EfficiencyOne

2023-2025 DSM Resource Plan
M10473

Before the
Nova Scotia Utilities and Review Board

Evidence of Drazen Consulting Group, Inc.

on Behalf of the Industrial Group

DRAZEN CONSULTING GROUP
Energy & Regulatory Economics

Project No. 211603
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EfficiencyOne

<u>2023-2025 DSM Resource Plan</u>

Section I–Introduction and Overview

Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Mark Drazen, 200 E. Hudson Ave, Englewood, New Jersey, USA, and 1405 Fairfield Road, Victoria, British Columbia, Canada.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility economics and regulation and a member of Drazen Consulting Group, Inc.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have worked in this field since 1972 in rate cases, regulatory analysis, project planning and negotiations throughout Canada (nine provinces and federal jurisdictions) and the United States (41 states and federal jurisdictions). Our firm has been in this field since 1937. I have degrees in mathematics and engineering from the Massachusetts Institute of Technology. Details are given in **Appendix A.**

Q ON WHOSE BEHALF ARE YOU SUBMITTING THIS EVIDENCE?

A I am appearing on behalf of the Industrial Group. This is a group of NS Power's industrial customers, who take service on the Medium Industrial and Large Industrial rates.

Overview

Q WHAT IS THE SUBJECT OF THIS EVIDENCE?

A This evidence concerns the amounts that EfficiencyOne (E1) proposes to charge NS Power for demand-side management (DSM) programs in the period 2023-2025.

Q WHAT ARE THE MAIN POINTS IN THIS EVIDENCE?

A They are:

- NS Power has the highest rates among Canadian integrated utilities;
- E1 reeds to explain better how it determines its proposed incentives;
- The incentive payment for any measure should take into account the bill reductions that the customer will receive and the resulting payback period;
- Some DSM measures have a payback period short enough that little or no incentive is required, so E1 could achieve the same energy savings at lower cost to NS Power ratepayers;
- To illustrate the magnitude of this issue, eliminating for measures with a three year payback would reduce the cost by about $8 million; and
- The proposed $10 million funding for developing and marketing demand reduction programs is largely unnecessary; there is already much experience with such programs in the utility industry, including NS Power.

Section II–Cost to NS Power

E1 Proposal

Q WHAT HAS E1 PROPOSED?

A E1 has proposed to charge NS Power $173 million over the three-year period. $150 million is for incentives and administrative costs for various demand-side management (DSM) measures, $13 million for enabling strategies, and $10 million for the development of demand reduction (interruptible) services.

E1 Proposed Charges to NS Power for DSM Measures ($Millions)				
Category	**2023**	**2024**	**2025**	**Total**
Residential – product rebates	$4.0	$4.6	$5.6	$14.1
Residential – existing	20.9	22.5	23.6	67.0
Residential – new	0.8	0.0	0.0	0.8
Subtotal	25.7	27.1	29.1	81.9
BNI – product rebates	7.4	7.4	8.4	23.2
BNI – custom	8.2	8.4	8.6	25.2
BNI – direct install	6.4	6.6	6.8	19.8
Subtotal	22.0	22.5	23.8	68.2
Subtotal measures	47.7	49.6	52.9	150.2
Enabling strategies	3.8	4.5	4.6	12.9
Demand response	1.5	3.5	5.0	10.0
Grand total	**$53.1**	**$57.5**	**$62.5**	**$173.0**

For comparison, the agreed-upon budget in the 2020-2022 plan was $110 million. Excluding the Demand Response amount, which was not a component of the previous plan, the proposal now is almost a 50% increase over last time.

Section III–Analysis of Incentives

Basis For Analysis

Q HOW DO YOU RECOMMEND THAT THE BOARD EVALUATE THIS PROPOSAL?

A This is viewed as a proposed supply contract, so the Board should ask the same question as when NS Power is considering a potential supply source (Muskrat Falls and Wreck Cove refurbishment, for example). That question is: *Is that supply being acquired by the lowest cost available?* In this proceeding the question is whether E1 is minimizing the cost of the suite of DSM measures. As explained below, it is not. In part this is a policy decision to subsidize low-income and underserved communities. But in part it is the result of E1 choosing to subsidize DSM measures to an extent greater than necessary.

NS Power Rates

Q WHY IS THE OVERALL LEVEL OF NS POWER RATES RELEVANT TO EVALUATING DSM?

