ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #1

Ref: [p. 7]

Please confirm that a Stage 2 analysis should, in Enbridge's proposal, include

a. the economic impacts on all customers outside of the new communities of the subsidies they are providing,

b. the economic impacts on the local communities of any subsidies provided by the municipalities,

c. the economic impacts across the province of any provincial funding,

d. the impacts on the Ontario electricity system,

e. quantification of the environmental costs and benefits of the expansion relative to:
   i. Status quo, and
   ii. Other options for provision of energy functionality to the community.

If any of the above are not proposed to be included, please explain why they should be excluded.

RESPONSE

Enbridge is of the view that the Stage 2 benefit test contemplated in EBO 134 limits the benefits to be included in the test to the estimated value of the energy savings that would be achieved by the customers that would be served by the project under consideration. The Company believes that the items noted above would more properly be included in a Stage 3 benefit analysis as contemplated in EBO 134.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #2

Ref: [p. 12]

Attached is a journal article dated April 22, 2014 authored by Professor Robert Howarth of Cornell University. Please advise whether Enbridge agrees with the conclusion of the author that, in addition to carbon dioxide emissions from combustion of natural gas, natural gas upstream and downstream methane emissions are equivalent to 3.8% of conventional gas, and 5.8% of unconventional gas including shale gas. Please advise the forecast mix of conventional vs. unconventional gas in years 10, 20, and 30 of its gas forecasts. Please provide a calculation of equivalent carbon dioxide emissions reflecting the upstream and downstream methane emissions. Please advise the total equivalent carbon dioxide emissions (including CO2 equivalent of methane from upstream and downstream emissions) for each cubic metre of natural gas expected to be burned in the expansion communities.

RESPONSE

Enbridge has reviewed the referenced study and has the following comments. The study by Professor Robert Howarth is based on U.S. data, which may differ from Canadian data. For example, Howarth estimates that the downstream emissions are 2.5%. In the U.S. there is still a large amount of cast iron distribution pipeline, which no longer exists in Canada. This number therefore is likely too high for Canadian natural gas use. Additionally, more recent studies from Environmental Defense Fund ("EDF") in the U.S. have found that distribution emissions were lower than previous studies had estimated, in part due to the efforts by natural gas utilities in upgrades and replacement of equipment as well as due to improved detection and analysis. This also suggests that the downstream emissions may be high even when used for U.S. natural gas use.

The Howarth study also notes that there have been several other studies, which have shown a wide range of values for conventional and unconventional gas.

Enbridge believes additional studies on the life cycle analysis for natural gas in Canada are required and therefore cannot confirm agreement with the findings stated in the article.

Enbridge manages a portfolio of natural gas supply, transportation, and storage assets in order to provide safe, reliable, and cost effective delivery of natural gas to sales service and bundled transportation customers throughout the calendar year. The Company's gas supply plan is based on balancing the principles of reliability, diversity, cost and flexibility. Enbridge conducts its planning process on an annual basis, but the execution of the plan is a dynamic process that requires constant attention and frequent adjustment in response to market developments. In recent years, Enbridge has shifted a portion of its gas supply purchases from the Empress hub in Alberta to supply sources in the northeastern United States and Ontario, such as the Dawn and Niagara hubs. However, the integrated nature of North American natural gas infrastructure complicates distinguishing between the origin of supplies when purchasing at large liquid hubs such as Empress and Dawn. As long as the natural gas meets Enbridge pipeline quality standards, the Company does not attempt to distinguish between conventional or unconventional gas.

Enbridge does not currently have enough data to estimate the upstream emissions for the natural gas that will be supplied to the expansion communities or to determine the project specific net GHG impacts based on the incremental natural gas use and the benefits that may be derived by displacing more carbon intense fuels.

The emissions from the downstream combustion of natural gas in the expansion communities are 0.001875 tonnes CO_2e/m^3, based on the default emission factor for Ontario.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #3

Ref: [p. 12]

Please provide all studies, reports, analyses and other documents or information in the possession of Enbridge dealing in whole or in part with the implications of Ontario's greenhouse gas reduction goals on Enbridge's business, including, without limitation, any estimates of the reductions in natural gas throughput volumes that will be required to meet those goals.

RESPONSE

Attached is the ICF report which Enbridge has used to inform its evolving carbon approach.

Enbridge Gas Distribution and Union Gas

Results from Aligned Cap & Trade Natural Gas Initiatives Analysis

November 2015

Outline

- Review of key assumptions defining Ontario Cap-and-Trade Scenarios
- Aligned Natural Gas Initiatives Assumptions
  - Renewable Natural Gas (RNG)
  - Combined Heat and Power (CHP)
  - Compressed/Liquefied Natural Gas (CNG/LNG)
  - Cap and Trade Energy Conservation (CTEC)
- Emissions Reduction Forecast and Initiatives Results
- Price Elasticity Demand Response
- Summary
- Appendix (separate file): Company-Specific Change in Natural Gas Demand

Assumptions: Cap-and-Trade Policy

- Ontario's cap-and-trade program begins: **January 1, 2017**
- Link with Quebec and California: **January 1, 2018** (linkage not modeled)
- **Free allocation Scenario**: EITE industry and natural gas distributors
- **No free allocation Scenario**: transportation fuel distributors, electricity generators, and natural gas distributors
- **Cap**: -3.2% / year from 2017 to 2020 and -2.3% from 2020 to 2030
- **Offsets**: capped at 8%
- **Price floor**: aligned with Quebec and California (starting at $13 in 2017)
- **Reserve bank**: 3 tiers fixed at $50/$55/$60 in 2017 and increasing annually

Assumptions: Activity Data

Business as usual

- Ontario's provincial forecast of GHG emissions
- Electricity sector aligned with Ontario's Long Term Energy Plan
- UG/EGD forecast of NG demand by customer segment out to 2030
- Beyond current DSM Plans no uptake of NG emission reducing opportunities

Cap-and-Trade Scenarios

- NG: RNG, CHP, CNG/LNG, CTEC
- Non-NG Transport: reduced activity, LCFS, and electrification

Model is populated with UG and EGD activity data and assumptions.

Renewable Natural Gas

- Both UG and EGD provided annual forecast volume of RNG based on the Alberta Innovates (May 2011) Study.
- RNG production estimates derived from: anaerobic digestion (AD) and gasification.
- Introduction of RNG from various methods for AD and gasification sources as they relate to the availability of RNG supplies, the related technology maturity, scale and costs.

*Actual market transformation will significantly depend on evolving policy and technology development support.

- Assumption is Ontario's cap-and-trade regulations permit the sourcing of RNG supplies from outside of provincial boundaries.

RNG Volume and Emissions Reductions Forecast	2017	2018	2019	2020	2021	2022	2023
Ontario Total Volume (million m^3/yr)	19	34	151	267	396	503	947
Ontario Emissions Reductions (Mt CO_2e/yr)	0.04	0.06	0.28	0.50	0.75	0.95	1.79

RNG Volume and Emissions Reductions Forecast	2024	2025	2026	2027	2028	2029	2030
Ontario Total Volume (million m^3/yr)	1,355	1,997	2,546	3,052	3,444	3,837	4,265
Ontario Emissions Reductions (Mt CO_2e/yr)	2.56	3.77	4.81	5.77	6.51	7.25	8.06

Notes: 1) RNG volume and emissions reduction estimates represent cumulative values.
2) Emissions reductions do not include offset volumes associated with RNG, please refer to Assumptions Book for offset potential associated with RNG.

Combined Heat and Power

- CHP growth will total 1000 MW by 2030. Of this total, assume 40% is behind-the-meter CHP and 60% is grid-connected CHP delivering power into the wholesale electricity market.
- Assume a 50:50 market share for UG-EGD franchise areas for both behind-the-meter CHP and grid-connected CHP.

Provincial CHP Cumulative Capacity (Additional to Current Installed Capacity) and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023
Ontario CHP (MW)	42	110	198	344	391	461	508
Ontario Emissions Reductions (Mt CO_2e/yr)	0.05	0.13	0.23	0.39	0.45	0.53	0.58

Provincial CHP Cumulative Capacity (Additional to Current Installed Capacity) and Emissions Reductions	2024	2025	2026	2027	2028	2029	2030
Ontario CHP (MW)	547	641	691	757	857	931	1,000
Ontario Emissions Reductions (Mt CO_2e/yr)	0.62	0.73	0.79	0.86	0.98	1.06	1.14

Combined Heat and Power (continued)

- Calculation methodology from a CHP calculator developed by EGD, based on the principle of coincidence of load, was used.
  - Assumes operating hours of CHP (in both categories) are 100% coincident with the hours of grid-connected gas generation, and additional CHP operating hours are assumed to be coincident with zero-carbon grid generation
  - e.g. CHP operating for 7,500 hours per year displaces gas-fired generation for 7,000 hours in the year, and zero carbon emitting generation (i.e. nuclear, hydro) for 500 hours in the year (i.e. CHP wears full GHG emissions for hours it displaces non-emitting electricity)

Parameter	
Average Efficiency of Gas-fired Grid-connected Power Plants (HHV)	45%
Line Transmission and Distribution Losses	5%
Average Annual Grid-connected Gas Plant Operating Hours	7,000
Boiler Thermal Efficiency (HHV)	78%

Parameter	Behind-the-meter CHP[1]	Grid-connected CHP[2]
Electrical Efficiency	37.5%	48.1%
Heat-to-Power Ratio	1.2	0.8
Average Annual Operating Hours	7,500	4,200
Resulting Total System Efficiency (total power + thermal energy output/fuel consumed)	83%	87%

[1] Efficiency and heat-to-power ratio based on assumption that behind-the-meter CHP is likely to be a mix of small reciprocating engines (e.g. institutional buildings) and gas turbines (e.g. industrial sites with a requirement for steam). Operating hours based on assumption that CHP will run to meet thermal demands of process load or operation of a facility.

