ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List No.1

Question:

Please provide all internal documents generated by Enbridge Inc., Enbridge Gas Distribution and Union Gas that examined, quantified or hypothesized about the impact of keeping the two utilities separate or merged.

a. Please include any document that include estimates of the rate impacts, revenue requirement and/or profitability of rebasing for either utility.
b. If the Board were to order a high-level examination of the scenario of the two utilities re-basing, what is the applicant's estimate of the cost of hours to generate and the time frame for which an evidence-based quality forecast to be generated?

Response:

a) The following attachments represents the internal documentation regarding the amalgamation:
   - Attachment 1: October 31, 2017 EGD, Union Gas and Enbridge Inc. Board of Directors presentation
   - Attachment 2: July 25, 2017 EGD, Union Gas and Enbridge Inc. Board of Directors memorandum
   - Attachment 3: November 15, 2017 EGD, Union MAADs & PCRMM Stakeholder Day presentation

b) The time and effort associated with preparing a rebasing application is significant as it involves a detailed examination of revenues and costs; rebasing cannot be done at a high level. The preparation of an application and evidence for rebasing takes approximately 18 months. Once the application and evidence are filed, the regulatory process takes approximately one year.

Utilities Integration

Board of Directors
October 31, 2017

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Utilities Integration

Executive Summary

- Further to previous discussions with the Board and following multiple touch points with regulators and government representatives, Management is recommending that we proceed with the filing of an application that would amalgamate the two utilities
- The OEB's Mergers, Amalgamation, Acquisition & Divestitures (MAADs) policy will be the basis for the utilities' amalgamation application
- Management assessed the available options and determined that the MAADs policy benefits customers by meeting the OEB's No Harm Test and keeps rates at inflation over the ten year term. MAADs benefits the utility by enabling a paced integration over a ten year period with the opportunity to achieve earnings in excess of the Allowed ROE
- Given the proposed 10 year term, the company will be taking on incremental risk relative to a conventional 5-year Custom IR approach. Management believes it can manage these risks through regulatory mechanisms, prudent cost management and leveraging risk management programs
- **Management is requesting Board approval to file with the Ontario Energy Board (OEB) two regulatory applications that will allow Enbridge to integrate Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (EGD)**
- **A final decision to proceed with the amalgamation is conditional upon a satisfactory regulatory decision expected in Q3 2018**

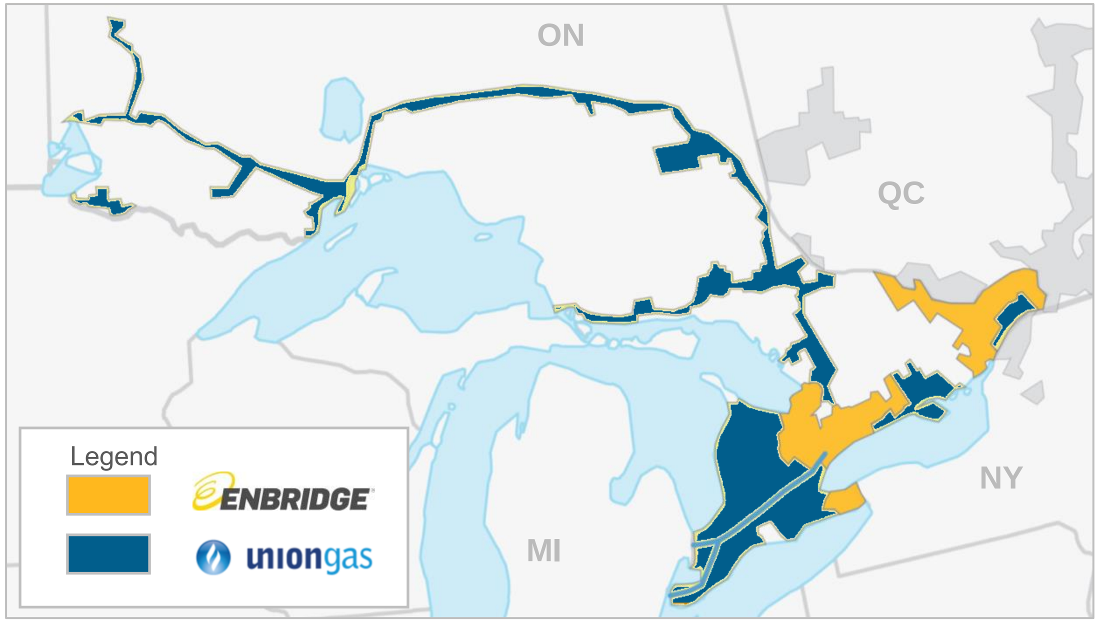
Opportunity to integrate the two utilities under the MAADs Policy at the end of the current IR terms in 2018

Utilities Integration

Strategic Rationale

- As outlined at the 2017 Strategic Planning session, EGD and Union are focused on opportunities to grow the core business and maximize returns through an **integrated** utility structure
- Integrating the two utilities creates a platform to achieve synergies in the base business that can be leveraged to support future growth
- An integrated utility is better positioned to deliver energy in Ontario in a lower carbon future
- Under the MAADs framework, the integrated utility will generate a benefit for both ratepayers and shareholders when compared to continuing operations on a standalone basis

The Combined Utility



Integration is the key to realizing synergies and will benefit both ratepayers and shareholders

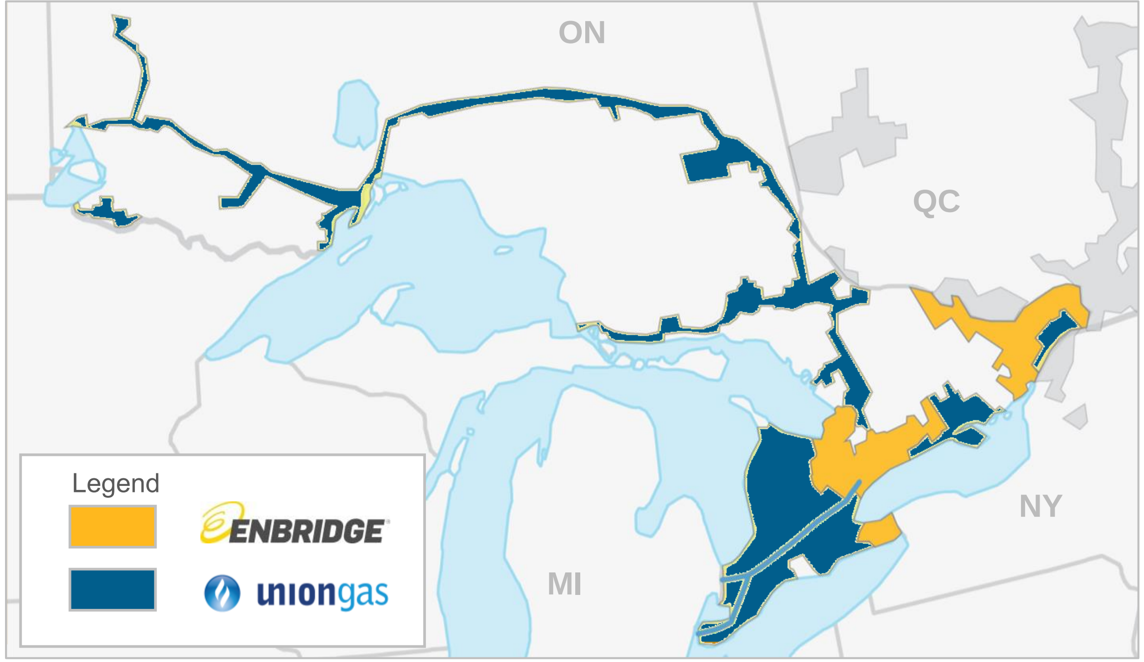
Utilities Integration

Presentation Outline

EGD & Union Today

- Both EGD and Union operate under 5 year Incentive Rate models until 2018; EGD under a Custom IR Framework and Union under a Price Cap Framework
- Under the Custom IR, EGD is at risk for capital cost overages; the ROE is reset each year to the OEB approved value; and earning in excess of ROE are shared 50:50 with ratepayers
- Under the Price Cap, Union's rates are set annually by increasing 2013 revenues by an escalator (40% of inflation); a "capital pass through" mechanism is used for excess capital; the ROE during the term is fixed at the OEB's approved 2013 ROE (8.93%); and Union retains 100% of first 100 bps of earnings above the allowed ROE, 50% above 100 bps, and 10% above 200 bps

EGD and Union Custom IR models are ending in 2018. The utilities have the opportunity to integrate under MAADs and operate under a Price Cap Inflation framework for 10 years



Key Statistics	EGD	Union
Customers (M)	2.2	1.5
Rate Base ($ B)	5.9	4.8
Deemed Equity	36%	36%
Allowed ROE	9.19%	8.93%
Regulatory Regime	Custom IR	Price Cap
Regime Period	2014 - 2018	2014 - 2018

Utilities Integration

Regulatory Models

COST OF SERVICE	CUSTOM INCENTIVE	MAADs
TERM: Annual	TERM: 5 YEARS	TERM: 10 YEARS
• Cost of Service allows a utility to set rates based on the cost of providing service to customers and the right to earn a limited profit • Reset annually allowing utility to true-up • Traditionally, all prudent capital spend is eligible to earn a rate of return • Revenue Requirement is directly linked to Rate Base ensuring allowed return achieved • Operating and maintenance costs are flowed through to rate payer • There is no earnings sharing mechanism as utility is only able to earn its allowed ROE • **A pure cost of service frameworks is no longer available**	• Incentive regulation sets rates using a measure of inflation and an efficiency target for the utilities. This mechanism promotes efficiency both within the distribution sector and through the regulatory process • The IR frameworks are typically set for 4 to 5 years • Rate base is decoupled from revenue and unbudgeted capital will act as a drag to ROE • Revenue decoupled from rate base, rather it is based on an annual inflator applied to the previous year • Re-basing typically occurs in the year prior to commencing IR Term • Operating & maintenance costs are typically managed to budget by utility • Potential to under-earn and typically a earnings sharing mechanism in place when utilities over earn • **Custom IR model does not contemplate amalgamations**	• The OEB's MAADs policy provides consolidating distributors with an opportunity to integrate and offset transaction costs with savings achieved as a result of the consolidation • Applicants must show that the costs to serve customers under consolidation will be no higher than they would otherwise have been • Terms can vary, EGD and Union proposing 10 years • Revenue is based on an annual inflator applied to previous year as such rate base is decoupled from revenue; unbudgeted capital acts as a drag to ROE • Inclusion of Incremental Capital Mechanism (ICM) mitigates ROE drag due to discrete capital expenditures approved by the OEB • Operating & maintenance costs are typically managed to budget by utility • Potential to under-earn exists; No earnings sharing mechanism in the first 5 years, sharing for last 5 years • **MAADs is a reasonable alternative**

Utilities Integration

MAADs Application

Key Elements of the MAADs Application

Integrate two utilities by filing MAADs application(s) with OEB:

- Rebasing deferred to 2029 (10 year deferral)
- Revenues increased annually at inflation under a Price Cap model based on last year of current IR Terms (end of 2018)
- Access to ICM for discrete and unplanned capital expenditures in excess of threshold capital implicit in MAADs model
- Shareholder takes on costs & risks of integration to achieve savings
- No earnings sharing for first 5 years, 50/50 sharing for second 5 years for earnings >300 bps above allowed ROE
- Opportunity to integrate Demand Side Management and continue cost effective delivery of Ontario government low carbon programs
- A threshold test (**OEB No Harm Test**) which requires customer prices under the MAADs price cap be lower than customer prices without the two entities amalgamating

The OEB No Harm Test

Approval of the MAADs application is subject to OEB review of the proposed utility integration meeting the OEB's No Harm Test. To satisfy the No Harm Test, the proposed application must:

- Ensure rates to customers be less than if utilities do not integrate
- Maintain safety, reliability and quality
- Adhere to Government & OEB policies
- Maintain a financially viable gas industry
- The test is met by:
  - Providing ratepayers a benefit – MAADs rates lower than status quo models (EGD Custom IR & Union Price Cap) for 10 years
  - No change to delivery of safe, reliable service
  - Continue to deliver DSM, Cap-and-Trade other programs & policies
  - Sufficient access to capital markets/ ability to fund integration
  - Opportunity for Company to recover investment

MAADs provides the best opportunity for the utilities to integrate and achieve full efficiencies while the customers benefit from stable rate increases at inflation

Utilities Integration

Price Cap Rate Making Mechanism (PCRMM) & Asset Management Plans

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Key Elements of the PCRMM Application

An OEB Rates Application to set out the ten year framework for how distribution revenues will be established:

- Establish 2019 base distribution revenues
  - Adjust 2018 OEB approved revenue requirement to reflect ending of Union’s deferred tax customer refund
- Establish Price Cap Inflator as inflation (zero productivity factor)
  - Third Party expert Total Factor Productivity study will be filed to support a zero productivity factor
- Detail ICM criteria with example projects that potentially will be sought for ICM recovery over the ten year term
- Request deferral and variance accounts for use during ten year term
  - Management will recommend removal of EGD’s pension variance account and Union’s Tax deferral account treatment
- Outline criteria for interest rate expense recovery application should a change in interest rates result in the utility consistently under earning versus the Allowed ROE

Key Elements of the Asset Management Plans

The Asset Management Plan is the foundation for all utility capital investments and will be filed annually as part of the OEB’s Rates Application process

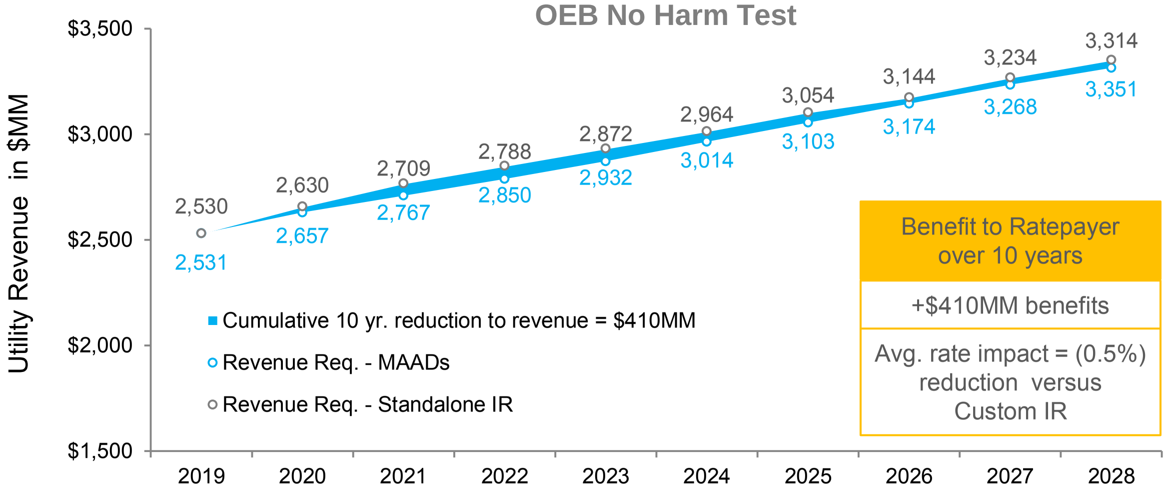
- Gas carrying asset optimization is based on engineering life cycle analysis to determine asset health
- Capital budgets for all utility capital will be optimized using a risk based assessment of asset health to determine maintenance versus replacement projects
  - IT, Facilities, Fleet and Equipment capital are included in the Asset Management Plan optimization
- Asset Management plans will be the basis for the OEB to approve the Utility’s ICM applications
- Management will work over the first two years to integrate the two utilities’ Asset Management plans
  - Individual Asset Management Plans will be filed with the 2019 Rates Application after the MAADs and PCRMM OEB Decision

Utilities Integration

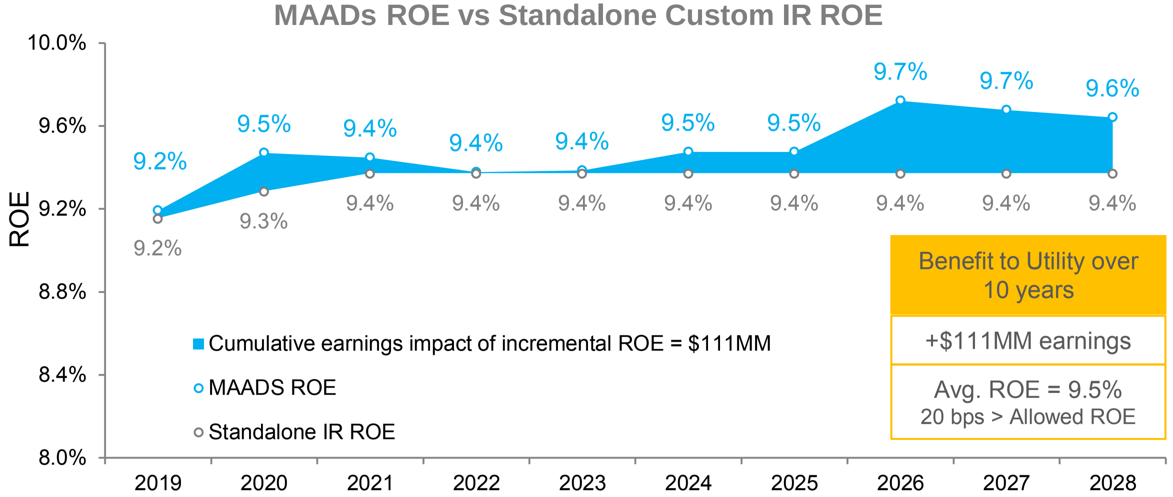
Why MAADs?

- EGD and Union current IR terms end in 2018. As both have operated under IR frameworks for an extended period of time, limited productivity opportunities remain available
- Amalgamation of EGD and Union represents an opportunity to increase efficiencies of each utility via synergy capture that are both beneficial to the ratepayer and shareholder
- To integrate successfully and generate savings for customers, 10 years is needed and the MAADs framework provides this versus a shorter term under custom IR
- The defined sharing mechanism within MAADs is also critical to addressing the risk inherent in a 10 year term
- Within the MAADs framework, the Price Cap inflator model (with ICM) is seen as best aligned with the utilities' near & long term operating outlook
- The risks EGD & Union are exposed to under the MAADs/ Price Cap framework is magnified versus the current custom IRs due to the 10 year deferred re-basing period, however Management believes these risks can be managed
- Both options (Custom IR or MAADs) require prudent management of operating and capital expenses within a fluid economic and regulatory environment

"Win" for the ratepayer – lower utility bill consolidated than standalone



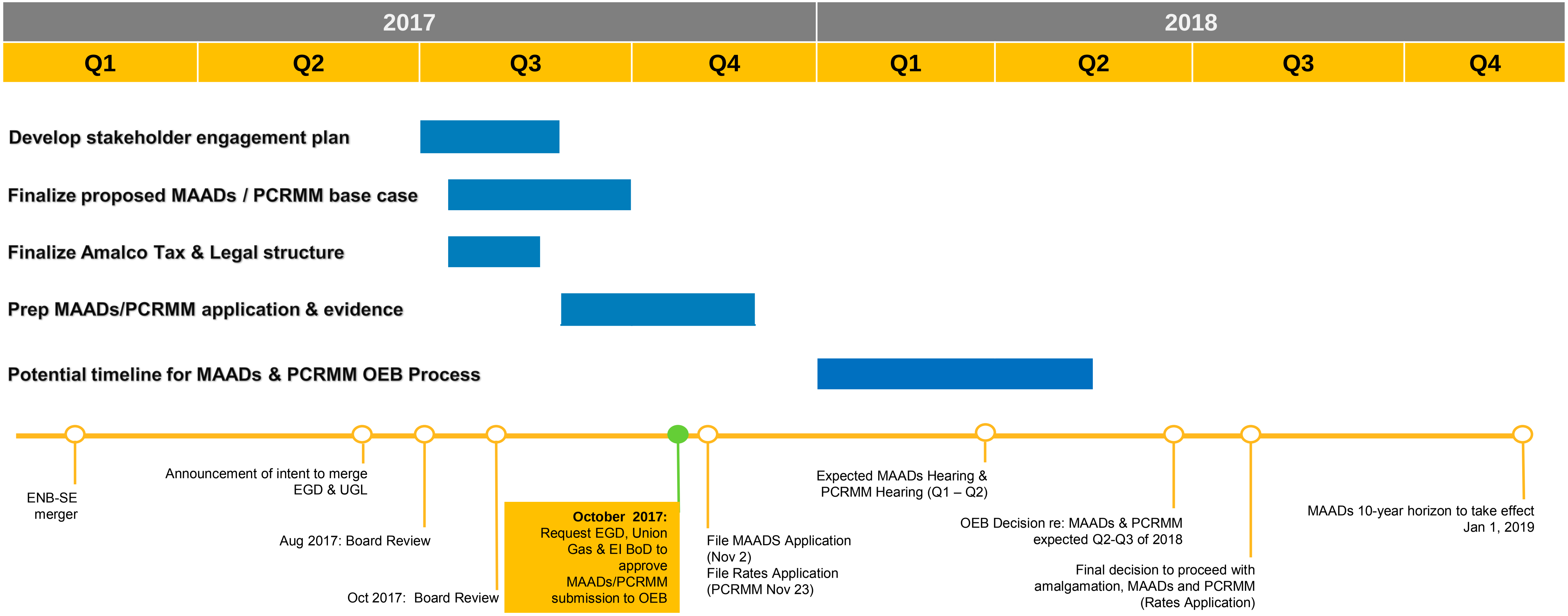
"Opportunity" for the utility – time to fully integrate and potential for excess earnings



Balanced Framework: $410M in ratepayer savings and Utilities have opportunity to outperform the Allowed ROE

Utilities Integration

Expected Timeline



EGD and Union would file the MAADs and Price Cap Rate Making Mechanism (PCRMM) with the OEB in early November; OEB decision anticipated in mid- 2018

Integration Opportunities

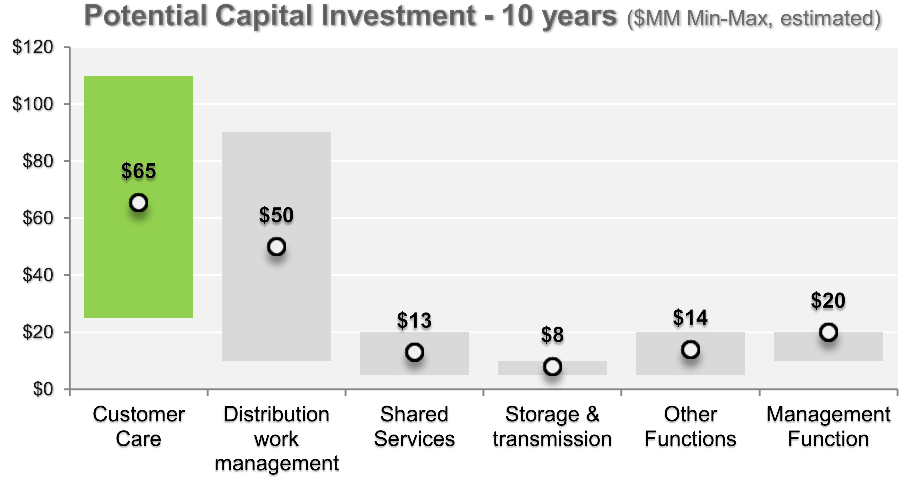
Integration Plan

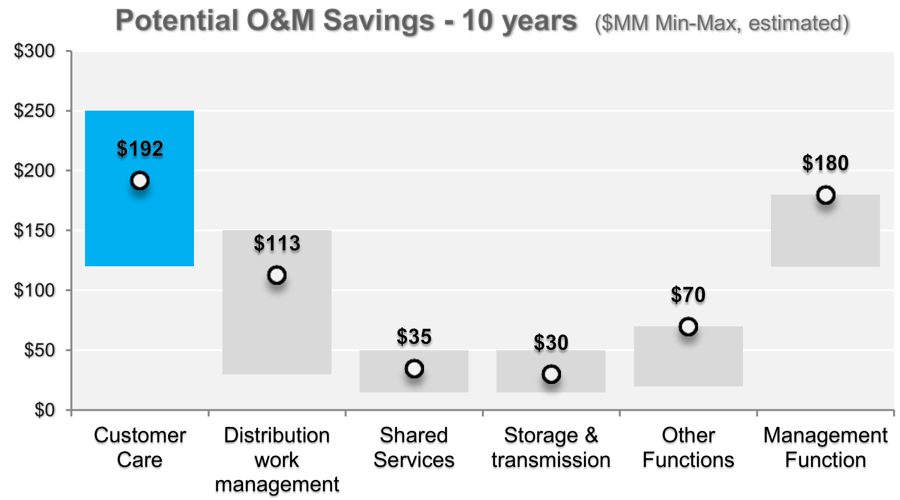
- To assess potential integration plans and projections, the Senior Leaders of both EGD and Union met jointly and reviewed the existing functional areas within each utility. The review allowed the leaders to compare and contrast historical operational results and future forecasted result.
- The senior leaders have extensive knowledge of the operations of each utility and were able to draw on the results from previous operations reviews and business process improvements that have been implemented over the past 15 years
- Based on this review, 5 key functional areas for integration were identified.
  - The cost estimates included are based on the known costs for each utility for both capital and operating expenses and forecasted expenditures
  - EGD & Union have also each developed 10 year Asset Management Plans as required by the OEB. These plans are based on engineering assessments of all assets to optimize maintenance versus replacement decisions as required
  - These Asset Management plans are the basis for the capital expenditures over the 10 year MAADs framework timeline

5 Key Areas for Integration
Customer Care
Distribution Work Management
Shared Services
Storage & Transmission Operations and Gas Supply & Control
Management and Other (Engineering, Integrity, Public Affairs, Demand Side Management, Cap & Trade, Business Development)

Integration Opportunities
Customer Care

Opportunity	**There is an opportunity under the integrated utility to unify customer care operations under a single system and supporting software platform. As well, to integrate to a single customer care model & effectively bring $/customer service cost down while maintaining service quality to our customers**
Scope	Cost reductions are to be achieved from a combination of: • increased number of e-bill customers through better customer care web services, • unification of the customer care software system onto a single platform, and • Implementation of best practices
Capital Estimate	The unclassified estimate of **$65 M** represents migration to one of the current existing software platforms and structures. The estimate is based on the original EGD SAP software implementation costs as a benchmark The two customer care groups have differences in operations and practices. The estimated range when comparing can be as high as $5 per customer
Opex Savings	2020- 2023 savings: Targets a $15 M/year reduction in the combined customer care services cost, or 10%. This reduction would equate to an estimated reduction of ~ $4 /customer across the combined 3.5 million customer base 2024 savings: Post implementation of a single software platform, an addition 7.5% reduction is targeted which can deliver $10 M/year from 2024 to 2028 Overall, the targeted reduction in annual O&M costs by 2024 is approximately 17% below the 2018 forecasted level of $150 Million and a total savings of **$192 M** over the 10 years
Basis for Estimate	Capital estimate based on system unification (i.e. not a full re-implementation). Cost estimate equates to approximately half of EGD's customer care system implementation cost of $120 M

