Enbridge Gas Integrated Resource Planning Proposal

OEB Staff Compendium

Panel 1 – Enbridge Gas

Cross-Examination

EB-2020-0091

March 1, 2021

Index

TAB 1

Was Appendix, preliminary page 2 247

APPENDIXB ONTARIO ENERGY BOARD GUIDELINES FOR ASSESSING AND REPORTING ON NATURAL GAS SYSTEM EXPANSION IN ONTARIO

1998 248

Was Appendix, preliminary page 3 249

CONTENTS

Was Appendix, page 1 258

I. OVERVIEW - PURPOSE AND OBJECTIVE OF THE GUIDELINES

259 The Ontario Energy Board ("OEB", "Board") Guidelines for Assessing and Reporting on Natural Gas System Expansion In Ontario ("The Guidelines") provide a common analysis and reporting framework to be applied by regulated Ontario Local Distribution Companies - Union Gas Limited and The Consumers' Gas Company Ltd. ("the utilities") to natural gas distribution system expansion. The principles upon which the Guidelines are based reflect the Board's conclusions in its Distribution System Expansion Reports under Board File No. E.B.O. 188. (Interim Report[12JM1-0:1] dated August 15, 1996; Final Report[1] dated January 30, 1998).

Portfolio Approach 260

The main change from prior policy and practice is the use of a portfolio approach, as opposed to a project-by-project approach, to the planning, analysis, management and reporting of distribution system expansion projects. The intent of the portfolio approach is to provide the utilities a greater degree of flexibility in determining which projects to undertake, while the Board retains overall regulatory control to ensure no undue cross subsidy or rate impacts result from distribution system expansion. 261

Financial Feasibility Analyses 262

The Guidelines provide the utilities with direction with respect to the structure of their system expansion portfolios and the methods for conducting financial feasibility analyses at both the individual project level and the portfolio level. The Guidelines standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis. 263

Reporting 264

The Guidelines establish a mechanism to evaluate the performance of each of the utilities' distribution expansion activities on a portfolio basis and on an individual project basis. The Guidelines also outline reporting requirements for system expansion plans and post expansion impacts. The forecast rate impacts of a utility's expansion plans will be presented in rates case filings on a prospective test year basis. 265

These reporting requirements are intended to provide the Board and interested parties with sufficient information to monitor the utilities' expansion activities and their associated rate impacts. The performance of the utilities related to implementation of these Guidelines will be evaluated as part of each utility's rates case. 266

Customer Connection Policies Was Appendix, page 2 267

Part of the utilities' management of distribution system expansion will be the provision of common customer connection policies. These will include policies relating to service line fees, customer contributions to otherwise financially unfeasible projects and for projects dominated by one or more large volume customers. 268

Environmental Considerations 269

To ensure that the utilities plan and construct system expansion facilities in an environmentally acceptable manner, the Guidelines also address the routing and environmental planning, documentation and reporting requirements for distribution expansion projects. 270

Was Appendix, page 3 271

1. SYSTEM EXPANSION PORTFOLIOS

1.1 Investment Portfolio 272

Each of the utilities will group into a portfolio (the "Investment Portfolio") the costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio is to include a forecast of normalized system reinforcement costs. 273

The Investment Portfolio will be designed to achieve a profitability index ("PI") *greater* than 1.0. 274

1.2 Rolling Project Portfolio 275

Each of the utilities will maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio") updated monthly, as an ongoing management tool for estimation of the future impacts of capital expenditures associated with distribution system expansion. The Rolling Project Portfolio will exclude those customers requiring only a service lateral from an existing main. 276

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the past twelve months for the Rolling Project Portfolio. It will include all future customer attachments, revenues and costs on the basis of the life cycle of each of the projects making up the Portfolio. 277

2. STANDARD TEST FOR FINANCIAL FEASIBILITY 278

The standard test for determining the financial feasibility at both the project and the portfolio level will be a DCF analysis, as set out below. 279

2.1 DCF Calculation and Common Elements 280

The DCF calculation for a Portfolio will be based on a set of common elements. For <u>revenue forecasting</u>, the common elements will be as follows: 281

