**EB-2012-0337**

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Sched. B);

**AND IN THE MATTER OF** an application by Union Gas Ltd. for an Order or Orders approving its 2013-2014 Large Volume Demand Side Management ("DSM") Plan.

# APPRO

# FINAL ARGUMENT COMPENDIUM

**February 5, 2012**

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TAB 1

## 2 Jurisdictional Review

Navigant carried out a review of jurisdictions which either: 1) allow large customers the option of not participating in natural gas or electric DSM initiatives and being excluded from cost recovery mechanisms (CRM) for such programs; or 2) simply exclude large customers from providing DSM funding for either natural gas or electric DSM programs.

The focus of the review was to gain a better understanding of the circumstances that allowed the jurisdictions identified in the Union report to be able to offer an opt-out option and how they align with the rate-making principles referred to by Union, that individual customers should not be able to pick and choose the distribution services that they want to use and pay for and that all customers within the rate class should be treated the same from a rate-making standpoint The research was extended to include customer groups that are excluded from the CRM to ensure that the OEB and stakeholders understand the full spectrum of DSM funding arrangements for large customers and to provide additional insight into the rate-making principles applied in other jurisdictions.

**DSM Cost Recovery and Opt-out Mechanisms**

The mechanisms used for cost recovery vary between jurisdictions. A survey of natural gas DSM programs found that: *"For those twenty-one gas utility companies that do offer gas DSM programs, there are different methods for cost recovery of the expenditures on the programs."* These included use of a systems benefit charge, a rate rider as well as other forms of cost recovery.

Where opt-out and self-direct provisions are offered they are generally based on customer size or connection conditions which serve as a proxy for size. For example, Arizona, Colorado, New Mexico, North Carolina, Ohio, Utah, Wyoming, Michigan, Minnesota, Montana, Ohio, Oregon, and Wisconsin all allow customers to opt-out or "self-direct" based on some level of energy consumption or demand[3]. Kentucky and Texas allow industries to self-direct if they are connected to the transmission system, while Washington qualifies customers to self-direct if they take power from a *"3-phase service at greater than 50,000 volts"*. Vermont bases its self-direct option on the level of energy efficiency charge (their CRM) paid. In Utah and Wyoming, eligibility is also based on size but the utility, Rocky Mountain Power, "allows customer to aggregate multiple meters to meet the programs minimum use requirements". Other states, such as Virginia, have excluded all customers over a given size (10MW in Virginia) from the state's energy efficiency law.

Regulators in some jurisdictions have based their decision to allow "opting out" based on a definition of the type of energy application or the customer's energy intensity. For example in Missouri allows industrial customers to opt-out of the utility's DSM initiatives and CRM fees if:

> *"they have a demand of at least 5,000 kW in the previous twelve months; ... they are an inter-state pipeline pumping station, regardless of size; or they ... they have a comprehensive demand*

[3] American Council for an Energy-Efficient Economy (ACEEE), Follow the Leaders, Improving Large Customer Self-Direct Programs, October 2011, Report Number IE112.

*or energy efficiency program in place that is saving an amount at least equal to "utility-provided programs" and that they have a demand of at least 2,500 kW in the previous twelve months"*

Similarly, Kentucky's DSM Statute *"allows industrial customers with energy intensive processes to opt-out entirely from participating in DSM programs. ... Consequently, industrial customers who opt-out are not assigned the cost of a utility's DSM programs, and do not pay a DSM surcharge on their energy bills"*.[4]

Table 1 below summarizes the different bases used for allowing opt-out or self-direct options in different jurisdictions. As the table indicates, some jurisdictions have indicated multiple reasons why customers may be allowed to opt-out or self-direct.

**Table 1: Basis for Opt-out/Self Direct Option**

| Basis for Opt-Out or Self-Direct | Jurisdictions |
|---|---|
| Level of Consumption or Demand | Arizona, Colorado, New Mexico, North Carolina, Ohio, Utah, Wyoming Michigan, Minnesota, Montana, Ohio, Oregon, and Wisconsin, Virginia (all over 10MW excluded). |
| Transmission Connection | Kentucky, Texas |
| Service size (3 phase over 50kV) | Washington state |
| Size Aggregated over Multiple Meters | Utah and Wyoming |
| Amount of energy efficiency charge (CRM) | Vermont |
| Type of Load | Missouri, Kentucky |

**Issues Peculiar to Power Producers**

Electricity is essentially a manufactured product rather than a primary form of energy. Natural gas, by contrast, is a fuel which can be used to produce electricity. A survey of APPrO members, discussed in the following section, indicates that natural gas purchased by these "large customers" is primarily used as fuel in the process of generating electricity. In fact, on average the respondents indicated that 96% of the gas purchased was used for generating electricity.

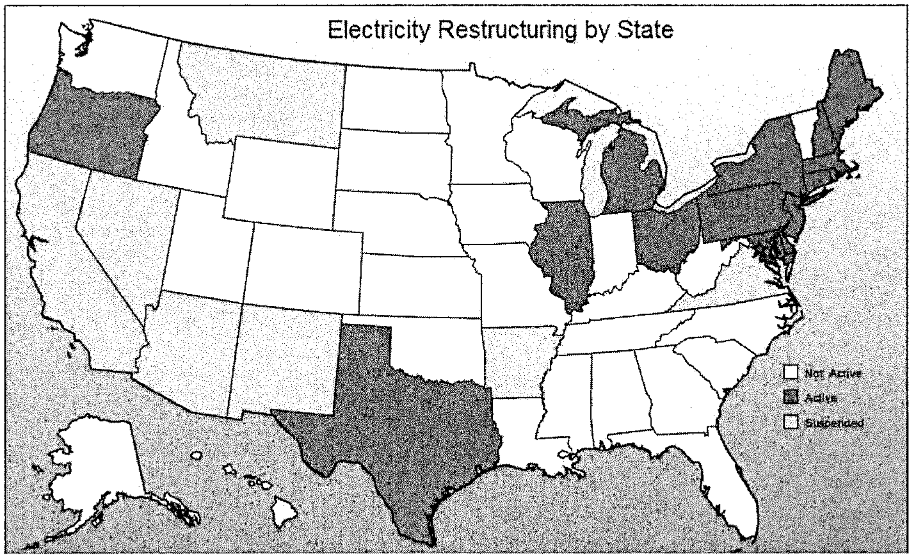
Depending on the structure of the electricity market, natural gas-fired generators in a given jurisdiction may be independent organizations or may be owned and operated by an investor-owned or public utility; normally a regulated entity. As Figure 1 illustrates, most US states have not deregulated their electricity industry. This means that in the majority of US states there are no independent natural gas generators as we have in Ontario and this type of generation is operated by a regulated electric utility.

[4] ACEEE, Follow the Leaders, page 34

NAVIGANT

A review of DSM programs offered by natural gas utilities across North America found no examples of programs directed at customers who use natural gas to generate electricity.[5]

Figure 1: US Electricity Restructuring




Source: US Energy Information Administration: Status of Electricity Restructuring by State. http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html

In the US, large industrial customers such as power producers have the option of directly accessing inter-state pipeline system, and the vast majority of natural gas fired electric generators in the US are attached to the inter-state natural gas pipeline system. Where generators are connected to a distribution system, the natural gas distributors often negotiate separate contract rates for such customers to avoid economic by-pass. As a result, electric generators using natural gas as fuel are often not included in general industrial tariffs or subject to cost recovery mechanisms such as a DSM CRM.

A survey of neighbouring jurisdictions[6] was completed to determine how cost recovery of DSM costs for large industries and natural gas-fired generators are treated.

- In ***Minnesota***, customers using natural gas for power generation are not charged the CRM if the generator is over 50 MW in size.[7] Smaller generators would be subject to the CRM depending on how their account is classified. Minnesota has allowed large industrial customers meeting a size threshold to self-direct since 1999 and has just extended this choice more directly to natural gas customers in 2011.[8] One of the

[5] See for example: Suzanne Tegen, University of Colorado and Howard Geller, Southwest Energy Efficiency Project, *Natural Gas Demand-Side Management Programs: A National Survey*

[6] A response was sought from the New York Public Service Commission but was not received within the time available for preparing this report.

[7] Personal communication with the Minnesota Public Utilities Commission.

[8] Prior to 2011, if a customer's electricity demand met the size threshold (20MW), their natural gas account was also deemed to qualify for "self direct".

considerations in the Minnesota Public Utilities Commission's decision to exclude generators from paying the DSM CRM was that this would effectively result in electricity consumers paying these costs twice; once by paying the CRM as part of natural gas charges and again in paying for the electricity generated from that natural gas consumption.

- In ***Michigan***, MichCon Gas has recently reached a settlement agreement[9] which extends the self-direct option to all "end use transportation" customers. Under this agreement, transportation customers would continue to pay a surcharge to support low income programs but will have the option to use the surcharge revenue that they would otherwise pay to MichCon in order to design, implement or enhance their own energy efficiency projects.[10] Customers were able to begin applying to the self-direct process in October 2012.
- ***Wisconsin*** does not have a "hard and fast policy" on the topic of allocating DSM costs and electric generating plants because most gas-fired generation interconnect to the inter-state pipeline system. The inter-state system is regulated by the Federal Energy Regulatory Commission (FERC) and does not have DSM programs because they typically do not serve individual end-use customers (although exceptions do exist for large industrial loads). In cases where a natural gas distribution company does serve a utility-sized generation unit the cost allocation is managed in the cost-of-service (COS) study, with no DSM costs being allocated to the generator. This is not a "hard policy" but appears to be fairly consistent across the utilities.
- ***Illinois*** natural gas distributors do not allocate DSM costs to large generators. The cost allocation occurs in the COS study and generators are not "users" of DSM services. As in Wisconsin, generators in Illinois always have the option to interconnect to the inter-state system, and the pipeline industry is quite competitive. In addition, natural gas distributors in Illinois have traditionally been provided latitude to discount distribution prices to attract load.
- ***Ohio*** enacted an *Energy Efficiency Bill* in 2009 (SB 221) that provides all customers with the ability to opt-out of energy efficiency programs in economic circumstances provided that such programs are uneconomic for that customer. To-date no one has requested to opt-out, but several larger customers served by First Energy are pressuring the company which may trigger the first filings in the near future. A possibility also exists that the current administration may be pressured to reverse that section of SB 221 and discontinue the provision of energy efficiency programs.

