EB-2020-0091

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas with respect to Integrated Resource Planning

---

Energy Probe Research Foundation
Compendium Panels: 2, 4 and 5

March 1-5, 2021

Index

PART 1 ENBRIDGE GAS PANEL 2

Filed: 2021-02-25
EB-2020-0091
Exhibit JT2.15
Page 1 of 1
Plus Attachment
ENBRIDGE GAS INC.
Undertaking Response to EP
To provide an illustrative example of the evaluation process that Enbridge would use to compare a hypothetical transmission project with an alternative where a demand response program is implemented that decreases the size of the transmission project by 20 percent.
Response:
Please see Attachment 1 for the requested illustrative example.

Filed: 2021-02-25, EB-2020-0091, Exhibit JT2.15, Attachment 1, Page 1 of 7

Illustrative Demand Response vs Pipeline Example

	Pipeline				IRPA					
	Pipeline NPV	Capacity Created (m3/hr)	NPV per Unit ($/m3/hr)	Stage 1 PI	Demand Response NPV	80% Pipeline NPV	Net IRPA NPV	Capacity Created (m3/hr)	NPV per Unit ($/m3/hr)	Stage 1 PI
	(a)	(b)	(c) = (a) / (b)		(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) / (g)	
Stage 1	AAA	100	A.AA	PI	XXX	AAA	AXA	100	A.XA	PI
Stage 2	BBB	100	B.BB	n/a	YYY	BBB	YBY	100	Y.BY	n/a
Stage 3	CCC	100	C.CC	n/a	ZZZ	CCC	ZCZ	100	Z.CZ	n/a
Total	ABC	100	A.BC	n/a	XYZ	ABC	XYC	100	X.YC	n/a

Notes:
1. DCF analysis that would be used to evaluate the NPV of a typical Demand Response program that decreases the size of a transmission project by 20 percent.
2. Evaluation horizon of 40 years.
3. Calculated NPV is divided by capacity created to determine the cost per unit of capacity.
4. The test will be evaluated at each stage as well as the total of all stages.

Stage 1 DCF Analysis
Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Incremental Revenues	Incremental transmission revenue received by Utility accounting for IRPA impact. Does not include gas commodity revenue.	XXX	XXX	XXX	XXX	XXX	XXX
Avoided Commodity/Fuel Costs		-	-	-	-	-	-
Avoided O&M & Municipal Tax	Lower municipal taxes from decreased size of transmission project.	XXX	XXX	XXX	XXX	XXX	XXX
Total Benefits		XXX	XXX	XXX	XXX	XXX	XXX
Costs:							
Incremental O&M	Includes Demand Response program costs (e.g. enrollment rebates, customer incentives).	XXX	XXX	XXX	XXX	XXX	XXX
Incremental Municipal Tax		-	-	-	-	-	-
Incremental Commodity/ Fuel Costs		-	-	-	-	-	-
Incremental Income Tax	Income tax effect from avoided municipal taxes and incremental O&M.	XXX	XXX	XXX	XXX	XXX	XXX
Total Costs		XXX	XXX	XXX	XXX	XXX	XXX
Net Operating Benefit/Cost		XXX	XXX	XXX	XXX	XXX	XXX
Capital							
Avoided Infrastructure Costs	Lower capital costs from decreased size of transmission project.	(XXX)	(XXX)	-	-	-	-
Change in Working Capital		-	-	-	-	-	-
Total Capital		(XXX)	(XXX)	-	-	-	-
CCA Tax Shield							
CCA Tax Shield	Lower CCA tax shield resulting from avoided infrastructure costs.	XXX	XXX	-	-	-	-
Net Present Value							
PV of Operating Cash Flow		XXX	XXX	XXX	XXX	XXX	XXX
PV of Capital		XXX	XXX	-	-	-	-
PV of CCA Tax Shield		(XXX)	(XXX)	(XXX)	(XXX)	(XXX)	(XXX)
Total NPV by Year		XXX	XXX	XXX	XXX	XXX	XXX