(a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer Attachment Horizon for each project; 282

(b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year; 283

(c) an estimate of average use per added customer which reflects the mix of customers to be added; 284

(d) a factor which reflects the timing of forecasted customer additions; and 285

Was Appendix, page 4

(e) rates derived from the existing rate schedules for the particular utility, net of the gas commodity component. 286

For <u>capital costs</u>, the common elements will be as follows: 287

(a) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land and land rights; 288

(b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and 289

(c) an estimate of the normalized system reinforcement costs. 290

For <u>expense forecasting</u>, the common elements will be as follows: 291

(a) gas costs as used in revenue forecasts (excluding commodity costs); 292

(b) incremental operating and maintenance costs; 293

(c) income and capital taxes based on tax rates underpinning the existing rate schedules; and 294

(d) municipal property taxes based on projected levels. 295

2.2 Specific Parameters 296

Specific parameters of the common elements include the following: 297

(a) a 10 year customer attachment horizon;. 298

(b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers); 299

(c) 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; 300

(d) discounting reflecting the true timing of expenditures. Up-front capital expenditures will 301
be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas costs, and operating and maintenance expenditures; and

(e) gas costs based on the weighted average cost of gas ("WACOG") excluding commodity 302
costs.

Was Appendix, page 5 303

3. MONITORING PORTFOLIO PERFORMANCE AND SHORT-TERM RATE IMPACTS

3.1 Rates Case Filings 304

The following information will be filed in each rates case: 305

Test Year 306

(a) the Investment Portfolio, including NPV, the total capital in the portfolio and the portfolio PI; 307

(b) an estimate of the aggregate NPV of all new facilities requiring a new franchise and/or certificate 308
of public convenience and necessity and of all "infills" (i.e. main extensions and service attachments in existing service areas excluding service lines to customers off existing mains) based on extrapolated historical data;

(c) an estimate of the Test Year rate impacts of the Investment Portfolio based on the: 309

(i) contribution to annual revenue requirement; 310

(ii) Rate Impact Measure presented as the ratio of added revenue to costs for each customer 311
class; and

(iii) class-specific estimated percent rate and annual average bill increases. 312

(d) estimates of the NPV and the benefit-cost ratio for the Investment Portfolio using a Societal Cost 313
Test ("SCT"), defined in the Report of the Board, E.B.O. 169 III, as an evaluation of the costs and/or benefits accruing to society as a whole, due to an activity. The SCT analysis should be consistent with that used for the utilities' DSM programs. The benefit-cost ratio shall be presented with and without monetized externalities.

Historic Year: 314

(a) the Historic Year Investment Portfolio, including the NPV, total capital in the portfolio, and the portfolio PI; 315

(b) the aggregate NPV, the total capital, and the portfolio PI for: 316

(i) the Rolling Project Portfolio at the end of the historic year; 317

(ii) all completed projects with negative NPVs; 318

(iii) all completed projects with positive NPVs; 319

(c) upon the request of the Board, a list of the projected results of individual extensions included in the Rolling Project Portfolio; 320

(d) actual expenditures on reinforcement projects; and 321

(e) the rate impact of the Historic Year Investment Portfolio reflecting actual capital expenditures and customer related data. Was Appendix, page 6 322

3.2 Ongoing Monitoring Information 323

The utilities shall establish a process to allow the Board to monitor the performance of their distribution system expansion project portfolios including financial and environmental requirements. 324

A. Financial Monitoring 325

In consultation with Board Staff, the utilities shall select projects from their Rolling Project Portfolios on an annual basis and shall file the following with respect to the sample: 326

(a) the cumulative number of customers attached at the end of the 3rd full year and the associated revenues and costs; and 327

(b) the corresponding year 3 customer attachment forecasts and associated revenues and costs. 328

B. Environmental Monitoring 329

In consultation with Board Staff, the utilities shall select a set of completed projects and file data on those projects on an annual basis as described below. The projects chosen should be selected in a random, stratified manner, reflecting the range of environmental impacts encountered in the time period and the various levels of environmental planning, documentation and reporting required. The selection should be reviewed by an independent auditing group within the utility, which group shall include (a) trained environmental auditor(s). The utility shall file the following with respect to each sample: 330

