will be $13.00/GJ, assuming there is sufficient demand at that price to keep some IT flowing. That is a huge benefit to the FT shippers, whose unit costs in this hypothetical are only about $3.75/GJ, i.e. the Empress cost of gas plus their FT toll and fuel.

Q. Is it not the case that market forces will always tend to force prices back towards a natural equilibrium?

A. Yes, that is true. To begin with, TransCanada's IT prices are constrained not just by Emerson FT shippers, but by the cost of downstream alternatives available to customers who might want to buy gas at Emerson. In August it is doubtful that any gas would flow through Emerson at a price of $13.00/GJ, and TransCanada would only maximize its revenue by charging a more reasonable toll.

In a situation where TransCanada is able to set the Emerson price with its IT toll, high prices will attract new FT shippers, eventually wiping out the market for IT and forcing prices lower. Where prices are trending below a level that reflects the FT toll, e.g. if there is a surplus of FT relative to demand, Emerson FT shippers will seek out higher priced markets downstream using diversions. In the longer run, if prices at Emerson are insufficient to recover the annual cost of FT service, FT shippers will exit the market by not re-contracting their annual FT service, eventually making IT the marginal supply again and forcing prices up.

Because of all these factors it is reasonable to assume that Emerson differentials will trend towards the FT toll level in the long run.

Q. If that is the case, how is the new market structure driven by unregulated IT tolls fundamentally different from the pre-RH-003-2011 structure?

A. There are two reasons to think it is different.

First, whatever the long run trend, it is likely that short term Emerson market prices will be more unstable than under the previous regime, with a greater probability of spikes and dips. Under the previous regime the marginal cost of gas at Emerson was largely driven by the very stable regulated IT toll. Under the new regime the marginal cost is a function of numerous factors. One of those is the balance between downstream demand and FT contract levels, both of which can change either up or down for numerous reasons. Another is the IT toll set by TransCanada, which can change daily and which is presumably influenced by numerous factors, including weather, the cost of downstream alternatives, and expected FT contracting behaviour.

The second point is that, on average, I think it is reasonable to expect there to be an overall upward bias in Emerson differentials relative to the FT toll level, especially during the winter [redacted]. One of the major constraints on TransCanada's IT prices is the willingness of new FT shippers to enter the market if differentials significantly exceed the cost of FT service. It is important to remember, however, that when potential shippers consider making a one-year commitment to FT service they are not really interested in price spikes that happened yesterday or that may happen next week. They are fundamentally interested in whether prices over the entire year of their FT commitment will be high enough to recover the annual cost of the service. They are therefore looking at forward markets, and it is reasonable to expect forward markets to exhibit seasonality, with higher prices in the winter, when demand is highest and TransCanada is most likely to be able to influence market prices, and lower prices in the summer.

It is also likely that potential FT shippers will account for the greater risk and price volatility associated with the new market structure when they make FT contracting decisions. In that case they may only contract for new FT if they see a premium in the forward markets, i.e. if the forward market tells them that they will be compensated for accepting the greater risk that is now associated with Emerson prices.

[redacted]

Q. In the new environment, is it possible that Emerson/Empress differentials will be consistently below the FT toll, making Emerson a relatively attractive market for a party like Centra?

A. I think that is unlikely. First, it is difficult to believe that Emerson will be "out of the money" during the winter, [redacted], over any sustained multi-year period. Looked at on an annual basis, the fact is that marketers will not contract for one-year Emerson FT service if they expect to lose money on that investment. They may in fact lose money in any given year, if things turn out differently than they expected and they do not hedge their position, but over time annual average prices must be sufficient to recover the cost of FT capacity. Otherwise, there will be no FT shippers.

3. Centra's Response to RH-003-2011 and Prospective Analysis

Q. You said that the market's response to implementation of the RH-003-2011 decision was an "explosion" of FT contracting. What was Centra's reaction?