[2] Efficiency and heat-to-power ratio from manufacturer specifications for an illustrative large (8.5 MW) reciprocating engine, based on assumption that grid-connected CHP will be designed to maximize electrical power output. Operating hours based on typical operating hours for district energy-connected CHP with seasonal heat load, and the assumption that wholesale CHP runs only when the grid needs the electricity and can be approximated by the same annual operating hours as district energy-connected CHP.

CNG/LNG for Transportation

- EGD and UG provided volume of natural gas consumption based on current fuel consumption per target sector (does not include light-duty vehicles) and NG market capture estimates
  - UG/EGD provincial total assumed to be 50:50 market share
- Analysis uses a 22% emissions reduction factor for displacement of any BAU fuel (diesel, gasoline, fuel oil) with NG

Provincial NG Consumption for Transportation and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023
Marine (million m^3/yr)	-	-	17	35	52	70	87
Rail (million m^3/yr)	-	-	33	65	98	130	163
On-Road Diesel (million m^3/yr)	20	86	216	388	560	862	1,422
On-Road Gasoline (million m^3/yr)	-	31	77	139	201	310	511
Ontario Total Volume (million m^3/yr)	**20**	**117**	**343**	**627**	**912**	**1,372**	**2,184**
Ontario Emissions Reductions (Mt CO_2e/yr)	0.01	0.06	0.18	0.33	0.49	0.73	1.16

Provincial NG Consumption for Transportation and Emissions Reductions	2024	2025	2026	2027	2028	2029	2030
Marine (million m^3/yr)	105	122	140	157	175	192	210
Rail (million m^3/yr)	195	228	260	293	325	342	342
On-Road Diesel (million m^3/yr)	2,241	3,233	3,664	3,879	4,009	4,052	4,095
On-Road Gasoline (million m^3/yr)	806	1,162	1,317	1,395	1,441	1,457	1,472
Ontario Total Volume (million m^3/yr)	**3,347**	**4,745**	**5,381**	**5,724**	**5,950**	**6,042**	**6,118**
Ontario Emissions Reductions (Mt CO_2e/yr)	1.78	2.53	2.87	3.05	3.17	3.22	3.26

LNG for Stationary Combustion (Load Displacement)

- Analysis based on estimate of annual natural gas consumption volume forecasts from 2017 to 2030 agreed on by the EGD/UG working group
  - Forecast corresponds to an approximately 46% market capture by 2030 of 'current' Ontario consumption of relevant stationary fuel types
- Assume that 38% of the total volume displaces propane fuel use, and the remainder displaces diesel and oil use
- Assume that the stationary NG volumes are split 50:50 between Enbridge and Union
- Analysis uses a 22% emissions reduction factor for displacement of stationary diesel and fuel oil with LNG; or 16% emission reduction factor for displacement of propane with LNG

Provincial Stationary LNG Consumption and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023
Ontario Total (million m^3/yr)	64	135	193	250	309	366	421
Ontario Emissions Reductions (Mt CO_2e/yr)	0.04	0.08	0.12	0.15	0.19	0.22	0.26

Provincial Stationary LNG Consumption and Emissions Reductions	2024	2025	2026	2027	2028	2029	2030
Ontario Total (million m^3/yr)	476	532	587	642	697	752	807
Ontario Emissions Reductions (Mt CO_2e/yr)	0.29	0.32	0.36	0.39	0.43	0.46	0.49

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Cap and Trade Energy Conservation

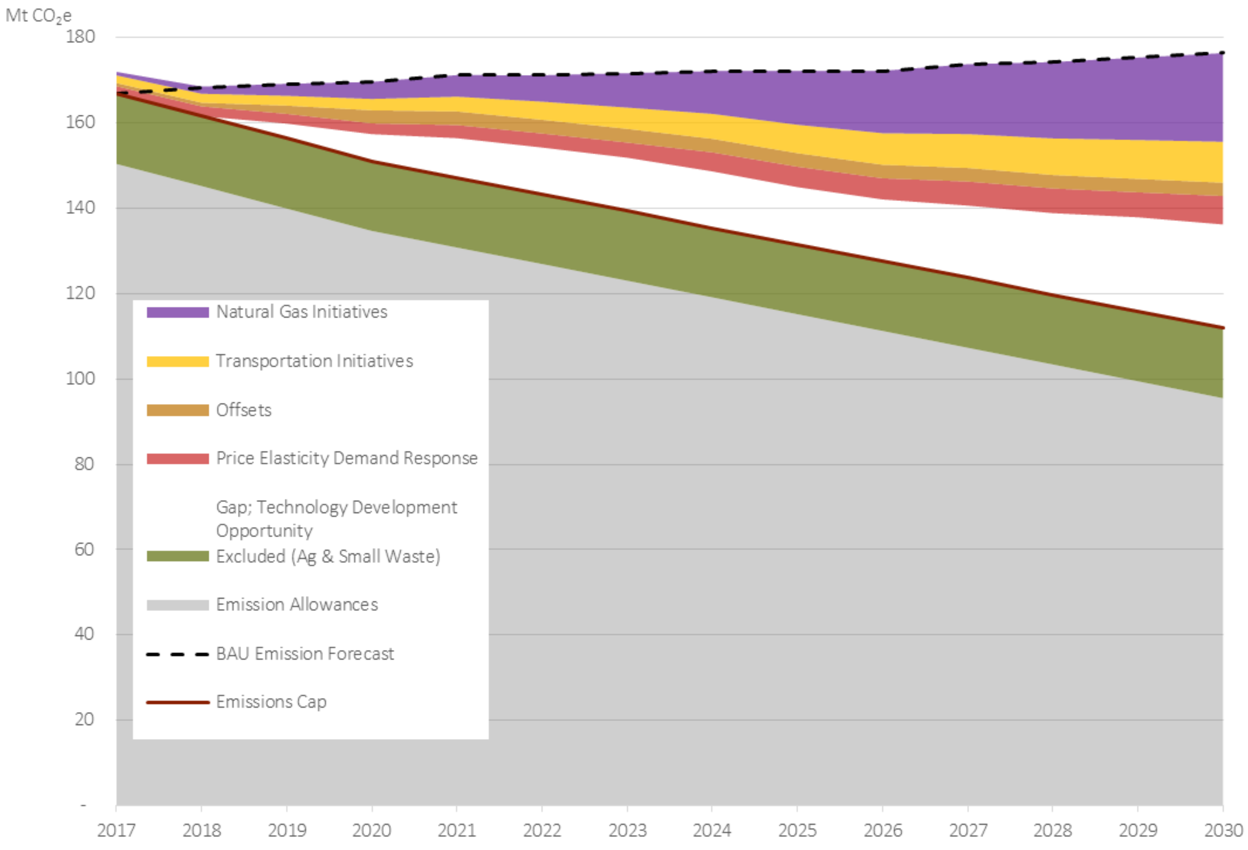
- Cap and trade energy conservation (CTEC) quantification based on aggressive scenarios run by EGD in Navigant DSM model, and translated to UG's franchise by assuming the same proportional increase in budget and savings over the current OEB-approved DSM plan
- UG provided an estimate of additional 'large volumes' savings
- Initiative divided into two 'slices'
  - 'Slice 1' is a medium/constrained scenario corresponding to the highest modelled scenario that would be considered to have a 'reasonable yield' as a traditional DSM program
  - 'Slice 2' is the additional savings obtained in a high scenario, which is a modelled scenario where DSM incentives are set at 100% of capital costs for all currently economic measures. Traditional DSM may not be an effective policy tool to access these savings due to the high cost per m^3 savings.

Provincial CTEC Cumulative Savings and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Medium/Constrained Scenario (Slice 1) (million m^3/yr)	263	513	756	989	1,215	1,432	1,637	1,835	2,033	2,232	2,430	2,628	2,826	3,025
Ontario Emissions Reductions (Mt CO_2e/yr)	0.50	0.97	1.43	1.87	2.30	2.71	3.09	3.47	3.84	4.22	4.59	4.97	5.34	5.72
High Scenario (Slice 1 + Slice 2) (million m^3/yr)	364	714	1,053	1,376	1,688	1,985	2,264	2,533	2,801	3,070	3,338	3,607	3,875	4,144
Ontario Emissions Reductions (Mt CO_2e/yr)	0.69	1.35	1.99	2.60	3.19	3.75	4.28	4.79	5.29	5.80	6.31	6.82	7.32	7.83

Assumptions: Non-NG Transportation Initiatives

- Electrification of light-duty vehicles
  - 1.5 million electric vehicles (EVs) by 2030
  - Assumed rapid penetration of EVs as a result of government incentive
  - 4.1 MWh/year required per EV for annual travel of 20,000 km
  - Non-emitting electricity generation used to power EVs
- Zero Emission Vehicle mandate modelled on the California ZEV mandate, beginning in 2017
- Reduce Vehicle Kilometres travelled, considers potential impact of transit programs incremental to the Big Move
- Low Carbon Fuel Standard modelled on the California LCFS, beginning in 2017 and following the same schedule for increased stringency
  - Accounts for existing renewable fuel mandates in Ontario

Ontario Emissions Reduction Forecast: With Free Allocation to Natural Gas Distributors