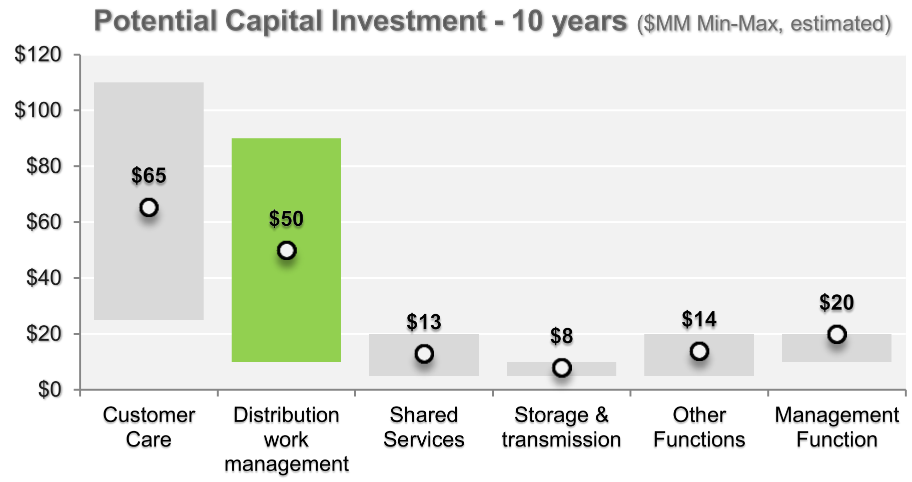


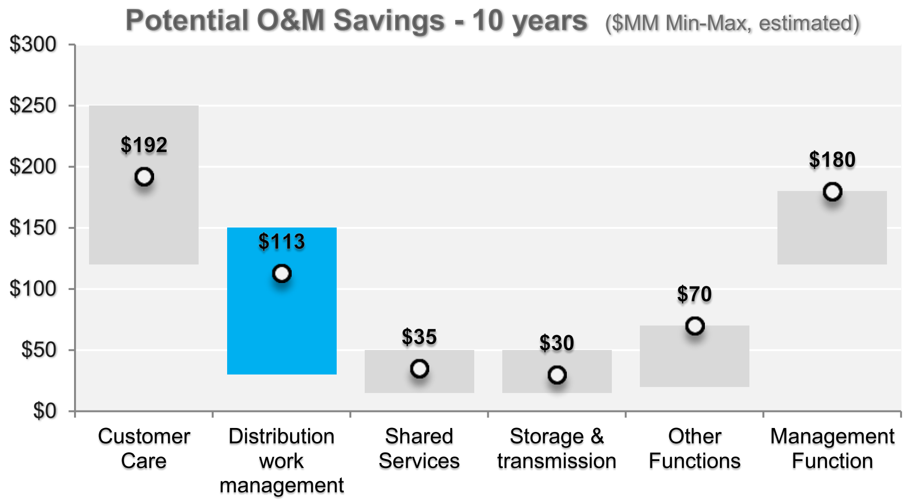


Create a single customer care model to maintain customer service and reduce costs

Integration Opportunities
Distribution Work Management

Opportunity	**Distribution work management is the planning, scheduling, compliance, work management systems (WMS), WMS support, asset management and support for overall work to maintain, plan and schedule our assets across Union and EGD** **There is an opportunity to adopt best practices, align systems and improve worker productivity**
Scope	A detailed analysis of software options will be conducted. Estimates today are based on integrating Union Gas into EGD's Maximo software system In addition, each distribution work management process is to be evaluated to identify the best practice at the lowest cost level which will then be implemented
Capital Estimate	EGD completed an implementation of Maximo in 2016 at a cost of ~$85 M. The integration of Union into Maximo ranges from $30 M for data and business process migration to $85 M for full implementation. Management has assumed **$50 M** in the business plan
Opex Savings	Savings have been estimated at $11 M/year or 10% of the estimated 2016 costs. The profile ramps up to $16 M/year in 2024 to 2028 due to optimizing 3rd party contracts. The total savings over the 10 year period is **$113 M** Given that both utilities have optimized workforces and internal processes on a standalone basis and the integrated utility has forecasted approximately 50,000 customer additions per year, an estimate of 10% further reduction in costs and workforce planning is seen as moderate to aggressive
Basis for Estimate	Capital estimate based on system unification (i.e. not a full re-implementation). Cost estimate equates to approximately half of EGD's Maximo system implementation cost of $85 M





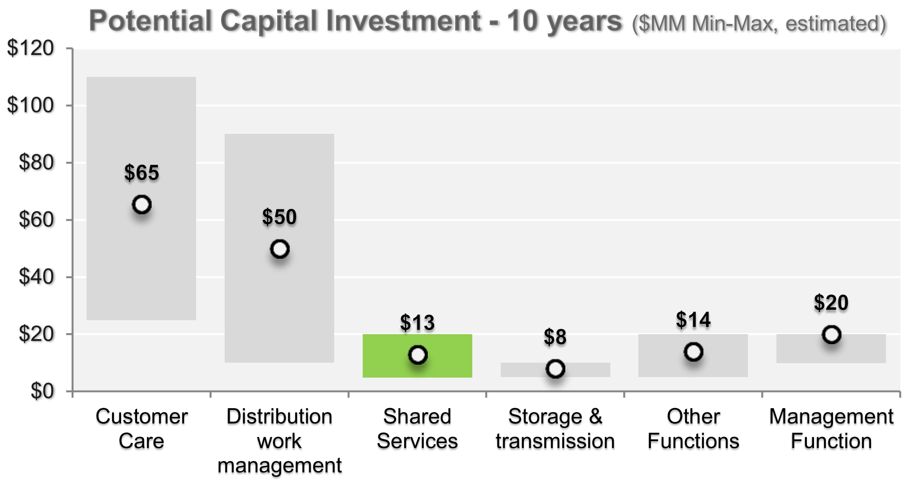
Adopt best practice and eliminate redundancy of systems; improve worker efficiency

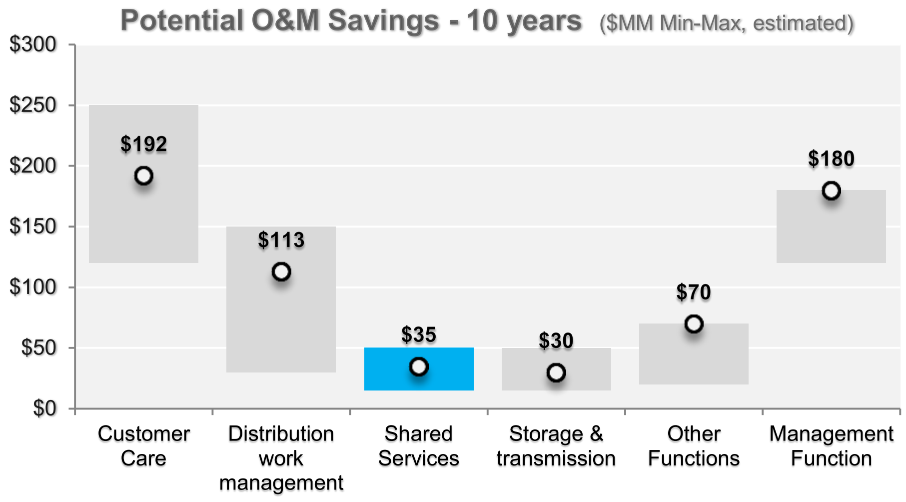
Integration Opportunities

Utility Shared Services

Opportunity	**There is an opportunity to reduce duplication of systems and software under Shared Services that are specific to the Utilities**
Scope	A review will also be undertaken to reduce the duplication of systems/ software at the utility, such as Utility contract management, utility billing financial analysis, IT service requests, and real estate services
Capital Estimate	An preliminary estimate to implement a common software platform for these areas of shared services is assumed to be between $5 M and $20 M. **$13 M** has been assumed in the business plan
Opex Savings	The targeted savings are estimated to be $2 M to $7M per year or 2% to 7% of the combined utilities annual operating costs. The total savings over the 10 year period is **$35 M**
Basis for Estimate	This cost estimate is based on historical IT smaller full system implementation costs and reflects a midpoint average number of systems being unified

Reduce duplication of systems and software specific to the Utilities





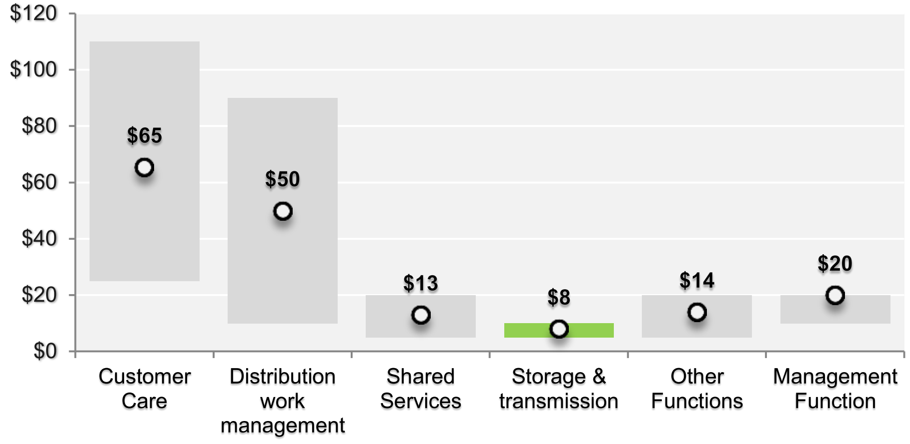
Integration Opportunities

Storage and Transmission Operations and Gas Supply and Control

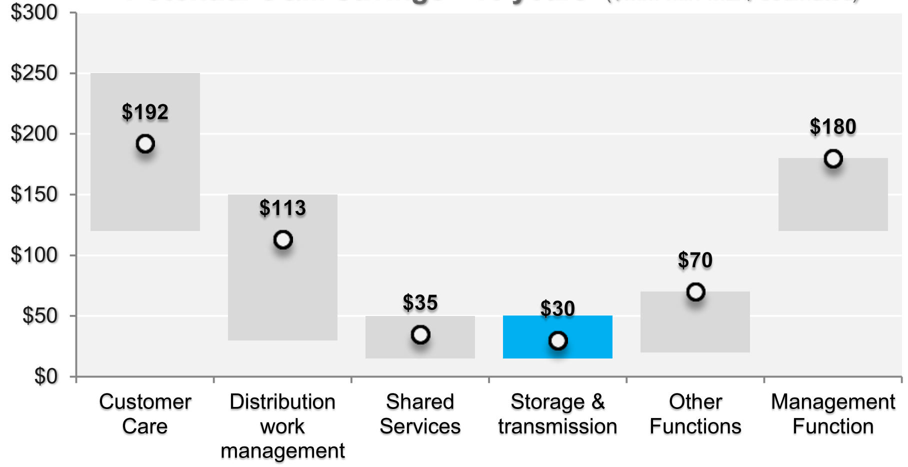
Opportunity	**The Storage and Transmission Operations and Gas Supply business function include operations and maintenance of the transmission pipeline systems, storage wells and reservoir** **Gas Supply and Gas Control includes the gas control room operations for both EGD and Union Gas, gas supply and upstream transportation contracting and settlement processes and associated systems and software for both utilities** **There is an opportunity to drive cost savings from harmonizing the SCADA systems and implementing process changes to optimize maintenance costs and alignment of contracts**
Scope	Union has more assets in the Storage and Transmission functions than EGD and its SCADA system is located in Chatham, whereas EGD's is located in Edmonton. Must assess the potential to sync to one system, one location In addition, a review of the different software applications that both EGD and Union use for their Gas Supply settlement processes will be conducted
Capital Estimate	A preliminary estimate to integrate the SCADA system and selection of software for gas supply operations to a common platform ranges from $5 M to $10 M. **$8 M** has been assumed in the business plan
Opex Savings	The savings are estimated to be on average $3 M/year, or 10% of the annual $30M cost. The total savings over the 10 year period is **$30 M**
Basis for Estimate	This cost estimate is based on historical IT smaller full system implementation costs and reflects a midpoint average number of systems being unified

Sync to common SCADA system and align Gas Supply systems and processes

Potential Capital Investment - 10 years ($MM Min-Max, estimated)



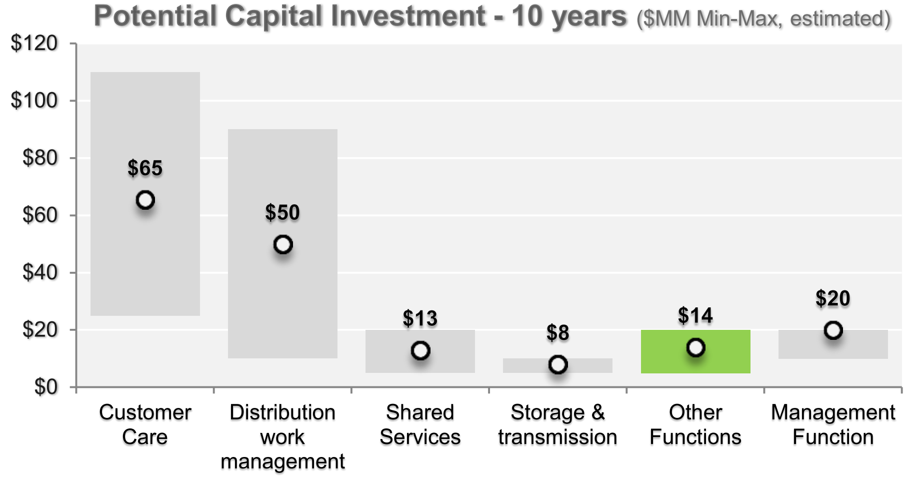
Potential O&M Savings - 10 years ($MM Min-Max, estimated)

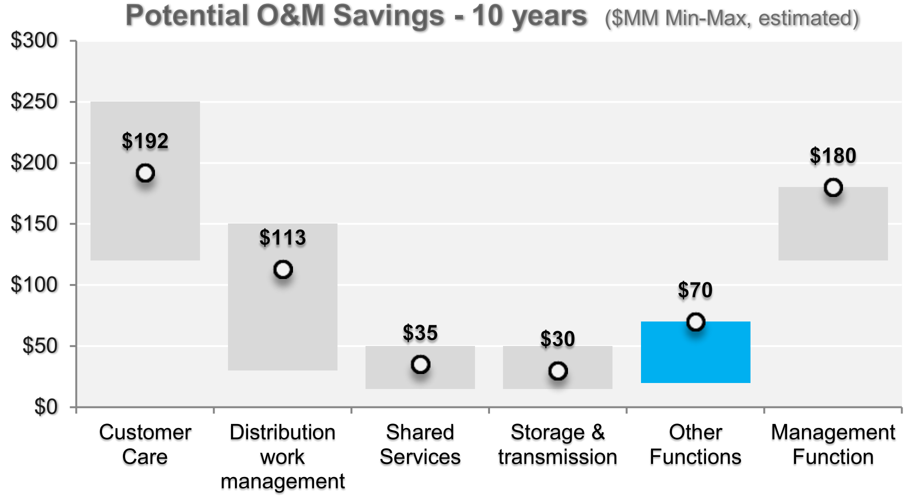


Integration Opportunities
Other Functions

Opportunity	**Other functions include business areas such as Engineering and Integrity, Information Technology, Public Affairs, Demand Side Management, Cap & Trade and other Low Carbon Business Development** **These groups have opportunities to integrate and drive productivity associated with elimination of smaller software systems, implementing sourcing models to reduce internal system support costs, implementing efficiencies through vendor contract management and process optimization cost savings opportunities**
Scope	The majority of savings will come from the rationalizing of Information Technology systems costs as both Union and EGD have several systems that facilitate day to day operation of the utilities. Some of the different systems are: GIS, extranet websites, different meter-reading based software, several data warehouses that facilitate data analytics and reporting
Capital Estimate	The integration of these utility systems is expected to start in 2019 and has preliminary cost estimate ranging from $5 M to $20 M. Management has assumed **$14 M**
Opex Savings	The annual savings estimate from this area is approximately $14 M/ year based on a 14% reduction to the annual combined O&M cost estimate. The savings are expected to be generated starting 2024 through 2028. The total savings over the 10 year period is **$70 MM**
Basis for Estimate	This cost estimate is based on historical IT smaller full system implementation costs and reflects a midpoint average number of systems being unified

Integrate the Information Technology systems between the two Utilities



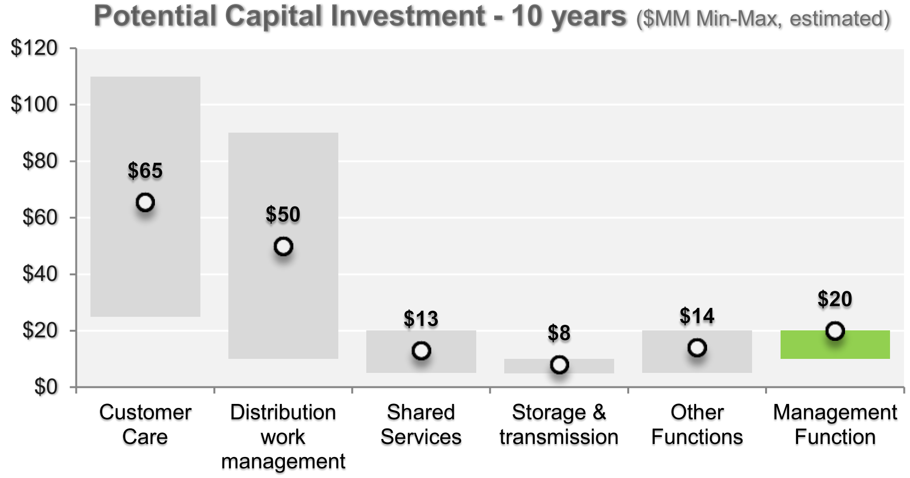


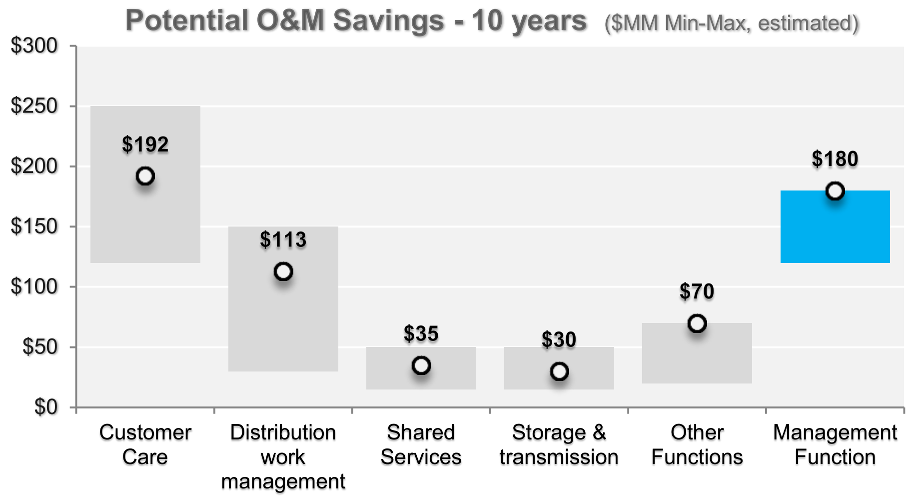
Integration Opportunities

Management Function

Opportunity	**There are opportunities to rationalize the management structure and other functions within the integrated utility. Identifying a single management structure and Executive Management Team will be one of the first integration efforts** **Broader workforce reductions are expected to occur at a much more gradual pace as various integration initiatives are undertaken over the 10 year deferred rebasing period**
Scope	Considerations by the new management team with respect to any workforce reductions will require a review and alignment of operational processes and the related systems, and the staff necessary to execute these processes so that safe, reliable business operations continue and service levels are maintained
Capital Estimate	There is approximately **$20 M** of severance costs that have been considered as capital that will occur in the first year.
Opex Savings	The savings from the rationalizing of the management structure is estimated to be **$180 M** over ten years. A 7% reduction in combined utility annual salaries and wages of $285 M (net of capitalization) This estimate for potential savings is considered aggressive as a percentage of the management level salaries. The estimate for management structure changes is input as $20 M per year with a first year severance cost of $20 M
Basis for Estimate	Based on compensation costs of to duplicate of Management functions

Align and rationalize management structure for combined Utility





Integration Opportunities

Summary

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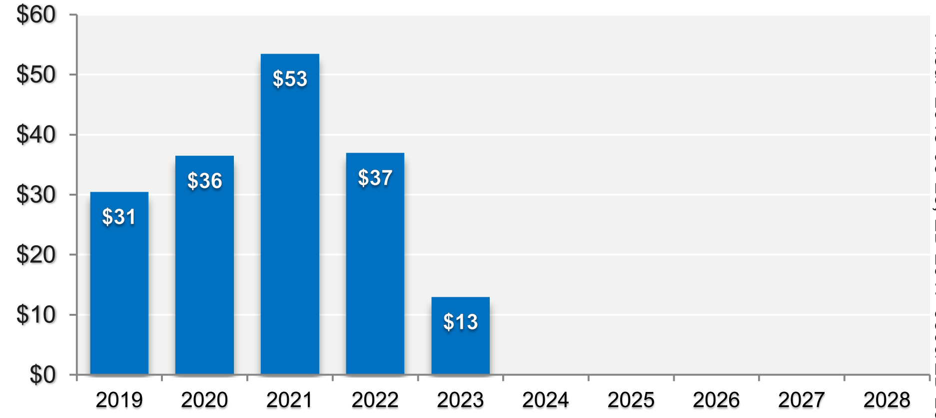
($MM)	Estimated CapEx	Estimated O&M Savings	Benefit / Cost Ratio (per current estimates)
Customer Care	65	192	2.9x
Distribution Work Management	50	113	2.3x
Shared Services	13	35	2.7x
Storage & Transmission	8	30	3.8x
Other Functions	14	70	5.0x
Management Functions	20	180	9.0x
Unidentified		60	
Total	$170	$680	4.1x

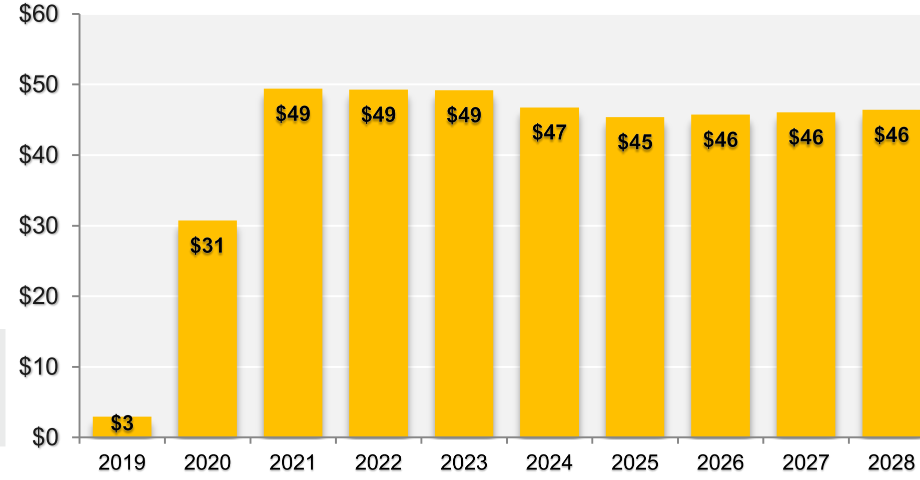
0.0x 2.0x 4.0x 6.0x 8.0x 10.0x

Up front capital investment supports synergies over the 10 year integration timeframe

Integration Annual CapEx ($Million)

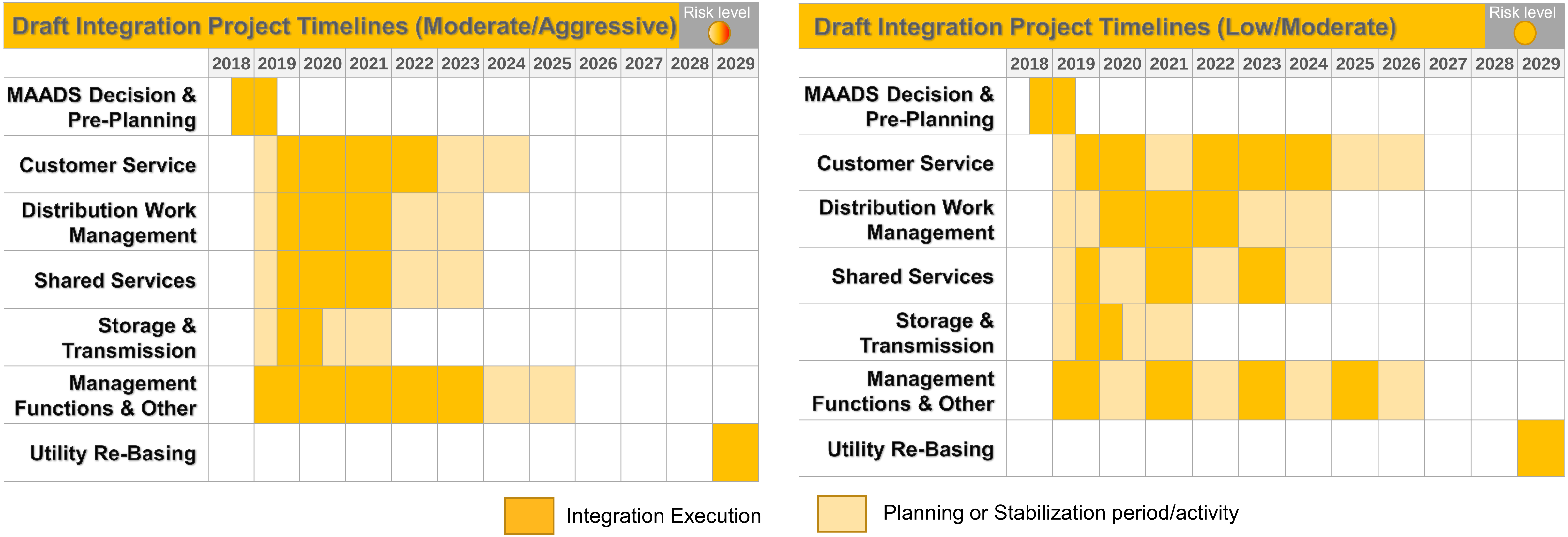


Net Annual O&M Savings (after –tax $Million)



Integration Opportunities

Project Timelines



There are a range of implementation timelines. The moderate to aggressive timeline selected allows for the delivery of benefits over the ten year timeframe