A. Centra's reaction, in terms of changes to its transportation portfolio, was relatively muted. Centra [redacted].

The other change Centra made immediately was to [redacted] Centra intends to rely on Emerson or Michigan supply, having FT service for the full amount of those expected purchases is absolutely necessary. That is because TransCanada will block any IT or STFT movements of gas from Emerson to the MDA. It is also likely that under the RH-003-2011 regime Peaking Delivered Services will decline in importance or at least become very expensive.

In November 2014 Centra contracted [redacted]. In the Application Centra characterizes that [redacted] as being driven mostly by [redacted]vice.

Q. What alternatives did Centra have, or does it have now?

A. When the RH-003-2011 Decision was issued the main risk it created for the market was high and unstable gas prices at Emerson. Emerson is the point where the vast majority of IT flowed at the time, and where market prices were closely linked to regulated IT tolls. If Centra was concerned about that, as it should have been, it would have considered the alternative of [redacted].

That approach would insulate Centra from price spikes and general price volatility caused by TransCanada's IT pricing behaviour. The Empress market, while it has its own volatility and is always potentially subject to price spikes associated with gas supply issues or NGTL delivery constraints, will not be affected much, if at all, by TransCanada's IT pricing behavior. If anything, the general tendency will be for high Emerson IT prices to depress Alberta gas prices.

The downside to Centra of protecting itself in that way is that it would incur incremental fixed costs for firm capacity that will likely be used for system purposes at a low load factor.

Q. Would those incremental fixed costs necessarily imply that this approach would increase Centra's total costs significantly?

A. No, because the capacity Centra would contract for has a market value that Centra can in principle capture if it does not need the capacity for its own system purposes. This is simply "capacity management", which Centra is familiar with and, presumably, fully capable of executing.

While Empress/MDA capacity is technically different from Empress/Emerson capacity, it has a market value that is (relative to cost) very similar. An Empress/MDA shipper can divert deliveries to Emerson in return for a usage-based diversion fee of about $0.08/GJ, which is simply the difference between the daily Empress and MDA FT tolls. Diversions have a lower priority than FT deliveries to the primary Emerson point, but TransCanada cannot refuse to divert and will do so as long as there is available capacity, which there always is unless there is a physical problem on the Emerson line.

On a net basis, then, Empress/MDA FT capacity is an asset with a market value that is essentially the same as Empress/Emerson capacity. If the market value Centra is able to capture for its excess capacity is equal to the cost of that capacity, the net incremental cost to Centra's customers will be zero.

Q. Is it reasonable to assume that the market value of new Empress/MDA capacity would equal its cost?

A. I have explained why it is reasonable to expect that in the long run Emerson FT capacity will have a market value equal to or greater than its cost on an annual basis, and likely greater than its cost during the winter. If that is not the case Emerson FT shippers will exit the market, eventually making gas transported using TransCanada IT the marginal supply and driving up market prices until those FT shippers are induced to re-enter the market. That adjustment mechanism may be slow and imperfect, and in some years Emerson FT shippers may lose money on an annual basis, but that situation cannot persist indefinitely or on average over any extended period.

Q. Assuming that turns out to be the case, would Centra necessarily be able to capture the theoretical market value of Empress/MDA capacity effectively?

A. Because of its circumstances and role as a distributor, Centra may have difficulty extracting the full notional market value of excess FT capacity on a consistent basis. How much difficulty it would have is an important question in the analysis of this alternative. The existing Emerson FT shippers are marketers, and are therefore not encumbered by Centra's highly variable system delivery obligations or the restrictions that Centra is effectively subject to in buying gas for resale, hedging its purchases or sales, or using other physical or financial market tools that marketers routinely employ. I think it is reasonable to assume, therefore, that Centra would be less efficient than an unregulated marketer in marketing capacity it does not need from time to time.

In that connection, different considerations may arise at different times of the year, and there may be different approaches Centra could take to the capacity management challenges it would face in this type of scenario. [redacted]

[redacted]

Although I know Centra is reluctant to go too far down the "asset management arrangement" road, that would be an obvious approach to dealing with these issues. For example, Centra might essentially hire a marketer to be its agent [redacted]. Obviously that type of arrangement would cost Centra something, depending on how much risk the counterparty assumed under the arrangement and other factors.