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[9] Corrected Settlement Agreement: In the matter of Michigan Consolidated Gas Company's Application for Approval of its Amended Energy Optimization Plan filed pursuant to the provisions of Public Act 295 of 2008, Case No. U-17050. Michigan Public Service Commission Website: http://efile.mpsc.state.mi.us/efile/cases2.php?all=yes&type=gas

[10] Michigan PSC, Case No. U-17050, testimony of Vicky Campbell, in U17050, pages 26-34.

**Canadian Jurisdictions**

In Ontario, the other large natural gas distributor (Enbridge) does not offer DSM programs for their very large[11] customers. We understand that the only customers currently in this rate class are five large customers which use natural gas to generate power. The DSM Plan submitted to the Board for 2012-2014 shows that the CRM unit rate variance for DSM is not applied to rate 125 accounts[12], though some portion of DSM costs associated with programs for low income customers may be paid by these customers.

The "Jurisdictional Review"[13] included as Appendix A in Union's "Demand Side Management Plan for Large Volume Customers" mentions that *"no other Canadian province currently offers an opt-out or self-direct program option"*.[14] We note that the Nova Scotia Utility and Review Board reviewed an application by Nova Scotia Power Inc. of a DSM rate rider request as part of NSPI's 2009 rate application. A settlement agreement relating to that application excluded the province's two largest industrial electricity customers from the proposed DSM cost recovery mechanism:

> *"It is understood that no payments can be made to customers for projects to be funded by an Energy Savings Account unless and until the Board provides a subsequent order on DSM cost allocation. The Parties agree that at a subsequent date, if the Energy Savings Account option is to be continued by a new administrator, any Party can seek changes or refinements to this option and/or recommend alternative options"*.[15]

The only other jurisdiction in Canada in which independent natural gas-fired electricity generators operate is Alberta, which does not have a CRM for DSM programs.

The only other jurisdictions in Canada in which independent natural gas-fired electricity generators operate are Alberta and BC. Alberta does not have a CRM for DSM programs. Questions were sent to the BC Utilities Commission regarding treatment of independent gas generators in that province; however, a response was not received in time to include in this report.

[11] Classed as Rate 125 customers who use (>600,000 m³/day). See: https://www.enbridgegas.com/businesses/accounts-billing/gas-rates/large-volume-rates/rate-125.aspx

[12] See table presented in EB-2011-0295, Exhibit B, Tab 2, Schedule 1, page 2 of 3

[13] "Review of Jurisdictions Which Offer a Self-Direct or Opt-Out Program Funding Mechanism for Large Customers".

[14] Page 2 of EB-2012-0337, Exhibit A, Tab 1, Appendix A, Filed: 2012-08-31.

[15] NOVA SCOTIA UTILITY AND REVIEW BOARD, IN THE MATTER OF an Application to approve Nova Scotia Power Incorporated's Demand Side Management Plan, NSUARB-P-884. Available on CanLi website: www.canlii.org

# TAB 2

alike, Union has experienced consistent growth in the number of projects and cost-effective natural gas savings generated in its large volume rate classes. Union has provided a summary of its historical Rate T1 and Rate 100 cumulative natural gas savings and projects in Table 1 below.

**Table 1: 2008 – 2011 Rate T1 and Rate 100 Cumulative Natural Gas Savings and Projects**

| | Customer Type | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|
| Cumulative Natural Gas Savings ($m^3$) | Power Generation | 8,105,669 | 67,715,197 | 85,135,577 | 87,708,786 |
| | Industrial | 462,796,246 | 617,062,026 | 896,800,700 | 1,392,613,906 |
| | ***Total*** | **470,901,915** | **684,777,223** | **981,936,277** | **1,480,322,692** |
| Projects Completed (1) | Power Generation | 3 | 11 | 24 | 25 |
| | Industrial | 91 | 113 | 107 | 247 |
| | ***Total*** | **94** | **124** | **131** | **272** |

(1) Includes all studies, capital and O&M projects

The Program will build on Union's success in driving substantial energy savings and bill reductions for customers. Union is proposing to allocate $6.207 million in the large volume rate classes for DSM in 2013. This value includes the proposed Large Volume program budget, as well as the allocation of Board-approved DSM portfolio and Low-income costs allocated to Rate T1, Rate T2 and Rate 100 customers. The amount is consistent with 2012, escalated for inflation[2] and is allocated between Rate T1, Rate T2 and Rate 100 in Exhibit A, Tab 1, Schedule 1. Figure 1 displays the percentage allocation for each budget item included in the $6.207 million. The values for each budget item in Figure 1 are included in Tables 2 and 3 below.

[2] For 2013, Union has applied the inflation factor of 2.22% based on the four quarter rolling average of the Gross Domestic Product Implicit Index as at Q2 2012, released at the end of August.

# TAB 3

MR. MacEACHERON: To power generator customers in the DSM program, that's correct.

MR. FRANK: Okay. And that covered approximately 60 projects, I think you said?

MR. MacEACHERON: That's correct.

MR. FRANK: And just -- can I get the time frame for that?

MR. MacEACHERON: It would have been the -- let me just...

MR. FRANK: I had understood it to be 2009 forward, but I'm not sure if it is 2008.

MR. MacEACHERON: It was 2009, 2010 and 2011.

MR. FRANK: Okay. And do you know what -- so there's $700,000 in incentives. Do you know what the total cost of those projects was?

Or, put another way, do you know the total costs that was funded by the customers themselves, compared to that 700,000?

MR. MacEACHERON: I don't have that information.

MR. FRANK: Can you undertake to get that for me, please?

MR. MacEACHERON: I'm not sure we have that. We can do our best.

MR. FRANK: Well, I note from -- in answer to some of the IGUA questions, that it appeared that that information was available.

MR. MacEACHERON: Our project files should have it. I just was a little uncertain, but I am confident we can find

# TAB 4

UNION GAS LIMITED

Undertaking of Mr.MacEacheron
To Mr. Frank

Please provide total amount in DSM Rates paid by these customers over this time period.

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Please see Attachment 1 for Rate 100.
Please see Attachment 2 for Rate T1.

UNION GAS LIMITED
Rate 100 - 2009 to 2011 DSM Rate and Deferral Impacts for Power Generation Customers

| Line No. | Particulars | | | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| 1 | Forecast Rate Class Volume in Rates ($10^3m^3$) | | | 2,281,152 | 2,271,427 | 2,254,074 |
| 2 | Actual Rate Class Volume in Deferrals ($10^3m^3$) | | | 1,805,104 | 1,882,972 | 1,892,682 |
| 3 | Actual Power Generation Volumes ($10^3m^3$) | | | 971,087 | 1,015,934 | 993,904 |
| 4 | Direct DSM in Rates ($000's) | | (1) | 1,699 | 1,896 | 2,112 |
| 5 | Unit Rate (cents/$m^3$) (line 4 / line 1) | | | 0.0745 | 0.0835 | 0.0937 |
| 6 | Power Generation Customer Impact ($000's) | (line 5 x line 3) | | 723 | 848 | 931 |
| 7 | Indirect DSM in Rates ($000's) | | (2) | 264 | 264 | 264 |
| 8 | Unit Rate (cents/$m^3$) (line 7 / line 1) | | | 0.0116 | 0.0116 | 0.0117 |
| 9 | Power Generation Customer Impact ($000's) | (line 8 x line 3) | | 112 | 118 | 116 |
| 10 | DSMVA in Deferrals ($000's) | | (3) | 254 | 541 | (1,278) |
| 11 | Unit Rate (cents/$m^3$) (line 10 / line 2) | | | 0.0141 | 0.0287 | (0.0675) |
| 12 | Power Generation Customer Impact ($000's) | (line 11 x line 3) | | 137 | 292 | (671) |
| 13 | Audited SSM in Deferrals ($000's) | | (4) | 1,714 | 1,735 | 705 |
| 14 | Unit Rate (cents/$m^3$) (line 13 / line 2) | | | 0.0949 | 0.0922 | 0.0373 |
| 15 | Power Generation Customer Impact ($000's) | (line 14 x line 3) | | 922 | 936 | 370 |
| 16 | LRAM in Deferrals ($000's) | | (5) | 46 | 66 | 85 |
| 17 | Unit Rate (cents/$m^3$) (line 16 / line 2) | | | 0.0026 | 0.0035 | 0.0045 |
| 18 | Power Generation Customer Impact ($000's) | (line 17 x line 3) | | 25 | 36 | 44 |
| 19 | Total Power Generation Customer Impact ($000's) | | | 1,919 | 2,230 | 791 |

Notes:
(1) EB-2012-0337, Exhibit B6.2, Attachment 1, column (a).
(2) EB-2012-0337, Exhibit B6.2, Attachment 1, column (b).
(3) EB-2012-0337, Exhibit B6.2, Attachment 1, column (c).
(4) EB-2012-0337, Exhibit B6.2, Attachment 1, column (d).
(5) EB-2012-0337, Exhibit B6.2, Attachment 1, column (e).