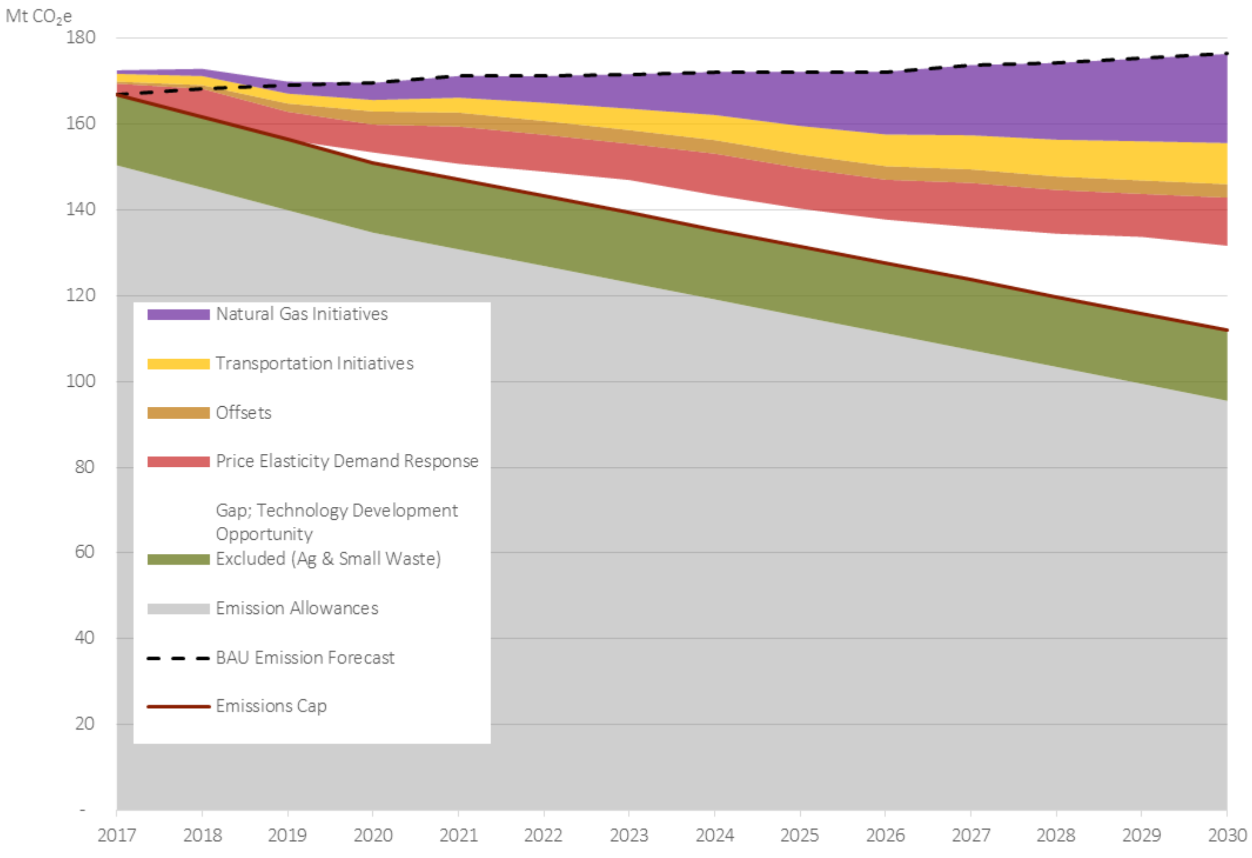
C&T scenario with free allocation informed by UG/EGD activity data and assumptions.

By 2030

- NG related initiatives **reduce emissions by 21 Mt CO_2e**, the largest GHG reduction potential in the study timeframe.
- Non-NG transport initiatives **reduce emissions by 10 Mt CO_2e**.
- Elasticity demand response to increasing fuel prices results in **reductions of 7 Mt CO_2e**.
- Gap; Technology Development Opportunity of **24 Mt CO_2e**

Cumulative allowance shortage of **161 Mt CO_2e** from 2017-2030.

Ontario Emissions Reduction Forecast: No Free Allocation to Natural Gas Distributors



C&T scenario assuming no free allocation informed by UG/EGD activity data and assumptions.

By 2030

- NG related initiatives **reduce emissions by 21 Mt CO_2e**, the largest GHG reduction potential in the study timeframe
- Non-NG transport initiatives **reduce emissions by 10 Mt CO_2e**.
- Elasticity demand response to increasing fuel prices results in **reductions of 11 Mt CO_2e**.
- Gap; Technology Development Opportunity of **20 Mt CO_2e**

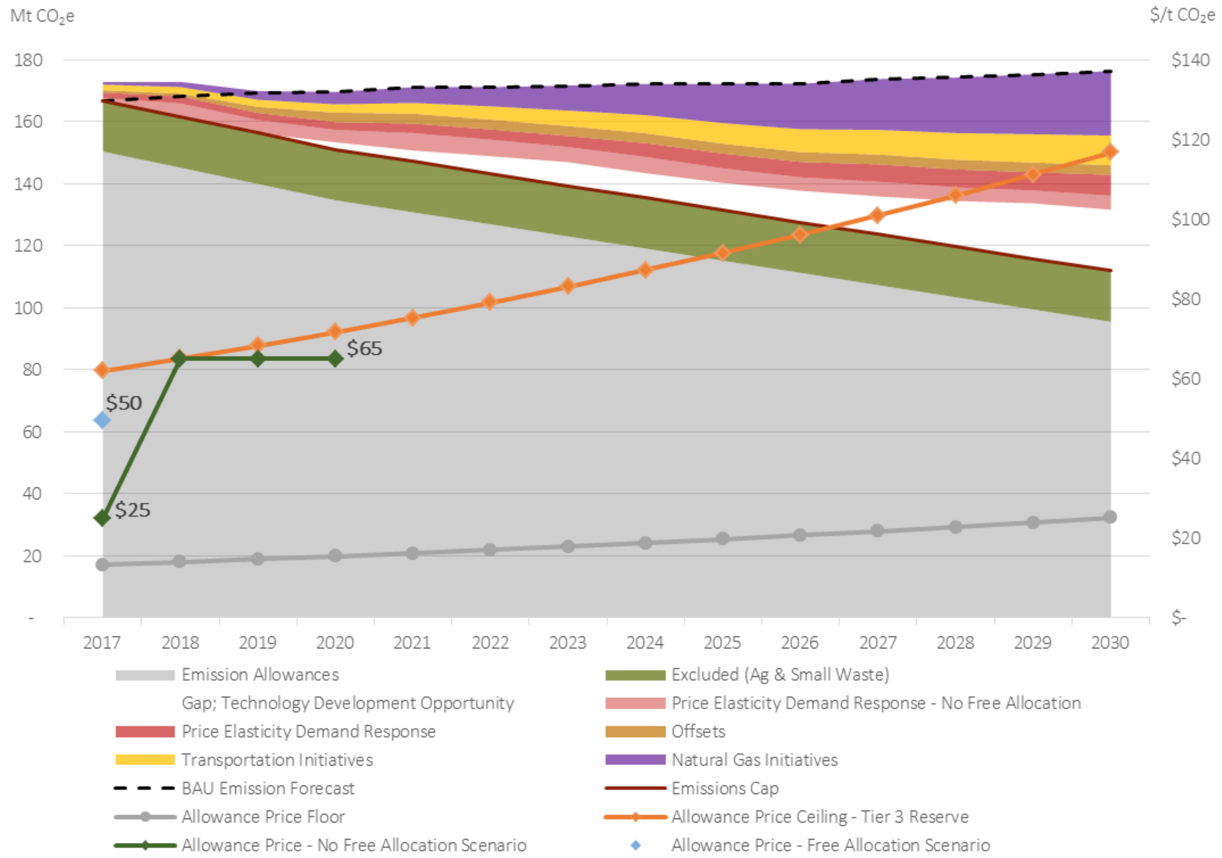
Cumulative allowance shortage of **100 Mt CO_2e** from 2017-2030.

Ontario Emissions Reduction Forecast: Potential for Complementary Initiatives

- Based on modeled results, Ontario cannot meet its GHG reduction objectives solely from within its own domestic market – will need to purchase allowances from other WCI jurisdictions, or close the gap with complementary initiatives targeting technology developments/innovation that achieve deeper GHG reductions (e.g. natural gas heat pumps, etc.).
- Serious consideration should be given to the ensuring auction proceeds are reinvested to achieve maximum emissions reductions for the province.
- It is important to establish complementary initiatives (for example - a natural gas technology fund) early in the cap-and-trade program development process to ensure technology solutions are commercialized early enough to deliver the needed GHG reductions, or cumulative allowance shortages will grow.

Model Output Allowance Price *NOT an allowance price forecast

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CP1	CP2			CP3			CP4			CP5			CP6



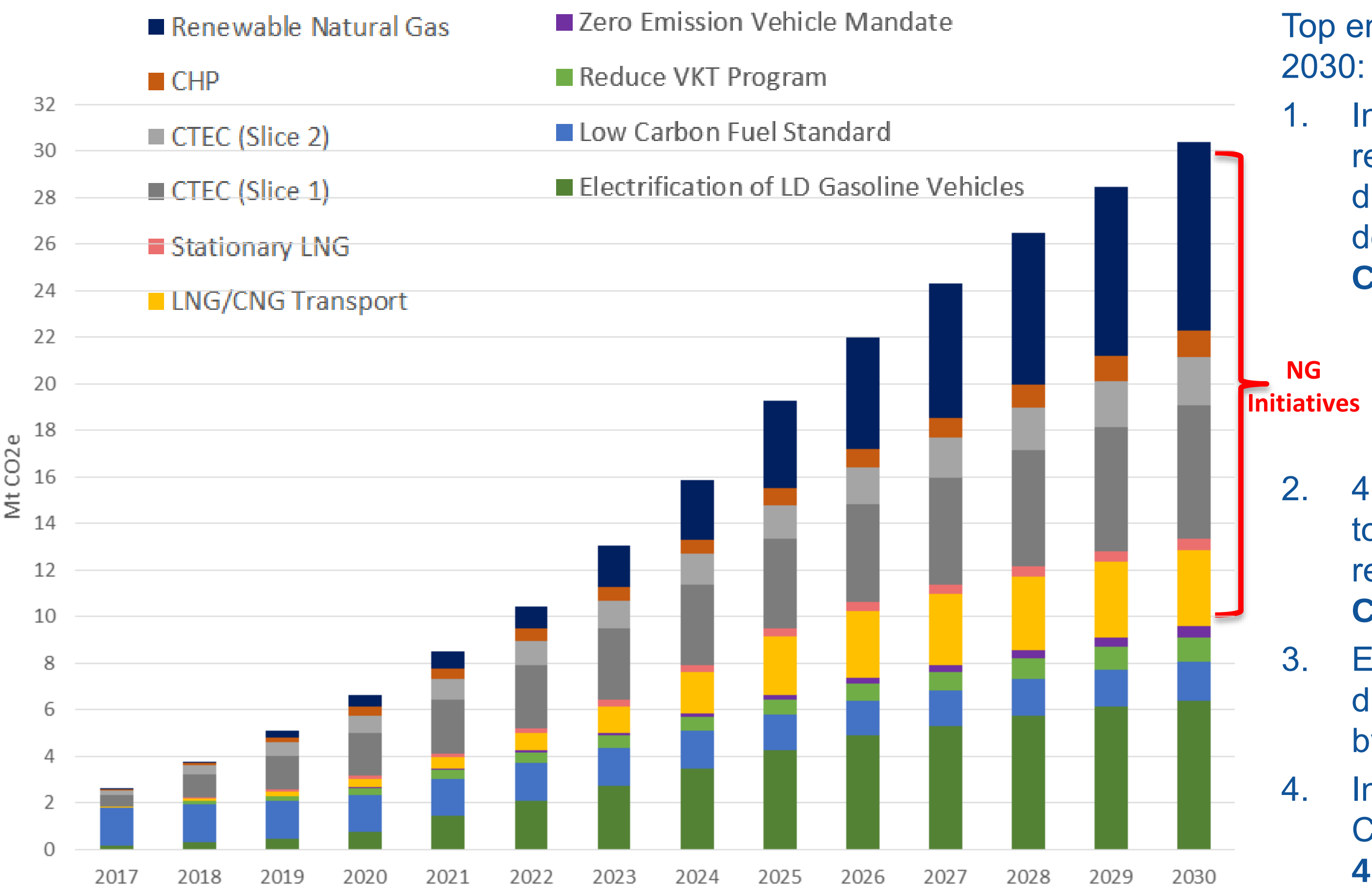
Model Assumptions:

- Ontario in a vacuum
  - No link to QC/CA allowance markets
- Price is solved per WCI compliance period (CP)
- Price is constrained between the WCI floor and ceiling
  - Assume the top tier reserve price is a hard ceiling price for modelling purposes
- If price exceeds ceiling, model stops solving

Model Results:

- The price exceeds ceiling after CP1 or CP2 for the free and no free allocation scenario, respectively
- There are insufficient emission reductions in Ontario to meet the reduction targets within these price constraints

Summary of Aligned Initiatives Results



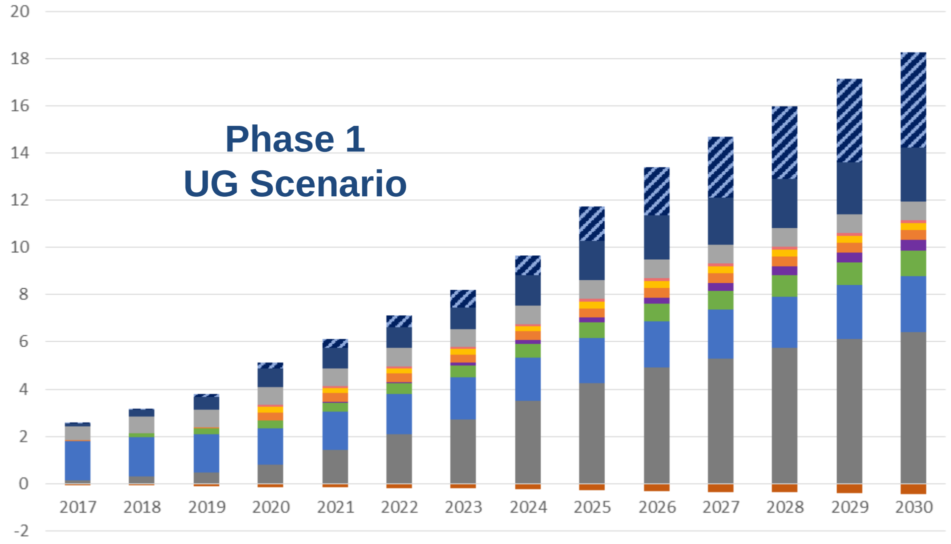
Top emission reduction initiatives in 2030:

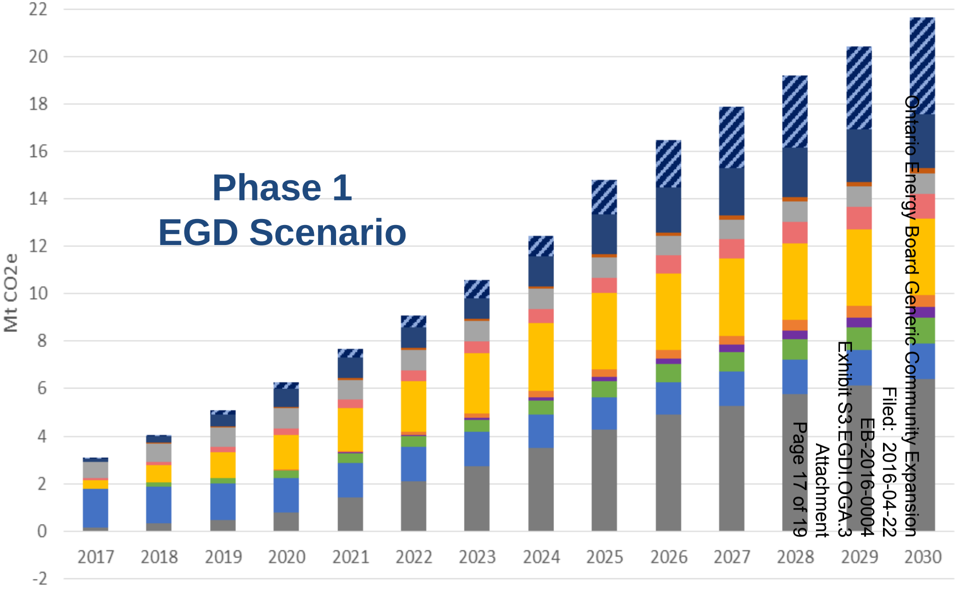
1. In total, NG energy efficiency reduces emissions by **8 Mt CO_2e** due to 4.1 billion m^3 of CTEC demand destruction and **1 Mt CO_2e** due to 1,000 MW of CHP.
   – Highest modelled CTEC scenario with 'reasonable yield' as traditional DSM program (Slice 1) reduces emissions by 6 Mt CO_2e due to 3.0 billion m^3 demand destruction.
2. 4.3 billion m^3 of RNG (~15% of total provincial NG consumption) reduces emissions by **8 Mt CO_2e**.
3. Electrification of 1.5 million light-duty vehicles reduces emissions by **6 Mt CO_2e**.
4. In total, 6.9 billion m^3 of CNG/LNG reduces emissions by **4 Mt CO_2e**.

Previous Initiatives Results

Provincial Totals Year 2030	Phase 1 UG Scenario	Phase 1 EGD Scenario	Phase 2 UG/EGD Aligned Scenario
	Mt (CO_2e)		
RNG	6	6	8
CTEC	1	1	8
LNG/CNG	1	5	4
CHP	-0.5	0.2	1

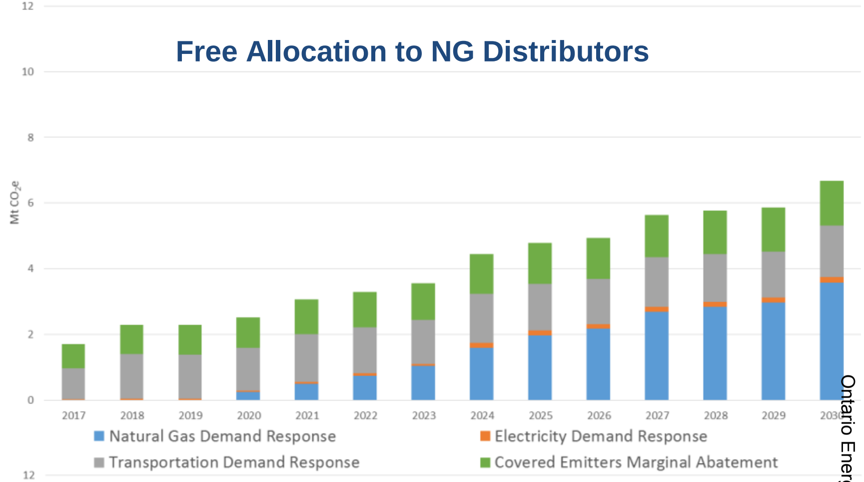
- Renewable Natural Gas - UG
- Renewable Natural Gas - EGD
- CHP
- CTEC (Cap & Trade Energy Conservation)
- Stationary LNG
- Rail & Marine LNG
- CNG in HD Trucks
- Zero Emission Vehicle Mandate
- Reduce VKT Program
- Low Carbon Fuel Standard
- Electrification of LD Gasoline Vehicles

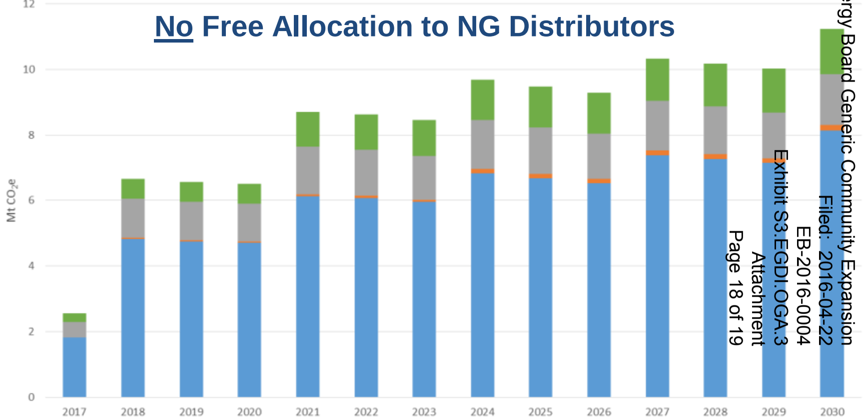




End users respond to high price of allowance / energy by reducing usage

- Price elasticity assumptions informed by **limited available research**.
  - Natural Gas: *The Likely Effect of Carbon Pricing on Energy Consumption in Canada*. Dr. D. Ryan & Noha Abdel Razek, University of Alberta, May 2012.
  - Transportation Fuels & Electricity: ICF expert opinion
- No physical constraint imposed in the model.
  - e.g. in reality, NG demand destruction would be limited by a minimum space heating requirement for Ontario's climate
- Price elasticity applied to prices consumers pay for:
  - Electricity
  - Transportation – light duty gasoline & diesel only
  - Natural Gas – residential, commercial & small industrial sub-sectors
- Industrial marginal abatement costs based on research for industry sector or sub-sector and ICF expert opinions.
  - Adjusted to avoid double counting EE abatement in complementary initiatives
- NG demand destruction would be reduced through free allocation to NG distributors (vs. no free allocation).