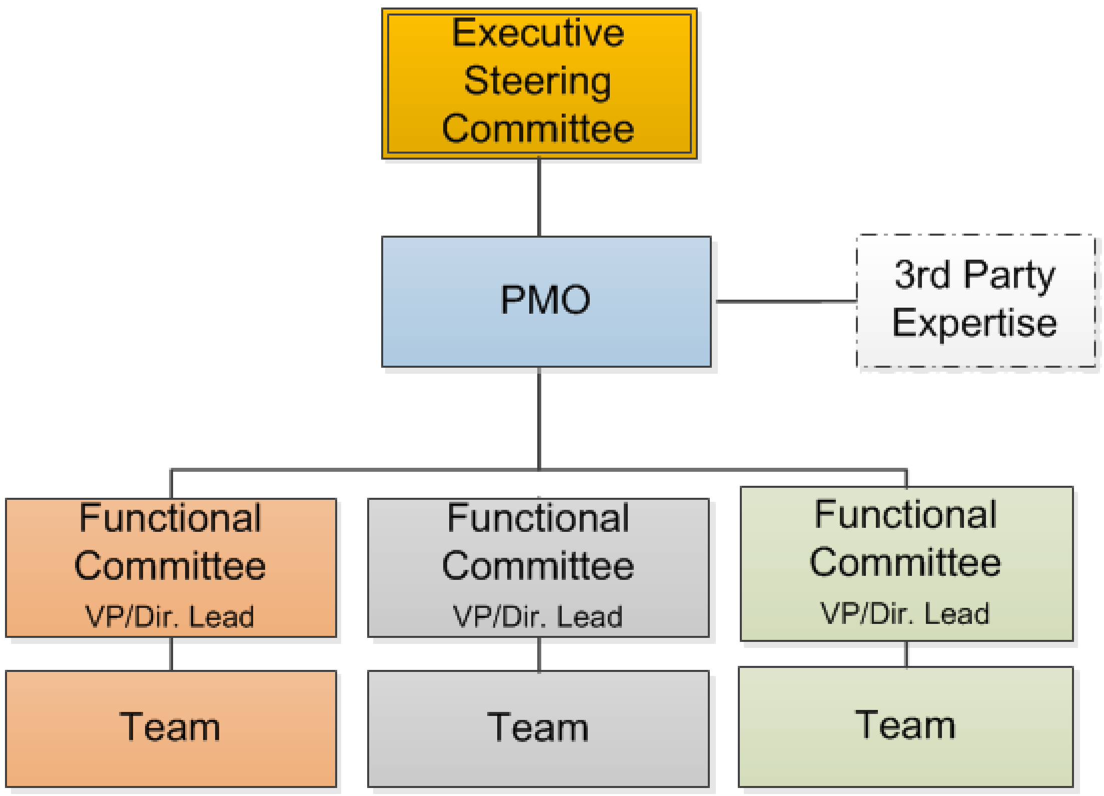
Integration Opportunities

Governance Structure

- A PMO office will be established in 2018 to provide oversight to all implementation plans and functions.
- The PMO will be accountable for:

  1. Developing a comprehensive integration roadmap
  2. Monitoring project streams and cross-stream issues/impacts
  3. Identification of program-level risks and mitigation strategies
  4. Driving results and accountability

- The implementation plans will be staggered to ensure organizational capacity to support and adopt the required changes
- Capital investments will be subject to stand alone investment review and approvals



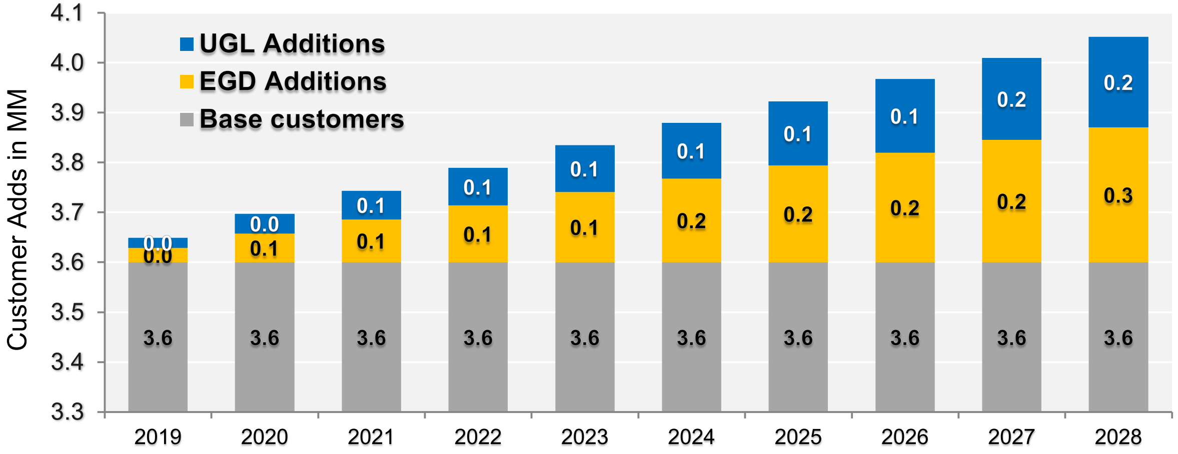
Integration governance will be a key success factor and will leverage “best practices” and past utility experience

Integration Financial Evaluation

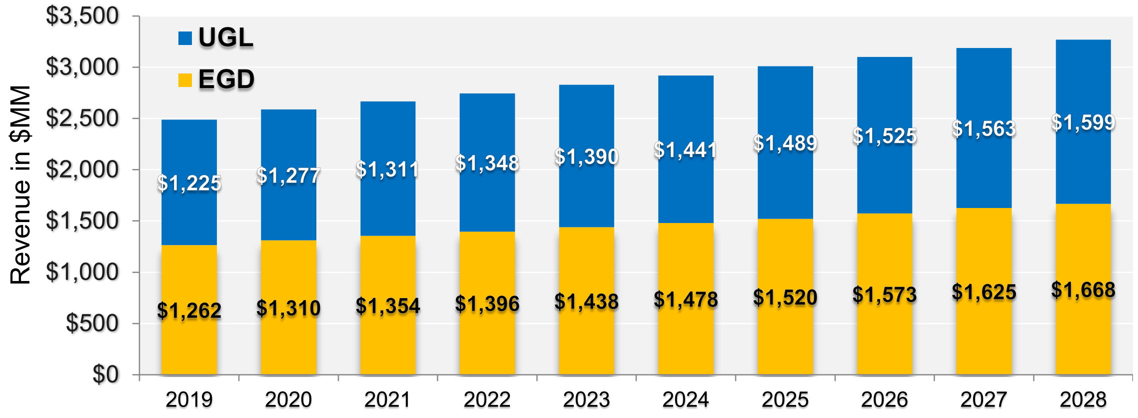
Base Case Key Economic Assumptions

- Customer growth escalates at 0.93%, or 50,000 per year, in the near term (driven by continuing trend of rapid GTA growth), tapering to 0.84%, or 42,000, in the long term
- Revenues growth driven by: customer addition profile and price cap escalator of 1.73%
- O&M escalates at 2.0% in the near term, dropping to 1.73% mid-long term

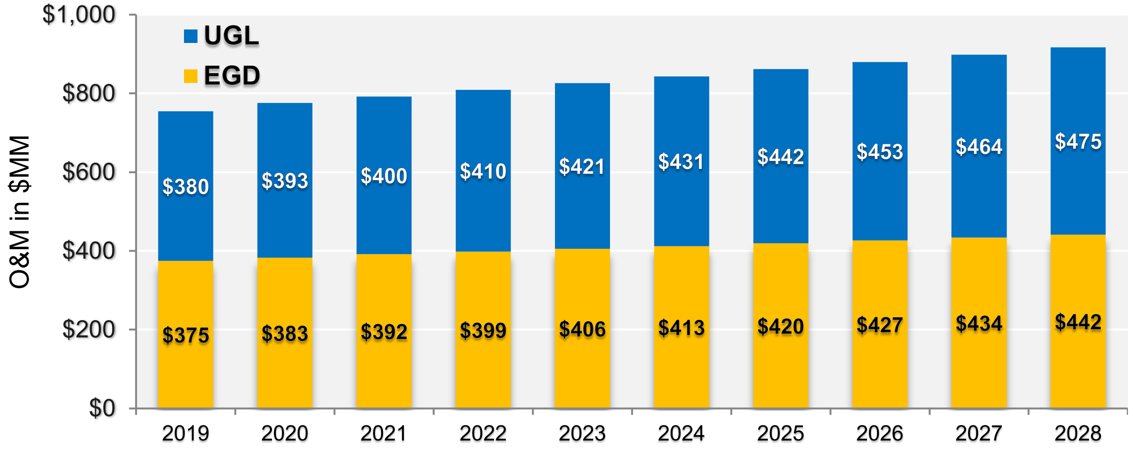
Customer Growth	Outlook Positive	Continuation of strong population growth (notably GTA)



Revenue Growth	Outlook Positive	Sizeable population growth and a GDPIPI revenue inflator that tracks to inflation drives a stable increasing revenue profile



O&M Profile	Outlook Stable	Conservatively, O&M increases are modeled to outpace inflation (2.0% vs 1.7%) until 2021, at which point they align

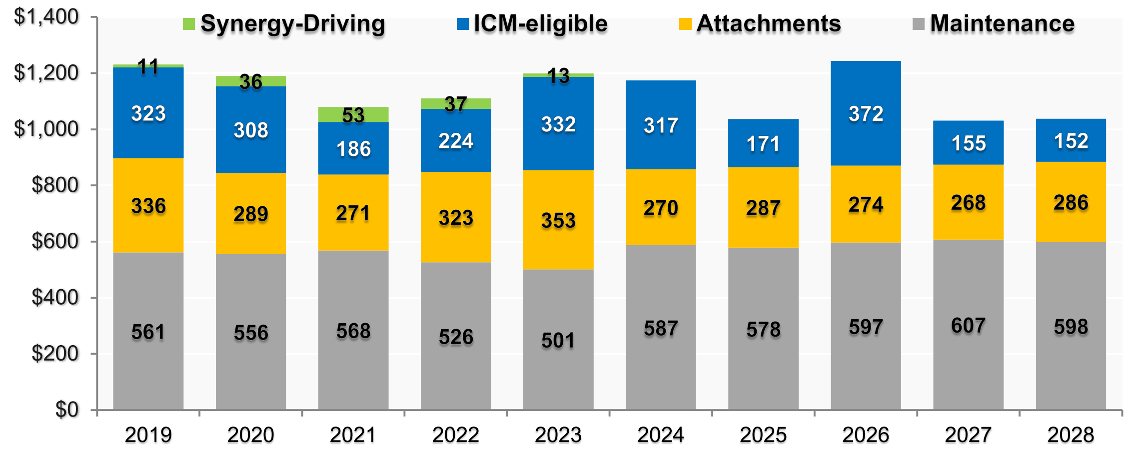


Integration Financial Evaluation

Base Case Key Economic Assumptions

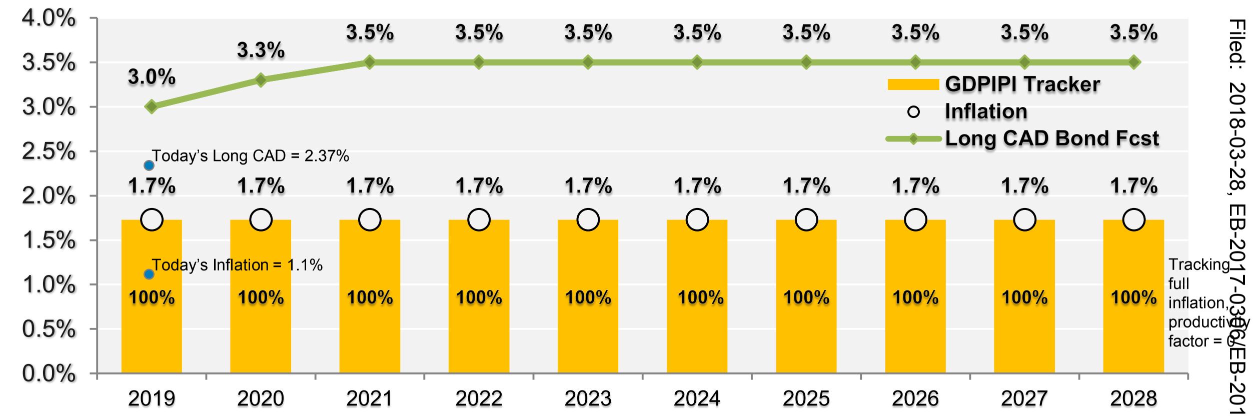
- Capital expenditures based on 10 year Asset Management Plans which is filed at base year; Incremental Capital (discrete projects) added to rate base at in service year Allowed ROE amounts through the ICM
- The Long CAD Bond forecast has a 50 bps increase from 2019 to 2021 and 113 bps increase from todays rate to 2021
- Allowed ROEs are based on utility forecast which is primarily driven by the Long CAD Bond
- Zero cost sharing assumed over the 10 year period (i.e. Returns on equity are less than the 300 bp threshold)

Capital Program	Outlook Stable	Stable & manageable profile, combined with ICM, reduces risks to ROE drag

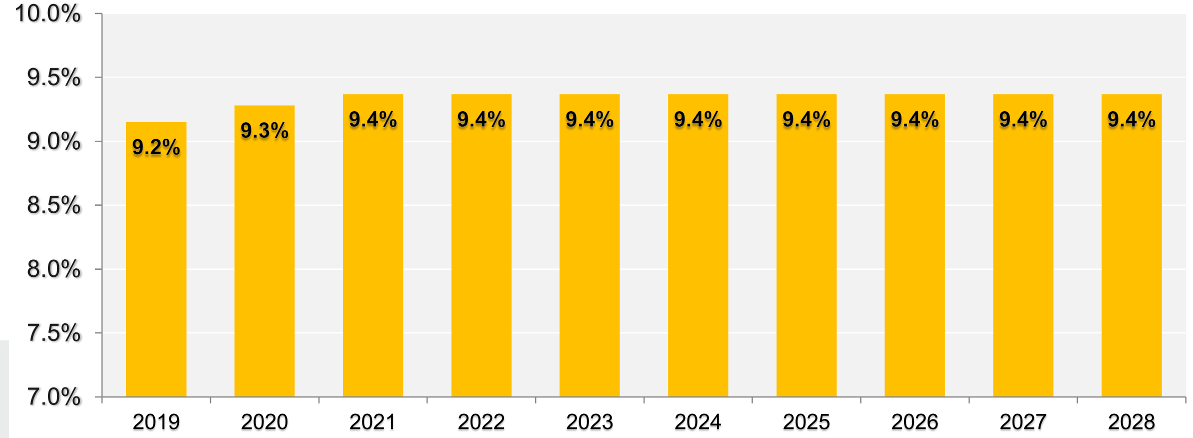


No rate adjustment under MAADs for higher interest rates or Allowed ROE

Inflation & Interest Rates	Outlook ST Increase	Historic low interest rate environment trending higher, partially offset by GDPIPI revenue tracking and hedging



Allowed-ROE	Outlook Stable	Allowed-ROE drivers (LT CAD GOV, Corporate bond yields) trending upward, gradually increasing allowed-ROE

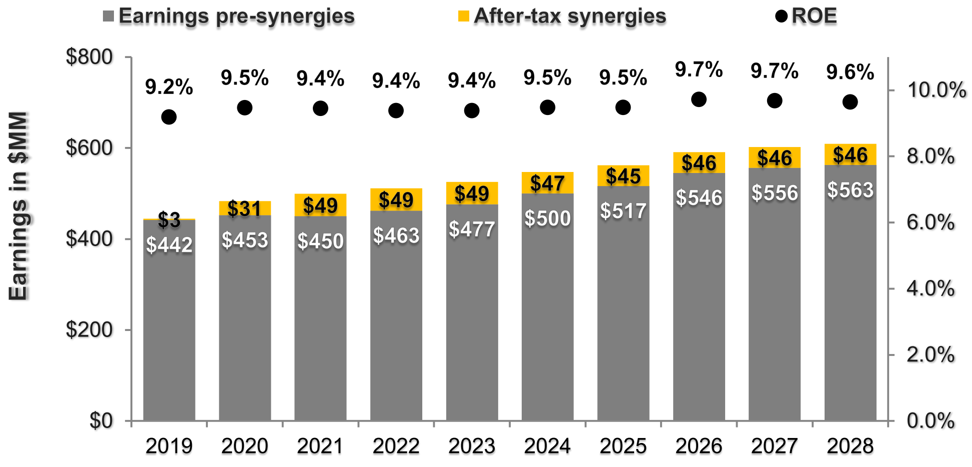


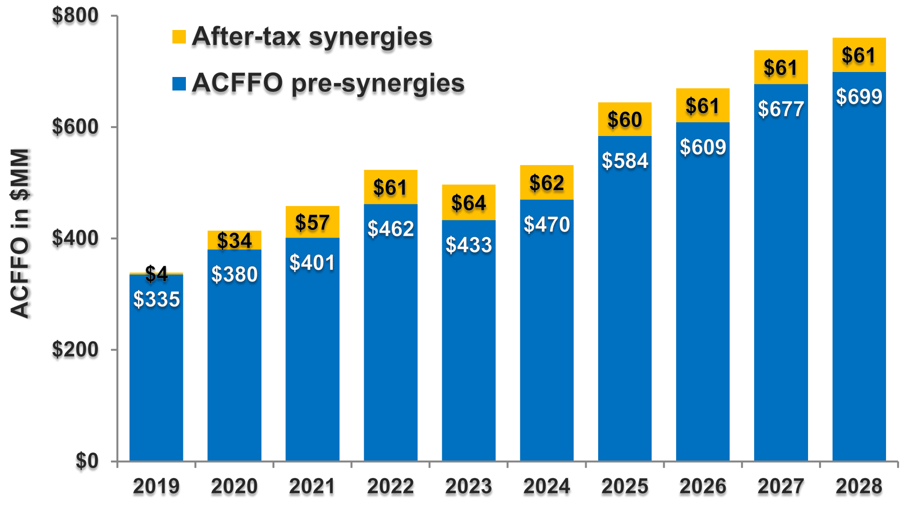
Integration Financial Evaluation

Base Case Financial Summary

Financial Summary

	Proposed Filing: 10 year MAADS (Escalated Price Cap + Incremental Capital Module)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
EGD	235	245	240	247	256	272	278	304	309	316	
UGL including deferred tax adj	207	208	210	215	220	228	238	242	247	247	
Utility Earnings before synergies	**442**	**453**	**450**	**463**	**477**	**500**	**517**	**546**	**556**	**563**	
Synergies	3	38	63	70	81	85	85	85	85	85	**680**
Drag due to funded synergy capital	(1)	(4)	(9)	(15)	(18)	(18)	(18)	(17)	(17)	(16)	**(133)**
Sub-Total Pre-Tax Synergies	2	34	54	55	63	67	67	68	68	69	**547**
After-tax impact of synergies	**3**	**31**	**49**	**49**	**49**	**47**	**45**	**46**	**46**	**46**	**412**
Utility Earnings with synergies	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**	
Earnings Sharing (2024 – 2028 >300bps)	-	-	-	-	-	0	0	0	0	0	
Utilities Earnings after sharing	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**	
Achieved ROE	9.2%	9.5%	9.4%	9.4%	9.4%	9.5%	9.5%	9.7%	9.7%	9.6%	
Allowed ROE	9.2%	9.3%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	





Average of $42 Million/ year of after –tax synergies provides opportunity to achieve earnings in excess of Allowed ROE while delivering inflationary rate increases to customers

[1] ACFFO is aligned with utility STIP measurement calculation method and has been grossed up (pre-tax and interest expense)
[2] Capital structure 36% equity/ 64% debt
[3] Income tax rates constant at 26.5%

Utilities Integration

Custom IR versus MAADs Risk Profile

	Custom IR	MAADs Framework & Price Cap	Off-Ramps or Other Protections
Financial Risk			
Interest Rate Risk	• Cost of Debt & ROE set each year to that years Enbridge cost of debt and OEB ROE	• OEB expects that GDP-IPI-FDD index inflator correlates to interest rate movement	• MAADs policy off-ramps: • when achieved ROE is 300 bps less than the Allowed ROE • Management proposal to recover higher interest expense due to higher interest rates

Inflation Rate Risk	• Embedded up front within 5 year forecast of costs & scrutinized by OEB (potential cost disallowance)	• GDP-IPI-FDD index updated annually to set distribution revenues	• MAADs policy off-ramps:
			  • when achieved ROE is 300 bps less than the Allowed ROE
			  • Early exit application with supporting evidence

Tax Risk	• Z-Factor treatment for exogenous events		• MAADs policy off-ramps:
			  • when achieved ROE is 300 bps less than the Allowed ROE
			  • Early exit application with supporting evidence

Regulatory Risk			

Productivity Factor Risk	• Embedded in up front application forecast of costs & scrutinized by OEB (potential cost disallowance)	• Established by third party study & scrutinized by OEB (potential increase to factor)	• MAADs policy off-ramps:
			  • when achieved ROE is 300 bps less than the Allowed ROE
			  • Early exit application with supporting evidence

Capital Cost Risk	• At risk for cost overruns on approved capital. No access to ICM	• At risk for cost overruns on ICM approved capital	• Request variance account treatment for large capital projects through OEB Leave To Construct process
Operational Risks			

Operating and Capital cost forecast Risk	• Embedded in up front 5 year forecast of costs & scrutinized by OEB (potential cost disallowance)	• Level set as amount in OEB base year distribution revenue and inflated annually by Price Cap Inflator	• MAADs policy off-ramps:
			  • when achieved ROE is 300 bps less than the Allowed ROE
			  • Early exit application with supporting evidence

Weather Risk	• Distribution revenues recovered through an annual forecast set of volumes based on normal weather		• File application with OEB to recover distribution revenues via a fixed charge
Volume Risk	• Residential customer volumes trued-up annually for average consumption and next years average use volume reflects prior year determinant		• File application with OEB to recover distribution revenues via a fixed charge

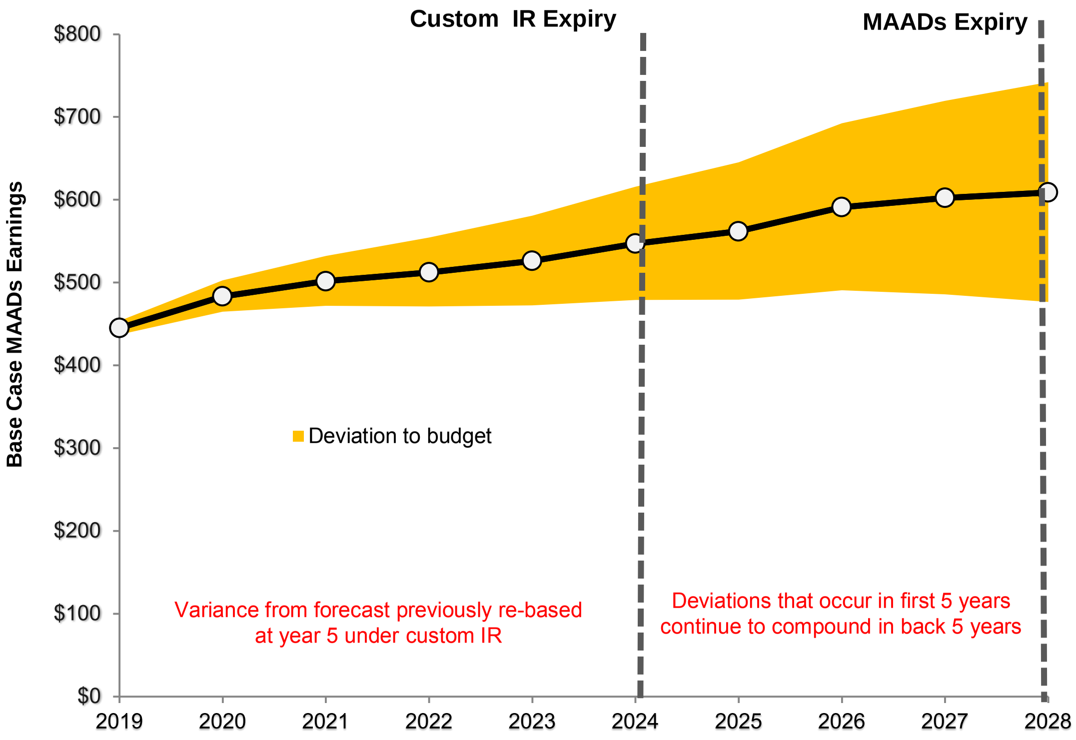
The risks and mitigants associated with integration under MAADs are consistent with the current 5 year term CIR and Price Cap mechanism that EGD and Union operate under today. The primary difference is the 10 year deferred re-basing period under the MAAD framework versus 5 years under the custom IR

Utilities Integration

Increased Exposure to Variance over the 10 year Term

- **The Utility is exposed to increased risk over the 10 year term due to the increased likelihood for deviations from base forecasts to occur**
- The OEB MAADs policy states that in approving an integration application, an entity has committed to a plan based on the circumstances. However, the policy also provides the opportunity to exit from the MAADs framework due to material unforeseen events
- To protect from this term risk, the utility, in its application, is seeking approval to recover higher interest expense should the utility consistently under earn due to changes in interest rates
  - An application seeking approval to exit the framework is expected to undergo scrutiny and demonstrate the need to amend the ten year deferred rebasing period.