UNION GAS LIMITED

Rate T1 - 2009 to 2011 DSM Rate and Deferral Impacts for Power Generation Customers

| Line No. | Particulars | | | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| 1 | Forecast Rate Class Volume in Rates ($10^3m^3$) | | | 4,871,937 | 4,853,733 | 4,827,587 |
| 2 | Actual Rate Class Volume in Deferrals ($10^3m^3$) | | | 3,311,476 | 4,057,920 | 4,541,959 |
| 3 | Actual Power Generation Volumes ($10^3m^3$) | | | 678,646 | 1,115,921 | 1,232,022 |
| 4 | Direct DSM in Rates ($000's) | | (1) | 1,194 | 1,332 | 1,484 |
| 5 | Unit Rate (cents/$m^3$) (line 4 / line 1) | | | 0.0245 | 0.0274 | 0.0307 |
| 6 | Power Generation Customer Impact ($000's) | (line 5 x line 3) | | 166 | 306 | 379 |
| 7 | Indirect DSM in Rates ($000's) | | (2) | 187 | 187 | 187 |
| 8 | Unit Rate (cents/$m^3$) (line 7 / line 1) | | | 0.0038 | 0.0039 | 0.0039 |
| 9 | Power Generation Customer Impact ($000's) | (line 8 x line 3) | | 26 | 43 | 48 |
| 10 | DSMVA in Deferrals ($000's) | | (3) | 1,963 | 1,012 | 2,880 |
| 11 | Unit Rate (cents/$m^3$) (line 10 / line 2) | | | 0.0593 | 0.0249 | 0.0634 |
| 12 | Power Generation Customer Impact ($000's) | (line 11 x line 3) | | 402 | 278 | 781 |
| 13 | Audited SSM in Deferrals ($000's) | | (4) | 2,241 | 1,419 | 4,402 |
| 14 | Unit Rate (cents/$m^3$) (line 13 / line 2) | | | 0.0677 | 0.0350 | 0.0969 |
| 15 | Power Generation Customer Impact ($000's) | (line 14 x line 3) | | 459 | 390 | 1,194 |
| 16 | LRAM in Deferrals ($000's) | | (5) | 29 | 35 | 70 |
| 17 | Unit Rate (cents/$m^3$) (line 16 / line 2) | | | 0.0009 | 0.0009 | 0.0015 |
| 18 | Power Generation Customer Impact ($000's) | (line 17 x line 3) | | 6 | 10 | 19 |
| 19 | Total Power Generation Customer Impact ($000's) | | | 1,060 | 1,027 | 2,421 |

Notes:
(1) EB-2012-0337, Exhibit B6.2, Attachment 1, column (a).
(2) EB-2012-0337, Exhibit B6.2, Attachment 1, column (b).
(3) EB-2012-0337, Exhibit B6.2, Attachment 1, column (c).
(4) EB-2012-0337, Exhibit B6.2, Attachment 1, column (d).
(5) EB-2012-0337, Exhibit B6.2, Attachment 1, column (e).

# TAB 5

## How DSM Cash Incentives are Being Distributed

Rate 100 and T2

| | 2008 | | | 2009 | | | 2010 | | | 2011 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DSM Funds Rec'd as % Pd in Rates | Total Customers | Number in Category | Percent | No. Of Customers | Number in Category | Percent | No. Of Customers | Number in Category | Percent | No. Of Customers | Number in Category | Percent | Averages of Averages |
| Number ≤ 10% | 34 | 20 | 59% | 36 | 21 | 58% | 37 | 17 | 46% | 37 | 15 | 41% | 51% |
| Number ≤ 100% | 34 | 29 | 85% | 36 | 25 | 69% | 37 | 25 | 68% | 37 | 23 | 62% | 71% |
| Number > 100% | 34 | 5 | 15% | 36 | 11 | 31% | 37 | 12 | 32% | 37 | 14 | 38% | 29% |
| Number > 250% | 34 | 4 | 12% | 36 | 9 | 25% | 37 | 9 | 24% | 37 | 8 | 22% | 21% |

Source: EB-2012-0337 Exhibit B6.8

Conclusions

1 On average 50% of large volume customers access less than 10% of the DSM incentives paid in rates
2 On average 70% of the customers use less DSM incentives that what is in rates
3 On average approximately 30% access an amount equal to or more than the DSM incentives paid in rates
4 On average 20% of the customers use more than 250% of the DSM incentives paid in rates and the underlying data shows that many of these have received close to or in excess of 1000% of the amounts in rates

**On average 7 or 8 Large Volume Customers have monopolized the vast majority of the DSM cash incentives!**

# TAB 6

I guess I just don't see where that gives us any more confidence in the level of funding that we receive in order to allow that to be entered into our economic test.

MR. POCH: So you think if Union says, on August 1st, We approve your plan, here's the amount of money, that's not good enough? You can't rely on that?

MR. RUSSELL: Well, is that a -- that's on an overall plan for the year, correct, not on a program by program -- I guess I should maybe --

MR. POCH: A plan for the next three months, I think is the way it works, or four months.

MR. RUSSELL: I guess I don't maybe have a thorough enough understanding of how that looks. But if I could also just comment back to the --

MR. POCH: Go ahead, and then we will come back.

MR. RUSSELL: The nature of our business, as well, often these efficiency measures, specifically the ones that I have listed, are significant. They're parts of significant investments that occur not every three months, not annually, but on a much longer-term basis.

Some projects -- the connection to the hospital is ten years in the making before we were able to undertake that project.

And so on a use-it-or-lose-it basis, we may have -- and the dates associated with those incentive fundings, a lot of them came to fruition in 2011 just as kind of a lot of projects coming to a head.

So on an annual basis, that use-it-or-lose-it I would see as a negative.

MR. POCH: I guess that harkens back to my conversation earlier with Mr. Zarumba that a longer window would encompass more projects. If the window is too short, it simply doesn't fit with your internal planning processes?

MR. RUSSELL: Longer is more flexible.

MR. POCH: Yes, okay. I guess I just want to circle back, then, to your first point. I still don't quite have it.

If you were assured -- if you were assured that the funding really is use-it-or-lose-it for a project, you have an assurance if you do this project you will get this funding from the utility, and if you don't do it, you're not going to get this funding, and you know -- and you know -- let's treat all of that that Union's administering it for its program reasonably well going forward.

I hear you have some concerns with how they have administered it in the past, but they're talking about a new program now. Assuming they hear you and they respond well to that and they structure the program well so they give companies like yours the assurances it needs, can we agree in that situation, obviously, that the availability of that money changes the economics of -- it may not change your economic test. It may not change the outcome for any given project you're considering if it is not enough money, or what have you, but it would change the economic -- the inputs to the economic test?

MR. SMITH: Thank you very much. Those are my questions.

MS. CONBOY: Thank you. Mr. Frank, have you got re-direct?

**RE-EXAMINATION BY MR. FRANK:**

MR. FRANK: Very brief, Madam Chair.

Just while we're on it, when was the Dundas project actually completed?

MR. RUSSELL: Early 2012.

MR. FRANK: And you said you just received the funds now?

MR. RUSSELL: Yes.

MR. FRANK: Okay. Mr. Poch was asking you certain questions about whether the new program would create enough certainty for you with regard to availability of funds that, for example, you might know by August of a certain year that certain funds are available.

My question for you is: When does LDE budget for capital expenditures or efficiency programs for any given year?

MR. RUSSELL: Generally speaking, for planned efficiency measures, that process takes place in Q3, September/October.

MR. FRANK: Q3 of what year?

MR. RUSSELL: Of the previous -- or of the year prior to the following -- the year in question.

MR. FRANK: So having a determination that certain funds are available in August of 2013, does that assist in any way in the budgeting that LDE does for 2013?

MR. RUSSELL: No.

MR. FRANK: Those are my questions, Madam Chair.

MS. CONBOY: Thank you very much.

The panel is excused with the Board's thanks.

We are going to break for two hours in order for Union to prepare for their argument in-chief.

There were a couple of areas that the Panel would be interested in hearing about, if you are able to cover it, and that is mindful of where we are in 2013, the first day of February and moving forward to getting a decision out as quickly as we can, does that affect the August 1st date that we've been speaking about over the past day and a half?

And, secondly, if the Board were persuaded by GEC's proposal of the two years, how might that affect the August 1st date? And, in fact, Mr. Poch may have covered a bit of that in his cross-examination.

The other thing is, Mr. Poch, I am aware that you are going to be taking off and might not join us after the lunch break, but we are reconvening on Tuesday to receive oral argument from intervenors. So I just wanted to make you -- remind you of that.

MR. POCH: Yes. Board Staff has in fact communicated with counsel, and I think he is taking a poll of who is available. I have indicated on my behalf it is problematic for me to be here, but I will certainly file written evidence that day for you, so hopefully I won't delay

TAB 7

able to confirm that?

MR. MacEACHERON: Again, I would refer to our Exhibit B5.1, which listed the customers for each rate class, and we have eight customers in the T2 rate class out of 20 and we have seven power customers in the Rate 100 class out of 18.

MR. FRANK: So are you saying it is about 15 over 38, 40 percent?

MR. MacEACHERON: That's correct.

MR. FRANK: Okay. And so 40 percent of the customers, do I understand, are getting about 10 percent of the projects, then?

MR. MacEACHERON: That's what that math would calculate.

MR. FRANK: Thank you. We were talking earlier about direct access, and I understood that one of the motivations or goals, perhaps - and you will correct me, because I am paraphrasing a little bit - was to give customers a bit more certainty of amount. Is that fair?

MR. MacEACHERON: For planning purposes?

MR. FRANK: Yes.

MR. MacEACHERON: They would know at the beginning of the year the amount of incentive dollars that they would have available to them, and that was really directed at that planning certainty or rate certainty.

MR. FRANK: Right. And that would give the customer access to approximately, I think you said, 68 percent of the rates paid for the year?

MR. MacEACHERON: That's correct. What they pay in rates associated with the DSM program, setting aside low-income, it would be about 68 percent.

MR. FRANK: Okay. But that customer would still have to have an approved energy plan to get access to those funds?

MR. MacEACHERON: That's correct.

MR. FRANK: And that would have to be done within a stipulated time frame to get them; correct?

MR. MacEACHERON: That's correct. Our program proposal calls for that plan to be done during the first four months of the calendar year.

MR. FRANK: Right. So we heard the phrase: If you don't use it, you lose it. That's correct, in that -- according to the terms of the --

MR. MacEACHERON: The use-it-or-lose-it phrase was made in connection with the direct access budget amount that would be identified and set aside for that customer for a period of time up until August 1st. So they had comfort to know that that money was there for them in that time period.

If they did not have a project that they were committed to executing in the calendar year identified by August 1st, then the funds that we were setting aside for them would be released and made available to all customers in the rate class for their use on energy efficiency.

That same customer who wasn't able to make a commitment or find a project would still have the ability to access funds through the aggregate pool.

MR. FRANK: I understand, but the direct access gets lost; correct?

MR. MacEACHERON: That's correct. Their entitlement reservation, you might say, on those funds would be removed.

MR. FRANK: And it can't -- well, if it's lost, it can't be carried forward, obviously; correct?

MR. MacEACHERON: That's correct.

MR. FRANK: Now, Mr. Crane has saved me a little bit of work on the questions I had about predictability.

If we could just take out his Exhibit K1.6, and it is the first page that he was taking everyone to, I just want to clarify one additional point.