While it is fair to assume that some amount of theoretical market value would "leak" out of Centra's hands in this type of scenario, relative to what would be achievable by an unregulated marketer, that does not imply that the alternative approach is unworkable. It is really a question of how big the leakage is likely to be and how it would affect the economics of the situation. If Centra's position [redacted]

Q. How would you compare Centra's response to the deregulation of IT prices to the responses of other market participants?

A. The risk the market faced when the NEB deregulated TransCanada's [redacted] IT prices was the potential for market instability and, in particular, IT prices and Emerson gas [redacted] that are much higher than would be seen under conventional regulation. One possibility was, and is, that ultimately competitive forces of the kind I have described will constrain TransCanada's IT pricing behavior [redacted] to a reasonable level, although whether and to what extent that would happen was obviously unknown.

In facing that threat Centra was in essentially the same position as the various marketers who were active at the time in serving markets [redacted]. Both Centra and the marketers [redacted], and until then had relied on the short term competitive market, operating in the context of regulated IT prices, to provide reliable supply at reasonable prices [redacted].

The deregulation of IT prices eliminated much of the logical basis for that reliance, and the question was how market participants would react.

The marketers, or at least some of them, apparently did not believe that market outcomes under the new rules would be favorable. Their response was therefore to protect themselves from TransCanada, at considerable cost and risk to themselves and their shareholders, [redacted]rvice. Rather than relying on Mainline IT service as they had in the past, they invested in FT service and became competitors to the IT service. They did not make that investment out of any sense of public duty; they did it because they believed they would be economically better off with that strategy than with a strategy of simply accepting whatever the market outcome turned out to be under the new market rules.

[redacted]

[redacted]. That was a bet many of the other major [redacted] participants were unwilling to make. As I have acknowledged, Centra's position is somewhat different from that of [redacted] market participants, because it is arguably less able to optimize any investment in FT capacity, [redacted].

Q. Have you analyzed quantitatively the impacts of the alternative approach that you have been discussing?

A. The question is one of [redacted].

In order to illustrate the potential overall net effect of the alternative approach, I have attempted to model the difference in Centra's downstream supply costs under the status quo versus one version of the overall alternative approach I have been discussing. That analysis is set out in Attachment 1. This is not an attempt to precisely model Centra's gas supply portfolio, and the analysis employs a number of simplifying assumptions. It does illustrate, however, at a feasible level of detail, how the various costs and benefits compare at a high level, and I believe it highlights the important factors.

For the purposes of that analysis [redacted].

I have based that comparison on Centra's 2015/16 gas cost forecast.

[redacted]

The next step in the analysis is to estimate the gas acquisition cost benefit, if any, [redacted]. In order to do that [redacted]

[redacted]

As shown in the middle table, the general effect is that Centra's supply costs would be [redacted]

The remaining factor to consider is the impact of capacity management activities and revenues, which will also offset the cost of the alternative Empress/MDA FT service. This is difficult to estimate, because I do not have the information Centra has or day-to-day experience in these markets. I note, however, that in order for Centra to "break even" in this model it would need to recover as capacity management revenue about $8 million out of the total annual cost of the Empress/MDA capacity of about $16 million.

For the reasons discussed above in connection with Centra's ability to recover capacity management revenue under different conditions, I have assumed that total recovery will be higher in the summer, when the capacity is not needed by Centra and can be sold in large blocks for monthly or longer terms. For the winter, when scheduling issues will make cost recovery more difficult, I have assumed that unit revenues will be lower. In this model I have calculated [redacted]. The model then assumes that in the summer Centra would recover [redacted] of the full theoretical market value, while in the winter it would recover only [redacted]. For each month the "Available Volume" assumed to be disposed of in the secondary market is the monthly physical capacity minus the monthly supplemental gas volumes. With those assumptions the unutilized summer capacity would be worth [redacted] while the unutilized winter capacity would generate $3.6 million, for a total of [redacted].

[redacted]

Q. What are your comments on those results?

A. I observe first of all that the difference between the two scenarios, based on Centra's forecasts, is not large, especially given the uncertainties with this kind of model around capacity management revenues and actual market prices. With these assumptions there is [redacted].