A Section 79L(9) of the *Electricity Efficiency and Conservation Restructuring (2014) Act* says:

> *The Board's assessment of the proposed electricity efficiency and conservation activities for the purpose of the approval* ***must take into account their affordability to Nova Scotia Power Incorporated's customers****, along with any other matters considered appropriate by the Board or as may be prescribed.* (emphasis added)

NS Power currently has the highest rates of integrated utilities in Canada. This will likely remain to be the case given that NS Power has filed for a series of rate increases over the period 2022-2024.

Electric Rates of Major Canadian Integrated Utilities				
	Residential (1,000 kWh)		Industrial (5 MW, 85% LF)	
	$/MWh	Rank	$/MWh	Rank
Halifax (NS Power)	**$171**	**1**	**$111**	1
Regina (SaskPower)	165	2	90	3
St. John's (Newfoundland Power)	136	4	91	2
Moncton (NB Power)	137	3	83	4
Vancouver (BC Hydro)	116	5	79	5
Winnipeg (Manitoba Hydro)	99	6	57	6
Montréal (Hydro-Québec)	$74	7	$52	7
Source: Hydro-Québec *Comparison of Electricity Prices in Major North American Cities*, p. 22.[1]				

Incentives

Q WHAT IS YOUR CONCERN ABOUT THE INCENTIVES PROPOSED BY E1?

A E1's calculations underlying the various incentives are not at all clear. What is clear is that except for the Custom program, E1 does not take into account the direct benefit to the customer of reduced bills. A "payback" analysis is needed to determine how cost effective a measure is to the individual ratepayer. In some cases, the reduction in bills is high enough[2] for a customer to install the measure without any incentive payment from E1. This means that E1 should be able to achieve the same amount of savings but with a lower cost (to NSP ratepayers) of incentives.

Q PLEASE GIVE AN EXAMPLE.

A A good example is "Case Lighting For Sign Retrofits" in the Business Energy Rebates Program.[3] The cost and saving information is:

[1] http://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf
[2] Equivalently, the payback period is short enough.
[3] This is shown in the response to SBA IR-19 Attachment 1, row 41.

Customer-Installed DSM Payback Analysis	
A - Measure unit cost	$721.53
B - Annual energy saving	2,816 kWh
C - NS Power rate	$0.132[4]
D -Annual bill reduction (B*C)	$371.71
E - Monthly bill reduction (D÷12)	$30.98
F - Months to full payback (A÷E)	**23.2**

If the customer installs the measure with no incentive from E1, the cost will be recovered in 23 months—just under two years. Despite what would seem to be a compelling case that no incentive (subsidy) is needed, E1 has proposed to provide an incentive in 2023 of $312.50 per installation. This incentive (subsidy) is 43% of the cost. E1 estimates 1,356 participants units in 2020, resulting in total cost to E1—actually, a cost to NS Power's customers—of $572,000 in 2023 and $1.8 million over the three years. Note that as rates increase the payback period gets shorter.

Q **IS THIS THE ONLY MEASURE WITH A SHORT PAYBACK PERIOD?**

A No. Over 50 measures have a payback period of 36 months or less. Many, but not all, are for small dollar amounts. Furthermore, this is not an "either/or" issue. The proposed incentives for measures with payback periods somewhat longer than three years may also have incentives that are higher than necessary.

Q **BY HOW MUCH COULD THE TOTAL COST OF INCENTIVES BE REDUCED?**

A That depends on what amount of subsidy is actually needed. In principle, the incentive for a measure should be no higher than needed to "sell" that measure to ratepayers. That will vary among measures. But just to show the magnitude of the issue, if incentives are eliminated for all measures having a payback of 36 months or less, the total cost of incentives is reduced by about $9 million over the three-year period.

[4] General Rate at 60% load factor; https://www.nspower.ca/about-us/electricity/rates-tariffs/general

Q **WHY DID YOU USE A THREE-YEAR PAYBACK?**

A That was chosen just to illustrate that this is not a minor issue. Note also that three years (or less) is just the time period for the full cost to be recovered; after that the savings are a pure benefit to the ratepayer. E1 has assumed that most DSM measures have a life of ten years or more. The Case Lighting example discussed above has an assumed life of 11.6 years. Further, the "culture of conservation" that E1 has fostered in Nova Scotia means—or should mean—that customers are willing to invest in DSM measures even with longer payback periods.

Q **HOW IS THIS PAYBACK ANALYSIS RELATED TO THE TRC MEASURE OF COST-EFFECTIVENESS?**

A They are different but should give directionally consistent indications.