MR. MacEACHERON: Okay. I have it in front of me.

MR. FRANK: Column D, average annual costs for DSM in 2013, the figures in there do not include any amounts for the Union DSM incentive, should there be one; correct?

MR. TETREAULT: That's correct.

MR. FRANK: And that global amount available for the three classes is $1.809 million; correct? I'm taking that from page -- sorry. Yes, page 21 of 36 at Exhibit A, tab 1.

MS. LYNCH: Yes, that's correct.

MR. FRANK: So can you tell me what the amount to an average customer in each of those classes would be, assuming a maximum incentive is paid to Union?

MR. TETREAULT: We can do that via an undertaking.

# TAB 8

b) Union has not completed a consumption forecast for 2014. The table below provides the requested data presuming no T1-T2 split for 2013 volumes only.

| Rate Class | Customer Classification | Number of Customers | Aggregate 2013 FIRM CD $m^3$ | Aggregate 2013 Interruptible CD $m^3$ | Aggregate MAV $m^3$ | Total Forecast 2013 Consumption $m^3$ |
|---|---|---|---|---|---|---|
| T1 | Industrial | 43 | 11,128,590 | 2,958,903 | 11,254,555 | 3,489,354,415 |
| | Power | 9 | 8,188,000 | 3,393,100 | 636,463,000 | 1,573,221,390 |
| | Greenhouse | 5 | 309,600 | 0 | 6,468,540 | 48,847,120 |
| | Commercial | 2 | 278,900 | 67,200 | 0 | 53,559,260 |
| | | | | | | |
| Rate 100 | Industrial | 11 | 3,005,600 | 2,820,000 | 4,944,540 | 1,009,208,520 |
| | Power | 7 | 2,233,900 | 455,000 | 0 | 915,517,000 |

c) Union has not completed a consumption forecast for 2014. The table below provides the requested data presuming T1 is split into T1 and T2 categories for 2013 volumes only.

| Rate Class | Customer Classification | Number of Customers | Aggregate 2013 FIRM CD $m^3$ | Aggregate 2013 Interruptible CD $m^3$ | Aggregate MAV $m^3$ | Total Forecast 2013 Consumption $m^3$ |
|---|---|---|---|---|---|---|
| T1 | Industrial | 32 | 1,668,850 | 605,000 | 5,620,540 | 475,915,400 |
| | Power | 1 | 31,000 | 0 | 167,000 | 5,000,500 |
| | Greenhouse | 5 | 309,600 | 0 | 6,468,540 | 48,847,120 |
| | Commercial | 1 | 111,400 | 67,200 | 0 | 19,222,970 |
| | | | | | | |
| | | | | | | |
| T2 | Industrial | 11 | 9,459,740 | 2,353,903 | 5,634,015 | 3,013,439,015 |
| | Power | 8 | 8,157,000 | 3,393,100 | 636,296,000 | 1,568,220,890 |
| | Greenhouse | 0 | 0 | 0 | 0 | 0 |
| | Commercial | 1 | 167,500 | 0 | 0 | 34,336,290 |
| | | | | | | |
| Rate 100 | Industrial | 11 | 3,005,600 | 2,820,000 | 4,944,540 | 1,009,208,520 |
| | Power | 7 | 2,233,900 | 455,000 | 0 | 915,517,000 |

# TAB 9

apologize.
It follows Interrogatory 35 at page 38 of 38, Exhibit D5, just for reference.
Did Navigant reach any conclusions regarding the use or the nature of the use of natural gas by those who responded to the survey?
MR. ZARUMBA: Yes. Our conclusion was that virtually all natural gas used in the power plant is used to produce electricity, approximately 96 percent -- excuse me, 98 percent, I stand corrected -- which is no surprise. It is a power plant. That is what they do. They have very few other end uses for natural gas.
MR. FRANK: And did Navigant reach any conclusions with regard to the implementation, the extent of implementation of energy management programs within the members surveyed?
MR. ZARUMBA: Yes, 83 percent of the respondents stated they have an energy management program.
MR. FRANK: Okay. And did you reach any conclusions regarding use of the DSM program, and, in particular, perhaps if we could turn up the appendix A to Exhibit D5?
MR. ZARUMBA: I...
MR. FRANK: I am looking at table 3, in particular.
MR. ZARUMBA: Yes, 54 percent of the respondents --
MR. FRANK: If we could just wait and make sure that people have had a chance?
So this is an appendix that follows page 38 of 38 of Exhibit D5. That would be the easiest way to find it. Are

# TAB 10

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Section 6.5, pages 26

Preamble: Union states that: "Energy use is typically not considered a core production management system metric as energy is widely viewed as a "cost of doing business"."

a) Please confirm that gas-fired generators consume tens of millions of dollars of natural gas each year.

b) Please confirm that any company that consumes this amount of gas, that energy management is central to their operation. If not confirmed please explain.

c) Please provide a detailed list of the programs in Union's full suite of offerings for these large state-of-the-art gas-fired generator customers.

---

**Response:**

a) Confirmed.

b) No, Union has found an organization's focus on energy management is directly correlated to cost of energy as a percentage of production costs.

Where natural gas is a large component of the overall cost of production for customers who use natural gas as a primary feedstock (e.g. gas-fired generators or fertilizer manufacturers), it would be expected that energy management is a central component to their operation. However, the cost of natural gas as a percentage of total cost to produce a product is relatively small for large volume customers who do not use natural gas as a primary feedstock. For example, natural gas use in the steel industry represents less than 5% of their total cost of production.

It has been Union's experience that all large volume customers employ two methods to manage energy and energy costs. The first is to reduce the cost of the purchased input and the second is to increase or maintain the output per unit of purchased input.

For these large volume customers, energy efficiency is only one of many potential options available to achieve lower costs and hence higher profits. Union has also

# TAB 11

incremental thermal energy, which it distributes to approximately 50 customers throughout the downtown core of London, Ontario, via a series of piping infrastructure under the right-of-ways of the City of London.

MR. FRANK: And what are your responsibilities as plant manager?

MR. RUSSELL: My primary responsibilities as plant manager are to ensure the reliable operation of the facility, the safe operation of the facility, both for its staff and for the general public, and for the economic performance of the facility, of which energy efficiency is a primary concern.

MR. FRANK: Are you familiar with Union's DSM programs?

MR. RUSSELL: I am.

MR. FRANK: And has LDE utilized Union's DSM programs in the past --

MR. RUSSELL: It has.

MR. FRANK: Particularly the past three years?

MR. RUSSELL: It has, yes.

MR. FRANK: Can you briefly describe the number of programs and the nature of them?

MR. RUSSELL: Yes. I can take you through a brief list of them, if that is okay.

MR. FRANK: Okay.

MR. RUSSELL: We have -- I was able to determine since 2009, we've undertaken -- or we've received rebates for six individual projects, five of which were directly for London

# TAB 12

# SEAN RUSSELL

1023 Flintlock Crt. • London, Ontario N6H 4M3 • (519) 670-1127 • sean_russell@rogers.com

## Core Competencies

Energy Generation

Infrastructure Management

Environmental Reporting and Compliance

Project Management

Energy Efficiency & Conservation

Renewable Energy

Budget Management

Regulatory Compliance

Contract Negotiations

HR/Staff Management

## Education

University of Western Ontario, London, ON

**B.ESc in Civil Engineering**, 2003

## Certifications

**PEO** – Professional Engineer Designation

**CAGBC LEED** Accredited Green Building Professional

**IVEY SCHOOL OF BUSINESS** Certificate of Business Management

# ENERGY PROFESSIONAL

Energy professional whose qualifications include a degree in Civil Engineering and a detailed knowledge of energy generation and district energy best practices. 10 years of management experience in energy generation, infrastructure and asset management, energy conservation, renewable energy and energy procurement.

## Experience

**Veresen Inc – London District Energy** — **Plant Manager**, 2011-Present

Manage the operation, sustainability, growth and financial performance of a high efficiency natural gas turbine power plant and district energy system.

- **Combined Heat and Power Generation**: Responsible for the dispatch, maintenance and operation of London District Energy's 18 MW cogeneration facility.
- **District Energy**: Ongoing maintenance, upgrades and efficiency improvements related to 13km of underground thermal piping system. Ensure that the 60 building connections are operating safely and efficiently.
- **Business Growth**: Responsible for development of new customer connections, expansions to the Combined Heat and Power assets via new facilities, and other cogeneration or district energy opportunities in the Southwestern Ontario region.
- **Financial:** Responsible for the financial performance of London District Energy, including monthly reporting.

**City of London** — **Corporate Energy Manager**, 2003-2011

Experienced in infrastructure planning, with focus on energy and asset management within a municipal government environment.

- **Energy Management Program**: Ongoing review, audit and capital program management ensuring optimized energy consumption at City facilities. Facility retrofits include lighting retrofits, heating and cooling system modernization and geothermal earth energy systems. Monitor program performance and provide reporting to City Departments and Municipal Council.
- **Green Building Program**: Responsible for sustainable development of new City Facilities. Responsible for overseeing 3 LEED Green Buildings, a recreation center/library, a materials recovery facility (recycling), and a water pumping station and reservoir.
- **Renewable Energy**: Project development of multiple renewable energy projects, including two rooftop solar photovoltaic systems, ground mounted solar PV and a landfill based biogas waste to energy Plant.

References Available Upon Request

# TAB 13

I mean, we're also -- we have expertise in energy efficiency in matters from top to bottom, from myself to our chief engineer, who has over 20 years of experience, to our staff.

I mean, there is a culture of conservation throughout London District Energy. We have even put it to the point of having staffs' individual performance review tied to the distribution system losses and having them look at reducing thermal losses through that.

So, I mean, to get back to your question about a guarantee, no, I don't think there is any way to guarantee that, but I do know that we will be pursuing, when available, when possible, energy efficiency projects.

MR. WANLESS: Just a couple of more questions. Everything else being equal, will higher gas costs motivate Veresen to spend more on energy efficiency investments?

MR. RUSSELL: In general terms, I think I can agree, because generally speaking, all things being equal, higher gas costs would equate to higher, potentially, economic savings on an energy efficiency project.