More importantly, however, this analysis does not captur[redacted]. The forward market numbers that underlie the model assume, essentially, [redacted]

[redacted]. Concern about the validity of that assumption is what motivated this enquiry in the first place. As illustrated by the discussion that follows [redacted]. Judgements about the likelihood of, and likely severity of, [redacted] and how much parties care about the impact of those disruptions in the overall context of Centra's rates, must be relevant to any consideration of these issues.

Q. Are you suggesting, based on your analysis, that the Board direct Centra to reconfigure its transportation portfolio in any particular way?

A. No. I am not in a position, based on this relatively simple analysis, to recommend specific changes to Centra's portfolio at this time, nor do I have the information necessary to make such recommendations. In any event, [redacted].

At the same time, these results, together with the more extreme case discussed in the next section, suggest that [redacted] My my analysis suggests that it is possible to avoid or mitigate that risk at a modest cost or, according to the analysis in Attachment 1, while creating a positive economic benefit. As explained in the next section, my view is that, faced with the massive uncertainties that existed in the market immediately after the RH-003-2011 Decision was implemented, [redacted]. While it is likely that market participants are adapting to the new environment, there are still risks in the market that it would be desirable and cost-effective to avoid.

4. 2013/14 Non-Primary Gas PGVA Deficiencies

Q The third issue to be addressed in this area is Centra's 2013/14 Non-Primary Gas PGVA deficiencies. How have you approached that issue?

A. The majority of the 2013/14 PGVA deficiency is attributable to supplemental gas costs, and in particular to the fact that [redacted], at prices that far exceeded the forecast costs embedded in rates. The reason Centra paid very high prices for its Supplemental Gas volumes was that market prices [redacted] were driven to extremely high levels by extremely high IT prices set by TransCanada [redacted].

TransCanada's ability to set IT prices at extraordinary levels was enhanced by the fact that there was sustained cold weather across eastern North America over that period. The cold weather caused TransCanada IT to be the marginal supply [redacted] over an extended period, [redacted]. The high commodity market prices themselves, however, were the direct result of TransCanada's actual IT pricing behaviour, and not, for example, physical constraints [redacted] The market risk that was created by the RH-003-2011 Decision manifested itself in spectacular fashion in the first winter after the Decision was implemented.

To begin with, the absolute size of the deficiency has nothing to do with whether it reflects reasonable behaviour by Centra. The deficiency arose because Centra's actual purchase prices differed from the forecasts embedded in Centra's rates by a large amount, but that fact by itself does not suggest any fault on Centra's part. In order for us to question the reasonableness of those costs it is necessary to consider what the result would have been had Centra done something differently, and show that it reasonably should have done something differently.

For these purposes it is not possible for me to inquire into or criticize individual purchase decisions that may have contributed to the large deficiency. Centra has not provided details of how exactly it managed to spend as much as it did, or what its reasoning was in relation to individual transactions. Even if I knew those details, however, it might be difficult to evaluate the reasonableness of individual purchasing decisions without understanding the entire context in which those decisions were made. For these purposes I have assumed that

Centra behaved reasonably in its day-to-day purchases, and did as well as could be expected given the circumstances it faced.

Q. In that case, what is the issue that needs to be examined?

A. If there is fault in all of this on the part of Centra it relates to Centra's failure to anticipate and appropriately mitigate the IT pricing-related risks I have been discussing. In particular, it appears that a significant portion of the PGVA deficiency would have been avoided if Centra had adopted a more conservative transportation planning approach designed to insulate it from the risks associated with the deregulation of Mainline IT prices.

In the last section I described an analysis that compared the expected results for Centra with its existing portfolio to the expected results with a hypothetical portfolio [redacted]. That analysis was based on Centra's 2015/16 forecast volumes and prices, i.e. assuming normal weather and currently expected future prices. The general conclusion, with those cost and volume assumptions, was that from a net cost perspective the two scenarios are roughly equivalent.

In order to understand the impact of Centra's portfolio design on its 2013/14 results I conducted essentially the same analysis using actual 2013/14 winter results. The results are set out in Attachment 2.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. Please summarize the results of the analysis in Attachment 2.