1. a description of how the project complied with the Board-approved environmental screening, planning, documentation and reporting requirements; 331

2. a table of significant features, how they were avoided or mitigated, and resulting impacts; 332

3. a table displaying the concerns raised by affected parties including member ministries of the Ontario Pipeline Coordination Committee, how they were addressed, and reasons for any outstanding concerns; 333

4. issues of significance arising from any post-construction monitoring; 334

5. where alternatives were investigated, a display of alternatives (routes/sites) which show the various trade-offs between customer attachments, and environmental, social and financial costs and a discussion of how the preferred alternative was chosen; 335

Was Appendix, page 7

6. evidence that all necessary approvals (permits, licences) were obtained; and 336

7. forecast versus actual costs of the environmental planning. 337

3.3 Risks of Non-performance 338

In the event that the actual results of the Investment Portfolio do not produce a positive NPV or a PI of at least 1.0, the following will occur: 339

(a) the utility will be required to provide a complete variance explanation in its rates case and the Board will determine whether or not an acceptable explanation has been provided; and 340

(b) the implications of a negative NPV or PI less than 1.0 will be determined by the Board on a case by case basis. 341

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES 342

The utilities will maintain a clear set of common Board-approved Customer Connection and Contribution in Aid Policies. 343

The criteria for contributions in aid of construction for service lines and mains will apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction will take into account the future load growth potential and timing of any such expansion. 344

The Customer Connection and Contribution in Aid Policies shall, as a minimum, include the following: 345

- Requirements for payment for all, or part, of a customer service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges. 346

- Requirements for contributions in aid of construction for connection of individual customers, subdivisions or communities requiring main extensions that would not otherwise be included in the Investment or Rolling Project Portfolios. 347

- Requirements for contributions in aid of construction for expansion projects dominated by one or more large volume customers. 348

5. ENVIRONMENTAL REQUIREMENTS FOR DISTRIBUTION FOR SYSTEM EXPANSION PROJECTS 349

The planning principles described in the Board's "Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities In Ontario (1995)" shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project. 350

Was Appendix, page 8 351

The utilities shall apply environmental screening criteria to determine when significant features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be applied depending on the impacts expected as determined through the screening process.

Once the study area for the project is determined, a regional officer of the utility who is familiar with the study area and has been trained in environmental matters, shall identify potential impacts through the screening process and determine the level of planning required. Depending on the 352 significance of the potential impacts anticipated, the planning requirements may involve environmental specialists of the utility, external consultants or other affected parties.

353

All provincial and local agency requirements (permits, licences) shall be obtained where necessary and the utilities shall apply their standard guidelines, drawings, and specifications.

354

6. DOCUMENTATION, RECORD KEEPING AND REPORTING

355

The utilities will maintain documentation for all projects which are to be included in the Rolling Project Portfolio. A record of the DCF analysis conducted for each project in the Rolling Project Portfolio shall be available for review upon request of the Board. The performance tracking of individual projects shall be as described in Section 3 of these Guidelines.

356

The utilities will maintain a record of the environmental planning, documentation and reporting requirements associated with all projects and Environmental Reports for those projects deemed to have significant environmental impacts.

357

For all expansion projects in the Rolling Project Portfolio with a capital cost greater than $500,000 ("major projects") the utilities shall file the NPV and DCF analysis in each rate case and shall keep a record of forecast and actual customer attachments for a period of three years after construction is completed. In addition, the utilities shall also file in each rate case, the NPV and DCF analysis for all major projects planned for the test year. Upon request of the Board, the utilities shall file forecast and actual customer attachments for major projects.

358

The utilities shall file quarterly with the Board Secretary, the updated monthly Rolling Project Portfolio results immediately upon completing the calculations.