MR. WANLESS: And everything else being equal, will financial incentives that reduce your costs of investing in energy efficiency motivate Veresen to spend more money on energy efficiency investments?

MR. FRANK: Sorry to interrupt. The question was directed at Veresen and the witness is a witness for LDE.

MR. WANLESS: I will substitute "LDE" for Veresen.

MR. RUSSELL: Sorry, can you just repeat it?

# TAB 14

I mean, we're also -- we have expertise in energy efficiency in matters from top to bottom, from myself to our chief engineer, who has over 20 years of experience, to our staff.

I mean, there is a culture of conservation throughout London District Energy. We have even put it to the point of having staffs' individual performance review tied to the distribution system losses and having them look at reducing thermal losses through that.

So, I mean, to get back to your question about a guarantee, no, I don't think there is any way to guarantee that, but I do know that we will be pursuing, when available, when possible, energy efficiency projects.

MR. WANLESS: Just a couple of more questions. Everything else being equal, will higher gas costs motivate Veresen to spend more on energy efficiency investments?

MR. RUSSELL: In general terms, I think I can agree, because generally speaking, all things being equal, higher gas costs would equate to higher, potentially, economic savings on an energy efficiency project.

MR. WANLESS: And everything else being equal, will financial incentives that reduce your costs of investing in energy efficiency motivate Veresen to spend more money on energy efficiency investments?

MR. FRANK: Sorry to interrupt. The question was directed at Veresen and the witness is a witness for LDE.

MR. WANLESS: I will substitute "LDE" for Veresen.

MR. RUSSELL: Sorry, can you just repeat it?

# TAB 15

Service, which is essentially a laundry for southwestern Ontario hospitals.

They had undertaken some energy efficiency measures through purchasing new equipment, and they received funding via us for that.

MR. FRANK: At whose initiative were the programs that you just described?

MR. RUSSELL: With the exception of the London Hospital Linen Service, the London District Energy initiatives were our own initiatives.

MR. FRANK: And when you say your own, what involvement, if any, did Union have in the development or planning of those initiatives?

MR. RUSSELL: Union Gas had no design input into the systems. Their role was merely administrative by way of processing the application forms.

MR. FRANK: Okay. But in terms of coming up with the idea, developing it, technical resources for implementation, et cetera, was Union involved in that?

MR. RUSSELL: No, they were not.

MR. FRANK: And if there hadn't been DSM funding available to LDE for the programs that you just mentioned, what would have happened to them?

MR. RUSSELL: Specifically with the condensate return project in which I mentioned we connected four customers more recently, that was a project that I managed and pushed forward. That project would have -- I can state that that project would have gone forward regardless of the funding.

TAB 16

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Appendix B
Preamble: Union provides some of the program incentives on slide 8. APPrO would like to better understand these incentives proposed.

a) For customers that would typically be eligible for Rate 100 or T2, and for each of the 10 program elements shown on slide 8, please provide the average cost of implementing these program elements (where reasonably possible) and show the total cost of implementing the program, incentive amount provided by Union, the amount that the customer would fund on its own and the percentage funded directly by each of Union through ratepayer funded DSM and the percentage funded directly by the customer.

---

**Response:**

Union does not track the cost of implementing at the program element level. Union does track the incentives provided and customer project cost at the measure level. Please see the table below for incentive funding provided by Union, the amount the customer would fund on its own and the percentages funded directly by Union and the customer accordingly.

| Rate T1 / Rate 100 - 2011 Results | | | | % Funding - average | | $ Funding - average | |
|---|---|---|---|---|---|---|---|
| Offering | # of Projects | Incentive $ Provided By Union | Customer Project $ | By Union | By Customer | By Union | By Customer |
| O & M | 157 | $ 1,989,254 | $ 23,169,661 | 9% | 91% | $ 12,670 | $ 147,577 |
| Capital | 43 | $ 1,180,959 | $ 31,632,015 | 4% | 96% | $ 27,464 | $ 735,628 |
| Engineering Feasibility | 17 | $ 104,373 | $ 395,718 | 26% | 74% | $ 6,140 | $ 17,138 |
| Process Improvement | 33 | $ 444,509 | $ 1,394,046 | 32% | 68% | $ 13,470 | $ 28,774 |
| Steam Trap | 20 | $ 80,243 | $ 252,633 | 32% | 68% | $ 4,012 | $ 8,620 |
| Education | 2 | $ 16,000 | $ 45,185 | 35% | 65% | $ 8,000 | $ 14,593 |
| | **272** | **$ 3,815,338** | **$ 56,889,258** | | | | |

# TAB 17

to receive customer incentives for projects and studies from the aggregate pool of budget available throughout the program year. This is consistent with Union's program approach in 2012 for these customers and the DSM program structure in Union's bundled contract rate classes that serve other similarly sized customers.

### 6.7 Program Duration

All Program offerings in the Large Volume Rate T1/Rate T2/Rate 100 Program will be delivered annually over the course of the two year DSM Plan. The offerings may change should market conditions change over the course of the Plan.

### 6.8 Cost Effectiveness

The estimated Total Resource Cost ("TRC") cost effectiveness for Union's Large Volume Rate T1/Rate T2/Rate 100 Program is displayed in Table 7. The actual cost effectiveness will be reported in Union's Annual Report for each program year.

**Table 7: Large Volume Rate T1/Rate T2/Rate 100 Program Cost Effectiveness**

| Measure | Participants | Total TRC Benefits | Total TRC Costs | Total Net TRC Before Program Costs | TRC Ratio |
|---|---|---|---|---|---|
| Large Volume Offerings (Custom) [1] | 41 | $ 188,260,716 | $ 22,056,635 | 166,204,080 | 8.5 |
| **Total** | | **$ 188,260,716** | **$ 22,056,635** | **$ 166,204,080** | |
| | | Promotion Costs | $ 100,000 | | |
| | | Administration Costs | $ 906,511 | | |
| | | EM&V Costs | $ 40,000 | | |
| | | **Program Total Net TRC** | | **$ 165,157,569** | |
| | | **Program TRC Ratio** | | | **8.1** |

1. TRC Benefits and TRC Costs based on 3 year historical (2009-2011) average of Rate T1/Rate 100 custom results

# TAB 18

MR. FRANK: I'm not sure, Madam Chair, if it is appropriate if Mr. Russell might give an example now, even though we haven't yet gone through his background, but he may have some -- something to add, or we can come back later and I can ask him --

MS. CONBOY: Let's come back later. We will hold that thought.

MR. FRANK: Okay. Mr. Zarumba, in the Navigant report there is a conclusion that states:

> "Navigant expects that there are very limited cost-effective opportunities to improve the efficiency of the generation process at gas-fired generation electric facilities, many of which are new, state of the art facilities."

Can you please explain your views on that conclusion, and your interpretation?

MR. ZARUMBA: An electric-powered generator essentially produces one product, electricity. In the case of a gas-fired generator, their largest controllable input is natural gas.

All the capital costs are fixed. Most of the labour costs are fixed. Even much of the maintenance cost is pretty much fixed; there is a little bit at the edge that might be incremental.

So they are -- you know, the one thing they can do, which increases efficiency, which increases the profitability of the plant, is to reduce heat rate.

So they have a very, very strong incentive to maximize the value of the plant.

Electricity is a commodity. It is a competitive market, and generally one with a very, very low profit margin.

That all adds up, you know, to an organization that, if they're going to stay in business for any length of time, needs to be highly efficient.

MR. FRANK: Okay. In your experience, do you have any -- sorry, do you have any experience about the extent to which or whether most plants would have any type of maintenance contracts with regard to the turbine or other major pieces of their equipment?

MR. ZARUMBA: Yes. Maintenance contracts are very common, especially in newer plants. In fact, often are generally required in order to maintain the warranty.

MR. FRANK: And that would conclude my examination of Mr. Zarumba.

MS. CONBOY: Thank you.

MR. FRANK: Unless there are any questions, I will go on with Mr. Russell.

MS. CONBOY: Please do.

MR. FRANK: And I believe Mr. Russell's CV has also been made available?

MS. CONBOY: It has.

MR. MILLAR: Yes. We will mark that as K2.2.

**EXHIBIT NO. K2.2: CV OF SEAN RUSSELL.**

MR. FRANK: Mr. Russell, I understand you're the plant manager at London District Energy's facility in London,

# TAB 19

## 2013 Cash Incentives as Percentage of the Total DSM Costs

## (excluding Low Income)

| Line | | (000) |
|---|---|---|
| 1 | 2011 Program Customer Incentives | $3,487 |
| 2 | 2013 Customer Incentives (2 Yr Escalation at 2.87% & 2.25%) | $3,668 |
| 3 | Total Large Volume Program and Allocated Portfolio Budget | $5,359 |
| 4 | Maximum Union Incentive | $1,809 |
| 5 | Total DSM Costs In Rates and Incentives (excl. Low Income) | $7,168 |
| 6 | | |
| 7 | Customer Incentives as a Percentage of Total LVC Budget (line1/Line3) | 68% |
| 8 | Customer Incentive of Percent of Total DSM Costs (line 1/Line5) | 51% |
| 9 | Union Incentive as Percentage of the Total DSM Costs (line 4/Line5) | 25% |

Sources:

Exhibit A Tab 1 Tables 2, 3 and 6

**Conclusion: The Cash Incentive Component of the Total DSM Program Cost Can Be As Little As Only 1/2 the Total Amount Paid by Customers**

# TAB 20

**Questions #11-12:**

**Table 5: Responses to questions 11-12**

| | Yes | No |
|---|---|---|
| If the option of "opting out" of DSM programs was provided by Union Gas would you do so? Customers opting out of the DSM programs would not contribute towards the cost of these programs and would not have access to technical advice or incentives offered by Union. | 77% | 23% |
| If provided with a "self-direct" option would you choose to do so? Under a self-direct arrangement your firm would not contribute towards the cost of DSM programs offered by Union but would be required to invest an equivalent amount in energy efficiency investments and to demonstrate the savings resulting from those investments. | 15% | 85% |

# TAB 21

current program from the DSM programs of prior years (e.g. separate scorecard, budget limitation, Union DSM incentive limitation, etc.). The focus group sessions encouraged discussion and customers proactively shared their views and perspectives related to Union's DSM program.