Stage 2 DCF Analysis
Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Avoided Infrastructure Costs		-	-	-	-	-	-
Avoided Commodity/Fuel Costs	Reduced costs incurred by customer due to annual reduction in consumption. Would not include load shifting (i.e. lower peak day consumption offset by higher consumption during off peak periods).	YYY	YYY	YYY	YYY	YYY	YYY
Avoided GHG Emission	Reduced Federal Carbon Charge associated with Avoided Commodity/Fuel Costs identified above.	YYY	YYY	YYY	YYY	YYY	YYY
Total Benefits		YYY	YYY	YYY	YYY	YYY	YYY
Costs:							
Incremental Customer Costs	Costs incurred by customer net of any rebates/incentives received from the Utility.	YYY	YYY	YYY	YYY	YYY	YYY
Incremental Commodity/ Fuel Costs	Costs incurred by customer due to the use of an alternative fuel to mitigate reduced use of natural gas.	YYY	YYY	YYY	YYY	YYY	YYY
Incremental GHG Emissions	Federal Carbon Charge associated with use of an alternative fuel identified above if applicable.	YYY	YYY	YYY	YYY	YYY	YYY
Total Costs		YYY	YYY	YYY	YYY	YYY	YYY
Net Operating Benefit/Cost		YYY	YYY	YYY	YYY	YYY	YYY
Net Present Value							
Total NPV by Year		YYY	YYY	YYY	YYY	YYY	YYY
Project NPV	Discounted using a societal discount rate (currently 4%).	YYY					

Stage 3 DCF Analysis

Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Other External Non-Energy Benefits	Quantifiable benefits such as GDP impact and jobs created to be included. Current DSM assumption is that the societal benefit is 15% of identified customer benefits.	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Total Benefits		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Costs:							
Other External Non-Energy Costs	Unlikely to identify quantifiable societal costs associated with a Demand Response program.	-	-	-	-	-	-
Total Costs		-	-	-	-	-	-
Net Operating Benefit/Cost		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Net Present Value							
Total NPV by Year		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Project NPV	Discounted using a societal discount rate (currently 4%).	ZZZ					

Filed: 2021-02-25, EB-2020-0091, Exhibit JT2.15, Attachment 1, Page 5 of 7

Stage 1 DCF Analysis

Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Incremental Revenues	Incremental transmission revenue received by Utility. Does not include gas commodity revenue.	AAA	AAA	AAA	AAA	AAA	AAA
Avoided Commodity/Fuel Costs		-	-	-	-	-	-
Avoided O&M & Municipal Tax		-	-	-	-	-	-
Total Benefits		-	-	-	-	-	-
Costs:							
Incremental O&M	Incremental O&M to maintain pipeline.	AAA	AAA	AAA	AAA	AAA	AAA
Incremental Municipal Tax	Incremental municipal tax paid for pipeline.	AAA	AAA	AAA	AAA	AAA	AAA
Incremental Commodity/ Fuel Costs		-	-	-	-	-	-
Incremental Income Tax	Income tax effect from incremental revenue, municipal taxes, and O&M.	AAA	AAA	AAA	AAA	AAA	AAA
Total Costs		AAA	AAA	AAA	AAA	AAA	AAA
Net Operating Benefit/Cost		AAA	AAA	AAA	AAA	AAA	AAA
Capital							
Incremental Infrastructure Costs	Capital costs for new pipeline.	AAA	AAA	-	-	-	-
Change in Working Capital		-	-	-	-	-	-
Total Capital		AAA	AAA	-	-	-	-
CCA Tax Shield							
CCA Tax Shield	CCA tax shield associated with capital costs for new pipeline	AAA	AAA	-	-	-	-
Net Present Value							
PV of Operating Cash Flow		AAA	AAA	AAA	AAA	AAA	AAA
PV of Capital		AAA	AAA	-	-	-	-
PV of CCA Tax Shield		AAA	AAA	AAA	AAA	AAA	AAA
Total NPV by Year		AAA	AAA	AAA	AAA	AAA	AAA

Stage 2 DCF Analysis
Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Avoided Infrastructure Costs		-	-	-	-	-	-
Avoided Commodity/Fuel Costs	Reduced costs incurred by customer associated with non-use of alternative fuels such as fuel oil, propane, electricity.	BBB	BBB	BBB	BBB	BBB	BBB
Avoided GHG Emission	Reduced Federal Carbon Charge associated with Avoided Commodity/Fuel Costs identified above if applicable.	BBB	BBB	BBB	BBB	BBB	BBB
Total Benefits		BBB	BBB	BBB	BBB	BBB	BBB
Costs:							
Incremental Customer Costs		-	-	-	-	-	-
Incremental Commodity/ Fuel Costs	Incremental natural gas costs incurred by customer.	BBB	BBB	BBB	BBB	BBB	BBB
Incremental GHG Emissions	Federal Carbon Charge associated with use of incremental natural gas identified above.	BBB	BBB	BBB	BBB	BBB	BBB
Total Costs		BBB	BBB	BBB	BBB	BBB	BBB
Net Operating Benefit/Cost		BBB	BBB	BBB	BBB	BBB	BBB
Net Present Value							
Total NPV by Year		BBB	BBB	BBB	BBB	BBB	BBB
Project NPV	Discounted using a societal discount rate (currently 4%).	BBB					