Additional 5 years of term amplifies risk (illustrative)



- Variances from forecast assumptions can compound over the 10 year period

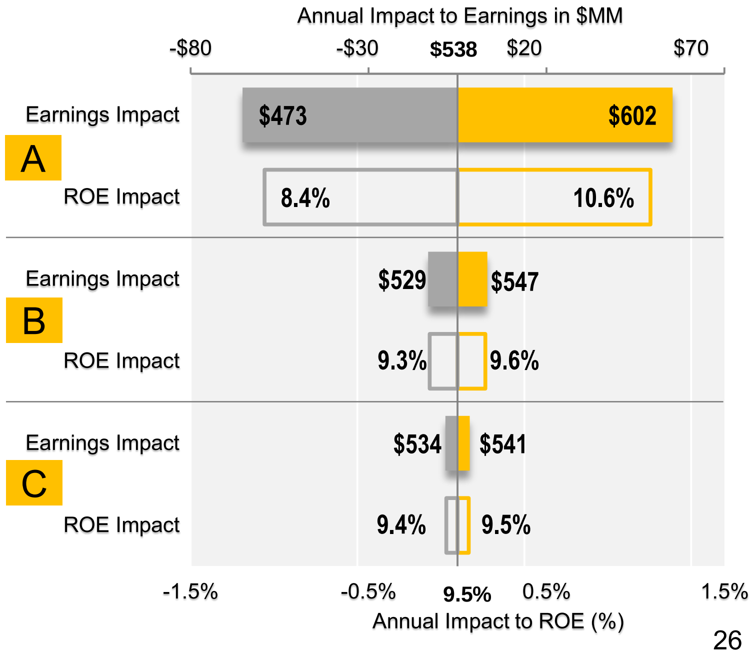
Risk mitigation must be prudently managed under the elongated MAADs term

Integration Risks

Financial Risks

Risks	Risk Level	Risk & Mitigant Description
Interest Rate Fluctuation	● (red)	**Rising interest rates on new debt issuances , short term debt and re-financing not fully captured via the PCI will drag on earnings and ROE.** • The base financial analysis assumes a rising yield curve, i.e. rates rise 50 bps 2019 – 2021 and 90 bps 2018 - 2021 • Interest rate risk can be managed by: 1) Developing a comprehensive hedge program consistent with other EI hedge programs 2) Allotting different proportions to short term and long term debt to mitigate yield curve trends
Inflation Tracking	● (amber)	**Decreases in the Gross Domestic Product Implicit Price Index Final Domestic Demand or (GDP IPI FDD), which acts as the PCI tracker, will reduce revenues and drag earnings and ROE over the 10 year period.** • GDP IPI FDD covers inflation in prices of capital equipment as well as consumer product prices. It provides broad coverage and is reasonably reflective of inflation in prices of distribution parts. • Overall, the GDP IPI FDD has tracked consistently with CPI from 1982 to 2016 including various sub-periods within the range (i.e. 5 years, 10 years, etc.) • The base case assumptions provide some buffer to changes in the GDP IPI FDD in relation to O&M costs as O&M costs were modeled to inflate faster than revenues (i.e. O&M increasing at 2% over the 10 years while revenue is assumed to inflate at 1.73%.) Therefore, to the extent that changes in O&M costs are correlated with the inflation tracker these could track more closely than modeled. • Inflationary trends will be monitored to allow Management to offset exposures through cost containment measures.
Tax Risk	● (amber)	**Increases in the tax rate over the 10 year period would reduce earnings over the 10 year period.** • Management will seek recovery of the cost impact through the OEB's Z-Factor regulatory mechanism which allows for the utility to file an application for costs as a result of exogenous events

Sensitivities		
A	Interest Rate Fluctuation	Interest rates shocked up/ down by 1 σ move across the yield curve on new issuances/re-financing and short term debt balances **(unhedged)**
B	Inflation tracking	Inflation rate reduced 1 σ (50 bps) above/below forecast of 1.73% (isolated to revenue)
C	Corporate Tax Rate Increase	Corporate tax rates shocked up/down 1.0% above forecast (26.5%)

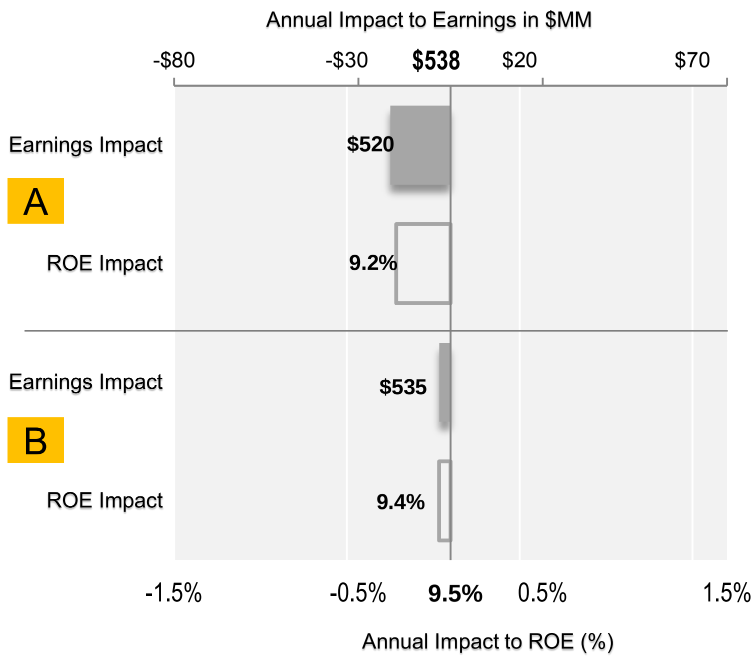


Integration Risks

Regulatory Risks

Risks	Risk Level	Risk & Mitigants Description
Productivity Factor	● (red)	**The utility is at risk to the OEB decision on the productivity factor . A productivity factor > 0 would reduce realized revenues and reduce the overall return.** • Evidence and support for a zero productivity factor is provided by experts who have specialized in utility regulation • If the productivity factor was deemed too high, Management would assess and either: 1) seek an OEB review of the decision; or 2) remove request for PCRMM and seek extension of current custom IR models with intention to file new custom IR in 2020
Capex Risk	● (yellow)	**Any capital disallowed such as from delays, cost overruns, or capital spending deemed ineligible for ICM treatment could drag ROE** • By seeking a 10 year deferred rebasing period, the utility is forgoing the ability to rebase its capital cost overruns from the 2013 to 2018 period or over the 2019 to 2028 period. • The inability to rebase capital costs means that EGD will not update its rates in 2019 to recover capital cost overages namely EGD's GTA system expansion project. • Management will seek to offset the earnings impact of the capital cost overages through the achievement of integration savings. • In addition, EGD & Union have each developed 10 year Asset Management plans which act as the basis for the capital expenditures over the 10 year MAADs framework timeline. The plans will be filed annually during the 10 year period to support ICM requests. • The utility will utilize the ICM available in the MAADs policy to seek recovery of discrete capital investments that exceed the annual ICM materiality threshold.

Sensitivities		
A	Prod. Factor Increased	Productivity Factor increased to 10% from 0% thereby reducing revenue (Inflation – Productivity Factor)
B	Capital Overspend	Capital overspend and non-recovery of $100 M



Integration Risks

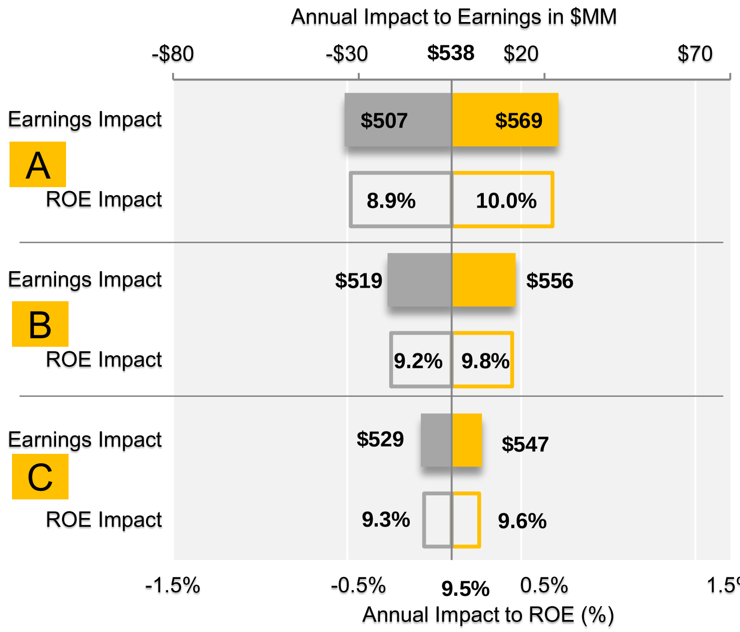
Operational Risks

Risks	Risk Level	Risk & Mitigants Description

Integration Plan & Synergies		**The risk of not achieving the estimated synergies can manifest as cost overruns to capital investments, underachievement in estimated savings or a timing of annual synergies.**
		• To mitigate the risk:
		  • A Project Management Office will be created
		  • A steering committee will be created led by the President of the combined Utility, supported by external experts who specialize in business integration.
		  • All capital investments will follow Enbridge's capital investment review and approval process prior to initiation and Management will implement a integration planning and monitoring function.

Customer Attachments		**Delayed or less-than-forecasted customer attachments will result is the loss of forecasted revenue collection, partially offset by the reduction in customer attachment CAPEX.** • The combined utility will continue to rely on its robust marketing and staffing efforts to ensure customers are selecting natural gas as their heating choice. In addition, the utility will investigate services and offerings to customer to ensure the attachment forecast is achieved.
O& M Costs		**Increases in O&M costs will reduce the utilities earnings and achieved ROE** • This risk exists today for both EGD & Union. Their O&M costs under either custom IR frameworks or the MAAD framework and PCRMM application must be managed prudently to minimize economic drag
Weather		**Both Union and EGD are at risk each year for collecting their distribution revenue due to warmer than budgeted weather** • This risk exists today for both EGD & Union and Management is evaluating the move to using a fully fixed charge approach for the collection of distribution revenues
Volume Risk		**Both Union and EGD have a 1-year risk profile to collecting approximately 40% to 50% of their distribution revenue which are based on consumed volumes.** • The current average use true-up mechanism that provides some protection against volume changes driven by weather/ efficiency improvements by adjusting revenue to be reflective of average temperatures and customer usage is under review. With this mechanism the utility continues to be at risk for usage variances below the average in any given year. This risk is offset by the longer term • Management will evaluate using a fully fixed charge approach for the collection of distribution revenues

Sensitivities		
A	O&M Change	OPEX tracks 5% above / below budget
B	Synergy Change	Synergy change of $25MM (pre-tax)
C	Customer Attachments reduced	Attachment forecast tracks 10% below the assumed ~50,000 customers/year



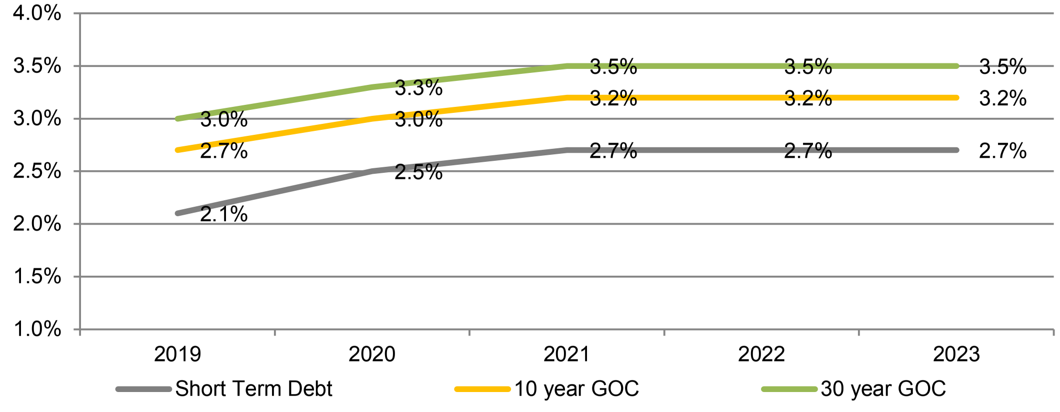
Integration Risks

Interest Rate Exposure

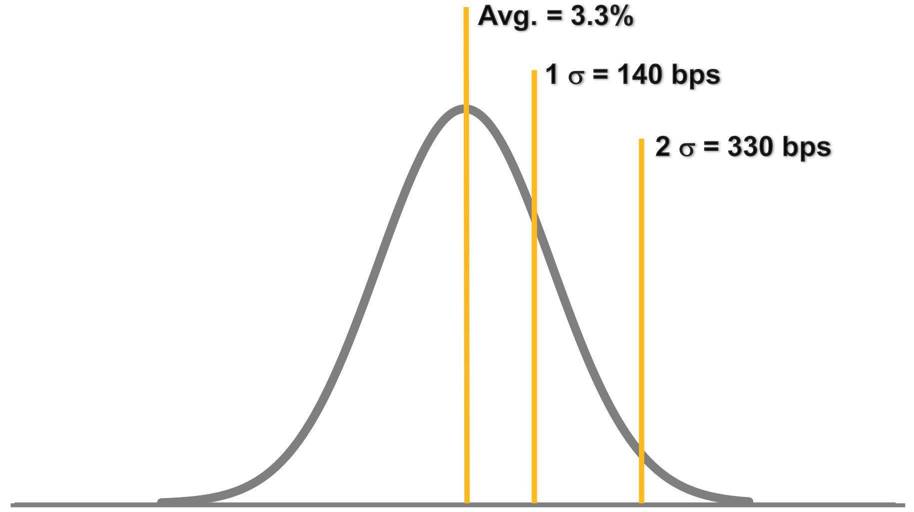
- Under the custom IR, EGD had limited exposure to interest rate movements as rates were set in the fall for the upcoming year
- The exposure was typically limited to < 1 year and could be trued up the following year for actual interest expense
- Customers have received the benefit of the refinancing at lower interest rates over the last two IR terms
- Under MAADs and the Price Cap, the combined Utility will <u>not</u> have the opportunity to set its rates on an annual basis
- The Utility will be exposed to changes in interest rates over the 10 year period
- If left unmitigated, the interest rate risk can become quite large
  - For example 1 σ move in 1 year on the 30 year GOC = 140 bps
- The Utility can leverage Enbridge's risk management experience and hedge a significant portion of this exposure to mitigate the risk

Interest rate risk can be partially mitigated

5 Year Interest Rate Forecast



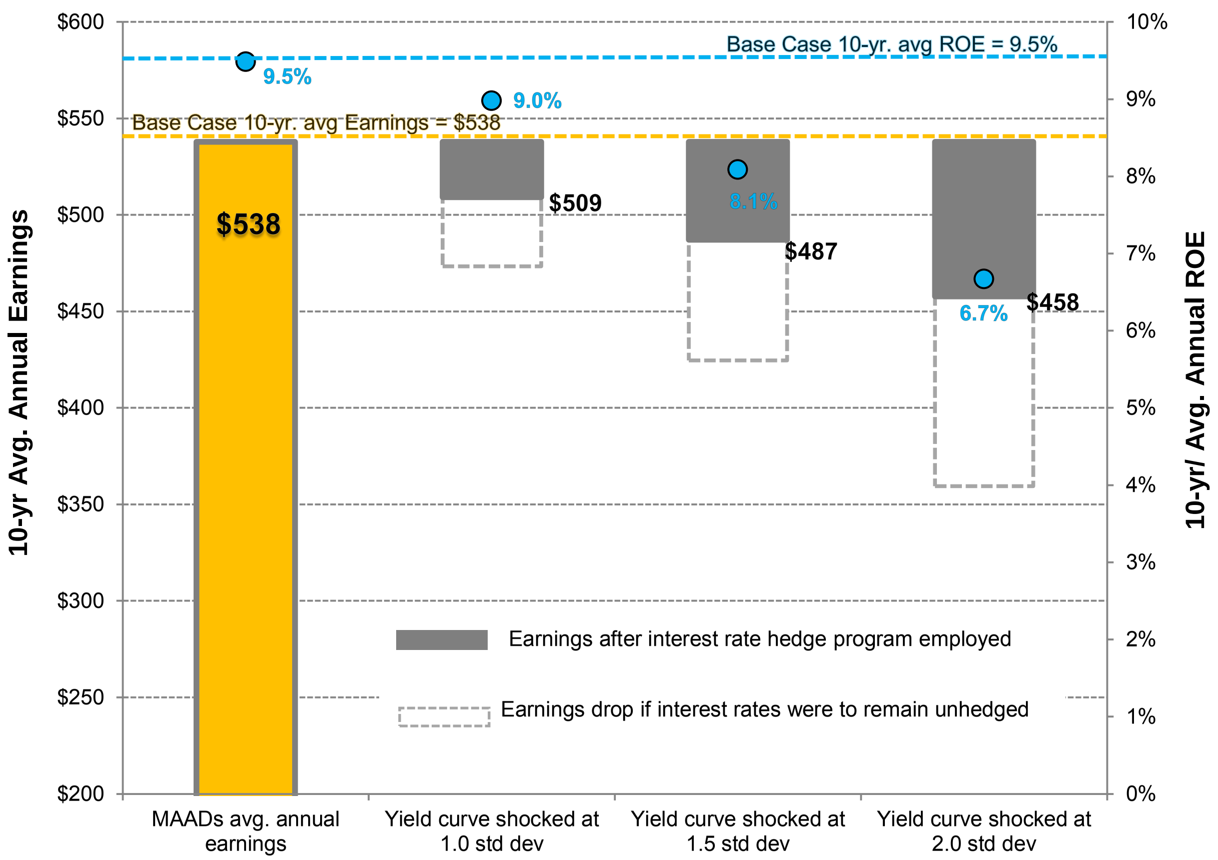
Example: 30 year Interest Rate Distribution and Standard Deviations



Integration Risks

Interest Rate Hedge Program

- The Utility could implement a 5 year rolling hedge program to mitigate its interest rate exposure
- Assuming a rolling hedge program:
  - Assuming a **1 standard deviation** shock across the yield curve – earnings would fall to $473 M
    - **After hedging, earnings would fall to $509 M, a $36 M savings**
  - Assuming a **1.5 standard deviation** shock across the yield curve – earnings would drop to $425 M
    - **After hedging, earnings would fall to $487 M, a $63 M savings**
  - Assuming a two standard deviation shock across the yield curve – earnings would drop to $359 M
    - **After hedging, earnings would fall to $458 M, a $98 M savings**
- Years 6 through 10 would be hedged on a lagged basis (i.e. 2024 would be hedged towards the end of 2019). This lag is due to liquidity of the yield curve.

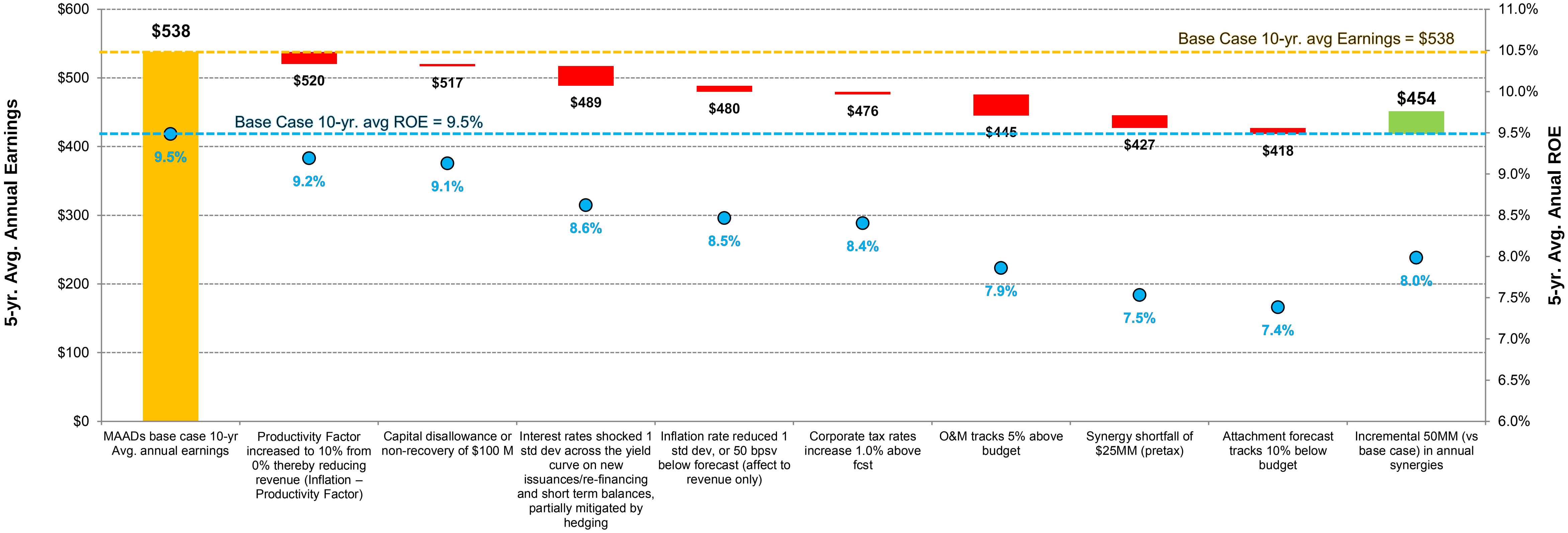


Interest rate risk can be partially mitigated via 5 year rolling hedge program; unmitigated exposure in high interest rate environment may require regulatory rate relief

Integration Risks

Summary of Risks by Type

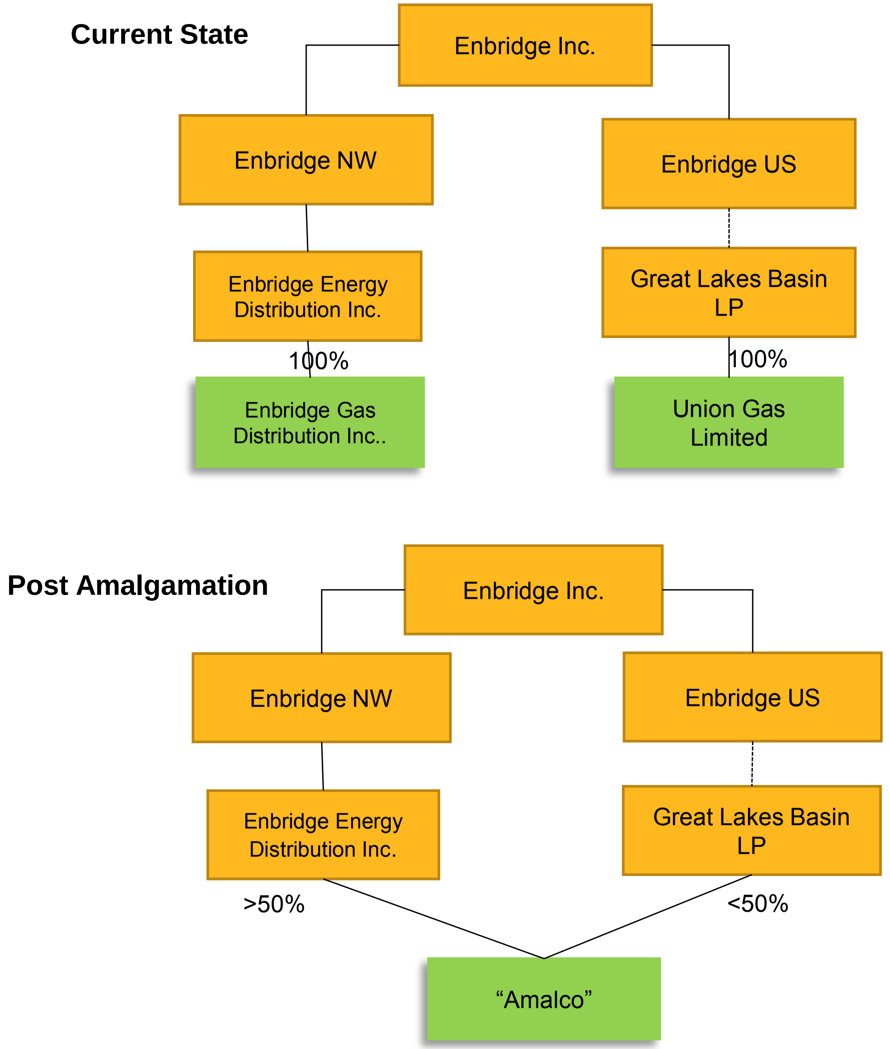
Risk Type	Base Case	Regulatory Risks		Financial Risks			Operating Risks			Mitigant
Δ in earnings		$(18 M)	$(3 M)	$(28 M)	$(9 M)	$(4M)	$(31 M)	$(18 M)	$(9 M)	$36 M



Interest rates increasing represents the largest financial risk

Utilities Integration

Pre and Post Structure



- Governance
  - Substantially consistent with current model employed by Union and EGD
  - One-Third of Board Members are Independent
  - Continued strong sponsorship form Enbridge Inc.
- Treasury Implications
  - External debt will be consolidated; new issuances to be completed out of combined entity
  - EGD and/or Union preferred shares likely to be redeemed prior to amalgamation
  - Dividend policy will be 100% of ACFFO; equity to be sourced from parent to maintain capital structure

Utilities Integration

Conclusion

- As EGD and Union's current IR terms are ending in 2018, both utilities face limited alternatives to generate further efficiencies and savings in the business
- Integration presents a "win-win" situation as it enables synergies and savings that are beneficial for the ratepayer and for the utilities
- Key aspects to integrate are the 10 year term provided by the MAADs framework along with the defined earnings sharing mechanism
- There are increased uncertainties under MAADs/ Price Cap versus the past custom IRs due to the 10 year term. Management believes the risks can be prudently managed and there is acceptable risk/ reward in integration
- **Management recommends the Board of Directors approve:**
  - **EGD and Union filing the MAADs application as well as the PCRMM application consistent with the terms presented in the Board presentation**
- Management will return to the Board if the terms vary based on discussions with the OEB

Utilities Integration

Recommendations

Management recommends that the Board of Directors:

1. Authorize Management of EGD and Union to file with the OEB the MAADs and PCRMM Applications in accordance with the information set out in the Utilities Integration presentation as soon as reasonably practicable; and
2. Approve the transactions contemplated in the MAADs Application substantially as described by Management to the Board, including amalgamation of EGD and Union subject to:
    a) determination by the Board and the boards of directors and common shareholders of EGD and Union that it is prudent to proceed with the amalgamation upon consideration of the OEB Decisions; and
    b) finalizing the terms of the amalgamation agreement and any other agreement required in connection therewith to be evidenced by approval of the boards of directors and common shareholders of EGD and Union.

Utilities Integration
Stakeholder Engagement

ENBRIDGE

Stakeholders Outreach Plan
- Employees
- Customers
- Government (Municipal, Provincial, Federal)
- Industry Associations
- Suppliers/ Vendors
- Indigenous Communities
- Community Partners (United Way etc.)
- Agencies (IESO, Green Ontario etc.)

Materials Developed
- Key Messages & Q&A
- Integration Leader Deck, Technical Appendix
- Stakeholder Plan (Key Messages & Contacts)
- Internal Communications
- One Page Summary
- ELINK Article
- Stakeholder Letter

Preliminary Stakeholder Engagement Timeline

Key Activity	Date
Stakeholder outreach (Government & OEB)	Ongoing
EGD, Union & EI Board	Oct 26 - 30/31
MAADs Application filing	Nov 2
Senior Leader Calls	Nov 2
ELT Notification	Nov 2
All Union/ EGD note	Nov 2
Targeted Stakeholder outreach (Gov't, Ind. Assoc.)	Nov 2- Nov 20
OEB Stakeholder Meeting	Nov15
Union/ EGD Senior Leader Forum	Nov 22/23
Rates Mechanism Application Filing	Nov 23
Updates in Existing Channels	Nov – Dec

Management has and will continue to actively consult with diverse stakeholder group

July 25, 2017

CONFIDENTIAL

BOARD OF DIRECTORS

Re: Potential Integration of Ontario Gas Utilities

One of the benefits Management recognized as part of the Spectra transaction was the potential to improve the efficiency and effectiveness of the Ontario natural gas utility operations through a combination of EGD and Union, or similar structure. Since the closing of the transaction in late February, executive Management has assessed various alternatives and concluded that an integration of EGD and Union would result in benefits to Enbridge and its utility customers without compromising safety, reliability and quality of service to customers.