The following is a summary of the feedback received from customers attending these sessions:

- Customers commented that they value Union's energy-efficiency focused engineering expertise, noting they do not want to lose access to this resource;
- Larger customers expressed an interest in having increased flexibility to access larger incentive amounts for larger projects. It was suggested that Union could provide a specific fund for energy-efficiency and let the customer determine how best to spend these funds;
- Some customers indicated that they were completing energy-efficiency initiatives on their own and would like the option to not participate in Union's DSM program and avoid any associated costs; and
- Some customers expressed concern regarding large one-time deferral charges. They suggested avoiding future potential charges by incorporating the underpinning costs into rates or, alternatively, collecting the deferral costs over a longer period of time.

Union provided each customer who attended the focus group sessions with a summary capturing what was heard at each meeting. The "As It Was Heard Report" is provided at Appendix C and Appendix E. After considering the feedback received from customers, Union developed the program described in Section 6.

During the month of July 2012, Union presented its proposed Plan through a series of five additional meetings with customers and stakeholders. These customers collectively accounted for over 60% of the total Rate T1 and Rate 100 volume throughput in 2011. A presentation from a customer meeting is provided at Appendix F.

# TAB 22

    - Example given – steam trap surveys, follow-up to ensure they're running efficiently with required repairs and replacements to improve efficiency.
- Struggling with the savings calculation and Union's contribution on the savings – does Union's effort match the contribution to savings?
- Hard to get money back through Enersmart incentives each year and some things we wish to do often do not get on the list of projects/programs to be completed.
- If the OEB wants the program then keep program O&M down and maximize ability to leverage incentives.

**Program Participation/Structure**

- We'd like to see an opt-out provision, where we would not participate or have to pay out anything but the low income portion. We wouldn't get any incentives for doing energy efficiency programs, nor would we have to pay a share of Union's deferred costs.
- If opt out, opting back in may be for 5 years – wouldn't be right to just opt in, do a project, then opt out right away again.
- Sometimes there's not a lot left we can do for a period of time, so we may want to opt out.
- We have plants in various jurisdictions in North America. Many energy companies recognize that we need to do DSM to reduce our costs and stay competitive, but in some areas, they allow us a fund and we determine how to spend it. If we don't use it in any given year, we lose it. (Paraphrased after meeting comment: If we put 100% in and we have access to 90% of those dollars. The 10% pays for administration and social programs. If you don't use it, it is lost. The audit is a simple audit.).
- Under the current system with Union Gas, we're putting money into the projects we're doing, and we're also paying Union Gas after the fact through deferral bills.
- We'd like to see either a pot of money to draw from, or the ability to opt out, or opt back in for a specified period of time (recognize that we shouldn't just opt in for a year, do the project, reap the savings/incentive then back out again).
- Compromise could be this pot of money – recognize we may not get value in the first year of a project, but over the lifetime. Example is a furnace replacement – large expenditure in the first year, but savings take time to accumulate.
- We are energy efficient to start with. Union Gas didn't give me anything more than I would have done with my own technical people, but I'm still paying for it as a T1 customer.

**Miscellaneous**

- I'd love to see you bring back the S&T deferral credits to offset deferral costs.
- Question regarding Enbridge and whether they have the same type of DSM programs as Union...
    - ANS: Enbridge programs are similar to Union's programs, although their Rate 125 for large customers does not have a DSM program – that rate class didn't

TAB 23

***Intervenor Consultation on 2013 – 2014 Large Volume Rate T1/Rate T2/Rate 100 DSM Plan***

On August 15, 2012, Union held a Consultative meeting with intervenors and interested parties. At the consultation, Union presented its 2013 – 2014 Large Volume DSM Program proposal, budget and annual scorecards, and feedback was provided by stakeholders. Following the consultation, Union circulated its presentation to the Consultative, including those not able to attend. In addition, Union offered stakeholders who attended the meeting the opportunity to review the summary of feedback received at the Consultative session to ensure it reflected their input and provide additional written comments on the Plan. The material provided to Union's Consultative, invitation and attendance list are provided in Appendix G. A summary of the feedback received and Union's position, including changes made from the original Plan proposal to the final Plan, is provided in Appendix H.

Union notes that although it consulted with stakeholders when developing the Plan and incorporated, where in Union's view appropriate, the feedback provided through consultation, it does not have consensus on the Plan. While some customers and stakeholders liked the program proposal, others indicated that they would like to opt-out of the Plan, thereby avoiding any costs associated with providing DSM programs or DSM related deferral account disposition. Union addresses its reasoning for not offering an opt-out option in Section 7. It is Union's view that the Plan is consistent with the Guidelines while balancing the goals of the Board and the interests of Union, its customers and its stakeholders.

## 1.2 Union's 2013 – 2014 Large Volume Program Overview

Union's Board-approved 2012 Rate T1/Rate 100 program is targeted to all customers within these rate classes. It includes the following five offerings: customer engagement, engineering feasibility and process improvement studies, O&M optimization, new equipment and processes, and energy management. The 2012 post-inflation program budget is $4.664 million. This budget includes the incentives provided to customers who undertake energy-efficiency initiatives within

TAB 24

VERESEN

**Veresen Inc.**
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October 11, 2011

**Via Electronic Mail**

John Pickernell
Board Secretary
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Atten: Board Secretary

**Re: Demand Side Management Guidelines for Natural Gas Utilities**
**Issuance of DSM Guidelines**

Further to the Ontario Energy Board's (OEB) letter dated June 30, 2011, regarding the Demand Side Management (DSM) Guidelines for natural gas utilities, Veresen Inc., (Veresen) wishes to express its views. Veresen is a publically traded energy infrastructure company that holds energy assets in Ontario consisting of natural gas fired electricity generation facilities including district heating, cogeneration and peaking generation, ranging in size from 15 MW to 400 MW.

Two of Veresen's facilities, the East Windsor Cogeneration Centre (EWCC) and our London District Energy (LDE) facility currently hold Union's T1 service contracts and thus are subject to the T1 rate class methodology. Both of these facilities have participated in the DSM programs offered through Union Gas with very good success. Veresen's position regarding this program is that it has played an important role in achieving increased energy effeciency at these facilities. In our view, eliminating these programs is not in the best interest of T1 shippers and importantly, may result in a reduction in DSM initiatives by generators such as ourselves. EWCC and LDE are not large industrials, and therefore the view's expressed by others such as IGUA or CME regarding the DSM program, are not representative of our position.

Veresen strongly encourages the Board to continue the DSM program as currently structured to further facilitate achivements in DSM in Ontario.

Yours truly,

Julia Ciccaglione
Vice President, Regulatory & Government Affairs
Veresen Inc.

Cc: Paul Eastman, VP Operations - East, Veresen Inc.

# TAB 25

MR. FRANK: Do you have a copy of a letter dated October 11, 2011, Mr. Russell, from Veresen to the Board?

MR. RUSSELL: I don't believe I do.

MR. WOLNIK: Here.

MR. RUSSELL: Thanks, John. Oh, yes, thank you.

MR. FRANK: Now, I understood you to say earlier that LDE is of the view that opt-out should be available?

MR. RUSSELL: Yes.

MR. FRANK: And can you please explain why LDE's views are like that today, notwithstanding what was in the letter of October 2011?

MR. RUSSELL: Yes. I think it can be most simply put as London District Energy was not fully aware of the full cost of the incentive payments in the various accounts and as they would be impacting our operating budgets.

MR. FRANK: Okay. And do you know anything about the circumstances under which the letter was written?

MR. RUSSELL: From what I understand from my colleagues at Veresen, that letter was written at the request of Union.

MR. FRANK: That completes my examination-in-chief.

MS. CONBOY: Thank you very much. As far as the order of cross-examination, I know that Union has asked to go last. So unless there are any objections, I see Mr. Wanless reaching for his button. Go ahead, Mr. Wanless.

MR. WANLESS: Yes, thank you. I have canvassed with my colleagues, and it's agreed, subject to your thoughts, that I would perhaps go first.

# TAB 26

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Ex.AIT1/p.31 , lines 19 through 21

Please explain how DSM activities *"are ancillary to and support the provision of regulated distribution, transmission and storage services".*

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**Response:**

Union considers its DSM activities to be ancillary to and supportive of the provision of regulated services because they are not directly related to the distribution, transmission and storage of natural gas.

# TAB 27

**Ontario Energy Board**

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Ontario

**BY E-MAIL AND WEB POSTING**

March 29, 2011

**To: All Rate-Regulated Natural Gas Distributors**
**All Participants in Consultation Processes EB-2008-0346 and EB-2008-0150**

**Re: Demand Side Management ("DSM") Guidelines for Natural Gas Utilities (EB-2008-0346)**

**Issues for Further Comment**

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The purpose of this letter is to inform participants of the Board's views and considerations regarding the role of ratepayer funded DSM activities for the next three years. This letter also invites interested stakeholders to provide written comments to inform the Board on specific issues relating to the role of ratepayer funded natural gas DSM for that period.

## Background

The Board initiated this consultation process in October 2008, in anticipation of the expiry of the DSM plans of both Enbridge Gas Distribution Inc. ("Enbridge") and Union Gas Ltd. ("Union") at the end of 2009. The purpose of this consultation was to establish, through guidelines, a revised DSM framework to be used by the two natural gas utilities in developing their next generation DSM plans. On April 14, 2009, the Board extended the natural gas utilities' existing DSM framework by one year to provide time for the impact of the *Green Energy and Green Economy Act, 2009* to become clear before developing a new multi-year DSM framework.

By letter dated January 7, 2010, the Board extended the natural gas utilities' DSM framework by another year and informed stakeholders that the Board would proceed with a review of the current framework.

The Minister of Energy's letter to the Board of July 5, 2010 urged the Board to consider expanding low-income gas DSM, as well as gas DSM generally. The Minister also recognized the Board's responsibility to balance ratepayers' interests.

Following a stakeholder meeting and a webinar on two Board-commissioned consultant reports, and informed by stakeholder comments on those reports, a Staff Discussion Paper, along with Board staff's proposed Revised Draft DSM Guidelines for Natural Gas Utilities, were issued for stakeholder comments. On February 14, 2011, written comments from 16 stakeholder groups were received.