Stage 3 DCF Analysis
Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Other External Non-Energy Benefits	Benefits such as GDP impact, jobs created, and resiliency as back up energy source during power outages may be included.	CCC	CCC	CCC	CCC	CCC	CCC
Total Benefits		CCC	CCC	CCC	CCC	CCC	CCC
Costs:							
Other External Non-Energy Costs	No quantifiable societal costs have been included to date.	-	-	-	-	-	-
Total Costs		-	-	-	-	-	-
Net Operating Benefit/Cost		CCC	CCC	CCC	CCC	CCC	CCC
Net Present Value							
Total NPV by Year		CCC	CCC	CCC	CCC	CCC	CCC
Project NPV	Discounted using a societal discount rate (currently 4%).	CCC					

ENBRIDGE GAS INC.

Undertaking Response to EP

To inform us how more detail on how risks would be addressed during the evaluation of the baseline and IRPA's, such as risk tools and what tools might they use.

Response:

Enbridge Gas considers the following risk categories:

- **Employee and Contractor Health and Safety**: Level of injury or illness due to incident;
- **Public Health and Safety**: Level of injury and number of people impacted;
- **Environmental**: Breadth and severity resulting in environmental damage/impact;
- **Financial**: Level of financial impact;
- **Operational**: Length of time and breadth of impact on utility & transportation customers and diversion of resources; and
- **Reputational**: Level of media coverage, impact on customers, potential penalties or impact on ability to operate due to compliance issues.[1]

Figure 1 below provides an illustrative example to inform the Board and parties how Enbridge Gas might document risk related to baseline facilities and IRPAs going forward, subject to the establishment of an IRP Framework for the Company. Enbridge Gas expects that as the Company gains expertise deploying IRPAs it will be able to reevaluate the risk impacts of each IRPA in various situations.

Figure 1

Risk of IRPA relative to traditional facilities				
Significantly Better	Better	Neutral	Worse	Significantly Worse

	IRPA Examples				
Risk Category	Demand Response	Demand Response & AMI	CNG	EASHP	ETEE
Employee & Contractor H&S					
Public H&S					
Environmental					
Financial					
Operational					
Reputational					

[1] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, p. 58; https://www.rds.oeb.ca/CMWebDrawer/Record/689895/File/document

PART 2 GEC/ED Energy Futures Panel 3

EB-2020-0091
Ex. JT 3.10 (A)
Filed 2021-02-24
Page 1 of 4

GEC Response to Energy Probe Undertaking

Question JT3.10(A)

To Provide a list of the inputs for the "TRC-plus" test.

Response:

Our sense from the discussion with Dr. Higgin during the technical conference is that he was interested in a hypothetical example to illustrate how the different inputs to the TRC+ test would be made. To that end, we have developed a hypothetical and will show how it applies to both a hypothetical demand response (DR) program as an IRPA and a hypothetical energy efficiency (EE) program as an IRPA.

For both of these examples, we assume peak demand of 90 units of gas, an existing maximum capacity of 100 units, and annual growth of 2 units. Thus, in this hypothetical, peak demand would be equal to the maximum existing capacity in five years. In other words, absent any demand-side investment, the capacity upgrade would be needed in five years. We also assume that the capacity addition will cost $25,000 and that a 4% real discount rate is used in the analysis. As Table 1 illustrates, that produces a net present value (NPV) cost for the infrastructure scenario of $20,548. That is the base case against which the two IRPA scenarios are compared.

Table 1: Cost of Infrastructure Scenario

Table 1: Cost of Infrastructure Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		0	0	0	0	0	0	0	0	0	0	0	0	0	
Cumulative Annual IRPA Peak Savings		0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Demand after DR	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Costs															**NPV**
Infrastructure		$0	$0	$0	$0	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	$20,548
IRPA		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$0	$0	$0	$0	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	**$20,548**
Other Benefits															
Avoided Energy Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Carbon Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other non-energy benefits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Net Cost		**$0**	**$0**	**$0**	**$0**	**$25,000**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$20,548**
Net Cost Difference vs. Infrastructure		n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

With respect to DR, and as shown in Table 2, it is assumed that the maximum DR potential is 10 units, but that it would take ten years of marketing and offering of financial incentives to customers to ramp up to that level of DR capacity. It is further assumed that the utility has to pay a financial incentive to customers of $50 to achieve 1 unit of DR capacity, and that such payments are required each year (i.e., it is an annual payment required to keep customers enrolled in the DR program). It is also assumed that the utility must spend a fixed $25 per year, regardless of participation levels, to manage the DR program and market it to customers. For simplicity, it is assumed that there are no gas or electric energy savings that result from the DR program. As Table 2 illustrates, these assumptions lead to a total DR scenario cost of $19,151, or a cost savings relative to the infrastructure scenario of $1397.