Aggressive 2030 targets and C&T policy will reduce demand for NG in Ontario

NG Initiatives (RNG, CNG/LNG, CTEC and CHP) have the potential to maximize Ontario's GHG reductions in the 2017-2030 timeframe, but policy and regulatory support will be key to achieving this potential. NG can contribute broad spectrum and cost-effectively as a foundational fuel to a low carbon economy:

- NG is critical for re-fueling heavy transport.
- RNG (decarbonized CH_4) is critical to leveraging existing energy infrastructure for GHG reductions and as a means of limiting consumer cost-pressures under cap-and-trade. Policy/regulatory support for some new infrastructure required for delivery, but this could be a modest investment compared to alternatives.
- Deeper energy efficiency and conservation understood as contributors to the solution - EGD/UG delivery of programs necessary for success.
- CHP efficiency benefits are well understood, and represent the most efficient use of NG for power generation in the near-term, and the use of RNG in the future.

However, there are caveats:

- NG for transport requires thinking through the role of NG Distributors in establishing the refueling infrastructure required to achieve early market adoption.
- RNG potential availability: EGD and UG are relying on preliminary market assessments. Policy/regulatory signals are needed to prioritize this before the understanding of market and technology potential can improve.
- Deeper energy efficiency and conservation must be considered beyond the lens of traditional DSM programs (complicated by OEB mandate).
- CHP may be the victim of unintended consequences in cap-and-trade design.

Short term (2017-2030):

- Opportunity for UG/EGD: price (vs. electricity) and infrastructure.
- Challenge for UG/EGD: regulator mandate, rate design considerations, money and time to deploy new infrastructure vs. 2030 target.
- NG demand destruction limited by minimum space heating needs and consumer resistance (cost) to electrifying building heating. Early start on NG technology innovation needed as an energy cost control measure, and as a means of preserving low-carbon electricity for electrification of light-duty transportation.

Long term (2030-2050):

- Demand destruction vs. BAU is inevitable. Technology innovation and green gas supplies needed for the economy to have access to cost-effective energy by pipeline.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
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INTERROGATORY #4

Ref: [p. 12]

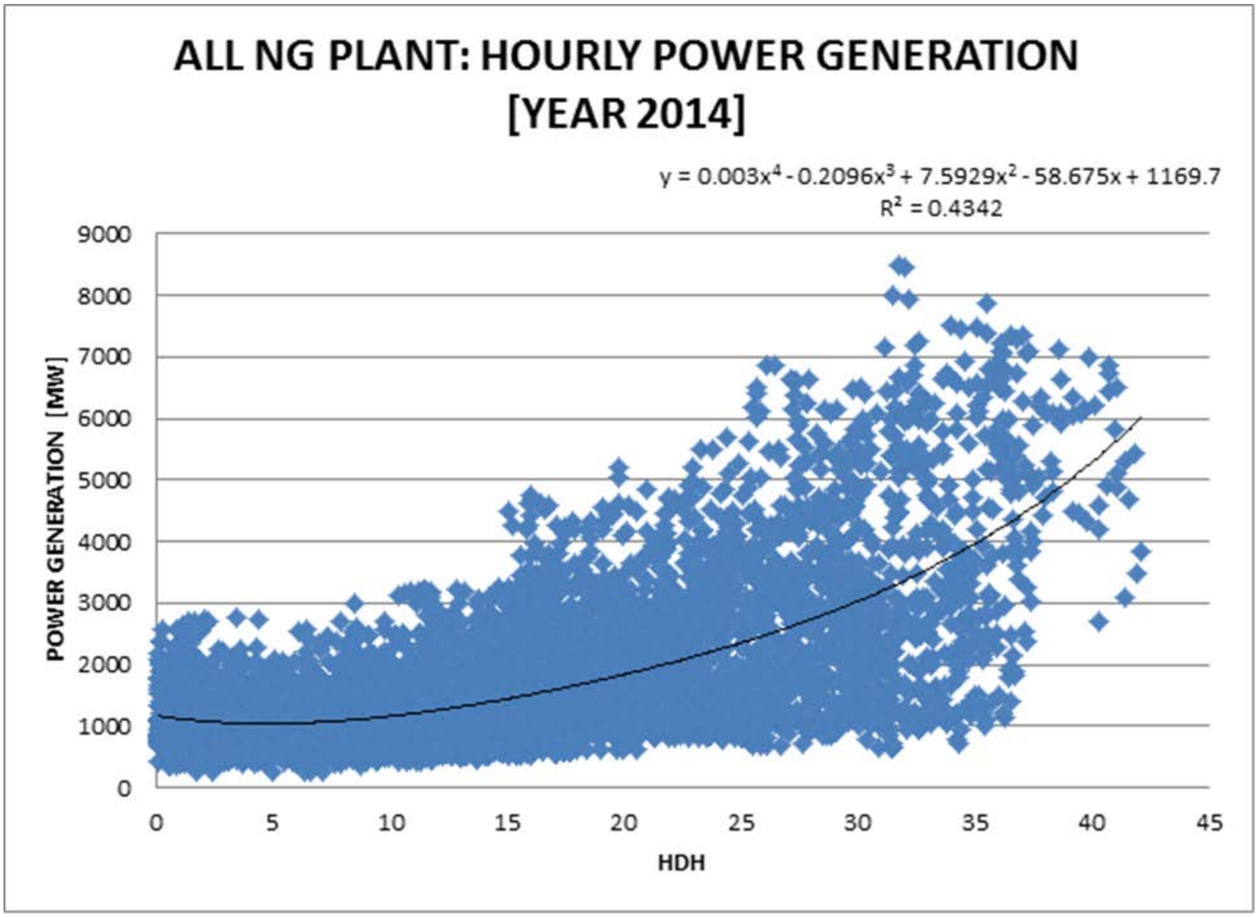
Please confirm that, in most communities in Ontario, the timing of the load for electric heating and water heating is not consistent with natural gas being the marginal electricity generation fuel at those times.

RESPONSE

Enbridge does not agree that in Ontario the timing of the load for electric heating and water heating is not consistent with natural gas being the marginal electricity generation fuel at those times.

Historic hourly generating data from all natural gas fired generation plants published by the IESO can be compared to the associated outdoor hourly temperature which indicates a statistical relationship between natural gas consumption and outdoor temperature. The relationship indicates that as outdoor temperatures decrease (or space heating increases) natural gas consumption increases. In fact the generation data from the IESO supports the assumption that natural gas is the fuel used for marginal electric generation during hours when space heating is in demand.

The following is a graph of the electric power generated from IESO controlled natural gas generation plants only for 2014 compared to outdoor temperature (Toronto) converted to Heating Degree Hours based on a 18 C balance point. The data shows a clear positive relationship between outdoor temperature and natural gas driven power generation.


ALL NG PLANT: HOURLY POWER GENERATION
[YEAR 2014]
y = 0.003x4 - 0.2096x3 + 7.5929x2 - 58.675x + 1169.7
R2 = 0.4342
POWER GENERATION [MW]
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
0
5
10
15
20
25
30
35
40
45
HDH

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
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INTERROGATORY #5

Ref: [p. 12]

Please advise whether Enbridge agrees that the Board's decision with respect to community expansion policies should be consistent with the provincial government's published climate change strategy.

RESPONSE

Enbridge agrees that the Board's decision with respect to community expansion policies should be consistent with the government's climate change strategy, as well as Enbridge's commitment to "develop new natural gas programs to improve access, which will generate economic activity, attract significant investment, create jobs, and break down barriers in our communities".

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #6
Ref: [p. 15]

Please provide detailed calculations, with sources, for the annual average energy cost savings of $1,700 and the average cost of conversion of $3,500.

RESPONSE

Please see the Company's response to CCC Interrogatory #8 at Exhibit S3.EGDI.CCC.8.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #7

Ref: [p. 15]

Please add ground source heat pumps to Table 1.

RESPONSE

Electric End Use Application	Energy Vector	Penetration	Heating Bill	Savings	Estimated Conversion Costs	Payback Period (Years)
Mix of Forced Air Furnace and Baseboards Electric heating	Electricity	18%	$3,114	$2,165	$7,250	4.5
Existing Electric Ground Source Heat Pumps (est. avg. COP 3.0)	Electricity	Unknown	$1,038	$89	$7,750	87

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #8

Ref: [p. 19]

Please provide the full PI calculations for each of the ten largest Enbridge projects. Please include in the response the customer class breakdown for each of the communities, the assumptions with respect to conversion rates, and all other assumptions necessary to review the PI calculations.

RESPONSE

Please see the table below containing the requested information.