A. [redacted]

[redacted]

Q. Are you suggesting that it was unreasonable [redacted]

A. Not entirely. The issue is whether Centra [redacted], given the new environment it faced and the unknown nature of that environment. It must have understood the nature of that risk, but even the [redacted] is not characterized by Centra as an attempt to address that risk. [redacted]

[redacted]. I was an interested observer of the Mainline transportation market in the fall of 2013, [redacted]

In the fall of 2013 LDCs across the country were frantically contracting for incremental FT service, [redacted]. I think it is fair to say that during that period nobody had a good idea of how the new market structure would play out. Many parties' reaction to that uncertainty was to invest in FT capacity to protect themselves against potential volatility, even though most would undoubtedly have preferred not to do that.

I think it is too harsh to say that reasonable behaviour by Centra [redacted]. Nevertheless, I think it would have been reasonable of Centra [redacted]. Centra, like everyone else, had no idea what TransCanada would do with its newfound ability to exercise its market power, and no idea what the market impact would be of whatever TransCanada chose to do. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

In fact, Centra ultimately did try to protect itself from TransCanada-[redacted]

Q. Are you proposing any specific disallowance?

A. Any judgment about the extent to which Centra should have reacted if it was behaving reasonably in the fall of 2013, given the information it had at that time, is somewhat arbitrary. [redacted]

[redacted]

[redacted]

Q. What is your overall conclusion on these issues?

A. I believe it would have been reasonable in the fall of 2013 for Centra to have sought to protect its customers from the risks associated with unregulated IT prices [redacted]

[redacted] is a reasonable estimate of the benefit that strategy would have created for customers.

Q. Does that conclude your evidence?

A. Yes.

Attachment 1

[redacted]

[redacted]

[redacted]

Attachment 2 - [redacted]

[redacted]

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PROFESSIONAL EXPERIENCE

Consultant and Legal Counsel January 2001 – July 2015

- Consultant to the Office of the Utilities Consumer Advocate ("UCA") in the Alberta Utility Commission 2013 Generic Cost of Capital Proceeding (AUC ID 2191), including the preparation of written direct and rebuttal evidence on capital structure, credit metric analysis, and business and regulatory risks. Testified on those matters at the oral hearing convened by the Commission.

- Consultant and Counsel to Tenaska Marketing Canada in NEB Proceeding RH-003-2011, TransCanada Pipelines Limited and NOVA Gas Transmission Ltd. ("NGTL") Application for Restructuring and 2012-2013 tolls and NEB Proceeding RH-001-2013, TransCanada Application for Tariff Changes.

- Consultant to the UCA in the Utility Asset Disposition Proceeding (AUC ID 20), 2011 Alberta Utilities Commission Generic Cost of Capital Proceeding (AUC ID 833), ATCO Gas 2011-2012 GRA (AUC ID 969), AltaGas Utilities Inc. 2010-2012 GRA (AUC ID 904) and 2013-2017 Phase II Application (AUC ID 2687), and various other Alberta proceedings.

- Consultant and Counsel to the UCA in NEB proceeding GH-5-2008, which examined the issue of NEB jurisdiction over the facilities, tolls, and tariffs of NGTL.

- Consultant to the UCA on various gas pipeline matters including NGTL revenue requirement and rate design issues in the context the development of a new toll and tariff structure for NGTL and associated NEB approvals, and NEB pipeline abandonment issues.

- Advised and appeared as an expert witness on behalf of the Consumers Association of Canada (Manitoba) Inc. in numerous proceedings before the Manitoba Public Utilities Board, including Centra Gas Manitoba Inc.'s 2012 Gas Transportation and Storage Portfolio Review Application, various general rate applications and cost of gas applications, the 2007 Competitive Landscape Proceeding, and Centra Gas Manitoba's application for approval of fixed price services for small volume retail customers.

- Consultant to BP Canada and the Mackenzie Explorers Group (BP, Chevron, Devon, Encana, Nytis) in relation to the Mackenzie Valley Pipeline project and the related GH-1-2004 proceeding before the National Energy Board ("NEB").