Table 2: Cost of DR Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		1	1	1	1	1	1	1	1	1	1	0	0	0	
Cumulative Annual IRPA Peak Savings		1	2	3	4	5	6	7	8	9	10	0	0	0	
Peak Demand after DR	90	91	92	93	94	95	96	97	98	99	100	120	130	140	
Costs															NPV
Infrastructure		$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$0	$0	$0	$16,889
DR Incentives		$50	$100	$150	$200	$250	$300	$350	$400	$450	$500	$0	$0	$0	$2,100
DR Non-Rebate Costs		$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$0	$0	$0	$162
DR Customer Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$70	$120	$170	$220	$270	$320	$370	$420	$470	$25,520	$0	$0	$0	$19,151
Other Benefits															
Avoided Energy Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Avoided Carbon Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Electricity savings		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Other non-energy benefits		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Total		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Net Cost		$70	$120	$170	$220	$270	$320	$370	$420	$470	$25,520	$0	$0	$0	$19,151
Net Cost Difference vs. Infrastructure		$70	$120	$170	$220	($24,730)	$320	$370	$420	$470	$25,520	$0	$0	$0	($1,397)

With respect to EE, and as shown in Table 3, it is assumed that a geotargeted set of programs could generate 1 incremental unit of peak savings each year. Savings are assumed to last 15 years, so the theoretic maximum cumulative savings would be 15 units. However, the program is assumed to be stopped after 10 years because the infrastructure project cannot be deferred past year 10. It is further assumed that the utility pays a financial incentive of $250 to customers per unit of peak savings and that represents 50% of the cost of the efficiency measures – meaning customers would incur another $250 themselves. It is also assumed that the utility spends $75 per year to manage and market the programs. Unlike DR, EE provides substantial additional benefits in the form of avoided gas energy costs, avoided carbon taxes, avoided electricity costs (many gas efficiency measures also save electricity) and other customer non energy benefits. The hypothetical assumptions used to value these benefits, along with the other DR and EE assumptions, are presented in Table 4. As Table 3 shows, this hypothetical EE scenario has an NPV cost of $17,021, or $3527 less than the infrastructure option.

Table 3: Cost of EE Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		1	1	1	1	1	1	1	1	1	1	0	0	0	
Cumulative Annual IRPA Peak Savings		1	2	3	4	5	6	7	8	9	10	10	5	0	
Peak Demand after DR	90	91	92	93	94	95	96	97	98	99	100	110	125	140	
Costs															**NPV**
Infrastructure		$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$0	$0	$0	$16,889
EE Incentives		$250	$250	$250	$250	$250	$250	$250	$250	$250	$250	$0	$0	$0	$2,028
EE Non-Rebate Cost		$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$0	$0	$0	$608
EE customer Costs		$250	$250	$250	$250	$250	$250	$250	$250	$250	$250	$0	$0	$0	$2,028
Total		$575	$575	$575	$575	$575	$575	$575	$575	$575	$25,575	$0	$0	$0	$21,553
Other Benefits															
Avoided Energy Costs		$20	$40	$60	$80	$100	$120	$140	$160	$180	$200	$200	$100	$0	$1,876
Avoided Carbon Taxes		$20	$39	$59	$78	$98	$117	$137	$157	$176	$196	$196	$98	$0	$1,835
Electricity savings		$5	$10	$15	$20	$25	$30	$35	$40	$45	$50	$50	$25	$0	$469
Other non-energy benefits		$4	$8	$11	$15	$19	$23	$26	$30	$34	$38	$38	$19	$0	$352
Total		$48	$97	$145	$193	$242	$290	$338	$387	$435	$483	$483	$242	$0	$4,531
Net Cost		$527	$478	$430	$382	$333	$285	$237	$188	$140	$25,092	($483)	($242)	$0	$17,021
Net Cost Difference vs. Infrastructure		$527	$478	$430	$382	($24,667)	$285	$237	$188	$140	$25,092	($483)	($242)	$0	($3,527)

Table 4: DR, EE and other General Assumptions

DR and DSM Assumptions	DR	DSM
Measure Life	1	15
Annual m3 saved	0	100
Annual kWh saved	0	50
Utility rebate	$50	$250
Customer measure cost	$25	$250
Utility non-rebate program cost	$20	$75