		Potential Customers			Forecast Customers [1]				DCF Analysis [3]	
	Community	Conversion	New	Total	Conversion	New	Total	Capital Investment [2]	NPV	PI
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
1	Fenelon Falls & Bobcaygeon	3,029	3,213	6,242	2,272	3,213	5,485	$ 111,956,990	$ (30,565,620)	0.70
2	Halliburton (Dysart)	2,035	0	2,035	1,526	0	1,526	$ 37,161,620	$ (18,073,815)	0.47
3	Minden	1,414	0	1,414	1,061	0	1,061	$ 26,418,325	$ (13,124,492)	0.46
4	Scugog Island	1,177	291	1,468	883	291	1,174	$ 19,714,126	$ (8,280,687)	0.58
5	Kirkfield	800	0	800	600	0	600	$ 15,604,747	$ (8,062,857)	0.44
6	Eganville	700	0	700	525	0	525	$ 14,063,487	$ (7,435,393)	0.43
7	Barry's Bay	500	0	500	375	0	375	$ 10,761,872	$ (5,984,185)	0.41
8	Kinburn/Fitzroy Harbour	500	0	500	375	0	375	$ 10,588,874	$ (5,829,203)	0.41
9	Village of Lisle	400	0	400	300	0	300	$ 9,966,800	$ (6,594,427)	0.34
10	Udora	400	0	400	300	0	300	$ 8,842,300	$ (5,587,035)	0.37

Notes and assumptions

1	For assumptions around conversion rates, please see EGD's response to S3.EP.7; Customer class breakdown is available in S3.SEC.18
2	Capital investment includes cost of transmission line, distribution line, stations, services and/or natural gas storage and regasification equipment where applicable. These estimates also include an allowance for incremental overheads and "Normailzed Reinforcement" cost as per EBO 188
3	"Discounted Cash Flow (DCF)" analysis is based on the common elements and parameter prescribed in EBO 188, Appendix B, Section 2.1 and 2.2: Specific parameters include: 1) a customer attachment Horizon of 10 years; 2) a revenue horizon 40 year for general service customers and 20 years for industrial customers; discount rate used is EGD's after tax WACC

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #9

Ref: [p. 19]

For all of the Enbridge projects in aggregate, please provide the total cost, the number of customers by year by rate class, the total revenues by year, the incremental throughput by year, the incremental operating costs by year, and the forecast cost of carbon by year.

RESPONSE

	Units	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
Capital cost	($million)	$50.2	$51.2	$44.2	$43.7	$29.6	$28.7	$48.9	$111.6	$1.4	$1.2
Customers											
-Residential	numbers	1,219	1,259	1,508	1,786	1,400	1,330	2,153	4,343	228	214
-Commercial/Industrial	numbers	74	121	93	84	51	54	95	220	8	6
Throughput	(10^3 m^3)	2,241	7,264	12,884	18,665	23,727	27,900	33,038	42,465	49,140	49,781
Revenue	($million)	0.80	2.58	4.58	6.66	8.52	10.07	12.00	15.57	18.11	18.35
O&M	($million)	(0.05)	(0.16)	(0.27)	(0.40)	(0.52)	(0.62)	(0.75)	(1.00)	(1.18)	(1.19)
Forecast cost of carbon	($million)	(0.07)	(0.24)	(0.43)	(0.62)	(0.78)	(0.92)	(1.09)	(1.40)	(1.62)	(1.64)

*Cost of carbon at $0.033/m^3. This cost reflects the estimated allowance purchases required for the incremental natural gas consumption, but does not reflect the net impact from switching from higher carbon emitting fuels.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #10

Ref: [p. 20]

Please explain how and to what extent Enbridge believes the Board's rules with respect to DSM should be applicable to uneconomic community expansions.

RESPONSE

Despite obvious differences in the nature of DSM and community expansion, both initiatives serve the public interest. In both cases it is Enbridge's view that a modest increase to customer rates justifies the net economic benefits to society. In defining its objectives for the proposed community expansion portfolio, Enbridge considered broad guidance on what might constitute a reasonable increase to rates. The Company felt the OEB's guidance in EB-2015-0029/0049 provided appropriate direction in this regard.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #11

Ref: [p. 25]

Please recalculate Tables 4 through 6 to include in the PI for each project a) the cost of all related reinforcements, and b) the cost of carbon.

RESPONSE

a) Please see the Company's responses to FRPO Interrogatories #9 and 10 at Exhibits S3.EGDI.FRPO.9 and 10.

b) The cost of carbon is assumed to be a pass-through item for feasibility and as such would not result in a change to the table.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #12

Ref: [p. 29]

Please provide details of what subsidies are included, and what subsidies are not included, in each of the columns relating to subsidies.

RESPONSE

With respect to Table 6 of the Company's evidence:

- Column 7 sets out the annual total subsidy amount that would be provided by all Enbridge customers in support of the Company's proposal if all of the thirty-nine projects were served through the construction of gas distribution mains.
- Column 10 sets out the annual total subsidy amount that would be provided by all Enbridge customers in support of the Company's proposal if all of the thirty-nine projects were served through the construction of LNG gas regasification and injection plants instead of gas distribution mains.
- Column 11 sets out the estimated annual subsidy amount that would be required to cover the extra cost of LNG supplies over traditional gas supplies assuming all thirty-nine projects were served through the construction of LNG gas regasification and injection plants instead of gas distribution mains.
- Column 12 sets out the sum of the figures shown in columns 10 and 11, being the total annual subsidy amount that would be required assuming all thirty-nine projects were served through the construction of LNG gas regasification and injection plants instead of gas distribution mains.
- Column 13 sets out the difference between Column 7 (the total subsidy amount that would be provided by all Enbridge customers in support of the Company's proposal if all of the thirty-nine projects were served through the construction of gas distribution mains) and Column 12 (the total annual subsidy amount that would be required assuming all thirty-nine projects were served through the construction of LNG gas regasification and injection plants instead of gas distribution mains). Negative values in this column indicate that a lower subsidy amount is required when service for all thirty-nine communities is provided by gas transmission mains. Positive values in this column indicate that LNG would provide an overall more economical supply option.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #13

Ref: [p. 30]

Please confirm that Table 7 does not include subsidies, tax increment relief, contributions in aid of construction, or any other such amounts (e.g. no SES, ITE or CIAC). If any such amounts are included, please restate Table 7 with no such amounts.

RESPONSE

Table 7 does include SES and ITE. Please see revised Table 7, after excluding SES and ITE.

Typical RPP	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
(Recent 3 years' average)	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)
Inflow	111	111	111	111	111	111	111	111
Outflow	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(71)
NPV	40	40	40	40	40	40	40	40
PI	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
Cash Flow of 39 Projects								
Inflow	45	7	4	5	4	7	13	25
Outflow	(154)	(34)	(22)	(28)	(25)	(41)	(49)	(115)
NPV	(109)	(28)	(18)	(23)	(21)	(34)	(35)	(90)
PI	0.29	0.19	0.20	0.18	0.17	0.17	0.28	0.22
Impact on RPP								
Inflow	156	118	115	116	115	118	124	136
Outflow	(225)	(105)	(93)	(99)	(96)	(112)	(120)	(186)
NPV	(69)	12	22	17	19	6	5	(50)
PI	0.69	1.12	1.24	1.17	1.20	1.06	1.04	0.73

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF OGA

INTERROGATORY #14

Ref: [p. 31]

Please provide the full calculations behind Table 10. Please in addition provide the full calculation of the figure of $351 million, and the calculation of the reduction due to cap and trade.

RESPONSE

Please note that Table 10 has been updated due to minor revisions of the Stage 2 calculations. The attached files contain the full calculations behind Table 10. Attachment 1 provides calculations of Stage 1 NPV and Attachment 2 provides full calculations of Stage 2 benefits after incorporating Cap and Trade costs. Please note that as a result of this revision Stage 2 NPV has changed to $338 million in lieu of $351 million.

Page 33 of Enbridge Gas Distribution’s evidence has also been revised to reflect these revisions and is being attached as Attachment 3.