Was Appendix, schedule page 1 359

SCHEDULE1 DISCOUNTED CASH FLOW METHODOLOGY

360

Net Present Value ("NPV") *= Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital*

Profitability Index ("PI") = *PV of Operating Cash Flow + PV of CCA Tax Shield* / *(PV of Capital)*

361

1. PV of Operating Cash Flow *= PV of Net Operating Cash (before taxes) - PV of Taxes*

a)	PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied.
	Net Operating Cash	=	*(Annual Gas Revenue - Annual Gas Costs - Annual O&M)*
	Annual Gas Revenue	=	*Customer Additions * Consumption Estimates per Customer * Revenue Rate per m^3*
	Annual Gas Cost	=	*Customer Additions * Consumption Estimates per Customer * Gas Costs per m^3 net of commodity costs*
	Annual O&M	=	*Customer Additions * Annual Marginal O&M Cost/customer*

Was Appendix, schedule page 2 362

b)	PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
	Annual Municipal Tax	=	*Municipal Tax Rate * (Total Capital Cost)*
	Total Capital Cost	=	*(Mains Investment + Customer Related Investment + Overheads at portfolio level)*
	Annual Capital Taxes	=	*(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)*
	Annual Capital Tax	=	*(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax - Annual Capital Tax)*

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon. 363

364

2. <u>PV of Capital</u> = *PV of (Total Annual Capital Expenditures - Annual Contributions)*

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure = *(Mains Investment + Customer Specific Capital + Overheads at the Portfolio level)*

Was Appendix, schedule page 3 365

b) Annual Contributions

Annual Contributions = *Cash payments (or principal portions of payments over time) received as Contributions in Aid of Construction*

Note: Above is discounted to the beginning of year one over the customer addition horizon. 366

367

3. <u>PV of CCA Tax Shield</u>

PV of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of : *<u>[(Income Tax Rate) * (CCA Rate) * Annual Total Capital]</u>*

(CCA Rate + Discount Rate)

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the $^{1}/_{2}$ year CCA rule.

4. Discount Rate

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

TAB 2

ECONOMIC FEASIBILITY PROCEDURE AND POLICY

Introduction

1. The purpose of this evidence is to present the current procedures and policies for determining the feasibility of the Company's system expansion projects. These procedures and policies are adopted to comply with the Ontario Energy Board's (the "Board") "*Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*", reported under EBO 188 dated January 30, 1998.

2. This evidence includes an overview of the Company's Customer Connection Policy, Customer Contribution and Refund Policy, Procedure for Capital Expenditure Approval and Method for Economic Feasibility Assessment.

3. The Company is also evaluating policy options to support expansion to potential new communities. Details on the Company's plans in this area are documented in Exhibit B1, Tab 3, Schedule 1.

4. The most recent feasibility parameters are used in this evidence, which are based on the 2012 system expansion portfolio and are updated to reflect EB-2012-0054 Decision with Reasons.

Customer Connection Policy

5. The Company uses a portfolio approach to manage the system expansion activities and ensures that the required profitability standards are achieved at both the individual project and the portfolio level. Investment Portfolio and Rolling Project Portfolio are two Board prescribed portfolio approaches and are discussed on page 3 of this exhibit.

Witnesses: F. Ahmad
P. Squires

6. The Company manages to achieve a Profitability Index ("PI") of greater than 1.0 for both portfolios as required by the Board under EBO 188.

7. The minimum PI required for individual projects is 0.80. For projects with a PI less than 0.80, the customer shall be required to pay a Contribution-in-Aid-of-Construction ("CIAC") to bring the project up to the required PI level.

8. Customers connecting to the existing mains are provided, at no cost, with a service connection up to a maximum of 20 meters. Any service length beyond 20 meters is charged to the customer at a rate prescribed in Rider G.

9. The length of service for feasibility assessment is measured from the customer property line to the meter.

10. Requests for exceptions to the minimum PI must be authorized by the Manager, Customer Portfolio and Policy.

11. During construction and operation of each project, the Company will comply with the "*OEB Environment Guidelines for HydroCarbon Pipelines and Facilities in Ontario*".

Customer Contribution and Refund Policy

12. CIAC may be obtained for projects having a negative Net Present Value ("NPV") or a PI less than 1.0. The contribution should be sufficient to bring the project PI up to a viable level as assessed by the Customer Portfolio and Policy group from time to time. Harmonized Sales Tax ("HST") is added to contribution payments.