General Assumptions	
Real discount rate	4%
Infrastructure Cost	$25,000
Avoided Energy Cost ($/m3)	$0.20
Carbon Tax $/tonne	$100
Carbon Tax $/m3	$0.20
Avoided electricity cost ($/kWh)	$0.10
Customer non-energy benefits	15% of non-CO2 benefits

The tables above collectively provide all the information needed to assess cost-effectiveness through the TRC+ test, as it is applied today in Ontario for DSM. The categories of impacts included in the TRC+ (again, as applied today in Ontario), along with the values from the hypothetical examples summarized above, are shown in Table 5 below. In this example, both the DR IRPA and EE IRPA would be cost-effective. However, the EE option produces greater net benefits (i.e., cost savings) and has a slightly higher benefit-cost ratio.

Table 5: TRC+ Test Calculations of Cost-Effectiveness

	DR	EE
Benefits		
Avoided Infrastructure Costs	$3,659	$3,659
Avoided Annual Gas Energy Costs	$0	$1,876
Avoided Gas Carbon Taxes	$0	$1,835
Avoided electricity costs	$0	$469
DSM Non-Energy Benefits Adder	$0	$352
Total	**$3,659**	**$8,191**
Costs		
IRPA Incentive Costs	$2,100	$2,028
Other IRPA Program/Admin Costs	$162	$608
Increased Utility O&M	$0	$0
Increased Carbon Taxes	$0	$0
Increase in other Fuel Costs	$0	$0
Increased Customer Costs	$0	$2,028
Total	**$2,262**	**$4,664**
Cost-Effectiveness Determination		
Net Benefits	**$1,397**	**$3,527**
Benefit-Cost Ratio	**1.62**	**1.76**
Non-Pipe Solution Cost-Effective?	**YES**	**YES**

Note that the TRC+ test, like all cost-effectiveness tests, should include all utility system impacts. However, the TRC+ test as currently applied in Ontario is missing a several potential benefits of energy efficiency and potentially other IRPA options. Specifically, it has not included the benefits of:

- market price suppression effects – reductions in demand for gas will lower the market clearing price for gas (even if the reduction is very small, the total value can be non-trivial when multiplied by total gas consumption by all of Enbridge's customers);
- option value – the modular nature of efficiency "buying time" to recalibrate peak load forecasts, which could lead to longer deferrals of even elimination of the need for an infrastructure upgrade; or
- risk mitigation – e.g., efficiency investments reducing customers' exposure to future gas price uncertainty.

All of those impacts should be added to future applications of the TRC+ test in Ontario.

Also, as explained in the EFG report in this proceeding, the analysis of cost-effectiveness of IRPA options such as DR and EE should include sensitivity scenarios, particularly with respect to potential impacts of more stringent climate policy impacts on gas demand and/or gas costs.

Part 3 OEB Guidehouse Panel

Guidehouse

Natural Gas Integrated Resource Planning in New York State and Ontario

Response to Undertaking No. JT3.10 (B)

Introduction

The Ontario Energy Board staff (the OEB staff) contracted Guidehouse Canada Ltd. (Guidehouse) to provide expert support to contribute to the OEB's review of integrated resource planning (IRP) for Enbridge Gas in the regulatory proceeding EB-2020-0091. Guidehouse prepared a report "Natural Gas Integrated Resource Planning in New York State and Ontario" to provide a summary of key IRP activities in New York State, a side-by-side comparison with each of the IRP issues in the Issues List for the EB-2020-0091 proceeding (Issues List) and Enbridge Gas's original IRP proposal in that proceeding (Enbridge Gas IRP Proposal), as well as Enbridge Gas's Additional Evidence filed with the OEB on October 15, 2020.

The original report was filed as OEB staff evidence on November 12, 2020 (OEB File Number: EB-2020-0091). In January 2021, several organizations filed interrogatories directed towards the Guidehouse report. During the Technical Conference for EB-2020-0091 on February 12, 2021, Guidehouse was assigned the following undertaking:

> **UNDERTAKING NO. JT3.10 (B): TO HIGHLIGHT THE DIFFERENCES AS THEY ARE IN THE TABLE AND PROVIDE SUPPLEMENTARY INFORMATION, PARTICULARLY ON THE DISCOUNT RATES THAT WOULD BE USED FOR EACH OF THE THREE APPROACHES.**

This document contains Guidehouse's response to this undertaking, as well as the related IR response to 1-BOMA-13, which included the original table and supporting information on which the undertaking was based.