No Board approval is being requested at this time; however, Management will begin engaging with stakeholders on the key elements of the plan with the objective of filing a regulatory application in the fourth quarter which would facilitate an effective date for the new business and regulatory construct of January 1 2019. This memorandum provides the Board with background on the proposed integration and focuses primarily on the regulatory framework and approach being contemplated. Board approval for the integration plan would be requested once Management finalizes its business plan, followed by filing of the regulatory application with the Ontario Energy Board (OEB).

Summary

Management has reviewed the available regulatory frameworks and determined the OEB's Merger, Acquisition, Amalgamation and Divestiture (MAAD) policy to be the most effective means to pursue the integration of the utilities to deliver benefits and savings to the company and customers.

The OEB's MAAD policy was originally established as a framework to encourage consolidation of Ontario's private and publicly owned electricity distributors. While the MAAD policy is focused on electricity distributers, the policy also applies to natural gas distributors. In advance of this informational memorandum, Management has conducted initial discussions about the regulatory framework for integration with the OEB management and senior Ontario Government officials. Management has confirmed with the OEB that the MAAD process is open to integrate EGD and Union and preliminary discussions with the provincial government representatives have confirmed the applicability of the MAAD approach. The Application will adhere to the objectives, guidelines and structure of the established MAAD policy.

The key elements of a MAADs Application are:

- A deferral of rebasing to 2029 (10 year deferral);
- A threshold test which requires an expected reduction in the overall cost of service by 2029 as compared to cost of service that otherwise would exist in the absence of integrating EGD and Union;

- Operate under a Price Cap model from 2019 to 2029 where revenues are annually escalated at inflation;
- Return on capital for discrete and unplanned capital expenditures via the OEB's Incremental Capital Module (ICM);
- The company manages the costs and risks of integration to achieve efficiencies over the rebasing deferral period; and
- No earnings sharing in the first five years of the ten year period and 50:50 sharing between the company and the ratepayers for the last 5 years to the extent that earnings are 300 bps above the OEB allowed Return on Equity (ROE).

Approval of a MAADs application is subject to OEB review of the proposed utility integration meeting the OEB's "No Harm Test" and not a detailed review of costs or rates information that is typical with prior Incentive Rate (IR) plans or cost of service applications. To satisfy the No Harm Test, the proposed Application must:

- Deliver rates to customers that are less than they otherwise would be in the absence of integration;
- Maintain the safety, reliability and quality standards of the utilities;
- Allow the integrated entity to continue to meet Government and OEB Policies; and
- Allow the continuation of a financially viable gas industry.

Management is developing an application that will seek approval to integrate under the MAAD policy and approval of a Price Cap mechanism for the ten year deferred rebasing period. The application would be filed in the fourth quarter to achieve a regulatory decision by the end of Q3 2018. Management expects an OEB hearing on the MAADs Integration Application given there is no opportunity for a settlement conference with intervenors. This is consistent with the recent electrical utility MAAD application. The hearing will address the ability to meet the no harm test.

A MAADs Application provides the best opportunity for the utilities to integrate with both the customers benefiting from stable rate increases at inflation and the company having sufficient time to integrate, achieve the full extent of the potential efficiencies and implement the best practices from each standalone utility.

The Application

Regulatory Framework (MAAD Policy)

The MAAD policy has been established as a framework to execute a merger/integration transaction under the OEB Act. This policy was developed to support the change in control and ownership of utilities in Ontario. EGD and Union would apply under this policy for its integration of EGD and Union. Specific to the policy is the change in ownership requirement under the OEB Act which states that, at minimum, a 20% change in shares or ownership necessitates the OEB approval of the transaction. The underpinning of an OEB approval is ensuring that the customers of the merging entities are not harmed by the integration. This test is referred to as the "No Harm Test".

Term and Deferred Rebasing

EGD and Union's current IR plans end on December 31, 2018. Prior to the merger of Enbridge and Spectra both utilities planned to rebase rates effective January 1, 2019 before proposing a new multi-year IR framework. Under the MAAD policy, integrating utilities can apply for a rebasing deferral for up to ten years to allow for the time necessary to manage the integration, transaction costs and associated savings. The OEB policy framework states that utilities need to select a definitive timeframe for the deferred rebasing period but do not require supporting evidence to justify the deferred rebasing period. Management believes that a ten year deferral of rebasing will allow the integrated utility sufficient time to achieve savings and implement best practices that will benefit both customers and shareholders, while managing the risks inherent under a 10 year plan.

Annual Revenue Adjustments via a Price Cap Inflator (PCI)

Union currently operates under a Price Cap framework where rates are escalated by 40 percent of inflation. EGD currently operates under a Custom IR model which establishes revenues as a forecast of that years cost of service. The MAAD framework states that utilities that are approved to integrate must have their annual revenue requirement established under a Price Cap framework. Therefore, as part of the MAADs application, EGD and Union will be required to establish a PCI for the integrated company to adjust rates annually from 2019 to 2028. The Price Cap framework escalates the prior year's OEB approved revenue requirement by the OEB approved PCI. The PCI is an escalation factor based on I – X where I represents inflation and X represents a productivity factor.

EGD and Union have retained independent experts to conduct a Total Factor Productivity benchmarking exercises to determine the appropriate utility productivity factors. The impact to annual revenues based on the level of the approved productivity factor is provided in the Financial Sensitivities section of this memo.

Incremental Capital Investments during Deferred Rebasing Period - Incremental Capital Module (ICM)

EGD and Union are finalizing their respective Asset Management Plans which identifies the need for capital expenditures over the period of 2019 to 2028.

The OEB developed the ICM to provide utilities under the Price Cap framework the ability to seek approval to adjust rates for discrete capital projects that are incremental to capital investment already planned in the rates. The eligible incremental capital amount sought for recovery is the capital in excess of the materiality threshold. The ICM is very similar to the capital cost pass-through mechanism that forms part of Union's existing price cap framework. This is in effect a capital expenditure threshold which serves to demonstrate the level of capital expenditures that a distributor should be able to manage with its current rates, growth in normal customer demand and normal volatility in business conditions. The materiality threshold is calculated using the existing OEB approved formula that takes into account the last OEB approved rate base and depreciation expense, annual revenue growth and the PCI. For EGD, costs that would exceed $480 million and for Union $390 million annually would be reviewed for inclusion under ICM. The ICM provides a clear approach to allow the integrated utility to earn a rate base return on expansion capital projects that exceed the calculated threshold.

Applications for approval to adjust rates for qualifying capital investments will be made as required during the deferred rebasing period and will be subject to OEB review and approval.

Integration Costs and Achieved Savings

The MAAD framework establishes that all integration costs and achieved savings accrue to the company over the 10 year MAAD deferred rebasing period. The OEB MAAD filing guidelines require utilities to forecast at a high level the incremental costs necessary to integrate and the expected projected savings from the utility integration. This information is required in order to assess the benefits of the integration and the integration costs to ensure that the financial viability of the integrated utility is maintained.

Management has reviewed benchmark information and then performed a high level review of the organizational restructuring and potential costs and savings that can be achieved through information technology and other functional integration in areas such as customer care operations. This integration planning exercise has estimated capital investments of between $50 M and $250 M over the ten year term delivering savings of between $350 M to $750 M over the same ten year term depending on the level of integration and timing of expenditures that will be achieved after an in-depth analysis, cost and risk estimating process is completed. (See Appendix A for Summary of Preliminary Cost Efficiency Opportunities) The OEB will not approve the potential costs and savings and related capital investments to achieve. The integrated utility will be at risk for these amounts. Best estimates of achievable amounts within the ranges have been used to demonstrate the net benefit potential identified at a high level to support the integration opportunity set. The within range estimates used are a realistic view of achievable results with the various identified opportunities given risks, change capacity and timing concerns and demonstrate the ability of the integrated utility to continue to be financially viable.

The integration costs and savings estimates that will be included in the Application exclude field operations. Management plans to assess the integration of field functions subsequent to integrating the corporate shared services such as Finance and Human Resources and common utility functions such as Engineering and Customer Care. Naturally, safety and reliable delivery of services will continue to be our top priority.

Earnings Sharing Mechanism (ESM) During the Next Generation IR Term

During the deferred rebasing period under the MAAD policy, the integrated entity will not be subject to earnings sharing for the years 2019 to 2023. For the years 2024 to 2028, the integrated utility will share all earnings greater than 300 basis points above the consolidated entity's annual ROE on a 50:50 basis.

This ESM will allow Management to pursue utility integration in a manner that will maximize the savings and value to the company and ratepayers. The savings and benefits achieved over the deferred rebasing period will be reflected in a lower cost of service to Ratepayers at rebasing in 2029.

EGD and Union Rate Zones – Customer Rates

A critical component of the OEB's No Harm Test is that customer rates are not negatively impacted during the integration term. The customer rates test not only applies to the billing rates but the method of cost allocation that underpins the allocation of the annual revenue requirement to each customer rate class.

EGD and Union plan to maintain the existing Rate Zones. Over the 2014 to 2018 incentive period certain cost allocation and rate design issues have arisen that need to be addressed. Further, given the Ontario energy landscape is evolving, future business requirements may necessitate changes to cost allocation and rate design. Management intends to file application requests with the OEB seeking approval for required changes.

Risks and Mitigants

The risks and related mitigation opportunities are consistent with the current 5 year term IR that EGD and Union operating under. If management does not seek a MAAD filing for an integrated utility, then an IR path will be available.

Applicability of the MAAD framework to EGD and Union: Management will structure the Application to align with existing OEB policy frameworks. The Application will be supported by external regulatory counsel and tested to ensure consistency with the recent OEB approved merger of four electricity utilities (i.e. Alectra). The integration of natural gas utilities is contemplated as a possibility in the Natural Gas Filing Requirements. Management has confirmed the availability of MAADs to support the integration with the OEB and will adapt its positions based on the regulatory process feedback to align to the OEB's policy objectives and mitigate application concerns.

Variability of Interest and Tax Rates: Any changes in interest and tax rates during the 10 year term would impact the financial results and would be at company's risk for base operations. The sensitivity chart below outlines the potential estimated impacts.

Deferral of rebasing for the term of ten years: The OEB policy states that utilities do not have to justify their selected term for deferral of rebasing. Management will outline in the Application the expected benefits to the company and ratepayers from a ten year rebasing deferral.

Earnings Sharing Mechanism: The ESM under the MAAD policy is described above. The Application evidence will outline the risk that the company is proposing to manage over the 10 year deferred rebasing period in order to justify the ESM as outlined in the MAAD policy.

OEB sets rates below inflation: Management has hired independent experts to conduct a Total Factor Productivity benchmarking exercises for EGD and Union to support the productivity factor proposal. The evidence will outline that both EGD and Union have operated under incentive mechanisms for approximately 15 years and that significant productivity gains have already been achieved. The evidence will also detail that future productivity gains in the existing base business are limited and not sufficient to support rate increases at less than inflation. The projected efficiencies from the integration of Union and EGD should not impact on the determination of the productivity factor.

Capital Cost Overruns not recovered in rates: By seeking a ten year deferred rebasing period, the utility is forgoing the ability to rebase its capital cost overruns from the 2013 to 2018 period or over the 2019 to 2028 period. The inability to rebase capital costs means that EGD will not update its rates in 2019 to recover capital cost overages namely EGD's GTA system expansion project. Management will seek to offset the earnings impact of the capital cost overages through the achievement of integration savings. The utility will utilize the ICM available in the MAAD policy to seek recovery of incremental capital investments that exceed the annual ICM materiality threshold. The ICM is described above.

Off-ramps under a MAADs framework: Over the ten year deferred rebasing period, the company will have to manage its costs in a manner similar to the current IR plans. The utility is exposed to risks from economic changes such as increases in interest rates and tax rates, and a lower than expected inflation rate. The OEB MAAD policy states that in approving an integration application, the entities have committed to a plan based on the circumstances. However, the policy also provides for the utility to file an application seeking an exit from the MAAD framework in the event of material unforeseen events. The application seeking approval to exit the framework approved under the MAAD policy is expected to have to pass regulatory scrutiny and require an explanation of the rationale to support the need to amend the ten year deferred rebasing period.

Proposed Adjustment to Union's 2019 base rates: Union's current rates reflect a credit to ratepayers of $17 M per year for deferred income taxes collected in rates prior to 1996. The accumulated deferred tax balance will be fully refunded to ratepayers by the end of 2018. The OEB approved the credit in rates as part of E.B.R.O 493/494. It would not be appropriate for the OEB to maintain the credit in rates when the original approval expires. The 2019 Union rates will be adjusted to reflect the end of this refund consistent with the OEB approval. Meetings with OEB staff will confirm this treatment.

Political and Rate Payer Action Risk: Management expects that there will be significant stakeholder interest in this Application, particularly from the Municipality of Chatham-Kent. Union plays a significant role in Chatham-Kent as a large employer and key contributor to the community. Further, Union through its undertakings with the provincial government is required to maintain its head office in the Municipality of Chatham-Kent. To address these concerns, management will meet with representatives of the municipality to confirm that Chatham-Kent operations are a critical part of the integrated utility and, while there will be changes to the operations in Chatham-Kent, there will continue to be significant functions supported in Chatham-Kent.

Management is in the process of developing and executing a comprehensive stakeholder engagement plan including a specific sub-plan for Chatham-Kent and is working with outside legal counsel to assess the undertakings with the provincial government. Detailed stakeholder engagement sub-plans are also being developed for employees, customers, government, media and all stakeholder groups.

Utility Revenues at risk due to variations in volumes (Weather and average use related): Both Union and EGD have 40% and 50% of their distribution revenue collected on a volumetric basis. This approach to rate design places a weather related risk on both utilities. Each utility has a true-up mechanism built into its current regulatory frameworks that accounts for that year's decline in residential customer average use and adjust the following years billing determinants to reflect a lower or higher volume forecast in the following year. The average use true-up mechanism provides some protection by adjusting revenue to be reflective of average temperatures and customer usage impacted by efficiency improvements which ensures the utility is not at risk for these changes.. The utility continues to be at risk for usage variances below the average in any given year. This risk is offset over a longer period of time for variances where revenues are above the average for any given year.

In April 2015, the OEB established a policy that requires electric distributors to fully recover distribution costs from residential customers through a fixed monthly charge. Recovering natural gas distribution costs through a fixed monthly charge would be consistent with the OEB policy for electric distributors. Management is evaluating the movement to a fully fixed charge approach to collection of distribution costs. Under the MAAD policy, the company is able to file for rate design modifications with the appropriate justification for OEB review. An application to move to a fixed charge approach would be filed in 2019 or 2020 depending on the outcome of the integration application.

Externalities during deferred rebasing term: Over the 10 year rebasing deferral period externalities such as increased regulations, pipeline integrity regulations and costs, costs greater than inflation, depreciation increases and no 2019 rate rebasing are potential risks which management may have to mitigate. Where these or other externalities impact the company in a significant manner, Management will look to file applications seeking appropriate treatment by the OEB. For example, a material change in environment regulations that resulted in a very material operating or capital costs for the integrated utility could result in management seeking a regulatory application since this would not reflect normal operating and capital risks.

Financial Overview

No Harm Test

A key component of the No Harm Test is that the ratepayer will not pay more under a plan where the utilities integrate relative to what they would have paid in the absence of integration. Table 1 below shows the No Harm Test revenue variance which is the difference between EGD and Union's proposed revenue requirement from 2019 to 2028 as separate utilities versus the integrated utility operating under a Price Cap framework where 2018 revenues are escalated annually at Inflation (~1.7%). Table 1 shows that the customer rate component of the No Harm Test is met. Over the ten years, customers will pay an estimated $442 M less under the MAAD framework then what they would have paid if EGD and Union operated as standalone utilities.

Table 1: OEB No Harm Test Financial Summary

No Harm Test
Utility Stand Alone Applications vs Utilities with Revenue escalated @ Inflation
Revenue Variance [Excess / (Shortfall) in $ Million]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
UGL	(32)	(33)	(34)	(35)	(34)	(36)	(39)	(34)	(29)	(23)	(330)
EGD	22	13	1	(9)	(21)	(26)	(25)	(25)	(24)	(19)	(113)
No Harm Test Variance	**(10)**	**(20)**	**(33)**	**(44)**	**(55)**	**(62)**	**(64)**	**(59)**	**(53)**	**(43)**	**(442)**

As stated above, the company will be filing to adjust Union Gas's 2019 base rates to reflect the stoppage of a deferred tax refund consistent with the current OEB ruling. Table 2 shows a reduction of the $442 M revenue shortfall identified in the No Harm Test by $170 M. Management will have to offset the residual $272 M revenue shortfall through the utility integration of systems, business functions and organizational restructuring. Under a MAAD framework customers will pay approximately $27 M less (annually) than what they would have paid if the two utilities did not integrate.

Table 2: Pre-Integration Revenue Variance

Revenue Variance Adjusted for UGL Tax Adjustment in 2019 Base Rates
Revenue Variance [Excess / (Shortfall) in $ Million]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Revenues from UGL Deferred Tax	17	17	17	17	17	17	17	17	17	17	170
Pre-Integration Revenue Variance	**7**	**(3)**	**(16)**	**(27)**	**(38)**	**(45)**	**(47)**	**(42)**	**(36)**	**(26)**	**(272)**

Table 3 outlines the impact from an initial forecast of the integration benefits. Management's initial review of restructuring the combined management and administrative staffing and the integration of systems and business functions of EGD and Union indicate a potential estimate of pre-tax savings of $567 M over ten years. This savings estimate is unclassified. Management estimates the potential for savings, net of costs, in a range of between $350 M and $750 M based on the requirement to invest capital in the range of between $50 million to $250 million.

The post-integration financial result is an estimated benefit of $122 million (pre-tax) over ten years relative to a higher allowed ROE during the ten year period. The 10 year average achieved ROE post-integration is estimated to be 9.78% versus the 10 year average allowed ROE of 9.65%. While the OEB allowed ROE had been used as a comparator, it is not possible for gas utilities to file and receive annual cost of service rate changes to incorporate changes in the OEB allowed ROE. In October 2016, the OEB issued the Handbook for Utility Rate Applications that states that gas utilities in Ontario no longer qualify for annual cost of services filings. Some type of custom rates with a period in excess of one year must be filed.

During the ten year period customer rates are estimated to increase at the rate of inflation and rate increases will exceed inflation only in the years that the integrated utility successfully accesses the OEB Incremental Capital Module.

Table 3: Initial estimate of the integrated utility earnings excess / (shortfall)

10 Year EGD and UGL Earnings Profile under MAAD
($ Million)

$ Millions	2017F	2018B	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total	Average
EGD and Union at MAAD base case														
Achieved Utility Earnings before synergies:														
- EGD (PCI)			247	247	250	253	254	255	260	264	269	275	2,573	
- UGL (PCI) including accumulated deferred tax adjustment			205	210	213	215	219	222	223	228	233	238	2,206	
Total Achieved Utility Earnings before synergies			452	457	463	468	473	477	484	492	501	513	4,779	
Earnings impact of synergies			5	31	41	41	50	55	56	52	47	49	425	
Achieved Utility Earnings with synergies			457	488	504	509	523	532	539	543	548	561	5,204	
Earnings sharing			-	-	-	-	-	-	-	-	-	-	-	
Achieved Utility Earnings with synergies after ESM			457	488	504	509	523	532	539	543	548	561	5,204	
Achieved ROE			9.40%	9.76%	9.84%	9.74%	9.83%	9.82%	9.82%	9.80%	9.81%	9.99%		9.78%
Allowed ROE	8.78%	9.11%	9.28%	9.28%	9.49%	9.66%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%		9.65%
ROE (Achieved vs Allowed)			0.12%	0.48%	0.35%	0.07%	0.03%	0.02%	0.01%	0.00%	0.01%	0.19%		0.13%

Financial Sensitivities

As noted, with a MAADs applications and a 10 year price cap model for rates, the company could be exposed to a number of financial risks. While these risks and the opportunities to effectively mitigate the risks are consist with the current 5 year term IR models that EGD and Union currently operate under, annual estimated sensitivities have been including for:

- Operating and Maintenance Costs and or Incremental Revenues
- Annual revenues with a PCI lower than inflation
- Non-recovery of capital expenditures
- Income tax rates
- Interest rates

The following chart provides the estimated impacts of these exposures.

Item	After-Tax Annual Earnings Impact ($ Million)
Cost savings or additional revenues generating 50 bps of higher ROE	$25
10% reduction to Inflation escalator	($19)
Capital Disallowance or non-recovery of $100 M	($6)
1% Increase in Tax Rate	($4)
1% increase in G.O.C 30 Yr. Bond on ROE, LTD & STD	($12)

The opportunities to mitigate these risks are largely based on the integrated utility's ability to manage both capital and operating costs. The risk associated with the inflation escalator will be determined during the MAADs hearing as noted above. Both EGD and Union have faced and managed similar risks over the past 15 years of consecutive IR frameworks. The primary difference being contemplated in this MAADs proposal is the 10 year term.

Appendix A: MAADs Application
Summary of Preliminary Cost Efficiency Opportunities

Subsequent to the merger of Enbridge Inc. and Spectra Energy on February 27, 2017, a small executive and senior management team from Enbridge Gas Distribution and Union Gas began to explore opportunities to restructure and combine the two utilities to drive benefits for customers and the companies. Management has reviewed benchmark information and then performed a high level review of the workforce restructuring and potential costs and savings that can be achieved through information technology and other functional integration. This high level review of the management and administrative functions of the two utilities has identified opportunities to potentially generate estimated savings of $272 million over ten years. This savings estimate is based on unclassified estimates for cost savings in the range of $350 million to $750 million with associated capital expenditures in the range of $50 million to $250 million over the ten year period.

The financial analysis is based on best estimates of achievable amounts within the ranges. The within range estimates used are a realistic view of achievable results with the various identified opportunities given risks, change capacity and timing. The integration costs and savings estimates exclude field operations. The priority of field operations is to maintain the safe and reliable delivery of natural gas.

The management team explored, at a high level, the opportunities to capture benefits over the 10 year time frame in the following areas: 1) Customer Care, 2) Distribution Work Management, 3) Shared Services, 4) Storage and Transmission, Gas Supply and Gas Control, and 5) Management and Other Functions.

Customer Care

Customer Care includes support for billings, call centers, meter reading, credit and collections, customer information systems (CIS) and CIS support. There is an opportunity to eliminate duplication of support services and the customer information system in this area. The range of pre-tax cost savings for the 10 year period is estimated to be between $120 million and $250 million based on potential capital investments of between $25 million and $110 million. A detailed analysis will be completed to develop an optimal benefit generation plan that includes analysis of costs per customer for CIS systems and the time needed to begin to optimize this expansive support area. The range for operating cost benefits considered the current metrics for support costs per customer, industry best practices, customer satisfaction scores, customer service levels, and the opportunity to review outsourcing strategies. The analysis will also determine the best opportunity for the integrated utility to continue to deliver exceptional customer experiences at an affordable cost ensuring the best available customer solutions are also incorporated.

Distribution Work Management

Distribution Work Management includes planning, scheduling, compliance, work management systems (WMS), WMS support, and support for overall work efficiency and productivity. There is an opportunity to eliminate redundancy of systems, improve worker efficiencies in the planning and scheduling of field work by adopting the best practices from both utilities and to consider outsourcing strategies. The same opportunities exist for the various support functions and software implementations to eliminate redundancy and consolidate. The range of cost savings for the 10 year period is estimated to be between $30 million and $150 million based on potential capital investments of between $10 million and $90 million. An analysis will be completed to develop a detailed and optimal benefit generation plan that includes analysis of costs per work type, comparisons of best practices across the two utilities and against industry benchmarks, and opportunities to fully leverage existing implementations.

Shared Services

With the full integration of the utilities, there will be additional benefits that can be achieved in the Shared Services functions including: Technical Information Systems, Human Resources, Finance, Supply Chain Management, Real Estate ad Enterprise Safety & Operational Reliability. These savings will be achieved with the opportunities to eliminate a number current duplicate systems and reporting that is required including regulatory and financial reporting, contracting and other functions. The range of cost savings for the 10 year period is estimated to be between $15 million and $50 million based on potential capital investments of between $5 million and $20 million. A detailed analysis will be completed to ensure optimal benefit generation.

Storage and Transmission Operations and Gas Supply and Control

Storage and Transmission includes operations and maintenance of the transmission pipeline systems and storage well and reservoir operations and maintenance. Gas Supply and Gas Control includes the gas control room operations for both EGD and Union Gas, gas supply and upstream transportation contracting and settlement processes and systems software for both utilities. There are some opportunities to apply the best practices across the utilities and to determine if there are operational benefits available related to the combination of these assets. The integration and alignment of the SCADA systems will also yield a potential benefit. The range of cost savings for the 10 year period is estimated to be between $15 million and $50 million based on potential capital investments of between $5 million and $10 million. A detailed analysis will be completed to develop a detailed optimal benefit generation plan.

Management and Other Functions

There are opportunities to rationalize the management structure and other functions within the operating business unit. The range of cost savings for the 10 year period is estimated to be between $170 million and $250 million based on potential capital investments of between $5 million and $20 million. A detailed analysis will be completed to generate an optimal benefit plan. The opportunity to rationalize top management will be balanced against the requirements to continue to safely and reliably operate the assets and deliver exceptional customer service.

General Considerations

Starting in 2018 following an OEB decision on the proposed MAADs regulatory framework, a Project Management Office (PMO) would be established to identify priorities, plans to optimize the various overlapping work activities, identify risks and develop appropriate risk mitigation strategies.

Communications with employees and stakeholders will start in August 2017 through a detailed stakeholder engagement plan and will be continuous throughout the implementation and stabilization period for any system and functional changes.

The implementation plans will be staggered to ensure organizational capacity to support and adopt the required changes. The PMO activities will provide oversight to all implementation plans and functions. Based on the preliminary management assessment, the current prioritization of integration programs would be to first optimize the overall management structure, then address the Customer Service opportunities, followed by Distribution Work Management and Asset Management. Other smaller system optimization and process improvements would be integrated into this prioritized plan as organizational capacity allows. With the merger at the parent company level, the integrated utility will continue to support shared service integration activities that commenced in 2017 and will continue into 2020 for various functions including Human Resources, Technical Information Systems, Supply Chain Management, Finance, Public and Government Affairs and Enterprise Safety & Operational Reliability, and Facilities.