Stage 2 Benefit Calculations

Inputs			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Customers																				
Residential			1,219	1,221	1,191	1,151	765	854	1,678	4,064	69	55								
Commercial			73	80	93	84	51	54	95	220	8	6								
LV Commercial			1																	
Total			1,292	1,301	1,284	1,235	816	908	1,772	4,284	77	61								
Volumes (cumulative) 10^3 m^3																				
Residential			1,463	4,391	7,284	10,095	12,394	14,337	17,375	24,264	29,223	29,372	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438
Commercial			393	1,545	3,333	5,161	6,400	7,297	8,256	9,889	11,079	11,189	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239
LV Commercial			385	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770
Total Volume			2,241	6,706	11,387	16,026	19,564	22,404	26,401	34,923	41,073	41,331	41,447	41,447	41,447	41,447	41,447	41,447	41,447	41,447
Fuel Prices per equivalent energy content																				
Rate 1																				
Natural Gas	$/m3		0.42	0.41	0.42	0.44	0.44	0.45	0.46	0.46	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Heating Oil	$/m3		1.11	1.20	1.25	1.31	1.37	1.39	1.42	1.45	1.47	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Propane	$/m3		0.83	0.84	0.93	0.94	0.99	1.03	1.05	1.06	1.08	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Electricity	$/m3		1.25	1.27	1.33	1.32	1.35	1.40	1.44	1.41	1.43	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Rate 6																				
Natural Gas	$/m3		0.35	0.34	0.35	0.36	0.37	0.38	0.39	0.39	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Heating Oil	$/m3		0.80	0.86	0.90	0.94	0.98	1.00	1.02	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
Propane	$/m3		0.70	0.71	0.79	0.80	0.84	0.87	0.89	0.90	0.92	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Electricity	$/m3		1.24	1.27	1.32	1.32	1.35	1.39	1.44	1.40	1.42	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44
Energy Cost Savings ($000)			**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Residential																				
Natural Gas			615	1,817	3,094	4,393	5,503	6,478	7,948	11,255	13,711	13,901	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932
Alternative fuels		split																		
Heating Oil		31%	544	1,711	2,952	4,252	5,433	6,412	7,916	11,277	13,741	14,051	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082
Propane		49%	652	1,920	3,484	4,900	6,267	7,514	9,281	13,230	16,082	16,444	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479
Electricity		20%	360	1,105	1,925	2,649	3,328	3,978	4,975	6,762	8,287	8,461	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480
			1,556	4,735	8,361	11,801	15,028	17,903	22,172	31,269	38,110	38,956	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041
Residential savings vs. other fuels			941	2,918	5,267	7,408	9,525	11,425	14,223	20,014	24,399	25,055	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109
Commercial																				
Natural Gas			143	541	1,189	1,888	2,394	2,785	3,196	3,889	4,415	4,504	4,524	4,524	4,524	4,524	4,524	4,524	4,524	4,524
Alternative fuels		split																		
Heating Oil		31%	406	1,077	1,628	2,233	2,710	3,046	3,405	3,994	4,458	4,575	4,592	4,592	4,592	4,592	4,592	4,592	4,592	4,592
Propane		49%	136	539	1,288	2,031	2,635	3,119	3,594	4,383	4,996	5,136	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159
Eletricity		20%	98	391	883	1,359	1,723	2,029	2,370	2,765	3,147	3,229	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243
			639	2,007	3,799	5,623	7,068	8,195	9,369	11,143	12,602	12,940	12,994	12,994	12,994	12,994	12,994	12,994	12,994	12,994
Commercial savings vs. other fuels			496	1,466	2,610	3,735	4,674	5,409	6,172	7,254	8,187	8,436	8,470	8,470	8,470	8,470	8,470	8,470	8,470	8,470
Conversion Costs ($000)			**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Residential																				
from	$/customer																			
Heating Oil	$	3,500	1,323	1,325	1,292	1,249	830	926	1,820	4,409	75	60	-	-	-	-	-	-	-	-
Propane	$	1,525	911	912	890	860	572	638	1,254	3,037	52	41	-	-	-	-	-	-	-	-
Electricity	$	7,250	1,768	1,770	1,726	1,669	1,109	1,238	2,432	5,892	100	80								
			4,001	4,007	3,908	3,779	2,511	2,803	5,506	13,338	226	181	-	-	-	-	-	-	-	-
Commercial																				
from	$/customer																			
Heating Oil	$	3,500	79	86	101	91	55	59	103	239	9	7	-	-	-	-	-	-	-	-
Propane	$	1,525	54	59	69	63	38	41	71	164	6	4	-	-	-	-	-	-	-	-
LV	$	50,000	50	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
Electricity	$	7,250	105	115	135	121	74	79	137	319	12	9								
			289	261	305	275	167	178	310	722	26	20	-	-	-	-	-	-	-	-
Total Conversion cost			4,290	4,269	4,213	4,054	2,678	2,981	5,816	14,060	253	200	-	-	-	-	-	-	-	-

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056
29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438	29,438
11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239	11,239
770	770	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41,447	41,447	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677	40,677
0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44
2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**
13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932	13,932
14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082	14,082
16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479	16,479
8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480	8,480
39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041	39,041
25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109	25,109
4,524	4,524	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511	4,511
4,592	4,592	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761
5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159	5,159
3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243	3,243
12,994	12,994	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163	12,163
8,470	8,470	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652
2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Stage 2 - Societal Benefits ($000)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy cost saving	1,438	4,385	7,877	11,143	14,199	16,834	20,396	27,268	32,585	33,490	33,579	33,579	33,579	33,579	33,579	33,579	33,579	33,579
Community Expansion Surcharge (SES)	(516)	(1,542)	(2,619)	(3,686)	(4,500)	(5,153)	(6,072)	(8,032)	(9,447)	(9,506)	(9,533)	(9,533)	(9,533)	(9,533)	(9,533)	(9,533)	(9,533)	(9,533)
Conversion Cost	(4,290)	(4,269)	(4,213)	(4,054)	(2,678)	(2,981)	(5,816)	(14,060)	(253)	(200)	-	-	-	-	-	-	-	-
Stage 2 Benefits net of Cost	(3,368)	(1,426)	1,045	3,403	7,021	8,700	8,507	5,175	22,886	23,784	24,046	24,046	24,046	24,046	24,046	24,046	24,046	24,046

NPV of Stage 2 Benefits

	Total NPV		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Discount Factor @ 4%		1.0000	0.9806	0.9429	0.9066	0.8717	0.8382	0.8060	0.7750	0.7452	0.7165	0.6889	0.6624	0.6370	0.6125	0.5889	0.5663	0.5445	0.5235	0.5034
PV of Energy cost saving net of SES	$373,338,860		904	2,680	4,767	6,500	8,130	9,415	11,100	14,333	16,579	16,524	15,929	15,316	14,727	14,161	13,616	13,092	12,589	12,105
PV of Conversion Cost	($35,535,433)		(4,207)	(4,025)	(3,819)	(3,534)	(2,245)	(2,403)	(4,507)	(10,477)	(181)	(138)	-	-	-	-	-	-	-	-
NPV of Stage 2 Benefits	$337,803,427		(3,302)	(1,345)	948	2,967	5,885	7,012	6,593	3,856	16,398	16,386	15,929	15,316	14,727	14,161	13,616	13,092	12,589	12,105

Residential bill Inc/(dec) due to Cap and Trade

				2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Heating Oil	$	107.75	31%	40,720	81,500	121,267	159,723	185,276	213,798	269,830	405,568	407,873	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710
Propane	$	96.85	49%	57,852	115,791	172,289	226,926	263,230	303,752	383,361	576,209	579,484	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094
Electrcity	$	(24.00)	20%	(5,852)	(11,712)	(17,426)	(22,952)	(26,624)	(30,723)	(38,775)	(58,281)	(58,612)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)

An additional Cap & Trade cost at 3.3 cents per m3 has been added to natural gas price forecast

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056
33,579	33,579	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760	32,760
(9,533)	(9,533)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)	(9,356)
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24,046	24,046	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405	23,405
0.4840	0.4654	0.4475	0.4303	0.4138	0.3978	0.3825	0.3678	0.3537	0.3401	0.3270	0.3144	0.3023	0.2907	0.2795	0.2688	0.2584	0.2485	0.2389	0.2297	0.2209	0.2124

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056
11,639	11,191	10,474	10,071	9,684	9,311	8,953	8,609	8,278	7,959	7,653	7,359	7,076	6,804	6,542	6,290	6,049	5,816	5,592	5,377	5,170	4,971
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11,639	11,191	10,474	10,071	9,684	9,311	8,953	8,609	8,278	7,959	7,653	7,359	7,076	6,804	6,542	6,290	6,049	5,816	5,592	5,377	5,170	4,971

409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710	409,710
582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094	582,094
(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)	(58,876)

Stage 1 Benefits: DCF Analysis

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Line No.	Description	Year 0	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Discount factors to project outset	1.0000	0.9806	0.9429	0.9066	0.8717	0.8382	0.8060	0.7750	0.7452	0.7165
	INCREMENTAL CAPITAL INVESTMENT										
1.	Net Investment Capital	(50,162,396)	(51,243,374)	(44,151,351)	(43,749,132)	(29,615,809)	(28,675,095)	(48,858,816)	(111,603,760)	(1,418,362)	(1,247,851)
2.	Working Capital	-	2,810	2,643	2,985	3,474	2,680	2,570	4,235	8,677	437
3.	Total Investment	(50,162,396)	(51,240,564)	(44,148,708)	(43,746,147)	(29,612,335)	(28,672,415)	(48,856,246)	(111,599,525)	(1,409,685)	(1,247,414)
4.	PV Of Total Investment At Project Outset	(50,162,396)	(50,245,507)	(41,626,318)	(39,660,343)	(25,814,039)	(24,033,346)	(39,376,465)	(86,485,966)	(1,050,442)	(893,773)
5.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(359,348,316)									
	CCA TAX SHIELD										
6.	CCA Tax Shield		396,063	1,174,017	1,858,954	2,444,305	2,880,258	3,170,855	3,596,998	4,656,856	5,275,970
7.	PV Of CCA Tax Shield At Project Outset		388,371	1,106,940	1,685,331	2,130,780	2,414,245	2,555,601	2,787,555	3,470,106	3,780,236
8.	**ACCUMULATED PV OF CCA TAX SHIELD**	56,073,607									
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
9.	Gas Distribution Revenue		830,244	2,693,954	4,787,324	6,972,375	8,919,982	10,537,537	12,558,193	16,302,720	18,952,958
10.	Gas Costs		(33,229)	(113,615)	(209,613)	(309,784)	(398,459)	(471,883)	(562,682)	(729,609)	(847,718)
11.	O&M Expenses		(53,446)	(160,222)	(272,933)	(400,374)	(520,503)	(622,550)	(753,985)	(1,002,347)	(1,177,704)
12.	Net Operating Cash (Before Taxes)		743,569	2,420,117	4,304,778	6,262,217	8,001,020	9,443,104	11,241,526	14,570,764	16,927,536
13.	PV of Net Operating Cash (Before Taxes) At Project Outset		729,129	2,281,847	3,902,720	5,458,979	6,706,491	7,610,819	8,711,814	10,857,561	12,128,591
14.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	274,688,698									
	TAXES										
15.	Income Tax (Before Interest Tax Shield)		(197,046)	(641,331)	(1,140,766)	(1,659,487)	(2,120,270)	(2,502,423)	(2,979,005)	(3,861,252)	(4,485,797)
16.	Municipal Tax		-	-	-	-	-	-	-	-	-
17.	Total Taxes		(197,046)	(641,331)	(1,140,766)	(1,659,487)	(2,120,270)	(2,502,423)	(2,979,005)	(3,861,252)	(4,485,797)
18.	PV of Total Taxes At Project Outset		(193,219)	(604,689)	(1,034,221)	(1,446,629)	(1,777,220)	(2,016,867)	(2,308,631)	(2,877,254)	(3,214,077)
19.	**ACCUMULATED PV OF TOTAL TAXES**	(94,116,966)									
	ACCUMULATED NPV AND PI										
20.	Net Present Value (STAGE 1 NPV)	(122,702,977)									