1.1 Guidehouse Response to 1-BOMA-13

Reference: Guidehouse, 2020, Pages 15/16, Table 1 and Table 2

Preamble:

Table 1 and 2 from Guidehouse report

Question(s):

(a) Please provide a combined table with 3 columns, including in the third column, the current use of benefit/costs categories required by the OEB's current requirements of Enbridge.

Guidehouse Response:

The OEB's current requirements for benefit-cost analysis (BCA) for Enbridge Gas differ for transmission and distribution system expansion projects and DSM programs. The table below summarizes the key BCA tests and guidance documents for each.

Benefit-Cost Test	Use	Guidance Document
Total Resource Cost +	DSM programs	Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020)[1]
E.B.O. 134 (three-stage analysis)	Transmission system expansion	Filing Guidelines on the Economic Tests for Transmission Pipeline Applications[2]
E.B.O. 188	Distribution system expansion	Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario[3]

Within Section 4.1 of the Guidehouse report, we summarized the original and revised Con Edison BCA Handbook for Non-Pipeline Solutions. The 2020 BCA updates are generally consistent with the original list of benefits and cost categories and reflect further specificity of the NPS opportunities and proposed framework (e.g., addition of shareholder incentives / earnings adjustment mechanisms [EAMs]). As such, we will respond to the question with a focus on the revised version from September 2020. Con Edison proposes to use a Societal Cost Test as its primary test, with UCT and RIM tests as secondary tests. As noted in section 3.1 and Table 3.1 of the BCA Handbook, all listed costs and benefits shown in the table below with the exception of lost utility revenue and shareholder incentives would be considered in the Societal Cost Test. These two categories are not included in the Societal Cost Test as they are considered transfers between stakeholder groups that have no net impact on society as a whole. The UCT and RIM tests would be conducted, but would serve in a subsidiary role to the SCT test and would be performed only for the purpose of arriving at a preliminary assessment of the impact on utility costs and ratepayer bills of measures that pass the SCT analysis. See Green Energy Coalition-6 for further details.

The tables below provide a side-by-side comparison of the benefits and costs within the revised Con Edison BCA Handbook for Non-Pipeline Solutions and the OEB guidance documents for natural gas DSM programs (TRC+), transmission expansion projects (E.B.O. 134), and distribution expansion projects (E.B.O. 188).

[1] https://www.oeb.ca/oeb/_Documents/EB-2014-0134/Filing_Guidelines_to_the_DSM_Framework_20141222.pdf
[2] https://www.oeb.ca/oeb/_Documents/Regulatory/Filing_Guidelines_Tx_Pipelines_Applications.pdf
[3] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/EBO-188-AppB-Guidelines-Gas-Expansion-19980130.pdf

Comparison of Benefit Categories between
Con Edison BCA Handbook and OEB BCA Guidance Documents

Benefit Categories from Con Edison Revised BCA Handbook	Considered in EBO 134 Stage 1 / EBO 188?[4]	Considered in DSM Framework (TRC+ test)?
Avoided Peaking Services	Yes	Yes, Avoided Supply Costs (capital, operating and commodity costs)
Avoided Pipeline and Storage Capacity Costs	Yes	Yes, Avoided Supply Costs (capital, operating and commodity costs)
Avoided Commodity Costs	No	Yes, Avoided Supply Costs (capital, operating and commodity costs)
Avoided On-System Capacity Expense	Yes	Yes, Avoided Supply Costs (capital, operating and commodity costs)
Reliability / Resiliency	Not specifically defined	Not specifically defined
External Benefits (e.g., Avoided CO2 and Other Emissions, Land and Water Impacts)	Not in stage 1, potentially in stages 2 or 3	• Avoided CO2 emissions are monetized as Avoided Supply Costs • Non-Energy Benefit Adder may also consider environmental, societal, utility and other participant benefits

[4] This column was based on the guidance for E.B.O. 188. Guidance for stage 1 of E.B.O. 134 is less detailed, but appears to be essentially identical in terms of the costs and benefits that should be included.

Comparison of Cost Categories between Con Edison BCA Handbook and OEB BCA Guidance Documents