Prior to any software or hardware implementation for systems, a review and alignment of work processes will be undertaken related to operating procedures, engineering standards and specifications, asset and operations documentation and records. Additional opportunities for benefits will be identified by working directly with business unit leads and teams as the detailed planning is undertaken. This process will also ensure that perceived benefits are rationalized.
Overview of Estimates for Integration Capital Investments and O&M Savings ($ Millions) over 10 years

Item	Potential Capital Investment		Potential O&M Savings	
	Minimum	Maximum	Minimum	Maximum
Customer Service	$25 M	$110 M	$120 M	$250 M
Distribution Work Management	$10 M	$90 M	$30 M	$150 M
Shared Services	$ 5 M	$20 M	$15 M	$50 M
Storage & Transmission	$5 M	$10 M	$15 M	$50 M
Management Functions & Other	$5 M	$20 M	$170 M	$250 M
Total	$50 M	$250 M	$350 M	$750 M

Note: Estimates are unclassified but indicative of the total opportunities based on prior experience with related system implementations and capital investments, percentages of total operating costs in each category, and a preliminary comparison of practices between the two utilities and industry benchmarking information. The maximum level of opportunities will be challenging to achieve given the capacity of the organization to support multiple initiatives and the upfront time required to plan and implement changes in all of these areas within the 10 year timeframe. Given the preliminary nature of the opportunity assessments, all transition costs not captured in the capital costs are consider net within the savings shown above.

MAADs Application

– and

Rate Setting Mechanism Application

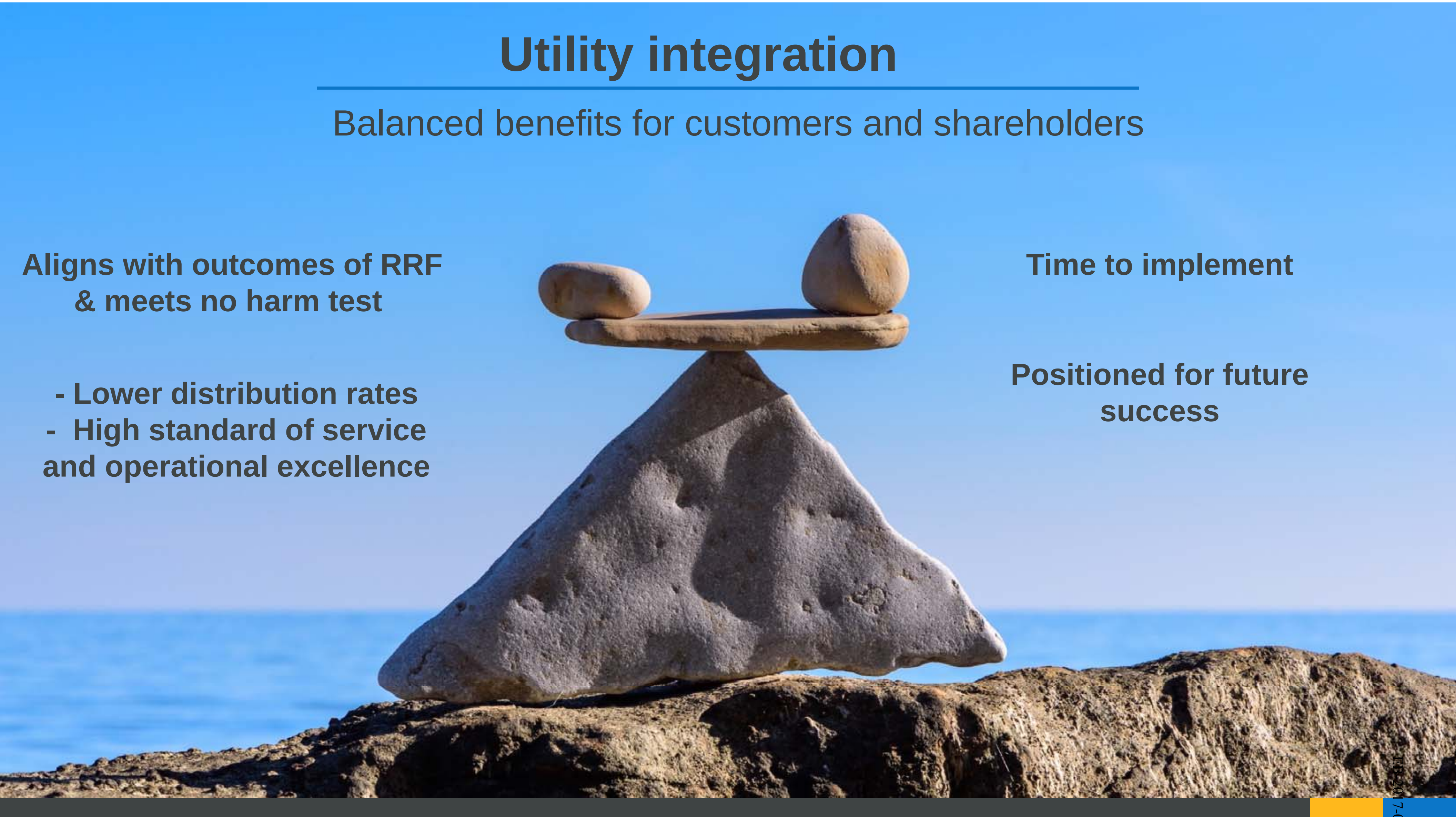
Enbridge Gas Distribution Inc. and Union Gas Limited
November 15, 2017

Enbridge Gas Distribution Inc.

An Enbridge Company

Agenda

1. Introduction
2. MAADs Application
3. Rates Setting Mechanism Application


Utility integration
Balanced benefits for customers and shareholders
Aligns with outcomes of RRF & meets no harm test
- Lower distribution rates
- High standard of service and operational excellence
Time to implement
Positioned for future success

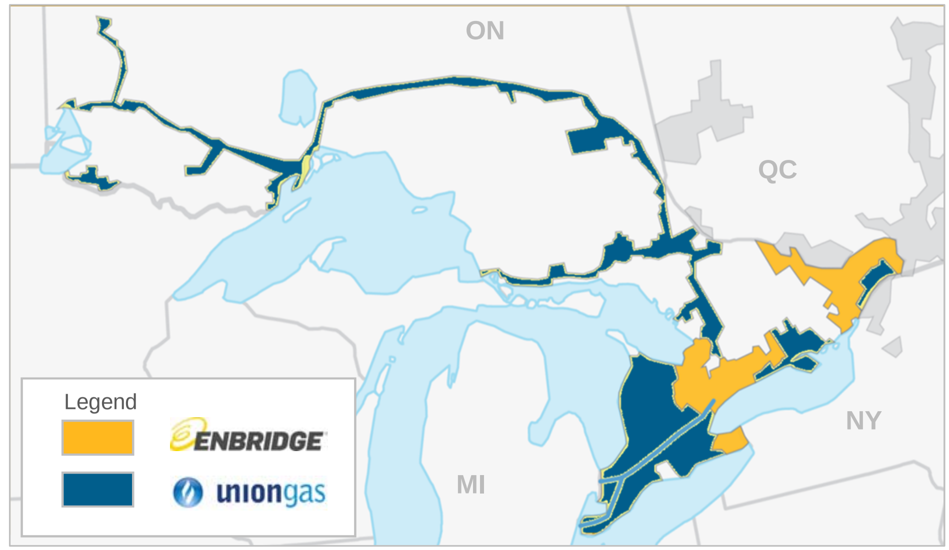
Why Now?

The timing is right

- Current Incentive Regulation frameworks:
- **<u>EGD</u>**: Custom IR
  - At risk for capital cost overages
  - ROE is reset each year
  - ESM 50:50 with ratepayers with no deadband
- **<u>Union Gas:</u>** Price Cap
  - Price cap increasing revenues by 40% of inflation/year
  - "Capital pass through" mechanism
  - ROE fixed at 8.93%
  - ESM deadband for first 100 bps, 50% shared above 100 bps, and 90% shared above 200 bps

➢ **Both IR terms end after 2018**

➢ **Harmonization opportunity allows for implementation of structural cost and service delivery efficiencies with stable rates for 10 years**



Key Statistics	EGD	Union Gas
Customers (M)	2.2	1.4
Rate Base ($B)	5.9	4.8
Equity	36%	36%
Allowed ROE	9.19%	8.93%
IR Framework	Custom IR	Price Cap
Period	2014 - 2018	2014 - 2018

Meets No Harm Test

Impact of the proposed transaction

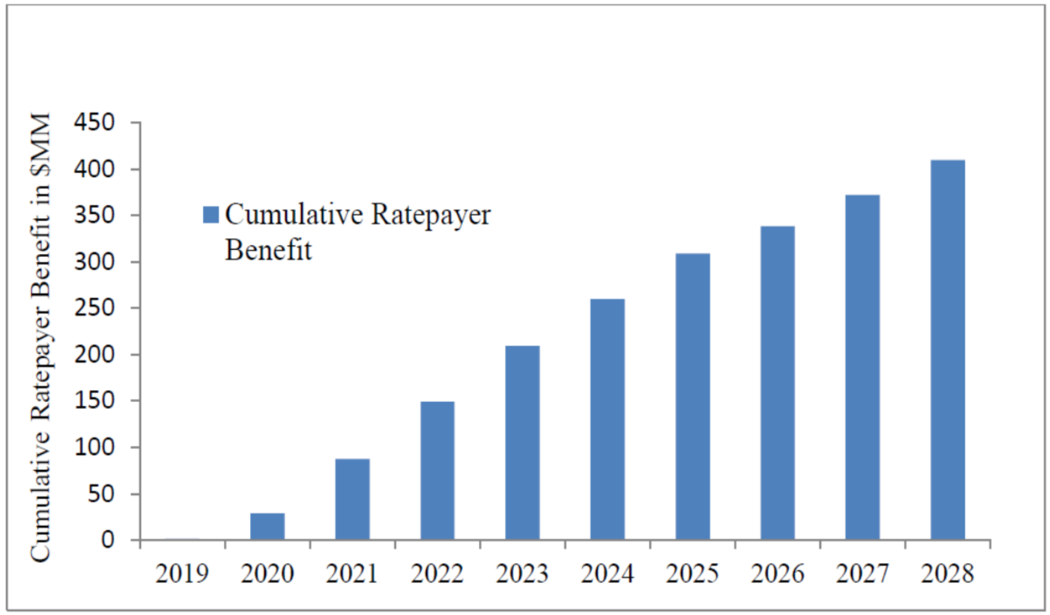
Follows guidance in OEB's Consolidation Handbook for consolidations and rate applications, where;

- Board will assess MAADs applications using the no harm test, consider whether transaction has an adverse effect on the Board's statutory objectives.

Proposal meets No Harm Test:

- **Price:** provides benefits to customers compared to continued stand-alone operations ($410 M over term).
- **Reliability & Quality of Service:** Continue to maintain safe, reliable and quality services.
- **Financial Viability:** No material impact on financial viability.

No Harm Test - Cumulative Ratepayer Benefit



Significant Benefits to Customers and Shareholders

Investments and savings

Create synergies through harmonization of workforce structure, systems, process, practices, polices and customer service delivery in:

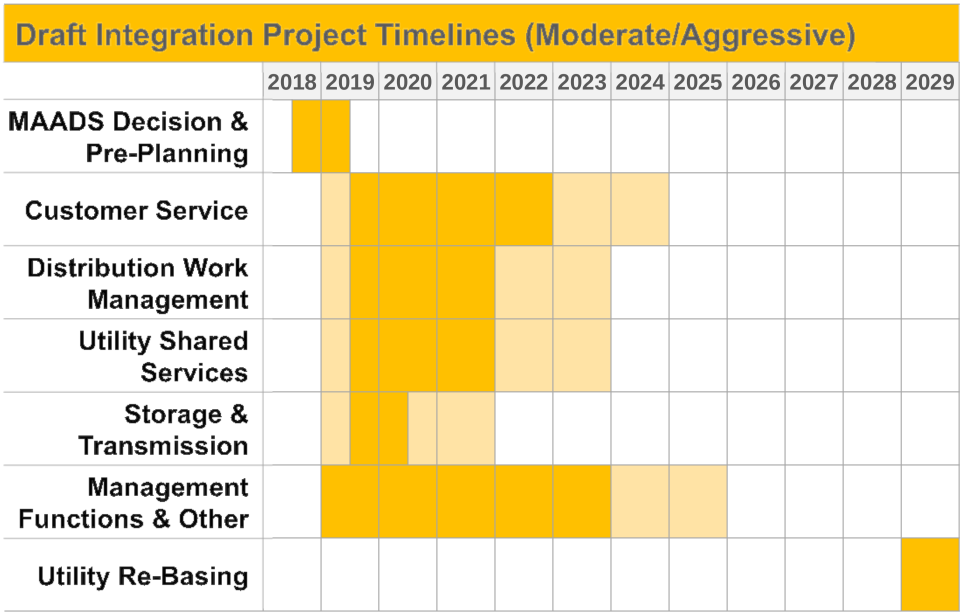
- Customer Care
- Distribution Work Management
- Utility Shared Services
- Storage and Transmission, Gas Supply and Gas Control
- Management Functions and Other Functions

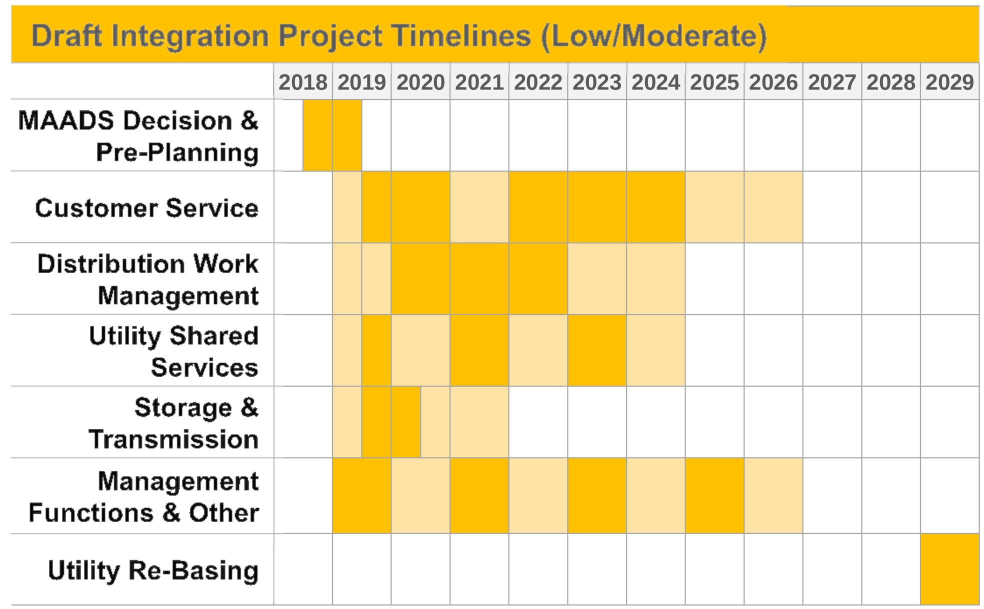
- Estimated upfront capital investment between $50M and $250M.
- Forecast synergies over the 10-year term of between $350M and $750 M, with timing uncertainties.

Front-end loaded investments support synergies over the 10-year integration timeframe

Significant Benefits to Customers and Shareholders

Integration opportunities





Integration Execution

Planning or Stabilization period/activity

There are a range of implementation timelines and detailed planning is required due to overlap in skills and resources required for implementation. Timing directly links to benefits over ten-year timeframe.

Rate Setting Mechanism Application

A rates setting mechanism application will be filed in approximately one week

Application under Section 36 for rate setting mechanism and related parameters.

Key points;

- Price Cap Index
- Productivity Factor
- Incremental Capital Module
- Base Rate Adjustments
- Customer Protection Measures
- Deferral and Variance Accounts
- Annual Adjustment Process, Stakeholder Consultation and Reporting

Rate Setting Mechanism Application

Price cap index

Proposing a price cap index (“PCI”)

Calculation: PCI = I – X ± Y ± Z

Where rates are a function of:

- An inflation factor (I)
- A productivity factor (X)
- Certain predetermined pass-through adjustments (Y factors)
- Certain non-routine adjustments (Z factors)

Mechanistic process analogous to current Union Gas method allows for regulatory simplicity.

Rate Setting Mechanism Application

Price cap index components

Inflation Factor

- Quarterly Gross Domestic Product Implicit Price Index Final Domestic Demand (“GDP IPI FDD”).

Productivity Factor

- An X factor of zero supported by report prepared by external consultant.

Y Factor (Pass through adjustments)

- Cost of gas and upstream transportation; DSM cost changes; LRAM for the contract market; cap-and-trade.

Z Factor (non-routine adjustments)

- Must meet following criteria: causation, materiality, prudence and outside management control.

Rate Setting Mechanism Application

Incremental capital module

Use OEB's Incremental Capital Module (ICM) to recover costs from incremental capital investment beyond what is funded through rates.

- Forecast capital investment supported by Asset Management Plans.
- Materiality threshold :
  - Spend that can be managed under Price Cap approach determined by the materiality threshold value.
  - Threshold value (%) = 1+ [(RB/d) x (g + PCI x (1+ g))] x ((1+g) x (1+PCI)) $^{n-1}$ + 10%
- Cost of capital using current OEB cost of equity and company cost of debt (same as EGD current).

Illustrative ICM Threshold Calculation for 2019 for EGD and Union

$ millions	EGD	Union
Base year	2018	2013
Rate base	6,246	3,734
Depreciation	305	196
PCI	1.73%	1.73%
Growth	0.93%	0.93%
Years since rebasing	1	6
Threshold value %	165%	168%
Threshold value	503	330

Qualifying capital investments are discrete projects causing budget to exceed threshold value

Rate Setting Mechanism Application

Base rate adjustments

- Two base rate adjustments required:
  - Increase Union Gas 2018 rates by $17.4M to recognize the full amortization of the accumulated deferred tax balance.
  - Decrease Enbridge Gas Distribution 2018 rates by $4.9M to recognize the difference between the Board approved CIS costs and CIS costs in rates.

Rate Setting Mechanism Application

Customer protection measures

- Rate setting mechanism application will include a proposed customer protection scorecard.
  - Scorecard will include measures for customer focus, operational effectiveness, public policy responsiveness and financial performance.
  - Purpose of the scorecard is to demonstrate our continued commitment to providing safe reliable service at an affordable price.

Rate Setting Mechanism Application

Deferral and variance accounts

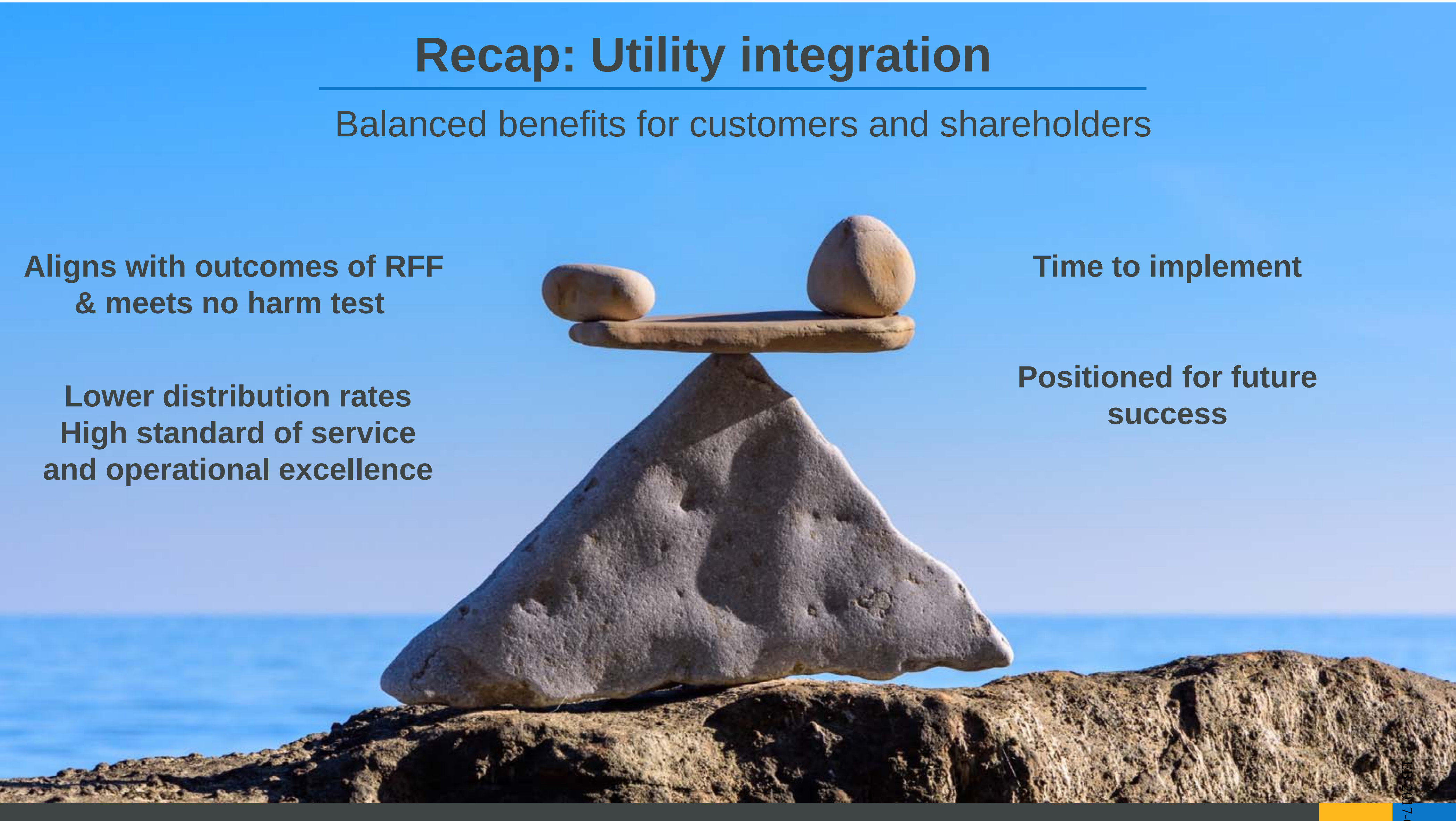
- For the most part, existing deferral and variance accounts will be maintained with two exceptions:
  - Enbridge Gas Distribution pension deferral.
  - Union Gas tax deferral.

Rate Setting Mechanism Application

Annual adjustment process, stakeholder meeting and reporting

- Annual adjustment process
  - Annual distribution rate adjustment for PCI.
  - Proposals to pass through capital using ICM.
  - Y-factor and Z-factor adjustments.

- Stakeholder meeting and reporting
  - Biennial stakeholder meeting to report on financial results, update on market trends, new capital projects, and integration planning and execution.
  - Annual reporting of financial results and scorecard results.
  - Continue to build on the comprehensive customer engagement process commenced by EGD and Union Gas in 2017 throughout the term.


Recap: Utility integration
Balanced benefits for customers and shareholders
Aligns with outcomes of RFF & meets no harm test
Lower distribution rates
High standard of service
and operational excellence
Time to implement
Positioned for future success

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 3

Question:
Please provide an estimate of the costs for the parent and each respective utility to address:

a. Transition costs
b. Transaction costs

Response:

Please see the response to BOMA Interrogatory #7 found at Exhibit C.BOMA.7.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 4

Reference: EB-2017-0306, Exhibit B, Tab 1,Page 20, Table 3 and Page 26, Table 4

Question:
Using the forecast of additional margins that would be generated based upon Table 3 and the estimate capital required, what is the Applicants' forecast of incremental rate of return for each year of the proposed rebasing period

a. assuming the minimum capital in Table 4 incremental capital contributed to rate base accordingly in the years planned?
b. assuming the maximum capital in Table 4 incremental capital contributed to rate base accordingly in the years planned?

Response:

The Applicants did not do a detailed projection on the minimum and maximum capital and O&M savings scenario. The minimum and maximum costs are management best estimates based on historical projects, and projected savings are based on current operational costs.

a. If the integration capital and O&M savings are reduced proportionately to the base case to reflect the minimum, the return on equity will be lower by an average of 0.22% relative to the base case.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Average
Incremental Return relative to base case	-0.01%	-0.22%	-0.33%	-0.26%	-0.12%	-0.25%	-0.24%	-0.24%	-0.24%	-0.25%	-0.22%

b. If the integration capital and O&M savings are increased proportionately to the base case to reflect the maximum, the return on equity will be higher by an average of 0.04% relative to the base case.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Average
Incremental Return relative to base case	0.01%	0.11%	0.16%	0.08%	0.00%	0.00%	0.00%	0.01%	0.01%	0.02%	0.04%

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 5

Reference: Exhibit B, Tab 1, Attachment 5
EB-2014-0261 Updated Settlement Proposal approved by the Board, April 30, 2015

Preamble: *"EGD 1 …c. Discount rate used to determine SRC provision should be examined in more detail at next rebasing.*
d. OEB directive to examine issue of whether a segregated fund (SRC) should be established as a means of protecting ratepayers – EGD to present such evidence ***as part of first application following this Custom IR".*** **(emphasis added)**

Question:
We would like to understand better why SRC should be deferred when it was not tied to rebasing.

Please explain what barriers prevent this study being done and applied in the near future.

a. If the study were ordered by the Board, please provide an estimate of an appropriate timeline to perform the study, seek approval and implement any resulting changes ordered by the Board.

Response:

a) As indicated in the evidence at EB-2017-0307, Exhibit B, Tab 1, page 30, during the deferred rebasing period changes in accounting practices and processes are an expectation as part of the implementation of an integrated accounting system. An example change is the depreciation expense methodology and calculation where EGD and Union currently have differences in approach and Amalco will adopt a common approach.

An analysis and determination of a common depreciation approach for use in the future for the amalgamated entity will be needed when a Board decision is rendered. A review of the SRC element resident in EGD's depreciation rates would not be useful in the near future.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 5

Reference: Exhibit B, Tab 1, Attachment 5
EB-2014-0261 Updated Settlement Proposal approved by the Board, April 30, 2015

Preamble:
"UGL 4. Parties agreed that the issue of Dawn Parkway capacity turnback post-2018 and how turnback risk should be dealt with in the context of the proposed facilities would be dealt with in Union's next cost of service proceeding.

The Settlement Proposal reads: *"The parties do not agree on the risk of Dawn Parkway capacity turnback post-2018. For the purposes of settlement, while the parties agree that leave to construct should be granted, there is no agreement of how turnback risk should be dealt with in the context of the proposed facilities. Parties agree that this issue will be dealt with in Union's next cost of service proceeding.*
For greater certainty, intervenors are in no way restricted or precluded from making any argument before the Board in that proceeding that it is appropriate that certain cost allocation measures should be put in place to insulate ratepayers from the effect of unutilized and underutilized capacity on the Dawn-Parkway system due to potential turnback risk. Accordingly, parties agree that no conditions related to capacity turnback are required at this time

Question:
Please explain what barriers prevent this issue being addressed at this juncture.

a. If the only issues are lack of evidence submitted and timeframes associated with this proceeding, what precludes this issue from being addressed in the near term? Please explain fully.

Response:

Addressing Dawn Parkway turnback is not necessary at this time as it is not an issue. In the event that there is Dawn Parkway turnback during the deferred rebasing period that is material, Amalco may consider addressing the issue earlier than rebasing.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 6

Preamble: We would like to understand better the implications of the merger on the storage market at Dawn. To be clear, we are interested in space that ties directly and not through other Michigan or Ontario pipelines such as Vector.