- Advised and assisted the Vulnerable Energy Consumers Coalition on issues arising in Ontario Energy Board ("OEB") proceeding EB-2008-0106, which examined various aspects of the design and pricing of utility retail merchant services in Ontario. Prepared Information Requests and draft written argument.

- Filed and defended expert testimony at the Ontario Energy Board ("OEB") on behalf of various retail customer groups on market and regulatory issues related to the regulation of Ontario natural gas storage, as part of the OEB's 2006 Natural Gas Electricity Interface Review proceeding.

- Consultant and Counsel to the Canadian Federation of Independent Business before the Alberta Energy and Utilities Board ("EUB") in various rate proceedings involving ATCO Gas, ATCO Electric, the Epcor companies, Fortis Alberta, and Direct Energy Regulated Services.

- Counsel to Coral Energy Canada Ltd. before the NEB in Phase 2 (Cost of Capital issues) of TransCanada PipeLines Limited's ("TransCanada's") 2004 Mainline Tolls proceeding, RH-2-2004.

- Filed and defended testimony at the NEB on behalf of the Cogenerators Alliance in TransCanada's North Bay Junction Application, RH-3-2004, and on behalf of the Cogenerators Alliance and Coral Energy in TransCanada's 2004 Mainline Tolls and Tariff Application, RH-2-2004, Phase 1.

- Consultant and Counsel to Cargill Power and Gas Markets before the EUB in the Board's 2004 Generic Cost of Capital Proceeding for Alberta Gas and Electric Utilities and in ATCO Pipelines' 2003/2004 General Rate Application.

- Filed and defended testimony at the NEB on behalf of the Firm Shippers Group in TransCanada's 2003 Mainline Tolls and Tariff Application and on behalf of Mirant Canada Energy Marketing Ltd. in TransCanada's 2001/2002 cost of capital proceeding.

TransCanada PipeLines Limited 1999 - 2000

Director, Regulatory Strategy
Director, Eastern Market Development

- Negotiated settlements of the 1999 and 2000 TransCanada Mainline tolls cases. Developed and directed the preparation and filing of the 2000 Mainline Tolls application, and led negotiations with 30+ parties on service and toll restructuring proposals for 2001 and beyond.

- Acted as the company's lead regulatory policy and toll design witness in litigated proceedings before the NEB and OEB related to toll design for short term transportation services, economic feasibility of new pipeline facilities, and gas utility unbundling.

TransCanada Gas Services (TCGS) 1986 - 1999

Vice-President, Regulatory Affairs	1997 – 1999
Director, Planning and Regulatory Affairs	1995 – 1997
Manager, Regulatory Affairs	1992 – 1995
Coordinator, Regulatory Affairs	1991 – 1992

- Throughout the 1991-99 period, directed TCGS's participation in regulatory proceedings and settlement negotiations in jurisdictions across North America. Areas of concentration included, as various times:

  - NOVA Gas Transmission Limited (NGTL) and ATCO Pipelines tolls and tariffs, including EUB regulation of NGTL and ATCO Pipelines.

  - NEB regulation of the TransCanada Mainline tolls, tariffs, and facilities applications, and NEB regulation of gas exports through long term licenses and short term orders.

  - Various OEB issues related to direct purchase mechanisms, service unbundling, and the design of competitive market structures for distribution customers. Active in the OEB's Ten Year Market Review and various associated Enbridge Gas Distribution and Union Gas proceedings. Appointed to the OEB's Gas Market Design Task Force.

  - Federal Energy Regulatory Commission (FERC) regulation of U.S. interstate gas pipelines, including several restructuring/unbundling proceedings under Order No. 636, and various other rate proceedings relevant to Canadian gas exports.

- Filed written testimony and appeared as a witness on behalf of the company in numerous regulatory proceedings before the NEB, the EUB, the FERC, the OEB, and the Manitoba Public Utilities Board. Testimony addressed toll design, cost allocation, cost of service, tariff, and facilities certification issues.