Witnesses: F. Ahmad
P. Squires

13. Where the use of a proposed facility is dominated by a single large volume customer, it is considered a dedicated facility for CIAC purposes. The dominant customer may be required to pay a contribution to result in a project NPV of zero or a PI of 1.0. Contribution amounts are subject to added HST.

14. Refunds of CIAC may be requested when the actual customer count on the system expansion exceeds the original forecast. For general service customers, these refunds are processed at the end of five years from the date of construction. The system expansion project is then re-evaluated with the actual customer count to determine a revised contribution that is required to bring the NPV to the original targeted level. The difference between this and the actual contribution paid by customers is the total amount to be refunded. Refunds are made based on the proportionate contribution of the customers.

15. Refunds for large volume customers will be determined based on a re-evaluation of the system expansion project taking into consideration extra investment and additional load brought on within five years to the specific piece of main constructed to serve the initial customer(s).

16. These refunds are made only for the specific piece of main put into service and no refunds are payable for customers added downstream of this piece of main. No interest is payable, and only customers who made a contribution are eligible for a refund. In order to be eligible for a refund, the customer must be consuming natural gas at the address for which refund is being claimed. If the customer moves, he or she is responsible for notifying the Company of the new address. Records of contributions are maintained by the Business Performance group at Enbridge.

System Expansion Portfolios – Accountability

17. Investment Portfolio: The Company evaluates all system expansion projects in a test year and ensures they achieve a portfolio PI threshold of 1.1. All new customers attaching to new and existing mains are included in this portfolio. The Manager, Customer Portfolio and Policy is accountable for ensuring that the required PI threshold is achieved.

18. Rolling Project Portfolio ("RPP"): The Company also maintains a rolling 12-month distribution expansion portfolio including the cumulative result of project-specific Discounted Cash Flow ("DCF") analyses. The RPP does not include customer attachments from existing mains constructed in prior years. The Company maintains RPP at a PI level greater than 1.0 and the Capital Management group in Finance is accountable for maintaining this level.

Procedure for Capital Expenditure Approval

19. Enbridge's procedure for obtaining management approval to make a capital expenditure for distribution system expansion is known as the Authorization for Expenditure ("AFE"), and is outlined in the AFE manual. A system expansion project is typically initiated by a Regional Customer Connections Field Representative, who identifies potential new customers. He or she will assess the required amount of plant additions to provide service and will initiate an AFE for approval.

20. A feasibility calculation is required with an AFE, which assesses the estimated revenue and benefits of attaching these new customers against the cost of serving them. The Capital Project Feasibility ("CAPF") program is an IT tool used for evaluating all projects except for Large Volume Customer additions. Large volume

projects are separately evaluated by Enbridge's Investment Review group with inputs from the special project group. All calculations related to project feasibility assessment are attached to an AFE as part of the approval process.

21. The Customer Connections representative inputs information on plant requirements, customer additions and timing, and volumetric data for Subdivision/Residential and Commercial/Industrial connections. For large-volume connections, the inputs are completed by the Investment Review group.

22. All AFEs are approved by the appropriate departmental managers, directors, VPs and President as set out in the workflows. In addition, all AFEs are approved by the Capital Management group in Finance and the workflows are monitored and managed by this group as well to ensure the appropriate individuals are in the workflow for approval of an AFE. The Group also ensures compliance with the Company's Connection Polices.

Method for Economic Feasibility Assessment

23. This section provides the method used to determine the input parameters including cost and revenues associated with a system expansion project. These parameters are discounted at the Utility's Weighted Average Cost of Capital ("WACC") to perform a DCF analysis. The Economic Feasibility of a project is measured using a NPV and PI.

24. Capital Cost: Budgeted average unit prices are used to estimate capital cost for mains and services based on the required pipe size and ground conditions. This procedure is used to develop capital estimates for all residential, commercial and industrial connections.

25. For large volume connections (i.e., above 340 000 m^3 annual consumption), field estimates are used to estimate mains and service cost.