Stage 1 Benefits: DCF Analysis

Line No.	Col. 1 Description	Col. 12 2026	Col. 13 2027	Col. 14 2028	Col. 15 2029	Col. 16 2030	Col. 17 2031	Col. 18 2032	Col. 19 2033	Col. 20 2034	Col. 21 2035	Col. 22 2036	Col. 23 2037
	Discount factors to project outset	0.6889	0.6624	0.6370	0.6125	0.5889	0.5663	0.5445	0.5235	0.5034	0.4840	0.4654	0.4475
	INCREMENTAL CAPITAL INVESTMENT												
1.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-	-	-
2.	Working Capital	403	-	-	-	-	-	-	-	-	-	-	
3.	Total Investment	403	-	-	-	-	-	-	-	-	-	-	
4.	PV Of Total Investment At Project Outset	278	-	-	-	-	-	-	-	-	-	-	-
5.	**ACCUMULATED PV OF TOTAL INVESTMENT**												
	CCA TAX SHIELD												
6.	CCA Tax Shield	4,980,608	4,691,692	4,410,191	4,145,579	3,896,845	3,663,034	3,443,252	3,236,657	3,042,457	2,859,910	2,688,315	2,527,016
7.	PV Of CCA Tax Shield At Project Outset	3,431,355	3,107,989	2,809,144	2,539,034	2,294,896	2,074,233	1,874,787	1,694,519	1,531,585	1,384,317	1,251,210	1,130,901
8.	**ACCUMULATED PV OF CCA TAX SHIELD**												
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)												
9.	Gas Distribution Revenue	19,204,960	19,325,690	19,325,690	19,325,690	19,325,690	19,325,690	19,325,690	19,325,690	19,325,690	19,325,690	19,325,690	19,134,437
10.	Gas Costs	(859,060)	(864,501)	(864,501)	(864,501)	(864,501)	(864,501)	(864,501)	(864,501)	(864,501)	(864,501)	(864,501)	(863,402)
11.	O&M Expenses	(1,193,960)	(1,201,763)	(1,201,763)	(1,201,763)	(1,201,763)	(1,201,763)	(1,201,763)	(1,201,763)	(1,201,763)	(1,201,763)	(1,201,763)	(1,190,476)
12.	Net Operating Cash (Before Taxes)	17,151,940	17,259,425	17,259,425	17,259,425	17,259,425	17,259,425	17,259,425	17,259,425	17,259,425	17,259,425	17,259,425	17,080,559
13.	PV of Net Operating Cash (Before Taxes) At Project Outset	11,816,708	11,433,423	10,993,676	10,570,842	10,164,271	9,773,338	9,397,440	9,036,000	8,688,462	8,354,290	8,032,971	7,643,964
14.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**												
	TAXES												
15.	Income Tax (Before Interest Tax Shield)	(4,545,264)	(3,928,380)	(3,928,380)	(3,928,380)	(3,928,380)	(3,928,380)	(3,928,380)	(3,928,380)	(3,928,380)	(3,928,380)	(3,928,380)	(3,880,981)
16.	Municipal Tax	-	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)
17.	Total Taxes	(4,545,264)	(6,363,730)	(6,363,730)	(6,363,730)	(6,363,730)	(6,363,730)	(6,363,730)	(6,363,730)	(6,363,730)	(6,363,730)	(6,363,730)	(6,316,330)
18.	PV of Total Taxes At Project Outset	(3,131,428)	(4,215,622)	(4,053,483)	(3,897,580)	(3,747,673)	(3,603,532)	(3,464,934)	(3,331,667)	(3,203,526)	(3,080,314)	(2,961,840)	(2,826,711)
19.	**ACCUMULATED PV OF TOTAL TAXES**												
	ACCUMULATED NPV AND PI												
20.	Net Present Value (STAGE 1 NPV)												

Stage 1 Benefits: DCF Analysis

Line No.	Col. 1 Description	Col. 24 2038	Col. 25 2039	Col. 26 2040	Col. 27 2041	Col. 28 2042	Col. 29 2043	Col. 30 2044	Col. 31 2045	Col. 32 2046	Col. 33 2047	Col. 34 2048	Col. 35 2049
	Discount factors to project outset	0.4303	0.4138	0.3978	0.3825	0.3678	0.3537	0.3401	0.3270	0.3144	0.3023	0.2907	0.2795
	INCREMENTAL CAPITAL INVESTMENT												
1.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-	-	-
2.	Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
3.	Total Investment												
4.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-	-	-
5.	**ACCUMULATED PV OF TOTAL INVESTMENT**												
	CCA TAX SHIELD												
6.	CCA Tax Shield	2,375,395	2,232,872	2,098,899	1,972,965	1,854,588	1,743,312	1,638,714	1,540,391	1,447,967	1,361,089	1,279,424	1,202,658
7.	PV Of CCA Tax Shield At Project Outset	1,022,161	923,876	835,042	754,749	682,177	616,583	557,296	503,710	455,277	411,500	371,933	336,170
8.	**ACCUMULATED PV OF CCA TAX SHIELD**												
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)												
9.	Gas Distribution Revenue	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437
10.	Gas Costs	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)
11.	O&M Expenses	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)
12.	Net Operating Cash (Before Taxes)	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559
13.	PV of Net Operating Cash (Before Taxes) At Project Outset	7,349,965	7,067,274	6,795,456	6,534,092	6,282,781	6,041,136	5,808,784	5,585,370	5,370,548	5,163,988	4,965,373	4,774,397
14.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**												
	TAXES												
15.	Income Tax (Before Interest Tax Shield)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)
16.	Municipal Tax	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)
17.	Total Taxes	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)
18.	PV of Total Taxes At Project Outset	(2,717,991)	(2,613,453)	(2,512,936)	(2,416,284)	(2,323,350)	(2,233,991)	(2,148,068)	(2,065,450)	(1,986,010)	(1,909,625)	(1,836,177)	(1,765,555)
19.	**ACCUMULATED PV OF TOTAL TAXES**												
	ACCUMULATED NPV AND PI												
20.	Net Present Value (STAGE 1 NPV)												

Stage 1 Benefits: DCF Analysis

	Col. 1	Col. 36	Col. 37	Col. 38	Col. 39	Col. 40	Col. 41	Col. 42
Line No.	Description	2050	2051	2052	2053	2054	2055	2056
	Discount factors to project outset	0.2688	0.2584	0.2485	0.2389	0.2297	0.2209	0.2124
	INCREMENTAL CAPITAL INVESTMENT							
1.	Net Investment Capital	-	-	-	-	-	-	-
2.	Working Capital	-	-	-	-	-	-	-
3.	Total Investment							
4.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-
5.	**ACCUMULATED PV OF TOTAL INVESTMENT**							
	CCA TAX SHIELD							
6.	CCA Tax Shield	1,130,499	1,062,669	998,909	938,974	882,636	829,678	8,110,929
7.	PV Of CCA Tax Shield At Project Outset	303,846	274,630	248,223	224,356	202,783	183,285	1,722,875
8.	**ACCUMULATED PV OF CCA TAX SHIELD**							
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)							
9.	Gas Distribution Revenue	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437	19,134,437
10.	Gas Costs	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)	(863,402)
11.	O&M Expenses	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)	(1,190,476)
12.	Net Operating Cash (Before Taxes)	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559	17,080,559
13.	PV of Net Operating Cash (Before Taxes) At Project Outset	4,590,767	4,414,199	4,244,422	4,081,175	3,924,207	3,773,276	3,628,150
14.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**							
	TAXES							
15.	Income Tax (Before Interest Tax Shield)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)	(3,880,981)
16.	Municipal Tax	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)	(2,435,350)
17.	Total Taxes	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)	(6,316,330)
18.	PV of Total Taxes At Project Outset	(1,697,649)	(1,632,355)	(1,569,572)	(1,509,204)	(1,451,158)	(1,395,344)	(1,341,677)
19.	**ACCUMULATED PV OF TOTAL TAXES**							
	ACCUMULATED NPV AND PI							
20.	Net Present Value (STAGE 1 NPV)							

Table 10: Other Public Interest Factors Including Stage 2 Benefits for New Customers

Col 1	Col 2	Col 3
Stage 1 Benefits: Based on project cash flows		**NPV**
Stage 1 NPV (at social discount rate = 4%)	A	(122,702,977)
Stage 2 Benefits: Based on Customers' cash flows		
Energy cost savings		379,631,637
Less: Conversion costs		(35,535,433)
Stage 2 Benefits (NPV)	B	344,096,203
Combined benefits (Stage 1 + Stage 2)	A+B	221,393,226

1. In the absence of any contribution in aid of construction the Community Expansion Portfolio produces a negative NPV of utility cash flows (Stage 1 analysis) of approximately $123 million. A social discount rate of 4% was used for these calculations.

2. A Stage 2 assessment was also done to evaluate new customer benefits for switching to natural gas at significantly lower retail rates than competitive fuels. The customers' cost of natural gas was compared to the cost of either propane or fuel oil or electricity and any savings are netted against the conversion costs. The net savings are then discounted at a social discount rate to produce an NPV of customer cash flows. The resulting NPV of customers' net fuel savings from this Stage 2 assessment for all 39 projects is approximately $344 million.

3. In a Cap and Trade (C&T) environment those using electricity for heating and water heating are expected to have lower exposure to the cost of carbon compared to those using natural gas, propane or heating oil for the purpose of heating and water heating. A revised Stage 2 analysis based on information provided in the Province's 2016 Budget indicates that under a C&T environment it would be expected that there would be a modest reduction in Stage 2 benefits reducing them to $338 million from the figure noted in Table 10.

4. The analysis summarized in Table 10 shows that in combination Stage 1 and Stage 2 benefits result in a total quantifiable public interest benefit of approximately $221 million. The revised Stage 2 benefit analysis indicates that the combined Stage 1 and Stage 2 benefit under a C&T environment would be reduced to $215 million.