Cost Categories from Con Edison Revised BCA Handbook	Considered in EBO 134 Stage 1 / EBO 188?[5]	Considered in DSM Framework (TRC+ test)?
Program Administration	Yes	• Yes, Program costs (Development, promotion, delivery, EM&V, administration). • Incentives to participants are not included in program costs
Incremental On-System Capacity Expenses	Yes	Yes, Avoided Supply Costs (capital, operating and commodity costs)
Lost Utility Revenue	Yes	Not as part of TRC+ test, however, Framework includes Lost Revenue
Shareholder Incentives	Not applicable	Not as part of TRC+ test, however, Framework includes Shareholder Incentive
Incremental Participant NPS Cost	Not in stage 1, potentially in stages 2 or 3	Yes, Net Equipment Costs (Installation, O&M, fuel cost)
Alternative Fuel Cost (e.g., Electricity)	Not in stage 1 (assuming that utility is not provider of the alternative fuel), potentially in stages 2 or 3	Yes, Net Equipment Costs (Installation, O&M, fuel cost)
External Costs (e.g., Alternative Fuel CO2 and Other Emissions, Land and Water Impacts)	Not in stage 1, potentially in stages 2 or 3	Indirectly through Non-Energy Benefit Adder (which assumes net external impacts are benefits)

Guidehouse notes several caveats regarding the interpretation of the EBO 134/EBO 188 economic tests. These tests are intended to assist the OEB in making determinations regarding potential transmission/distribution system expansion, by outputting a Net Present Value (NPV). They were not designed to compare alternative options to meet a system need. However, it is possible to repurpose either of these tests as an options analysis, by comparing the NPV produced by the EBO 134/188 tests for different options to meet a system need, and determining which option has the highest NPV (note that all options for meeting a system need may yield a negative NPV).

Guidehouse also notes that OEB guidance regarding stages 2 and 3 of the EBO 134 test is limited. The OEB indicates in its Filing Guidelines on the Economic Tests for Transmission Pipeline Applications that "the second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage. The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two."

[5] This column was based on the guidance for E.B.O. 188. Guidance for stage 1 of E.B.O. 134 is less detailed, but appears to be essentially identical in terms of the costs and benefits that should be included.

1.2 Guidehouse Response to Undertaking No. JT3.10 (B)

UNDERTAKING NO. JT3.10 (B): TO HIGHLIGHT THE DIFFERENCES AS THEY ARE IN THE TABLE AND PROVIDE SUPPLEMENTARY INFORMATION, PARTICULARLY ON THE DISCOUNT RATES THAT WOULD BE USED FOR EACH OF THE THREE APPROACHES.

Guidehouse Response:

In the list below, Guidehouse summarizes the major differences of the benefits and costs within the Revised Con Edison BCA Handbook for Non-Pipeline Solutions and the OEB guidance documents for natural gas DSM programs (TRC+), transmission expansion projects (E.B.O. 134), and distribution expansion projects (E.B.O. 188).

Comparison of Benefit Categories between Con Edison BCA Handbook and OEB BCA Guidance Documents

- **Reliability / Resiliency** is captured as a benefit category for Con Edison BCA Handbook, and is not captured in any of the Ontario tests (EBO 134 Stage 1, EBO 188, TRC+).
- **Avoided Commodity Costs** are included in the Con Edison BCA Handbook as well as the TRC+ test, but are not included in EBO 134 Stage 1 or EBO 188.
- **External Benefits** are considered differently across the set of tests.
    - The Con Edison BCA Handbook notes "To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed."
    - EBO 134 / EBO 188 do not consider external benefits in Stage 1, but may consider them in Stages 2 or 3, although guidance is limited.
    - The TRC+ test includes Avoided CO_2 Emissions directly and may also consider other external benefits as part of the Non-Energy Benefit Adder.

Comparison of Cost Categories between Con Edison BCA Handbook and OEB BCA Guidance Documents

- **Program Administration** is included in Con Edison BCA Handbook as well as the EBO 134 Stage 1 / EBO 188, and TRC+ tests, although participant incentives are not included in the TRC+ test. The Con Edison BCA Handbook does include participant incentives in Program Administration costs. [6]

---

[6] Page 12 of Con Edison BCA Handbook defines Program Administration Costs: "Administrative related costs directly associated with implementing a Gas BCA project or program. These can include costs associated with setting up a program, ongoing costs associated with monitoring and accounting for a program, and *incentives paid to participants*."