The Board has benefited from the extensive stakeholder comments received since the beginning of this consultation. Informed by these comments, the staff discussion papers, the consultant reports, the policies of the Government, and market developments, the Board wishes to inform participants of the Board's views and considerations regarding the role of ratepayer funded DSM programs going forward.

**DSM Framework**

The Board notes that the original regulatory framework for natural gas utility sponsored DSM programs was established through guidelines set out in its E.B.O. 169-III Report of the Board dated July 23, 1993. Until 2006, Union and Enbridge filed DSM plans in accordance with the E.B.O. 169-III Report. In 2006, the Board conducted a generic proceeding (EB-2006-0021) which led to three-year DSM plans starting in 2007, which the Board later extended by two years. The most recent approved DSM plans are now scheduled to end in 2011.

As stated in the 2006 Decision, the intent of the proceeding was to "streamline processes, harmonize practices, and re-examine the rules of DSM"[1]. The Board did not "revisit the general principles adopted and conclusions reached in the Report of the Board E.B.O. 169-III"[2].

In the current consultation, some parties have proposed significant increases to scope and budgets for ratepayer funded gas DSM. The Board notes, however, that other stakeholder submissions proposed that the Board should reassess the role that ratepayer funded natural gas DSM activities should play going forward. They argued that a number of developments have taken place since the original regulatory framework was developed in 1993 that warrant a fundamental reassessment of the long-term role of ratepayer funded DSM activities.

In its E.B.O. 169-III Report, the Board noted that "experience with gas DSM is limited, and it has yet to be fully evaluated in any jurisdiction in Canada or elsewhere." As noted by a number of participants, the landscape for conservation has since developed into an environment with a larger number of private and public entities delivering energy efficiency programs. The Board notes that today's market for conservation goods and

[1] Board Decision with Reasons, EB-2006-0021, Phase 1, dated August 25, 2006, p.5.
[2] Ibid, p.6.

services provides an array of solutions that are economically attractive to consumers. This has led to customers implementing DSM technologies without requiring a ratepayer funded or tax-funded subsidy.

In addition, the Board notes that the implementation of higher mandatory efficiency standards for new building construction, as part of the Ontario Building Code, and the more stringent efficiency standards and ratings of appliances, including water heaters and furnaces, has led and is expected to lead, to significant natural gas savings over time.

The Board recognizes that ratepayer funded natural gas DSM programs were originally meant to achieve savings beyond those that would have naturally been achieved by customers as a result of market forces or higher energy efficiency standards. In light of current market conditions, achieving incremental benefits through ratepayer funded natural gas DSM programs will be more limited and by necessity more costly to implement.

The Board notes that Enbridge and Union have achieved significant natural gas savings through their DSM activities since the issuance of the Board's E.B.O. 169-III Report. However, the Board also notes that, over that period, the level of complexity associated with satisfactorily measuring the savings achieved by these DSM activities has been a recurring concern. The Board agrees with the view that there is a need to focus on DSM programs that provide value to ratepayers as a whole with a high degree of confidence that results are actually achieved.

**Role of Ratepayer Funded DSM Activities**

DSM programs by their nature involve a level of cross subsidization; in effect a payment from those who do not take advantage of DSM programs to those who do. Although long standing regulatory principles state that cross subsidies should be avoided where possible, the Board has determined that some level of cross subsidization can be appropriate to address certain system wide and societal benefits within pre-determined limits. The Board has concluded, however, that the justification for gas DSM cross subsidies is eroding, and that expansion of DSM initiatives funded by natural gas ratepayers is not warranted at this time.

The Board notes that ratepayer funded natural gas DSM programs to date have broadly consisted of one or more of the following:

a) Programs, such as resource acquisition, with financial incentives (i.e. subsidy) towards the equipment and installation costs to make the DSM investment more attractive to the customers;

b) Programs, such as market transformation, aimed at educating contractors and trades and influencing customers' conservation behaviour (e.g., case studies, conferences and tradeshows for building contractors, distribution of flyers and media advertising targeting natural gas customers, school education materials, etc.); and

c) Research and development (R&D) activities and pilot programs.

The Board notes Enbridge's acknowledgement that "... many traditional gas utility DSM programs have reached, or are close to reaching maturity (e.g. high efficiency furnaces, programmable thermostats, low-flow showerheads)."[3] In the Board's view, this is an indication that part of the natural gas utilities' objective for DSM may have been achieved and a gradual reduction in "traditional" natural gas DSM activities would lead to lower budget requirements. On the other hand, an increased focus on "deep measures," such as thermal envelope improvements, could lead to larger budget requirements.

The Board also notes staff's comments that a greater focus on deep measures may imply that fewer participants can be reached at a given budget level and that the cost per participant would be much larger on average; a result that would increase cross subsidization. To illustrate that point, staff noted[4] that Union's average cost per customer for broadly available measures (energy efficient showerheads, bathroom and kitchen aerators, 2 metre pipe wrap, and programmable thermostats) in 2009 was $121. Whereas its average 2009 total cost per low-income participant for its deep measures (attic, wall and basement insulation, and draft proofing) was $2,750.

The Board further notes the federal and provincial governments' decision to withdraw from their deep measure residential programs (i.e., the federal ecoENERGY Retrofit and the Ontario Home Energy Savings Program). The Board agrees with the view expressed by one participant that these government withdrawals should signal a cautionary approach in considering a significant expansion of ratepayer funded deep DSM programs.

An increased focus on deep measures in the residential sector may or may not be appropriate, but in any event should be accommodated within the current DSM budget levels. This approach would alleviate concerns regarding cross-subsidization levels. In addition, maintaining the DSM budget levels would be consistent with the Board's view of the appropriate role of natural gas DSM, as described below.

## DSM Budget Level & Plan Term

The Board notes that the core business of a natural gas utility, and that for which the Board makes orders approving or fixing just and reasonable rates, as found in the *Ontario Energy Board Act, 1998* at Section 36(2), are those activities in relation to the "the transmission, distribution and storage of gas." The Board created the DSM

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[3] Board proceeding EB-2010-0175, Enbridge's 2011 DSM plan application dated May 28, 2010, Exhibit B, Tab 1, Schedule 2, p. 2.
[4] Staff Discussion Paper, EB-2008-0346, dated January 21, 2011, p. 40.

framework within that context recognizing that the acquisition of demand reduction resources could represent an alternative to acquiring additional supply resources. The environment and market for demand resources has evolved substantially. It is questionable whether it remains necessary or appropriate for utilities to provide (and ratepayers to fund) services which are widely available through the market.

The current DSM budget levels, which now represent about 2.8% and 4.1% of Enbridge's and Union's respective distribution revenues, have come to represent a sizeable portion of their business. The Board finds it appropriate at this time to limit the ratepayer funded portion of the natural gas DSM budgets to their current levels. Although the Board has been supportive of DSM activities within utilities over the years and remains supportive of DSM generally, it is concerned with the extent to which cross subsidies are appropriate within the Board's mandate of regulating gas distribution, and whether it is necessary for ratepayers to fund services which are available through a variety of channels in the marketplace.

The Board is also concerned that the availability of ratepayer funded DSM programs may have the effect of discouraging or impairing the penetration of market-driven activities.

To the extent non-market support continues to be required for these services beyond that available from the current level of ratepayer funding, the Board believes that alternative sources of funding would be more appropriate.

The Board agrees with staff's proposal of a three-year plan term, which would end in December 2014. Some participants commented that the length of the term should be longer to provide utilities with additional regulatory and funding certainty. The Board finds however, that a three-year term will provide a sufficient period of regulatory and funding certainty.

With respect to low-income programs, the Board is of the view that funding should be considered independently from DSM budgets for the residential sector. For the next three-year period, the Board expects funding for low-income DSM programs to stay at the current level or increase. The Board notes that, in addition to the monetary (i.e. reduction in energy costs) and non-monetary (i.e. improvement in living conditions) benefits these programs bring to low-income consumers, the impact of these programs can be more readily ascertained due to their lower free ridership rates. However, the Board would like further stakeholder comments on the appropriateness of continuing to recover the current low-income DSM budget funding through residential rates or whether funds should be recovered from all rate classes.

With respect to commercial and industrial DSM programs, the Board acknowledges the comments made by some participants that these programs can result in corporate entities financing, through their distribution rates, conservation measures that benefit their competitors. Accordingly, the Board seeks further comments from stakeholders on the appropriateness of programs directed to these customer segments.

The Board also seeks further comments on the natural gas utilities' role in providing natural gas DSM education and training programs, as well as their role in funding R&D and pilot programs through distribution rates.

## Issues for Further Comment

Having determined that the budgets for ratepayer funded natural gas DSM activities should not be expanded, the Board seeks further stakeholder comments on the following issues:

1. How should the low-income DSM budget be set? Should the low-income budget stay at the same level or increase? Should the current low-income budget funding from the residential class be maintained or should the funding be recovered from all rate classes? Is there a different set of programs that are appropriate for low-income consumers e.g. should "deep" measures be promoted for this group of customers to a greater extent? What approach should be used to coordinate gas DSM programs with electricity CDM programs for low-income consumers?

2. Do industrial and commercial DSM programs with significant incentives create competitive advantages for the participants of the programs relative to their competitors? What programs, if any, are appropriate for these sectors? Should there be a focus on monitoring consumption, data analysis or benchmarking energy use in buildings and industrial processes? Should DSM programs in these sectors focus more on energy audits and efficiency training or case studies to highlight best practices and new technologies, rather than financing equipment and installation costs for specific DSM projects?

3. What should be the natural gas utilities' role, if any, in providing natural gas DSM education and training programs funded through distribution rates? Should they focus on targeting contractors, trades and professional associations to ensure DSM messages reach end-users?

4. What should be the natural gas utilities' role, if any, in undertaking R&D and pilot programs funded through distribution rates? Should utilities work with key industry leaders to encourage further changes in building codes and improve standards in heating equipment?

## Invitation to Comment

Participants are invited to provide written comments on the aforementioned list of issues by **April 21, 2011**, in accordance with the filing instructions set out below.

**Cost Awards**

As noted in the Board's October 31, 2008 letter, cost awards will be available to eligible persons under section 30 of the *Ontario Energy Board Act, 1998* for their participation in this consultation.