The TRC ratio is the total avoided costs (over the life of the measure) divided by the measure cost. The payback ratio is the measure cost divided by the customer's bill reduction.

TRC ratio = (Total avoided cost) / (Measure cost) *[Higher is better]*

Payback period = (Measure cost) / (Monthly bill reduction) *[Lower is better]*

The TRC screens for *overall* cost-effectiveness of the measure (regardless of how the cost is split between E1 and the ratepayer). The payback analysis screens for cost effectiveness *to the individual customer*. The more cost-effective to the customer, the less incentive that is needed.

The connection between the two is that a high TRC ratio means that the measure is expected to save lots of energy. That, in turn, means a quick payback in the form of lower bills.

Q **IS APPLYING THE PAYBACK TEST TO INCENTIVES A NEW ISSUE?**

A No. the Industrial Group and NS Power raised the issue in the hearing in the 2016-2018 proceeding (M06733). In its decision, the Board said:

> *[67] … [T]he Board acknowledges and accepts the concerns on incentives raised by Mr. Pickles, and more particularly Mr. Drazen, on behalf of the Industrial Group.*

[68] Mr. Drazen also raised the concern about a lack of information, noting that several of the measures El proposed are so cost effective that customers should be expected to do them on their own, without any incentive. NSPI noted that the evidence from El seemed to suggest that the information El used in determining incentives is focused extensively on information from customers and trade allies who may have a vested interest in having a high incentive. It argued El's Plan does not address the other side of the issue and that is, how much can be afforded. NSPI also argued the process contains no specific quantitative criteria analysis or guidelines with respect to incentives.

* * *

[74] The Board is also very concerned about the lack of rigor with respect to the determination of incentives. The Board is not satisfied that E1 presently has sufficiently rigorous programs to provide the minimum incentives necessary to achieve the savings targets. Indeed, a large part of E1's analysis seems to be to ask participants what they want. (pages 23, 26)

The Board directed E1 to undertake research and make recommendations on a more rigorous program for determining incentives. Thereafter, E1 retained CLEAResult to carry out that review (M07544).

The CLEAResult report identified payback period as an important metric:

Participant Cost Test/ Project Payback*: Instead of providing customers with Participant Cost Test results****, payback analysis is a simpler method of communicating the benefits of making a purchase*** *decision for an efficient option. For example, it is much easier to tell a customer that their purchase decision will pay back within 2-3 years, instead of providing them with a Participant Cost test ratio that is greater than 1.0, which indicates that their NPV is positive*.[5]

Q WHAT HAS E1 SAID ABOUT USING THE PAYBACK PERIOD IN DETERMINING INCENTIVES?

A Industrial Group information request IR-24(b) in M09096 asked:

[5] M07544 Incentive Setting Methodology: CLEAResult Report & EfficiencyOne Implementation Plan, Second Revision May, 11, 2017, PDF 33, emphasis added.

Please explain whether and how E1 took into account the bill savings to customers in determining the incentive amount for each measure. If these bill reductions were considered, please provide the calculations.

The response was:

As per EfficiencyOne's incentive setting and review procedures, bill savings to customers are considered for the following customer and decision types: "Commercial and Industrial Customer, Large Capital Equipment Purchase" and "Commercial and Industrial Customer, Large Purchase". Effectively this means that ***the Custom program would be the only program to consider customer payback as a threshold for incentive levels.*** *The 2020-2022 DSM Plan does not include assumptions for specific rebates on specific Custom projects, as actual energy savings for each project are modelled on a case-by-case basis when participating in the program. Simple payback calculations consider the customer bill savings when developing and presenting the customer with an incentive offer.* ***As per CLEAResult recommendations, and EfficiencyOne's incentive setting procedures, incentives should not be provided to customers to the point where the simple payback is less than one year, unless justified for special reasons.*** (emphasis added)

This does not explain why the payback analysis is not applied to all programs nor why it is only measures with a payback under 12 months that should not get an incentive. CLEAResult said this is a suggested upper limit and should not be implemented as a hard limit or cap.[6]

It is not only companies who are motivated by payback periods. As noted in the CLEAResult study:

Residential customers for larger purchases will look at a combination of upfront costs and utility bill savings. *They may look at purchases in terms of payback. As such, when setting incentive levels for this specific combination of customer, technology and replacement decision, the cost to customer threshold may be best aligned with the project costs as well as the Incremental Equipment Cost and payback.*[7]

[6] M07544 Incentive Setting Methodology: CLEAResult Report & EfficiencyOne Implementation Plan, Second Revision May, 11, 2017, PDF 71.
[7] M07544 Incentive Setting Methodology: CLEAResult Report & EfficiencyOne Implementation Plan, Second Revision May, 11, 2017, PDF 43, emphasis added

E1 has not matured its approach to extend payback analysis beyond the custom program.