Legal Counsel 1986 - 1991

- Directed the company's participation in various regulatory proceedings related to gas exports and facilities certification. Represented the company as counsel before the

NEB, OEB, and EUB on various toll, tariff, service, export license, and facilities matters.

- Drafted and participated in the negotiation of numerous long-term export and domestic gas sales and transportation contracts, and was responsible for all related regulatory and producer approval processes.

EDUCATION AND PROFESSIONAL QUALIFICATIONS

University of Calgary	*Bachelor of Laws*	1985
University of Calgary	*Bachelor of Arts (Philosophy)*	1981
Law Society of Alberta	*Member*	1986 – present

Mark P. Stauft
List of Testimony

2014 - Alberta Utilities Commission, 2013 Generic Cost of Capital proceeding. On behalf of the Utilities Consumer Advocate, prepared written direct and rebuttal evidence, and related information request responses, on credit metrics, capital structure, and business and regulatory risk. Testified at the oral hearing.

2012 – Manitoba Public Utilities Board, Centra Gas Manitoba Inc., Transportation and Storage Portfolio Review Application. Written direct testimony and Information Request Responses on behalf of the Consumers Association of Canada (Manitoba) Inc. Testified at the oral hearing

2011 – Alberta Utilities Commission, AltaGas Utilities Inc., 2010-2012 General Rate Application, Proceeding 904. Written direct testimony and Information Request Responses on behalf of the Utilities Consumer Advocate. Testified at the oral hearing.

2011 – Alberta Utilities Commission, ATCO Gas, 2011-2012 General Rate Application, Proceeding 969. Written direct testimony and Information Request Responses on behalf of the Utilities Consumer Advocate. Testified at the oral hearing.

2010 – Manitoba Public Utilities Board, Centra Gas Manitoba Inc., 2010/2011 Cost of Gas Application. Written direct testimony and Information Request responses on behalf of the Consumers Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors. Testified at the oral hearing.

2009 – Manitoba Public Utilities Board, Centra Gas Manitoba Inc., 2009/2010 and 2010/2011 General Rate Application. Written direct testimony and Information Request responses on behalf of the Consumers Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors. Testified at the oral hearing.

2007 – Manitoba Public Utilities Board, Review of Natural Gas Competitive Landscape. Written direct testimony and Information Request responses on behalf of the Consumers Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors. Testified at the oral hearing.

2007 – Manitoba Public Utilities Board, Centra Gas Manitoba Inc., 2007/2008 and 2008/2009 General Rate Application. Written direct testimony and Information Request responses on behalf of the Consumers Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors. Testified at the oral hearing.

2006 – Ontario Energy Board, Natural Gas Electricity Interface Review, Hearing Order EB-2005-0551. Written direct testimony, Interrogatory Responses, and written reply testimony on behalf of IGUA, AMPCO, CCC, VECC, City of Kitchener, and Canadian Manufacturers and Exporters, Inc. on regulatory and market issues related to the deregulation of utility-owned gas storage facilities in Ontario. Testified at the oral hearing.

2004 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of a New Receipt and Delivery Point at North Bay Junction and Associated Tolls, Hearing Order RH-3-2004. Written direct testimony and Information Request responses on behalf of the Cogenerators Alliance, a group of electric generators in Ontario. Testified at the oral hearing.

2004 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of 2004 Mainline Tolls and Tariffs, Hearing Order RH-2-2004, Phase 1. Written direct testimony and Information Request responses on behalf of the Cogenerators Alliance and Coral Energy. Testified at the oral hearing.

2003 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of 2003 Mainline Tolls and Tariffs, Hearing Order RH-1-2002. Written direct testimony, reply testimony, and Information Request responses on behalf of the Firm Shippers Group (Mirant Canada, Coral Energy, PG&E National Energy Group and Energy East). Testified at the oral hearing.

2002 – Ontario Energy Board, Enbridge Consumers Gas, Application for Approval of Fiscal 2002 Rates, Docket No. RP-2001-0032. Written direct testimony and interrogatory responses on behalf of the Consumers Association of Canada. Testified at the oral hearing.

2002 – National Energy Board, TransCanada PipeLines Limited, Fair Return Application, Hearing Order RH-4-2001. Written direct testimony and Information Request responses on behalf of Mirant Canada. Testified at the oral hearing.