**Attachment A to this letter contains important information regarding cost awards for this consultation.**

**Filing Instructions**

All filings to the Board in relation to this consultation must be addressed to the Board Secretary. Two paper copies of each filing must be provided. The Board asks that participants make every effort to provide an electronic copy of their filings in searchable/unrestricted Adobe Acrobat (PDF) format and to submit their filings through the Board's web portal at https://www.errr.ontarioenergyboard.ca. A user ID is required to submit documents through the Board's web portal. If you do not have a user ID, please visit the "e-filing services" webpage on the Board's website at www.ontarioenergyboard.ca and fill out a user ID password request. Additionally, interested stakeholders are asked to follow the document naming conventions and document submission standards outlined in the document entitled *RESS Documents Preparation – A Quick Guide* also found on the "e-filing services" webpage. If the Board's web portal is not available, electronic copies of filings may be filed by e-mail at boardsec@ontarioenergyboard.ca. Those who do not have internet access should submit the electronic copy of their filing on a CD.

Filings must be received by **4:45 pm** on the required date. They must quote file number **EB-2008-0346** and include your name, postal address, telephone number and, if applicable, an e-mail address and fax number.

All materials related to this consultation will be posted on the "Regulatory Proceedings" portion of the Board's website at www.ontarioenergyboard.ca. The material will also be available for public inspection at the Board's office during normal business hours.

Questions regarding this consultation should be directed to Lenore Dougan at 416-440-8141 or by e-mail at GasDSM@ontarioenergyboard.ca. The Board's toll free number is 1-888-632-6273.

Yours truly,

*Original Signed By*

Kirsten Walli
Board Secretary

Attachments: A – Cost Award Information

## Attachment A - Cost Award Information (EB-2008-0346)

### Activities Eligible for Cost Awards

The Board has determined that cost awards will be available in relation to the following activities:

| Activity | Total Eligible Hours per Participant |
|---|---|
| Provision for written comments | Up to 10 hours |

Groups representing the same interests or class of persons are expected to make every effort to communicate and co-ordinate their participation in this process.

### Cost Awards

When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of its *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

The Board will use the process set out in section 12 of its *Practice Direction on Cost Awards* to implement the payment of the cost awards. Therefore, the Board will act as a clearing house for all payments of cost awards in this process.

For more information on the cost awards process, please see the Board's *Practice Direction on Cost Awards* and the October 27, 2005 letter regarding the rationale for the Board acting as a clearing house for the cost award payments. These documents can be found on the Board's website at http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms.

# TAB 28

The current rate class applicable to the Brighton Beach facility was T1. This rate applies to a very wide range of industrial users, with varying load profiles. Union's rate proposal invoked T1 rates applied in two blocks. This, Coral suggested, was a recognition by Union that the Brighton Beach profile was unique, and justified a very different rate treatment, outside of the normal restrictions imposed by the T1 rate rules.

The development and design of a rate or rate class is a process that is governed by principles which have been developed by scholars and practitioners. Principles are necessary because of the high degree of interdependence of gas distribution system participants. Of all the principles governing the establishment of rates and rate classes, the most fundamental is that requiring that rate classes should be responsible for a reasonable proportion of the costs they cause the system to incur.

The revenue requirement established by the Board in rates cases such as the present case represents the system's overall financial burden. In order for rates to be just and reasonable, which is the statutory requirement, each rate class should bear a proportion of that burden roughly coincident with the costs incurred by the system operator, in this case Union Gas, in providing the necessary infrastructure and services to arrange for, store and transport the commodity to that rate class' members. Where a disproportionate amount of the revenue requirement is visited upon a rate class, that rate class is either subsidizing or being subsidized by other system participants. Rates are developed to avoid any such disproportionality to the extent reasonably possible. For this reason, so-called end-use rates have not been a common feature of regulated markets. In order to ensure that the appropriate cost causation allocation is made respecting a specific category of user, the regulator must first establish the demands placed upon the system by the consumer arising from the consumer's usage profile, not the category of its business undertaking. It is also important to note that there may be important sub-categories of generation end-users. Co-generation plants for example, where the plant produces steam for industrial users as well as electricity, have markedly different operational considerations, compared to pure merchant operations, such as the one at Brighton Beach.

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doubted your qualifications.

MR. ZARUMBA: Thank you. And I don't doubt yours either. You're an excellent attorney.

MR. WANLESS: I would ask you to turn to Environmental Defence's Interrogatory No. 2. This is your response to Interrogatory No. 2.

MR. FRANK: Mr. Wanless, could we get the exhibit number for that?

MS. CONBOY: D1?

MR. WANLESS: I believe it is Exhibit No. D1.

MR. WANLESS: Page 4. Do you have it?

MR. ZARUMBA: Yes.

MR. WANLESS: And we asked if the Ontario Energy Board were -- permitted the opting-out option, do you believe that the expected magnitude of natural gas savings in cubic metres would rise, fall, or stay the same for customers that opted out?

And you responded that you didn't have sufficient information to answer this question. Is that still your answer?

MR. ZARUMBA: Yes. Although, I will be honest, I don't believe that opting out would really change investment behaviour, resting on my earlier comment.

Where DSM is most effective is customers that, you know, have no access to capital, have a lack of information, or it is just not top of mind.

I think DSM is incredibly effective under those circumstances.

When you have a business entity such as an electric generator, where efficiency essentially is the most important attribute, I think that DSM actually would have little or no benefit.

MR. WANLESS: Mr. Russell, I have a few questions for you now.

MR. RUSSELL: Mm-hmm?

MR. WANLESS: According to the last paragraph of your testimony, you state that:

> "While we appreciate Union's efforts on these matters, we at LDE do not believe that Union's DSM programs is an imperative to our operations. We are self-motivated, have extensive expertise in these matters, and would be dedicated to seeking natural gas savings regardless of Union's involvement or assistance."

Is that correct?

MR. RUSSELL: That's correct.

MR. WANLESS: We have asked you some questions earlier regarding -- or some questions were asked earlier regarding your economic model. In fact, we asked, as an interrogatory, for specifics.

You did give a response back, but -- I wasn't sure -- it seemed to be fairly general. And I was wondering if you could provide more specifics on that.

MS. CONBOY: Could you point us to the interrogatory in question, please, Mr. Wanless?

MR. WANLESS: Yes. It's Interrogatory No. 5. Also

# TAB 30

> Regulation is intended to be a surrogate for competition in the marketplace and the legislation intended that the Company has an opportunity to recover its costs and to earn a fair rate of return on its shareholders' equity...The system requires the regulator to act on faith with the utility, bearing in mind the prospective nature of the evidence. The regulator expects the utility, in return, to provide the best possible forecast data that can be made available, on a timely basis.

The Board also said in paragraph 4.2 of RP-1999-0001:

> The Board appreciates that business plans are not carved in stone and the utility must have flexibility to meet ongoing demands of the marketplace; however, this flexibility must be balanced against the utility's obligations as a regulated entity. This is particularly true when the Company is not responding to exogenous events, beyond the Company's control, but is implementing its own initiatives.

Union stated that there have been at last 20 separate proceedings before the Board relating to QRAMs, deferral accounts, and rebasing and argued that the Board's discovery-related powers are tools that the Board has at its disposal which go well beyond what even a court of law has in a civil context. The implication of these arguments is that these issues should have been identified by intervenors and Board staff via interrogatories, document production, and technical conferences.[16]

The Board disagrees with Union's assertion that it is the responsibility of intervenors and Board staff to undertake adequate discovery to ensure that the record is complete. Union is a rate regulated entity, and the information asymmetry in evidence in this proceeding is illustrative of the need for the Board to reiterate Union's affirmative disclosure obligations.

At paragraph 4.5 in RP-1999-0001 the Board clearly sets out a utility's affirmative obligation to disclose by stating:

> The Company has an affirmative obligation to provide the Board with the best possible evidence and it is not incumbent on the intervenors to ensure, through cross examination of the Company's witnesses, that the record is adequate and complete. The Company cannot shirk its

[16] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 3.

# TAB 31

possibility regarding T1, and the $500,000 transfer maximum and the impact that would have on rates, but he did not also add in -- and there is also a possibility of a rate impact due to an allocation of the Union DSM incentive; correct?

MR. TETREAULT: Yes, that's correct.

MR. FRANK: And, again, I don't think we all need to do the math here, but do I understand the allocation of that 1.809 million -- if you don't have it now, you could just undertake to check, but my calculations is it would be broken down 30 percent to the Rate 100, 31.33 percent to the T1, and 38.67 percent to the rate T2 customers. Do those sound reasonable?

[Witness panel confers]

MR. TETREAULT: Yes, those sound reasonable, subject to check.

MR. FRANK: Thank you. So we're looking at additional potential rate impact in excess of $500,000 for each of those classes, and potentially up to almost $700,000 for one of them; is that correct?

MR. TETREAULT: That's fair.

MR. FRANK: Earlier you were asked some questions about the impact that an opt-out might have on customers who do not opt out. And I just want to ask you -- it appeared to me that there was an assumption made that the budgeted amount would remain in, and I think it was called the incentive piece, and would then, therefore, be spread amongst customers who remained in a class where certain customers opted out. Was that the assumption made?

MS. LYNCH: Our expectation is that the overall budget would remain the same, and the incentive piece would be reallocated for customers who opted out.

MR. FRANK: Okay. But if the Board so directed, there would be no impediment to removing prorated amounts for customers who opted out, based on an appropriate formula?

MR. TETREAULT: If the -- yeah, if the Board ordered us to reduce the DSM budget in rates for a particular class, we would do so. There's no impediments to that, from a mathematic standpoint.

MR. FRANK: Thank you.

And I understood you to say earlier -- I believe it was you, Mr. Tetreault -- that if that was removed, that would remove the main cross-subsidy cost?

MR. TETREAULT: Yes. When I was referring to earlier in the cross from CME was the fact that if -- and in her example -- there was one customer remaining in the class, that customer would pay -- would pay all the DSM costs allocated to that class at that point.

MR. FRANK: Right. But if the incentive piece was removed -- the $900,000 in that example -- such that that customer remained responsible only for $100,000, as it had been previously, then there would be no impact as a result of the opt-out, on that portion at least?

MR. TETREAULT: Yes, that's fair. Recognizing of course that any type of opt-out for any customer of costs that had been allocated to the -- to any particular rate