Q WHAT IS YOUR RECOMMENDATION REGARDING INCENTIVES?

A At the very least, E1 should provide full information on how the incentives were determined. E1 should also add payback information in its schedule of measures. It is then up to the Board to decide whether and how to modify proposed incentives.

Q DOES THIS ANALYSIS IMPLY REJECTING ANY SPECIFIC PROPOSED DSM MEASURES?

A Not necessarily; the analysis above focuses on making sure that the amount of each incentive payment is no more than necessary. If the Board agrees that that given the beneficial payback periods, it should reduce the overall budget, it would be E1's task to implement these lower incentives, or it could also choose to eliminate measures where the payback period is so good, incentives are not necessary at all.

Section IV–Demand Response

Q WHAT COSTS ARE INCLUDED FOR DEMAND RESPONSE?

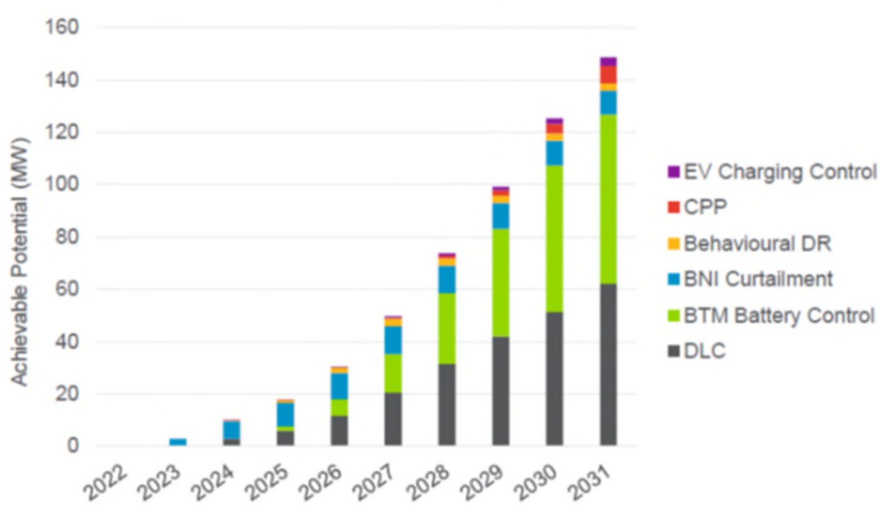
A E1 has proposed to include $10 million over three years for development and implementation of demand reduction (DR) programs:

E1 Proposed Demand Response Spending ($Millions)				
	2023	**2024**	**2025**	**Total**
Residential	$0.4	$2.2	$2.8	$5.4
BNI	1.1	1.3	2.1	4.5
Total	$1.5	$3.5	$5.0	$10.0
Source: Application, Appendix A, Tables 10-12, PDF 41-43.				

Q WHAT PROGRAMS HAS E1 PROPOSED?

A The programs that E1 proposes to study and the expected effect are shown in Figure 4 of the Guidehouse report:[8]

Figure 4. Peak Load Reduction from All DR Options for Settlement Plan (MW at generator)



[8]Application, Appendix A, Attachment 5, PDF 290.

Of the six programs, four—EV Charging, Critical Peak Pricing (CPP), Behavioural DR and BNI Curtailment—produce little peak reduction. There is little benefit from E1 pursuing these beyond what is in place now. These are also the programs that E1 would omit in the Alternate Scenario.[9] Only behind-the-meter (BTM) Battery Control and Direct Load Control (DLC) are expected to produce meaningful peak reductions. But DLC is the type of program that NS Power already administers (the Large Industrial Interruptible Rate).and the Battery Control forecast is speculative.

Q WHAT IS YOUR EVALUATION OF THE DEMAND CONTROL PROGRAMS?

A Developing more demand control load is worthwhile. NS Power can certainly benefit from increased ability to reduce system peak demand. However, this is essentially a rate design matter; which can and should be handled mostly by NS Power. E1 can play a role as a supplier of equipment (smart thermostats, batteries and the like), although this, too, is often considered a utility (or utility-supplied) service.

Q WHY SHOULD THIS BE HANDLED MOSTLY BY NS POWER?