Question:

Please provide:

a. The non-utility storage space currently under UGL ownership that ties directly in to Dawn.
b. The non-utility storage space currently under EGD ownership that ties directly in to Dawn.
c. The market-based storage space currently under ownership by a Union or EGD affiliate that ties directly into Dawn
i. Please specify the individual companies (i.e., MHP, AltaGas, etc.)
d. All other market-based storage space currently under ownership by non-Enbridge Inc.-affiliated parties that ties directly into Dawn.
i. Please specify the individual companies.

Response:

a) Union owns 80.9 PJ of non-utility storage space connected to Dawn.

b) EGD owns 19.4 PJ of non-utility storage space connected to Dawn. 1.1 PJ of non-utility storage is associated with the Black Creek contract with Union.

c) Market Hub Partners Canada L.P. owns 4.2 PJ of market based storage space connected to Dawn through the St. Clair Pool and its 50% ownership of the Sarnia Airport Pool.

d) AltaGas owns 2.9 PJ of market based storage space connected to Dawn through its 50% ownership of the Sarnia Airport Pool.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 7

Preamble: We would like to understand better the implications of the merger on the storage market at Dawn. To be clear, we are interested in space that ties directly and not through other Michigan or Ontario pipelines such as Vector.

Question:

Please provide a contrast between current STAR rules and existing FERC rules for disclosure of contracts, parties, parameters and prices for storage services. Please describe fully.

Response:

FERC rules were considered in the development of STAR. The amalgamation has no impact on the STAR reporting requirements.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 6

Preamble: We would like to understand better the implications of the merger on the secondary market for services such as exchanges.

Question:
For each month of the last two years, please populate a table with the following data:

a. Month
b. Company
c. Receipt point of gas exchanged
d. Delivery point of gas exchanged
e. Energy (in GJ) exchanged in that month
f. Revenues realized from exchanges
g. Unit rate of revenue per GJ exchanged
h. Published basis differential between the receipt and delivery points for that month

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Response:

The proposed amalgamation will have no impact on the secondary market for services such as exchanges. Both Union and EGD utilize temporarily available excess capacity to offer exchange services to third parties. Following amalgamation, Amalco will continue to offer exchange services to the market.

Attachment 1 provides a listing of exchanges contracted with Union. Attachment 2 provides a listing of exchanges contracted with EGD. Counterparties are not listed as these services are contracted in a competitive market.

The actual value of exchange revenue obtained on a particular path is not readily comparable to the monthly average as the value of the path fluctuates daily based on market conditions and availability of capacity.

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	**Path**	**Energy Exchanged (GJ)**	**Exchange Net Revenue ($ MM CAD)**	**Unit Rate ($ CAD/GJ)**	**Published Basis Differential ($ CAD/GJ)**
January 2016	Parkway to East Hereford	580,599	$ 0.143	$ 0.25	Note 1
	Parkway to Enbridge CDA	115,934	$ 0.026	$ 0.23	$ 0.298
	Parkway to TCPL EDA	64,818	$ 0.094	$ 1.45	Note 1
	Parkway to TCPL Iroquois (Waddington)	1,760,228	$ 0.514	$ 0.29	$ 1.093
	Parkway to TCPL NDA	49,062	$ 0.019	$ 0.39	Note 1
	Parkway to TCPL SSMDA	231,884	$ 0.050	$ 0.22	Note 1
	Other Paths	111,049	$ 0.021	$ 0.19	Note 2
	Exchange Costs		-$ 0.500		3
January 2016 Total		**2,913,574**	**$ 0.369**	**$ 0.13**	**$ -**
February 2016	Parkway to East Hereford	434,141	$ 0.063	$ 0.15	Note 1
	Parkway to TCPL EDA	57,651	$ 0.092	$ 1.59	Note 1
	Parkway to TCPL Iroquois (Waddington)	1,125,195	$ 0.360	$ 0.32	$ 0.204
	Parkway to TCPL NDA	47,478	$ 0.015	$ 0.32	Note 1
	Parkway to TCPL Niagara	69,584	$ 0.034	$ 0.49	-$ 0.874
	Parkway to TCPL SSMDA	101,954	$ 0.014	$ 0.13	Note 1
	Other Paths	300,575	$ 0.011	$ 0.04	Note 2
	Exchange Costs		-$ 0.418		Note 3
February 2016 Total		**2,136,578**	**0.171**	**$ 0.08**	**$ -**
March 2016	Parkway to East Hereford	304,536	$ 0.012	$ 0.04	Note 1
	Parkway to Napierville	93,000	$ 0.028	$ 0.30	Note 1
	Parkway to TCPL EDA	59,553	$ 0.086	$ 1.45	Note 1
	Parkway to TCPL Iroquois (Waddington)	946,683	$ 0.326	$ 0.34	-$ 0.018
	Other Paths	587,871	$ 0.020	$ 0.03	Note 2
	Exchange Costs		-$ 0.178		Note 3
March 2016 Total		**1,991,643**	**0.294**	**$ 0.15**	**$ -**
April 2016	Empress To Emerson 2	219,353	$ 0.149	$ 0.68	$ 0.902
	Parkway to East Hereford	159,427	$ 0.094	$ 0.59	Note 1
	Parkway to Napierville	33,710	$ 0.013	$ 0.39	Note 1
	Parkway to TCPL Iroquois (Waddington)	936,949	$ 0.187	$ 0.20	$ 0.024
	Parkway to TCPL SSMDA	151,225	$ 0.011	$ 0.07	Note 1
	TCPL Empress to Parkway	174,136	$ 0.134	$ 0.77	$ 1.274
	Other Paths	273,172	-$ 0.003	-$ 0.01	Note 2
	Exchange Costs		-$ 0.178		Note 3
April 2016 Total		**1,947,972**	**0.408**	**$ 0.21**	**$ -**
May 2016	Parkway to Napierville	65,410	$ 0.026	$ 0.39	Note 1
	Parkway to TCPL Iroquois (Waddington)	216,740	$ 0.027	$ 0.13	$ 0.084
	Other Paths	975,730	$ 0.005	$ 0.00	Note 2
	Exchange Costs		-$ 0.052		Note 3
May 2016 Total		**1,257,880**	**0.006**	**$ 0.00**	**$ -**
June 2016	Parkway to Napierville	63,300	$ 0.025	$ 0.39	Note 1
	Other Paths	133,807	$ 0.010	$ 0.08	Note 2
	TCPL Empress to Parkway	242	$ 0.000	$ 0.75	Note 3
June 2016 Total		**197,107**	**0.035**	**$ 0.18**	**$ -**

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	**Path**	**Energy Exchanged (GJ)**	**Exchange Net Revenue ($ MM CAD)**	**Unit Rate ($ CAD/GJ)**	**Published Basis Differential ($ CAD/GJ)**
July 2016	Parkway to Napierville	70,960	$ 0.028	$ 0.40	Note 1
	Parkway to TCPL Iroquois (Waddington)	142,765	$ 0.021	$ 0.15	$ 0.031
	Other Paths	272,847	$ 0.007	$ 0.02	Note 2
	Exchange Costs		-$ 0.018		Note 3
July 2016 Total		**486,572**	**0.038**	**$ 0.08**	**$ -**
August 2016	Parkway to Napierville	65,410	$ 0.025	$ 0.38	Note 1
	Parkway to TCPL EDA	643,297	$ 0.561	$ 0.87	Note 1
	Parkway to TCPL Empress	9,000	$ 0.021	$ 2.32	-$ 0.855
	Parkway to TCPL Iroquois (Waddington)	484,022	$ 0.164	$ 0.34	-$ 0.144
	Other Paths	192,585	$ 0.015	$ 0.08	Note 2
	Exchange Costs		-$ 0.035		Note 3
August 2016 Total		**1,394,314**	**0.750**	**$ 0.54**	**$ -**
September 2016	Parkway to Napierville	63,300	$ 0.022	$ 0.35	Note 1
	Other Paths	161,954	$ 0.006	$ 0.04	Note 2
	Exchange Costs		-$ 0.173		Note 3
September 2016 Total		**225,254**	**- 0.145**	**-$ 0.64**	**$ -**
October 2016	Parkway to TCPL Iroquois (Waddington)	122,459	$ 0.024	$ 0.20	$ 0.403
	Parkway to TCPL SSMDA	171,272	$ 0.011	$ 0.06	Note 1
	Other Paths	89,381	$ 0.004	$ 0.05	Note 2
	Exchange Costs		-$ 0.020		Note 3
October 2016 Total		**383,112**	**0.019**	**$ 0.05**	**$ -**
November 2016	Parkway to Enbridge CDA	55,650	$ 0.016	$ 0.29	Note 1
	Parkway to TCPL Iroquois (Waddington)	672,542	$ 0.572	$ 0.85	$ 1.252
	Parkway to TCPL SSMDA	402,487	$ 0.028	$ 0.07	Note 1
	Other Paths	728,450	$ 0.002	$ 0.00	Note 2
	Exchange Costs		-$ 0.105		Note 3
November 2016 Total		**1,859,129**	**0.513**	**$ 0.28**	**$ -**
December 2016	Parkway to East Hereford	99,394	$ 0.060	$ 0.61	Note 1
	Parkway to TCPL EDA	42,978	$ 0.027	$ 0.64	Note 1
	Parkway to TCPL Iroquois (Waddington)	2,976,360	$ 1.431	$ 0.48	$ 2.876
	Parkway to TCPL SSMDA	129,880	$ 0.017	$ 0.13	Note 1
	Other Paths	104,843	$ 0.017	$ 0.16	Note 2
	Exchange Costs		-$ 0.653		Note 3
December 2016 Total		**3,353,455**	**0.900**	**$ 0.27**	**$ -**
January 2017	Parkway to East Hereford	44,527	$ 0.011	$ 0.25	Note 1
	Parkway to TCPL Iroquois (Waddington)	2,569,824	$ 1.244	$ 0.48	$ 1.778
	Parkway to TCPL SSMDA	400,828	$ 0.062	$ 0.16	Note 1
	Other Paths	113,932	$ 0.011	$ 0.10	Note 2
	Exchange Costs		-$ 0.479		Note 3
January 2017 Total		**3,129,111**	**0.850**	**$ 0.27**	**$ -**

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	**Path**	**Energy Exchanged (GJ)**	**Exchange Net Revenue ($ MM CAD)**	**Unit Rate ($ CAD/GJ)**	**Published Basis Differential ($ CAD/GJ)**
February 2017	Parkway to East Hereford	241,590	$ 0.083	$ 0.34	Note 1
	Parkway to TCPL Iroquois (Waddington)	2,435,207	$ 1.022	$ 0.42	$ 0.176
	Parkway to TCPL SSMDA	303,609	$ 0.030	$ 0.10	Note 1
	TCPL Iroquois (Waddington) to Parkway	155,323	$ 0.040	$ 0.26	-$ 0.176
	Other Paths	143,990	$ 0.009	$ 0.06	Note 2
	Exchange Costs		-$ 0.404		Note 3
February 2017 Total		**3,279,719**	**0.778**	**$ 0.24**	**$ -**
March 2017	Empress To Emerson 2	235,827	$ 0.054	$ 0.23	$ 0.777
	Parkway to TCPL Iroquois (Waddington)	2,422,104	$ 1.290	$ 0.53	-$ 0.065
	TCPL Empress to Dawn	156,022	$ 0.142	$ 0.91	$ 1.389
	TCPL Empress to TCPL Emerson 1	105,864	$ 0.032	$ 0.30	$ 0.777
	Other Paths	286,644	$ 0.013	$ 0.05	Note 2
	Exchange Costs		-$ 0.347		Note 3
March 2017 Total		**3,206,461**	**1.185**	**$ 0.37**	**$ -**
April 2017	Parkway to TCPL Niagara	-	$ 0.127	$ -	-$ 0.717
	Other Paths	608,829	$ 0.005	$ 0.01	Note 2
	Exchange Costs		-$ 0.088		Note 3
April 2017 Total		**608,829**	**0.044**	**$ 0.07**	**$ -**
May 2017	MichCon to Dawn	429,924	$ 0.045	$ 0.11	$ 0.082
	Other Paths	77,410	$ 0.004	$ 0.06	Note 2
	Exchange Costs		-$ 0.023		Note 3
May 2017 Total		**507,334**	**0.027**	**$ 0.05**	**$ -**
June 2017	Other Paths	1,330,790	$ 0.022	$ 0.02	Note 2
	Exchange Costs		-$ 0.007		Note 3
June 2017 Total		**1,330,790**	**0.015**	**$ 0.01**	**$ -**
July 2017	Parkway to TCPL Iroquois (Waddingto	137,158	$ 0.017	$ 0.12	$ 0.016
	Other Paths	176,040	$ 0.013	$ 0.07	Note 2
	Exchange Costs		-$ 0.003		Note 3
July 2017 Total		**313,198**	**0.026**	**$ 0.08**	**$ -**
August 2017	Other Paths	139,923	-$ 0.011	-$ 0.08	Note 2
	Exchange Costs		-$ 0.005		Note 3
August 2017 Total		**139,923**	**- 0.016**	**-$ 0.11**	**$ -**
September 2017	Parkway to TCPL SSMDA	319,154	$ 0.016	$ 0.05	Note 1
	Other Paths	61,864	$ 0.013	$ 0.22	Note 2
	Exchange Costs		-$ 0.004		Note 3
September 2017 Total		**381,018**	**0.025**	**$ 0.06**	**$ -**
October 2017	Parkway to TCPL EDA	71,665	$ 0.043	$ 0.60	Note 1
	Parkway to TCPL SSMDA	160,951	$ 0.012	$ 0.07	Note 1
	Other Paths	73,688	$ 0.013	$ 0.17	Note 2
	Exchange Costs		-$ 0.006		Note 3
October 2017 Total		**306,304**	**0.062**	**$ 0.20**	**$ -**

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	Path	Energy Exchanged (GJ)	Exchange Net Revenue ($ MM CAD)	Unit Rate ($ CAD/GJ)	Published Basis Differential ($ CAD/GJ)
November 2017	Dawn to N Border IC	-	$ 0.023	$ -	Note 1
	Parkway to TCPL Iroquois (Waddingto	2,023,893	$ 1.079	$ 0.53	$ 1.266
	Other Paths	106,685	$ 0.016	$ 0.15	Note 2
	Exchange Costs		-$ 0.270		Note 3
November 2017 Total		**2,130,578**	**0.849**	**$ 0.40**	**$ -**
December 2017	Dawn to N Border IC	-	$ 0.023	$ -	Note 1
	Parkway to North Bay JT	106,763	$ 0.030	$ 0.28	Note 1
	Parkway to TCPL Iroquois (Waddingto	3,565,702	$ 1.542	$ 0.43	$ 2.312
	Other Paths	69,811	$ 0.017	$ 0.25	Note 2
	Exchange Costs		-$ 0.444		Note 3
December 2017 Total		**3,742,276**	**1.169**	**$ 0.31**	**$ -**

Notes:
1 - The delivery point is not traded on a regular basis and therefore the basis differential could not be calculated
2 - Other Paths represent an amalgamation of paths that had less than $10,000 of revenue for the month
3 - Exchange Costs represent the costs incurred for exchange transactions during the month.
This would include items such as diversion costs, delivery point surcharges and incremental fuel.

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	Path	Energy Exchanged (GJ)	Exchange Net Revenue ($ MM CAD)	Unit Rate ($ CAD/GJ)	Published Basis Differential ($ CAD/GJ)
January 2016	Dawn to Enbridge CDA	282,442	n/a	1	$ 0.517
	Dawn to Enbridge EDA	9,028	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	2,831,311	n/a		$ 1.312
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	22,322	n/a		Note 2
	Dawn to TCPL SSMDA	123,701	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	60,611	n/a		Note 2
	Dawn to Parkway	56,511	n/a		Note 2
January 2016 Total		**3,385,926**	**$ 1.448**	**$ 0.43**	Note 3
February 2016	Dawn to Enbridge CDA	91,833	n/a	1	$ 0.260
	Dawn to Enbridge EDA	8,976	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	919,336	n/a		$ 0.392
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	110,266	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	28,113	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
February 2016 Total		**1,158,524**	**$ 0.530**	**$ 0.46**	Note 3
March 2016	Dawn to Enbridge CDA	296,494	n/a	1	$ 0.038
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	1,178,203	n/a		$ 0.007
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	138,465	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
March 2016 Total		**1,613,162**	**$ 0.501**	**$ 0.31**	Note 3
April 2016	Dawn to Enbridge CDA	259,591	n/a	1	-$ 0.012
	Dawn to Enbridge EDA	1,398	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	1,179,194	n/a		$ 0.022
	Dawn to TCPL Niagara	1,028,670	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	22,578	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
April 2016 Total		**2,491,431**	**$ 0.886**	**$ 0.36**	Note 3

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	Path	Energy Exchanged (GJ)	Exchange Net Revenue ($ MM CAD)	Unit Rate ($ CAD/GJ)	Published Basis Differential ($ CAD/GJ)
May 2016	Dawn to Enbridge CDA	132,188	n/a	1	-$ 0.009
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	474,716	n/a		$ 0.086
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	117,825	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	15,058	n/a		Note 2
	Dawn to Parkway	73,856	n/a		Note 2
May 2016 Total		**813,643**	**$ 0.194**	**$ 0.24**	Note 3
June 2016	Dawn to Enbridge CDA	995,780	n/a	1	-$ 0.015
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	46,376	n/a		$ 0.072
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	564,674	n/a		Note 2
June 2016 Total		**1,606,830**	**$ 0.423**	**$ 0.26**	Note 3
July 2016	Dawn to Enbridge CDA	1,266,865	n/a	1	-$ 0.025
	Dawn to Enbridge EDA	372	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	495,864	n/a		$ 0.036
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	22,400	n/a		Note 2
	Dawn to Parkway	989,284	n/a		Note 2
July 2016 Total		**2,774,785**	**$ 0.812**	**$ 0.29**	Note 3
August 2016	Dawn to Enbridge CDA	1,081,284	n/a	1	-$ 0.018
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	748,031	n/a		-$ 0.144
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	20,860	n/a		Note 2
	Dawn to Parkway	1,184,451	n/a		Note 2
August 2016 Total		**3,034,626**	**$ 0.868**	**$ 0.29**	Note 3

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	**Path**	**Energy Exchanged (GJ)**	**Exchange Net Revenue ($ MM CAD)**	**Unit Rate ($ CAD/GJ)**	**Published Basis Differential ($ CAD/GJ)**
September 2016	Dawn to Enbridge CDA	882,345	n/a	1	$ 0.027
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	440,661	n/a		-$ 0.143
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	49,623	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
September 2016 Total		**1,372,629**	**$ 1.016**	**$ 0.74**	Note 3
October 2016	Dawn to Enbridge CDA	292,998	n/a	1	$ 0.241
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	133,148	n/a		$ 0.459
	Dawn to TCPL Niagara	1,062,959	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	41,370	n/a		Note 2
October 2016 Total		**1,530,475**	**$ 0.889**	**$ 0.58**	Note 3
November 2016	Dawn to Enbridge CDA	110,504	n/a	1	$ 0.453
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	357,016	n/a		$ 1.318
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	17,936	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	30,240	n/a		Note 2
November 2016 Total		**515,696**	**$ 0.100**	**$ 0.19**	Note 3
December 2016	Dawn to Enbridge CDA	601,832	n/a	1	$ 0.620
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	2,894,896	n/a		$ 2.966
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	60,347	n/a		Note 2
	Dawn to Parkway	662,532	n/a		Note 2
December 2016 Total		**4,219,607**	**$ 2.797**	**$ 0.66**	Note 3

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	Path	Energy Exchanged (GJ)	Exchange Net Revenue ($ MM CAD)	Unit Rate ($ CAD/GJ)	Published Basis Differential ($ CAD/GJ)
January 2017	Dawn to Enbridge CDA	550,889	n/a	1	$ 0.251
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	1,614,949	n/a		$ 1.869
	Dawn to TCPL Niagara	21,076	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	162,068	n/a		Note 2
January 2017 Total		**2,348,982**	**$ 1.780**	**$ 0.76**	Note 3
February 2017	Dawn to Enbridge CDA	393,999	n/a	1	$ 0.086
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	1,575,930	n/a		$ 0.216
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	179,053	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
February 2017 Total		**2,148,982**	**$ 0.992**	**$ 0.46**	Note 3
March 2017	Dawn to Enbridge CDA	778,753	n/a	1	$ 0.011
	Dawn to Enbridge EDA	-	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	1,658,912	n/a		-$ 0.055
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
March 2017 Total		**2,437,665**	**$ 1.566**	**$ 0.64**	Note 3
April 2017	Dawn to Enbridge CDA	403,123	n/a	1	$ 0.001
	Dawn to Enbridge EDA	33,549	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	84,721	n/a		-$ 0.189
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
April 2017 Total		**521,393**	**$ 0.143**	**$ 0.27**	Note 3

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	**Path**	**Energy Exchanged (GJ)**	**Exchange Net Revenue ($ MM CAD)**	**Unit Rate ($ CAD/GJ)**	**Published Basis Differential ($ CAD/GJ)**
May 2017	Dawn to Enbridge CDA	177,384	n/a	1	-$ 0.010
	Dawn to Enbridge EDA	25,517	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	-	n/a		-$ 0.061
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
May 2017 Total		**202,901**	**$ 0.180**	**$ 0.89**	Note 3
June 2017	Dawn to Enbridge CDA	473,160	n/a	1	-$ 0.015
	Dawn to Enbridge EDA	13,800	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	-	n/a		$ 0.020
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
June 2017 Total		**486,960**	**$ 0.307**	**$ 0.63**	Note 3
July 2017	Dawn to Enbridge CDA	784,081	n/a	1	-$ 0.012
	Dawn to Enbridge EDA	21,932	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	189,001	n/a		$ 0.016
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	1,426	n/a		Note 2
July 2017 Total		**996,440**	**$ 0.422**	**$ 0.42**	Note 3
August 2017	Dawn to Enbridge CDA	269,937	n/a	1	-$ 0.013
	Dawn to Enbridge EDA	14,136	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	31,652	n/a		-$ 0.095
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
August 2017 Total		**315,725**	**$ 0.261**	**$ 0.83**	Note 3

(a)	(c) & (d)	(e)	(f)	(g)	(h)
Month	**Path**	**Energy Exchanged (GJ)**	**Exchange Net Revenue ($ MM CAD)**	**Unit Rate ($ CAD/GJ)**	**Published Basis Differential ($ CAD/GJ)**
September 2017	Dawn to Enbridge CDA	96,000	n/a	1	$ 0.074
	Dawn to Enbridge EDA	14,340	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	-	n/a		$ 0.012
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	-	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	1,380	n/a		Note 2
September 2017 Total		**111,720**	**$ 0.260**	**$ 2.33**	Note 3
October 2017	Dawn to Enbridge CDA	535,888	n/a	1	$ 0.167
	Dawn to Enbridge EDA	16,895	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	10,234	n/a		$ 0.428
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	42,729	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
October 2017 Total		**605,746**	**$ 0.280**	**$ 0.46**	Note 3
November 2017	Dawn to Enbridge CDA	44,479	n/a	1	$ 0.163
	Dawn to Enbridge EDA	3,270	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	1,969,919	n/a		$ 1.331
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	1,925	n/a		Note 2
	Dawn to TCPL SSMDA	154,948	n/a		Note 2
	Dawn to TCPL North Bay	-	n/a		Note 2
	Dawn to TCPL Union EDA	25,358	n/a		Note 2
	Dawn to Parkway	28,323	n/a		Note 2
November 2017 Total		**2,228,222**	**$ 1.053**	**$ 0.47**	Note 3
December 2017	Dawn to Enbridge CDA	1,575,159	n/a	1	$ 0.200
	Dawn to Enbridge EDA	1,023	n/a		Note 2
	Dawn to TCPL Iroquois (Waddington)	3,893,513	n/a		$ 2.390
	Dawn to TCPL Niagara	-	n/a		Note 2
	Dawn to TCPL East Hereford	-	n/a		Note 2
	Dawn to TCPL SSMDA	18,463	n/a		Note 2
	Dawn to TCPL North Bay	342,588	n/a		Note 2
	Dawn to TCPL Union EDA	-	n/a		Note 2
	Dawn to Parkway	-	n/a		Note 2
December 2017 Total		**5,830,746**	**$ 3.148**	**$ 0.54**	Note 3

Notes:
1 - EGD does not disaggregate Transactional Revenues by exchange type.
2 - The majority of the exchange deals entered into by EGD are either Dawn/CDA or Dawn/Iroquois exchanges and the monthly
3 - Transactional Services Revenue includes other items such as diversion costs, and avoided and/or incremental fuel costs.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 6

Preamble: We would like to understand better the implications of the merger on the secondary market for services such as exchanges.

Question:
Please provide a contrast between current STAR rules and existing FERC rules for disclosure of parties, energy transferred and prices for transportation and exchange services. Please describe fully.

Response

Please see the response to FRPO Interrogatory #7 found at Exhibit C.FRPO.7.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

MAADs Issues List – Issue No. 7

Reference: EB-2017-0306 B1, TAB 1, pg. 14

Preamble:
"As a subsidiary of Enbridge Inc., a multi-national publicly traded entity subject to thorough public disclosure requirements, Amalco will follow the same rigorous governance practices as EGD and Union have followed in the past."

And

EB-2014-0255 Corporate Governance for Regulated Natural Gas and Electric Utilities, Elenchus Final Report, filed December 19, 2016, page 64.
*"**Principle #2: Directors should exercise their independent judgment in the best interests of the utility with appropriate balance given to the interests of customers.***
Best Practices include:
☐ *The board has a majority of directors who are independent of management and independent of affiliates, and are not the employees or councillors of municipal shareholders."*

Question:
Please provide the names of the individuals on the respective Boards of EGD and UGL at the time of the merger announcement. Please provide:

a. Their titles, years of service as an employee of the gas utility or parent.
OR
b. Any years of service with an affiliated company underneath either Enbridge Inc. or Spectra.
OR
c. If no service as employee with the companies within ownership of Enbridge Inc. or Spectra, the nature of any related board affiliations with the respective companies
d. Using the referenced Elenchus Final Report to the Board,
    i. Does the current EGD Board of Directors meet the Best Practice criteria?
    ii. Does the current UGL Board of Directors meet the Best Practice criteria?
    iii. Will AMALCO expect its future Board to meet this Best Practice criteria?

Response:

a- c) Given the reference to the current board of directors in part d), the Applicants assume subsections a-c are in relation to the current boards of EGD and Union and not the board composition pre-Enbridge Inc./Spectra merger. The current boards of EGD and Union were constituted on the effective date of the merger in February 2017, after the merger was first announced in September 2016. The Applicants have noted in each case the year since which each board member has held a director position or been employed, as applicable, with an Enbridge Inc. or Spectra affiliate in continuous service.