26. If a main is oversized to meet future growth potential, it may be re-priced at the size required to meet customers' load requirements for feasibility calculations. The actual cost of the main must be shown on the AFE.

27. An incremental overhead allowance is added to the cost of mains and services and is incorporated in the CAPF program for feasibility analysis.

28. Consumption and Revenue: For subdivision and residential connections, consumption is estimated based on building type (single, semi-detached, townhouse) and configuration (bungalow, split or two-storey). The CAPF program calculates customer revenue based on consumption levels input by the local Customer Connections representative.

29. A load sheet is used to estimate consumption of commercial and industrial connections. The load sheet information is provided by the customer and contains consumption of various appliances installed at the premises.

30. For large volume connections, consumption information should include monthly volumes and the customer's contract daily demand. The Investment Review group calculates revenue, based on the input consumption profiles and the most recent Board Approved revenue rates.

31. Customer Attachment and Revenue Horizon: The maximum customer attachment horizon for regular residential, commercial and industrial connections is 10 years. The revenue horizon is 40 years from the in-service date of the initial mains.

32. For large volume customers, the customer attachment horizon is 10 years. The maximum revenue horizon is 20 years from the customers' initial service date if this is a reasonable expectation.

33. Marginal Operating and Maintenance ("O&M) Expenses: According to the most recent feasibility parameters, the incremental O&M cost for adding residential connections is estimated to be $70.13 per customer.

34. For commercial and industrial connections, the incremental O&M cost is $196.92 per customer.

35. For large volume connections, incremental O&M is determined based on the average annual expense for various rate classes except for rate 125 and is shown in Table 1. For Rate 125 customers, marginal O&M is determined on a case by case basis.

Table 1

Marginal O&M Expense per Customer

Rate Class	R9	R110	R115	R135	R145	R170	R300
Marginal O&M per customer	$4,103	$6,152	$7,685	$4,089	$4,921	$5,702	$5,679

Witnesses: F. Ahmad
P. Squires

36. Gas Costs: Gas costs are based on the Weighted Average Cost of Gas ("WACOG") less the commodity component. Currently the WACOG (excluding commodity) is $.0821/m^3 for conventional heating and water heating loads at residential, commercial and industrial facilities.

37. For large volume connections, gas costs are based on the customer's load profile characteristics which will typically warrant a customized gas cost calculation consisting of four components including: 1) Unbilled and Unaccounted for Gas ("UUF"), 2) transportation, 3) annual storage and 4) peak day delivery. The Investment Review group calculates gas cost based on the customers' monthly volumes, contract demand and service requirement (Western or Ontario). All gas costs include UUF, but only Western contracts include transportation costs. The customers' load profile dictates the amount of load balancing, storage, and peak day costs/credits are included in gas costs. Firm customers will incur peak day costs, while interruptible customers will receive peak day credits. UUF and transportation costs will be applied to the customers' load, storage costs to the customers' stored gas, and peak day costs to the customers' peak day storage requirement if the customer is firm. Peak day credits will be applied to interruptible customers' average daily volume. The formula used for calculating amounts of stored gas and peak day storage requirements are included with the table of costs found in Table 2.

38. The interruptible gas cost categories are: (a) Rate 145 customers with a minimum 16 hour curtailment notice; and (b) Rate 170 customers with 4 hours curtailment notice.

Witnesses: F. Ahmad
P. Squires

Table 2

Gas Cost for Large Volume Customers

		UUF ($\$/m^3$)	Transportation (Western Only) ($\$/m^3$)	Annual Storage ($\$/m^3$)	Peak Day Delivery ($\$/m^3d$)
		Annual load	Annual load	Stored gas[1]	Excess on peak day over average daily
Firm	Rates 100, 110,115, 135				
	a) Volume				
	b) Cost				
	Rates 100,110,115	0.00096	0.05870	0.01055	1.13250
	Rate 135	0.00096	0.05870	0.00000	(1.34821)[3]
Interruptible	Rates 145 and 170				
	a) Rate 145 with 72 hour curtailment	0.00096	0.05870	0.01055[2]	(1.34821)[3]
	b) Rate 145 with 16 hour curtailment	0.00096	0.05870	0.00770[2]	(0.23048)[3]
	c) Rate 170[4]	0.00096	0.05870	0.00770[2]	(0.23048)[3]

1 (Volume from November to April/181 days – Annual Load/365 days)*181 days
2 Applied to uncurtailed volumes.
3 Applied as a credit based on the customers' average daily volume
4 If Enbridge Gas Distribution is restricted in utilizing its interruption rights a custom calculation should be performed by the Investment Review group.