A It is unclear how much value is added by having E1 work on developing and demand control rates. alongside of NS Power. For example, the Guidehouse report shows E1 playing a “support” role in defining DR program parameters and initiating DR events. NS Power is shown to have a support role in installing end-use technology, billing, settlement, EM&V, customer service.[10] But the design and administration of DR rates have always been considered a rate design matter, both in Nova Scotia and elsewhere. For example, the Large Industrial Interruptible credit is stated as a part of the rate for that service and included as an element of the monthly bill.

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[10] Application, Appendix A, Attachment 5, Table 21, PDF 327.

Utilities in general and NS Power in particular have been designing and implementing DC services for years. NS Power already has considerable experience with developing rates for interruptible power. The Large Industrial Interruptible Rate has been in effect for over a quarter century. For the large paper mills, NS Power developed the ELIIR rate, then the Load Retention Tariff and then the ELIADC rate. Several other utilities already offer the type of load control service for small customers being considered here. In fact, one such utility is Tampa Electric, an Emera company:

Utilities With Small Load Interruptible Services

Utility	Rate or Rider
Connexus Energy (Minnesota)	PowerNap Water Heating
DTE Energy (Detroit Edison)	Interruptible Water Heating Option
East Central Energy (Michigan)	Interruptible Water Heating
Georgia Power	Power Credit (Air conditioner)
Lake Region Electric Coop	Peak Shave Interruptible Water Heating
North Western Electric Coop (Ohio)	Water Heater Radio Control Switch
Tampa Electric (Florida)	Load Management Program
Xcel New Mexico	Residential Controlled Air Conditioning and Water Rider
Xcel New Mexico	Commercial and Industrial Controlled Air Conditioning Rider

Q WHY DO YOU SAY THE BATTERY CONTROL PROGRAM IS SPECULATIVE?

A The Guidehouse study contains a forecast of Battery Control. But this forecast is based on a lot of assumption. The amount of Battery Control capacity will depend on the amount of battery capacity and the Guidehouse study is forthright about the lack of that information:

> *Due to a lack of information on battery adoption projections in Nova Scotia, Guidehouse developed high-level battery adoption forecasts using assumptions drawn from Guidehouse Insights reports and industry expertise.*[11]
>
> * * *
>
> *Battery projections are typically an input to the DR analysis, but Guidehouse does not necessarily develop this as part of the analysis.* ***Due to a lack of information/data on battery projections in Nova Scotia, Guidehouse developed high-level battery projections using a relatively simple approach*** *that estimates battery adoption based on simple payback analysis. Detailed modelling of battery projections was outside the scope of the DR study.*[12]

[11] Application, Appendix A, Attachment 5, PDF 301.

[12] Application, Appendix A, Attachment 5, PDF 301 footnote 8, emphasis added.

Section V–Summary

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A The incentives that E1 has proposed are higher than necessary in some cases. The Board should direct E1 to provide a more transparent and rigorous explanation of the derivation of incentives and revise the budget accordingly. This should incorporate consideration of the bill reductions to customers.

Next, much of the development and implementation of small customer interruptible rates can and should be handled by NS Power. While E1 can play a useful role in supplying equipment, NS Power should be the party that develops and administers the service. The $10 million E1 budget for this work should be reduced, save and except the direct costs of equipment.

Q DOES THAT CONCLUDE YOUR EVIDENCE?

A Yes, it does.

Experience of Mark Drazen

Mr. Drazen has worked since 1972 on economic analysis of energy and utility service, pricing in regulated and deregulated utility markets, contract negotiations, and strategic planning throughout the United States and Canada. His experience covers electric, natural gas, oil pipeline, telecommunications, transportation, waste and water utilities in nine Canadian Provinces and in 41 states in the U.S.

He has appeared as an expert witness before courts, federal, provincial and state regulatory agencies (including the National Energy Board, the Canadian Radio-Television and Telecommunications Commission, the Federal Energy Regulatory Commission and the Federal Communications Commission).

Drazen Consulting Group offers economic, project planning, regulatory consulting and litigation support services to clients that include industrial utility users, municipalities, schools, hospitals, utilities and government agencies. The founding firm (Michael Drazen and Associates) was established in 1937.

The firm's work covers all aspects of utility regulation (and deregulation), including revenue requirements, cost of capital, cost analysis, pricing, valuation, performance-based regulation and industry restructuring.

Mr. Drazen is a graduate of the Massachusetts Institute of Technology, with the degrees of Bachelor of Science in Mathematics, Master of Science in Electrical Engineering, and Electrical Engineer.