- **Lost Utility Revenue** is included in Con Edison BCA Handbook as well as the EBO 134 Stage 1 / EBO 188, but not the TRC+ test. Note: Lost Utility Revenue does not apply to the SCT in the Con Edison BCA Handbook, as these are considered transfers between stakeholder groups that have no net impact on society as a whole. Lost Utility Revenue is included in the RIM test, which has a subsidiary role to the SCT test in the Con Edison BCA Handbook.
- **Shareholder Incentives** are included in Con Edison BCA Handbook, but neither of the Ontario tests. Note: Shareholder Incentives do not apply to the SCT in the Con Edison BCA Handbook, as these are considered transfers between stakeholder groups that have no net impact on society as a whole. Lost Utility Revenue is included in the RIM test, which has a subsidiary role to the SCT test in the Con Edison BCA Handbook.
- **Incremental Participant Cost** is included in Con Edison BCA Handbook as well as the TRC+ test. EBO 134 Stage 1 / EBO 188 does not consider this in Stage 1, but may consider them in Stages 2 or 3, although guidance is limited. The Con Edison BCA Handbook defines Incremental Participation Costs as costs that would be incurred by providers of Gas BCA services, less incentives recognized in Program Administration Costs with a floor of zero.[7]
- **Alternative Fuel Cost** is included in Con Edison BCA Handbook as well as the TRC+ test. EBO 134 Stage 1 / EBO 188 does not consider this in Stage 1, but may consider them in Stages 2 or 3, although guidance is limited.
- **External Costs** are considered differently across the set of tests, similar to External Benefits described above.
  - The Con Edison BCA Handbook notes "To the degree these [costs] exist but are not readily quantifiable, their impacts may be qualitatively assessed."
  - EBO 134 / EBO 188 do not consider external costs in Stage 1, but may consider them in Stages 2 or 3, although guidance is limited.
  - The TRC+ test may consider other external benefits as part of the Non-Energy Benefit Adder.

In the list below, Guidehouse summarized the prescribed discount rates within the Revised Con Edison BCA Handbook for Non-Pipeline Solutions and the OEB guidance documents for natural gas DSM programs (TRC+), transmission expansion projects (E.B.O. 134), and distribution expansion projects (E.B.O. 188).

Con Edison Discount Rate from Revised Con Edison BCA Handbook for Non-Pipeline Solutions:

> Page 9 of Handbook: Apply the appropriate discount rate to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is set in CECONY's rate cases at the utility's cost of capital.[6] Benefit and Cost streams should be discounted at the

---

[7] Page 13 of Con Edison BCA Handbook defines Incremental Participant Cost: "Total incremental costs incurred by Gas BCA providers relative to their baseline costs, including equipment and participation costs assumed by participants or providers, _net of payments to provider or incentive/rebates to participants with a floor of zero_. For example, if an energy efficiency program included an upgraded natural gas water heater, the participant cost included would reflect the difference between the higher and lower efficiency natural gas water heaters, net of incentives.."

Weighted Average Cost of Capital ("WACC") unless specified otherwise. (Footnote 6: CECONY's Weighted Average Cost of Capital is currently 6.61% for the twelve months ending December 31, 2020. See CECONY Gas Case 19-G-0066)

TRC+ Discount Rate from Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020)

Page 35: Traditionally, the natural gas utilities have used a discount rate that is equal to their Board approved weighted average cost of capital ("WACC"). The Board is of the view that the gas utilities should use a discount rate (real) of 4% when screening prospective DSM programs to determine if they are cost-effective for considerations part of the new 2015 to 2020 multi-year DSM plan.

E.B.O. 134 Discount Rate from 1987 OEB Staff Report (June 1, 1987), referenced in Filing Guidelines on the Economic Tests for Transmission Pipeline Applications[8]

Guidehouse notes that the E.B.O. 134 guidance does not explicitly define a discount rate and leaves room for interpretation, particularly with regard to Stages 2 and 3.[9]

Page 53 of PDF:
The Board directs all utilities to employ DCF analysis as part of its assessment of the feasibility of projects for system expansion.

Page 54: The Board finds that Union's three-stage test has considerable merit. The Board requires each utility to develop a three-stage process as outlined below to aid the Board in its determination of the public interest.

The first stage is a test based on a DCF analysis.

The second stage should be designed to quantify other public interest factors not considered at stage one. All· quantifiable ·other public interest information as to costs and benefits should be provided at this stage.

The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two.

E.B.O. 188 Discount Rate from Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario

Page 4: a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity;

---

[8] Ontario Energy Board. In the matter of the Ontario Energy Board Act, R.s.o. 1980, Chapter 3321 and in the matter of a Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario. E.B.O 134. Report of the Board. June 1, 1987 http://www.rds.oeb.ca/HPECMWebDrawer/Record/177859/File/document

[9] Guidehouse is also aware that Enbridge Gas described how discount rates would be applied in their proposed cost-effectiveness tests on Page 66-67 of the transcript for the Technical Conference for EB-2020-0091 on February 11, 2021.
Page 66-67 MR. SZYMANSKI: Yes, we are. So stage 1 would represent the utilities' incremental after-tax cost of capital, which – and what we are proposing for stage 2 and stage 3 is to use a societal discount rate, which is the 4 percent.

Page 10: Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied.

Page 11: PV is calculated with an incremental, after-tax discount rate.