Witnesses: F. Ahmad
P. Squires

TAB 3

MR. PARKES: Right, okay. So you talked a bit there about the contribution in aid -- or contributions in aid of construction policies. So that kind of falls out, I guess, of the economic tests for the natural gas system expansion and kind of your assessment of what the upstream system reinforcement costs associated with a particular expansion might be.

So just wondering, those costs inputs that are put into those tests, is that kind of linked back to the asset management planning process and your needs assessment at a geographically specific level? So I mean in theory, if we know that a part of the system is close to requiring a major infrastructure expansion if demand continues to grow, then that would be reflected in the reinforcement costs you would see in these tests. So there would be a higher customer contribution required, so that would sort of act as a balancing factor to pull download growth or at least ensure that it was paying for itself. So just wondering if that level of sort of specificity on geographic needs and likely system reinforcement costs is or can be incorporated into those economic expansion calculations.

MR. CLARK: So if I can just start to talk about the connection of new customers in that scenario, that if there was a reinforcement identified that was required in order to connect, say, that subdivision of customers, that what goes into that CIAC calculation is the capacity that they require, not an overall system benefit capacity, right?

So what is going into that cost assessment is

specifically what do we need to service those homes that
are coming on.

MR. PARKES: Okay, but there is a mention in that
test -- I can't remember the exact wording, but it says
something about system reinforcement costs or upstream
system costs.

MR. CLARK: Right. So the costs will be both, you
know, the piping -- again using that subdivision example,
would both be the costs of constructing the piping in that
new subdivision and connecting those customers, as well as
potential upstream reinforcement that could be required and
that could be directly connected, that subdivision could be
kilometres away.

But again the scoping and costing of that upstream
reinforcement is associated purely with the load addition
of that subdivision.

MR. PARKES: Yeah.

MR. CLARK: Right. Just to be clear, if they need an
extra 100 cubic metres, we are sizing it up and costing it
out for an extra 100 cubic metres.

MR. PARKES: Yeah, and I get it's, you know, these
needs are often driven by lots of little incremental pieces
and not one specific customer connection. But I am just
wondering if that's an area that might be explored as well.
Yeah, I think I will leave it there for now, that's all my
questions for today.

MR. CLARK: Just one final comment again linking on my
earlier one, again the timing associated with that type of

work can be a challenge as well because again by the time -- especially in that subdivision example, by the time they approach us, they are looking for installations within, you know, a year to 18 months. So it would make it challenging to source out IRPAs.

MR. PARKES: Yeah, I get that an IRPA from Enbridge's perspective might not work there, but it was more if the correct cost inputs were in place, then customers would, would see the accurate connection costs that are required to upgrade the system and that may influence their choice in whether to connect, I guess, theoretically.

MR. MILLAR: Okay, thank you very much, Mike. Lisa, let's turn it over to you.

EXAMINATION BY MS. DEMARCO:

MS. DeMARCO: Thanks very much, Michael and Michael. I am going to follow up on one of Michael's questions just to make sure we are doing an apples and apples comparison here, and it's really around the distinction between non-pipeline alternatives, which is the (inaudible) that's used in the ConEd experience versus an IRPA. I have just heard in addition to the screening criteria that I went through with Mr. Gillett, we have now got a temporal aspect screening criteria as well. Is that right, Mr. Clark?

MR. CLARK: Yes, and I believe that's in the evidence, that we are looking at projects in the three to five or beyond time period for screening. Anything sooner than that, we wouldn't have the time to respond and those are being considered as emergent.