2001 – Ontario Energy Board, Enbridge Consumers' Gas, Application for Approval of Fiscal 2001 Rates, Docket No. RP-2000-0040. Written direct testimony on behalf of the Coalition for Efficient Energy Distribution. Testified at the oral hearing.

2000 – National Energy Board, AEC North Suffield Pipeline Ltd., Application for a Certificate to Construct Facilities, Hearing Order GH-2-2000. Written direct testimony on behalf of NOVA Gas Transmission Limited.

2000 – Ontario Energy Board, Union Gas Limited, Application for Approval of Performance Based Rates and Unbundling of Services, Docket No. RP–1999-0017. Written testimony on unbundling of upstream transportation on behalf of TransCanada PipeLines Limited.

1999/2000 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of Changes to the IT and STFT Toll Schedules, Hearing Order RH-1-99. Filed the Application and written direct and reply testimony on behalf of TransCanada PipeLines Limited. Testified at the oral hearing.

1999 – Ontario Energy Board, Enbridge Consumers' Gas, Docket No. RP-1999-0001. Written direct testimony on unbundling issues on behalf of TransCanada Gas Services. Testified at the oral hearing.

1998 – Federal Energy Regulatory Commission, Northern Natural Gas Company, General Rate Application, Docket No. RP-98-203. Written Answering Testimony on behalf of TransCanada Gas Services.

1997 – National Energy Board, TransCanada PipeLines Limited, Application for Approval of 1998 Facilities, Hearing Order GH-2-97. Information Request Response on market issues on behalf of TransCanada Gas Services. Testified at the oral hearing.

1997 – Ontario Energy Board, Request for Comments Concerning Legislative Change, E.B.O. 202. Written comments on behalf of TransCanada Gas Services.

1997 – Federal Energy Regulatory Commission, Iroquois Gas Transmission System L.P., General Rate Application, Docket No. RP-97-126. Written Cross-Answering Testimony on behalf of TransCanada Gas Services. Testified at the oral hearing.

1997 – Alberta Energy and Utilities Board, NOVA Gas Transmission Limited, Application for approval of a load retention service. Written direct evidence on behalf of TransCanada Gas Services. Testified at the oral hearing.

1996 – Federal Energy Regulatory Commission, Northern Natural Gas Company, General Rate Application, Docket No. RP95-185. Written Answering Testimony on behalf of TransCanada Gas Services.

1996 – Manitoba Public Utilities Board, Review of Natural Gas Supply Procurement, Storage, and Transmission Functions of Centra Gas Manitoba, Inc. Written direct and reply testimony on behalf of TransCanada Gas Services.

1996 – Alberta Energy and Utilities Board, Gulf Canada Limited, Application to Construct Facilities. Written evidence on Gulf's "sidestreaming" extraction proposal on behalf of TransCanada Gas Services.

1995/96 – Alberta Energy and Utilities Board, NOVA Gas Transmission Limited, 1995 General Rate Application. Written testimony and Information Request responses on behalf of TransCanada Gas Services.

1995/96 – Federal Energy Regulatory Commission, ANR Pipeline Company, General Rate Application, Docket No. RP94-43. Written Direct, Cross Answering, and Surrebuttal Testimony on behalf of TransCanada Gas Services. Testified at the oral hearing.

1994 – National Energy Board, Western Gas Marketing Limited, Application for a Gas Export License. Hearing Order GH-3-94. Testified before the Board on market issues.

1994 – Federal Energy Regulatory Commission, Natural Gas Pipeline Company of America, General Rate Application, Docket No. RP93-36. Written Direct and Answering Testimony on behalf of TransCanada Gas Services.

1994 – Federal Energy Regulatory Commission, Tennessee Gas Pipeline Company, General Rate Application, Docket No. RP91-203. Written Answering Testimony on behalf of TransCanada Gas Services.

1993 – Ontario Energy Board, Inquiry Concerning Impediments to the Direct Purchase of Natural Gas. Written testimony on behalf of TransCanada Gas Services.