EGD Board:

- Cynthia Hansen, Executive Chair, employee since January 1999
- Jim Sanders, President, employee since January 1989
- David Unruh, independent director since January 1998

Union Board:

- Cynthia Hansen, Exec VP, Utilities & Power Ops
- Steve Baker, President, employee since July 1989
- David Unruh, independent director since January 1998

d) Enbridge Inc. has a comprehensive governance system that follows best practices and fully meets, and in many cases exceeds, the requirements of all applicable laws, rules, regulations and standards. Notably, Enbridge Inc. has been publicly recognized for its strong governance, corporate sustainability, employment and public reporting practices for several years, including the following most recent awards in 2017:

Corporate Sustainability

- Global 100 List of the Most Sustainable Companies in the World: This award, from Corporate Knights, recognizes Enbridge as being one of the most sustainable companies in the world, ranked 12th overall.
- Best 50 Corporate Citizens in Canada: This award, from Corporate Knights, recognizes Enbridge as being one of the best 50 corporate citizens in Canada. Enbridge came in sixth place.
- Dow Jones Sustainability World and North America Indices: The Dow Jones Sustainability Index included Enbridge in its North America Index.
- Newsweek Green Rankings: In its Green Rankings—which are based on energy use, GHG emissions, and water and waste productivity—*Newsweek* ranked Enbridge the highest among energy companies.
- CDP: Awarded Enbridge a performance score of ‘C’ for our 2017 climate disclosure and ‘B’ for our water disclosure submission.

Governance

- Corporate Governance Rankings: The Globe and Mail Report on Business ranked Enbridge 41st out of 242 companies on its annual Corporate Governance Rankings using a rigorous set of governance criteria that go beyond minimum mandatory rules imposed by regulators.

Employment

- Canada's Top 100 Employers: This award, from Mediacorp, recognizes employers that lead their industries in offering exceptional workplaces for their employees.

Financial and Sustainability Reporting

- Corporate Reporting Award, Chartered Professional Accountants of Canada: Enbridge received a 2017 Award of Excellence for Corporate Reporting.

As a publicly traded entity, with securities listed on the TSX and the NYSE, Enbridge Inc. is subject to various securities and corporate laws and standards. Enbridge Inc.'s governance practices are detailed in its publicly filed documents, including its Management Information Circular (Proxy Statement) for its annual general meeting of shareholders.

Enbridge Inc. employs a governance model whereby certain governance functions that are common across the Enbridge Inc. organizations are overseen at the parent company level. The utilities enjoy, as Amalco will, significant benefits by having committees such as the Audit, Finance & Risk Committee, Human Resources and Compensation Committee, the Corporate Social Responsibility Committee and the Safety and Reliability Committee operating at the parent level.

The utilities leverage the broad representation of independent board members at the parent level, as well as the identification and implementation of governance best practices for a widely-held multi-national energy infrastructure organization and efficiencies of having a consistent application of corporate policies, standards and enterprise systems like the compliance program and Statement on Business Conduct, information technology standards/security and a strong COSO and SOX environment. Carrying out such functions at the subsidiary level in addition to or separate from the parent level would result in considerable duplication of effort, inefficiencies, loss of significant benefits and unnecessary additional costs at the subsidiary level.

In the OEB's February 9, 2017 letter to stakeholders for EB-2014-0255, the OEB concluded by stating:

> The OEB thanks Elenchus for its report and proposed guidance. The OEB will be reviewing the recommendations of the report as it considers the matter of corporate governance within the context of its performance-based regulatory framework.

The Applicants note that the OEB has not adopted the referenced Elenchus report into regulation of any form. In particular, the *Affiliate Relationships Code for Gas Utilities* ("ARC") provides in section 2.1.3 that a utility shall ensure that at least one-third of its board of directors is independent from any affiliate. The ARC is consistent with the independence requirements of the *Ontario Business Corporations Act*. The OEB would have to amend the ARC in order to adopt the Elenchus recommendations in this regard.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: B1, TAB 1, pg. 20-21, Table 3

Preamble: We would like to understand better how the figures in Table 3 were developed.

Question:
Please provide all working sheets that contributed to the aggregated numbers in Table 3.

a. Please include all assumptions for both the amalgamated company and the separate utilities.
b. Please describe how the costs were rebased for each utility for 2019?
c. What stretch or productivity factors were assumed for each utility in calculating the costs for the individual utilities over the ten year period?
    i. What were the assumptions and methodology behind those figures?
d. Please explain why starting in 2023, the costs for the amalgamated company increase more than the two separate companies for each of the last 6 years.
    i. What drives that effect?

Response

a) Assumptions used are provided in the tables on the following pages:

a. Assumptions for Enbridge Gas Distribution (Stand-alone)

Table 1

(i) EGD Assumptions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1. Distribution Revenues										
1.1 Customer Additions	29,263	28,995	28,169	27,690	27,396	26,926	26,218	25,611	25,397	25,251
1.2 Escalation factor:										
1.2.1 GDPIPI	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
1.2.2 Productivity factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1.2.3 Growth factor	0.93%	0.92%	0.84%	0.87%	0.84%	0.82%	0.80%	0.78%	0.77%	0.75%
2. Utility O&M ($M)										
2.1 Customer Care	92	94	95	97	99	101	102	104	106	108
2.2 RCAM	52	53	54	55	56	57	58	59	60	61
2.3 DSM	66	68	68	69	70	71	73	74	75	76
2.4 Pension	22	23	25	25	26	26	27	27	28	28
2.5 Departmental	209	213	217	221	225	229	233	237	241	245
2.6 Total Utility O&M	441	451	460	468	476	484	492	501	509	518
3. Capital Additions, ICM threshold, Rate base and Depreciation										
3.1 Capital expenditures ($M)	633	724	575	635	577	586	610	820	594	601
3.2 Rate Base ($M)	7,025	7,422	7,776	8,060	8,330	8,576	8,842	9,238	9,623	9,869
3.3 Depreciation (weighted Average)	3.2%	3.3%	3.3%	3.3%	3.2%	3.2%	3.1%	3.0%	3.0%	2.9%
3.4 ICM threshold ($M)	503	507	506	512	515	518	521	524	527	531
3.5 ICM capital ($M)	111	217	70	123	62	68	89	296	67	70
4. Cost of Capital										
4.1 Cost of long term debt	4.4%	4.7%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
4.2 Allowed ROE	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
5 Taxes										
5.1 Income tax rate	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
5.2 Municipal taxes ($M)	51	53	56	59	61	64	66	69	72	75

Table 2

(ii) EGD Revenues and Earnings - Stand Alone

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Capital										
Rate base	7,025	7,422	7,776	8,060	8,330	8,576	8,842	9,238	9,623	9,869
Required rate of return	6.19%	6.27%	6.31%	6.31%	6.30%	6.31%	6.33%	6.34%	6.35%	6.36%
	435	**465**	**490**	**509**	**525**	**541**	**559**	**586**	**611**	**628**
Cost of Service										
Gas costs	-	-	-	-	-	-	-	-	-	-
Operation and maintenance	441	451	460	468	476	484	492	501	509	518
Depreciation and amortization	328	349	367	382	392	401	411	419	428	439
Fixed financing costs	3	3	3	3	3	3	3	3	3	3
Municipal and other taxes	51	53	56	59	61	64	66	69	72	75
	822	**856**	**886**	**911**	**932**	**952**	**973**	**992**	**1,012**	**1,035**
Income Taxes	**43**	**36**	**52**	**53**	**60**	**54**	**60**	**51**	**70**	**75**
Total Revenues	**1,300**	**1,357**	**1,428**	**1,473**	**1,516**	**1,546**	**1,592**	**1,629**	**1,693**	**1,738**
Utility Earnings	**231**	**248**	**262**	**272**	**281**	**289**	**298**	**312**	**325**	**333**

Table 3

(iii) EGD Rate Base

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Property, Plant, and Equipment										
Cost or redetermined value	10,108	10,646	11,220	11,743	12,258	12,747	13,249	13,830	14,410	14,925
Accumulated depreciation	(3,443)	(3,582)	(3,802)	(4,042)	(4,287)	(4,529)	(4,766)	(4,950)	(5,146)	(5,415)
Net property, plant, and equipment	6,666	7,064	7,418	7,701	7,971	8,217	8,483	8,880	9,264	9,510
Affiliate shared Asset	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Net PP&E in Rate base	6,657	7,055	7,409	7,692	7,962	8,208	8,474	8,871	9,255	9,501
Allowance for working capital	368	368	368	368	368	368	368	368	368	368
Total Rate base	**7,025**	**7,422**	**7,776**	**8,060**	**8,330**	**8,576**	**8,842**	**9,238**	**9,623**	**9,869**

Table 4

(iv) EGD Capital Structure

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Long term debt										
Principal	4,218	4,513	4,689	4,922	5,051	5,204	5,480	5,627	5,852	6,020
Component	60.04%	60.81%	60.30%	61.07%	60.64%	60.69%	61.98%	60.90%	60.81%	61.01%
Cost Rate	4.67%	4.66%	4.68%	4.67%	4.66%	4.67%	4.66%	4.73%	4.74%	4.76%
Return Component	2.80%	2.84%	2.83%	2.85%	2.83%	2.84%	2.89%	2.88%	2.88%	2.90%
Short term debt										
Principal	178	137	187	136	180	184	79	186	207	196
Component	2.54%	1.84%	2.41%	1.69%	2.16%	2.15%	0.89%	2.01%	2.15%	1.98%
Cost Rate	2.10%	2.50%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%
Return Component	0.05%	0.05%	0.07%	0.05%	0.06%	0.06%	0.02%	0.05%	0.06%	0.05%
Preference Shares										
Principal	100	100	100	100	100	100	100	100	100	100
Component	1.42%	1.35%	1.29%	1.24%	1.20%	1.17%	1.13%	1.08%	1.04%	1.01%
Cost Rate	2.80%	3.28%	3.44%	3.44%	3.44%	3.44%	3.44%	3.44%	3.44%	3.44%
Return Component	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.03%
Common Equity										
Principal	2,529	2,672	2,799	2,901	2,999	3,087	3,183	3,326	3,464	3,553
Component	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%
Cost Rate	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
Return Component	3.29%	3.34%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%
Required Rate of Return	**6.19%**	**6.27%**	**6.31%**	**6.31%**	**6.30%**	**6.31%**	**6.33%**	**6.34%**	**6.35%**	**6.36%**

a. Assumptions for Union Gas (Stand-alone)

Table 5

(i) UG Assumptions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1. Distribution Revenues										
1.1 Customer Additions	17,742	17,288	17,290	17,284	17,257	17,201	17,195	17,217	17,296	17,432
1.2 Escalation factor:										
1.2.1 GDPIPI	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
1.2.2 Productivity factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1.2.3 Growth factor	0.93%	0.90%	0.89%	0.88%	0.87%	0.86%	0.85%	0.85%	0.84%	0.84%
2. Utility O&M										
2.1 Customer Care	-	-	-	2	4	6	8	10	12	14
2.2 DSM	63	63	63	63	63	63	63	63	63	63
2.3 Departmental & Others	380	393	400	408	417	425	434	443	452	461
2.4 Total Utility O&M	443	456	463	473	484	494	505	516	527	538
3. Capital Additions, ICM threshold, Rate base and Depreciation										
3.1 Capital expenditures ($M)	587	429	450	438	609	589	426	423	436	436
3.2 Rate Base ($M)	6,417	6,732	6,852	7,003	7,116	7,362	7,549	7,586	7,612	7,638
3.3 Depreciation (weighted Average)	2.9%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
3.4 ICM threshold ($M)	330	331	334	336	339	341	344	347	350	354
3.5 ICM capital ($M)	211	77	114	96	264	249	76	58	88	31
4. Cost of Capital										
4.1 Cost of long term debt	4.4%	4.7%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
4.2 Allowed ROE	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
5 Taxes										
5.1 Income tax rate	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
5.2 Municipal taxes ($M)	79	81	83	85	87	89	91	93	95	97

Table 6

(ii) UG Revenues and Earnings- Stand Alone

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Capital										
Rate base	6,417	6,732	6,852	7,003	7,116	7,362	7,549	7,586	7,612	7,638
Required rate of return	5.99%	6.05%	6.16%	6.18%	6.22%	6.23%	6.20%	6.24%	6.24%	6.24%
	384	**408**	**422**	**433**	**443**	**459**	**468**	**473**	**475**	**477**
Cost of Service										
Gas costs	-	-	-	-	-	-	-	-	-	-
Operation and maintenance	443	456	463	473	484	494	505	516	527	538
Depreciation and amortization	298	319	330	340	353	369	382	393	404	415
Fixed financing costs	2	2	2	2	2	2	2	2	2	2
Municipal and other taxes	79	81	83	85	87	89	91	93	95	97
	822	**858**	**878**	**901**	**926**	**954**	**980**	**1,004**	**1,028**	**1,052**
Income Taxes	**24**	**35**	**40**	**43**	**47**	**55**	**63**	**68**	**73**	**85**
Total Revenues	**1,231**	**1,300**	**1,340**	**1,377**	**1,416**	**1,468**	**1,511**	**1,545**	**1,575**	**1,614**
Utility Earnings	**211**	**225**	**231**	**236**	**240**	**248**	**255**	**256**	**257**	**258**

Table 7

(iii) UG Rate Base

$ Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Property, Plant, and Equipment:										
Cost or redetermined value	9,995	10,574	10,953	11,361	11,742	12,265	12,754	13,109	13,466	13,834
Accumulated depreciation	(3,783)	(4,047)	(4,306)	(4,564)	(4,830)	(5,108)	(5,409)	(5,729)	(6,059)	(6,400)
Net property, plant, and equipment	6,212	6,527	6,647	6,798	6,911	7,157	7,344	7,381	7,407	7,433
Affiliate shared Asset	-	-	-	-	-	-	-	-	-	-
Net PP&E in Rate base	6,212	6,527	6,647	6,798	6,911	7,157	7,344	7,381	7,407	7,433
Allowance for working capital	205	205	205	205	205	205	205	205	205	205
Total Rate base	**6,417**	**6,732**	**6,852**	**7,003**	**7,116**	**7,362**	**7,549**	**7,586**	**7,612**	**7,638**

Table 8

(iv) UG Capital Structure

$ Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Long term debt										
Principal	3,958	4,161	4,314	4,377	4,450	4,607	4,677	4,575	4,592	4,609
Component	61.68%	61.81%	62.96%	62.51%	62.53%	62.58%	61.95%	60.31%	60.33%	60.34%
Cost Rate	4.26%	4.27%	4.36%	4.41%	4.47%	4.49%	4.46%	4.56%	4.57%	4.57%
Return Component	2.63%	2.64%	2.75%	2.76%	2.80%	2.81%	2.76%	2.75%	2.75%	2.76%
Short term debt										
Principal	45	44	(33)	1	0	1	51	176	176	175
Component	0.70%	0.65%	-0.48%	0.01%	0.01%	0.01%	0.67%	2.32%	2.31%	2.30%
Cost Rate	2.10%	2.50%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%
Return Component	0.01%	0.02%	-0.01%	0.00%	0.00%	0.00%	0.02%	0.06%	0.06%	0.06%
Preference Shares										
Principal	104	104	104	104	104	104	104	104	104	104
Component	1.62%	1.54%	1.52%	1.49%	1.46%	1.41%	1.38%	1.37%	1.37%	1.36%
Cost Rate	3.12%	3.57%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%
Return Component	0.05%	0.06%	0.06%	0.06%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
Common Equity										
Principal	2,310	2,424	2,467	2,521	2,562	2,650	2,718	2,731	2,740	2,750
Component	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%
Cost Rate	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
Return Component	3.29%	3.34%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%
Required Rate of Return	**5.99%**	**6.05%**	**6.16%**	**6.18%**	**6.22%**	**6.23%**	**6.20%**	**6.24%**	**6.24%**	**6.24%**

a. Assumptions for Amalco (Enbridge Gas Distribution and Union Gas)

Table 9

(i) Amalco Revenues - Price Cap

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
EGD	1,305	1,353	1,397	1,440	1,482	1,523	1,565	1,619	1,672	1,715
UG	1,225	1,277	1,311	1,348	1,390	1,441	1,489	1,525	1,563	1,599
Amalco Total Revenues	**2,530**	**2,630**	**2,709**	**2,788**	**2,872**	**2,964**	**3,054**	**3,144**	**3,234**	**3,314**

(ii) Amalco Utility Earnings with synergies

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility Earnings - Price cap										
EGD	235	245	240	247	256	272	278	304	309	316
UG	207	208	210	215	220	228	238	242	247	247
Utility Earnings before synergies	**442**	**453**	**450**	**463**	**477**	**500**	**517**	**546**	**556**	**563**
After-tax synergies from attachment 12 in the evidence EB-2017-0306:										
Earnings drag - To fund synergy capital	1	3	3	(2)	(10)	(16)	(17)	(17)	(16)	(16)
O&M savings with synergies - after tax	2	28	46	51	60	62	62	62	62	62
Net synergies - after tax	**3**	**31**	**49**	**49**	**49**	**47**	**45**	**46**	**46**	**46**
Utility Earnings with synergies	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**
Earnings sharing	-	-	-	-	-	-	-	-	-	-
Amalco Utility Earnings after synergies	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**

Table 10

(ii) EGD Revenues and Earnings - Price Cap

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Revenue Requirement										
2018 Revenue Requirement	1,233									
Less Rate smoothing	(5)									
DSM	(68)									
Flow-through adjustments	-									
2018 Revenue Requirement for escalation	1,160									
Escalation factor										
GDPIPI LRP Forecast	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
Growth factor	0.93%	0.92%	0.84%	0.87%	0.84%	0.82%	0.80%	0.78%	0.77%	0.75%
Revenue Requirement with escalation	**1,191**	**1,223**	**1,254**	**1,287**	**1,320**	**1,353**	**1,388**	**1,422**	**1,458**	**1,494**
Flow through										
DSM	66	68	68	69	70	71	73	74	75	76
Flow-through adjustments	-	-	-	-	-	-	-	-	-	-
ICM recovery	5	19	32	40	48	54	60	77	92	97
Total flow-through	71	87	100	109	118	125	133	150	167	174
Other Revenues	43	43	44	44	44	45	45	46	46	47
Total Revenues	**1,305**	**1,353**	**1,397**	**1,440**	**1,482**	**1,523**	**1,565**	**1,619**	**1,672**	**1,715**
Utility Earnings	**235**	**245**	**240**	**247**	**256**	**272**	**278**	**304**	**309**	**316**

Table 11

(iii) UG Revenues and Earnings - Price Cap

$ Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Revenue Requirement										
2018 Revenue Requirement	1,161									
Less Rate smoothing	-									
DSM	(63)									
Flow-through adjustments	(116)									
2018 Revenue Requirement for escalation	982									
Escalation factor										
GDPIPI LRP Forecast	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
Growth factor	0.93%	0.90%	0.89%	0.88%	0.87%	0.86%	0.85%	0.85%	0.84%	0.84%
Revenue Requirement with escalation	**1,008**	**1,035**	**1,062**	**1,089**	**1,118**	**1,147**	**1,176**	**1,207**	**1,238**	**1,270**
Flow through										
DSM	63	63	63	63	63	63	63	63	63	63
Flow-through adjustments & others	125	135	135	135	137	138	139	139	139	138
Accumulated deferred tax drawdown	17	17	17	17	17	17	17	17	17	17
ICM recovery	12	27	35	44	55	76	94	100	106	111
Total flow-through	217	242	250	259	272	294	313	319	325	329
Total Revenues	**1,225**	**1,277**	**1,311**	**1,348**	**1,390**	**1,441**	**1,489**	**1,525**	**1,563**	**1,599**
Utility Earnings	**207**	**208**	**210**	**215**	**220**	**228**	**238**	**242**	**247**	**247**

a. Assumptions for Incremental Capital Module (Enbridge Gas Distribution)

Table 12

(i) EGD ICM threshold calculation

	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ICM THRESHOLD CALCULATION FORMULA										
ICM Threshold Value = 1 +[(rb/d) * (g + PCI * (1 + g))] * ((1 + g) * (1 + PCI))^n-1 + 10%										
Threshold Factor	10%									
Base year	**2018**									
Ratebase	6,246									
Rebasing Depreciation Expense	305									
Growth rate	0.93%	0.92%	0.84%	0.87%	0.84%	0.82%	0.80%	0.78%	0.77%	0.75%
PCI	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
N - Number of years since rebasing	1	2	3	4	5	6	7	8	9	10
ICM Multiplier	1.65	1.66	1.66	1.68	1.69	1.69	1.71	1.72	1.73	1.74
ICM Threshold value	503	507	506	512	515	518	521	524	527	531

Table 13

(ii) EGD Growth factor

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2018 Distribution revenues	1,228									
Incremental Revenues from growth	11	11	10	11	11	11	10	10	10	10
Distribution revenues @ 2018 frozen rates	1,239	1,251	1,261	1,272	1,283	1,293	1,304	1,314	1,324	1,334
Growth factor (%)	**0.93%**	**0.92%**	**0.84%**	**0.87%**	**0.84%**	**0.82%**	**0.80%**	**0.78%**	**0.77%**	**0.75%**

Table 14

(iii) EGD ICM Revenue Requirement

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM capital	111	217	70	123	62	68	89	296	67	70
Cost of Capital										
Rate base	55	216	351	437	516	566	628	800	956	996
Required rate of return	6.09%	6.28%	6.37%	6.38%	6.40%	6.40%	6.41%	6.42%	6.42%	6.42%
	3	14	22	28	33	36	40	51	61	64
Cost of Service										
Operation and maintenance	-	-	-	-	-	-	-	-	-	-
Depreciation and amortization	1	6	9	12	14	16	18	23	28	30
	1	6	9	12	14	16	18	23	28	30
Income Taxes	(0)	(0)	0	0	1	1	2	2	3	4
Total Revenue Requirement	**5**	**19**	**32**	**40**	**48**	**54**	**60**	**77**	**92**	**97**

a. Assumptions for Incremental Capital Module (Union Gas)

Table 15

(i) UG ICM threshold calculation

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM THRESHOLD CALCULATION FORMULA										
ICM Threshold Value = 1 +[(rb/d) * (g + PCI * (1 + g))] * ((1 + g) * (1 + PCI))^n-1 + 10%										
Threshold Factor	10%									
Base year	**2013**									
Ratebase	3,734									
Rebasing Depreciation Expense	196									
Growth rate	0.93%	0.90%	0.89%	0.88%	0.87%	0.86%	0.85%	0.85%	0.84%	0.84%
PCI	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
N - Number of years since rebasing	6	7	8	9	10	11	12	13	14	15
ICM Multiplier	1.68	1.69	1.70	1.72	1.73	1.74	1.76	1.77	1.79	1.81
ICM Threshold value	330	331	334	336	339	341	344	347	350	354

Table 16

(ii) UG Growth factor

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2018 Distribution revenues	948									
Incremental Revenues from growth	9	9	9	9	9	9	9	9	9	9
Distribution revenues @ 2018 frozen rates	957	965	974	982	991	999	1,008	1,016	1,025	1,034
Growth factor (%)	**0.93%**	**0.90%**	**0.89%**	**0.88%**	**0.87%**	**0.86%**	**0.85%**	**0.85%**	**0.84%**	**0.84%**

Table 17

(iii) UG ICM Revenue Requirement

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM capital	211	77	114	96	264	249	76	58	88	31
Cost of Capital										
Rate base	151	338	415	509	631	865	1,040	1,071	1,101	1,127
Required rate of return	6.09%	6.25%	6.31%	6.34%	6.36%	6.39%	6.40%	6.41%	6.42%	6.43%
	9	21	26	32	40	55	67	69	71	72
Cost of Service										
Operation and maintenance	-	-	-	-	-	-	-	-	-	-
Depreciation and amortization	6	11	14	17	22	30	35	37	39	41
	6	11	14	17	22	30	35	37	39	41
Income Taxes	(2)	(2)	(2)	(2)	(4)	(6)	(5)	(3)	(1)	1
Total Revenue Requirement	**13**	**30**	**38**	**47**	**58**	**80**	**97**	**103**	**109**	**115**
Incremental revenues from community expansions	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Revenue Requirement (Net)	**12**	**27**	**35**	**44**	**55**	**76**	**94**	**100**	**106**	**111**

b) 2019 costs were forecasted at a high level on an aggregate basis and were rebased as follows:

O&M costs
The departmental O&M and Customer Care costs were assumed to increase by 2% for EGD and at inflation rate for Union Gas over the 2018 budget. Pension costs are based on estimate from Mercer. DSM costs are the board approved numbers. EGD RCAM are based on historical and are assumed to be 85% of budgeted CAM.

Capital costs
The capital costs are the forecasts from the Asset Management Plan of each Utility.

Cost of capital
The cost of capital parameters reflects the forecast for Enbridge treasury. Long term debt assumes new debt issuance to finance rate base growth and refinancing of debt coming to maturity.

c) There is a certain amount of assumed productivity embedded in the O&M cost assumptions. Both utilities incur incremental O&M costs to attach customers each year. It has been modelled that these cost increases will be offset by productivity gains. The increased O&M costs modelled therefore only assumes an inflationary increase.

The productivity factor applicable to the Price Cap of zero with a stretch factor of zero was used for the two Utilities.

The productivity factor was proposed based on the total productivity analysis and associated recommendations prepared by Jeff Makholm provided at EB-2017-0307, Exhibit B, Tab 2. EGD and Union's productivity growth is in line with the economy as whole and the economy-wide inflation is appropriate for setting rates during the deferred rebasing period

d) Throughout the ten year period, the Revenue Requirement for the amalgamated company (Amalco) is lower than the Revenue Requirement total of the two separate companies. We do not understand the question.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0306 B1, TAB 1, pg. 32

Preamble: *"While a detailed analysis of options is required, the estimated cost efficiencies are based on integrating Union and EGD into a Maximo software system. Management estimates that a potential range of implementation costs could be between $30 million for data and business process migration to $85 million for full implementation. The estimate for migrating Union processes and data into Maximo is approximately $50 million."*

We would like to understand better how these broad estimates were made and how EGD's prior experience was incorporated into the estimates.

Question:
Please provide all estimates received from the software vendor supporting the estimates.

a. If estimates were not received, what was relied upon for these estimates.
b. What was the cost for Enbridge's implementation and migration excluding the software?
c. How was that source estimate adjusted for Enbridge's prior experience?

Response

a- c) To understand how the high level integration planning estimates were generated please see the response to BOMA Interrogatory #16(d) part (i) found at Exhibit C.BOMA.16.

With respect to the other parts of the question, the Applicants have not conducted a detailed integration planning exercise and therefore have no information regarding vendor estimates.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0306 B1, TAB 1, pg. 33 and Attachment 4

Preamble: *"The Enbridge corporate office functions began to integrate and optimize at the close of the Enbridge Inc. and Spectra Energy merger in Q1, 2017. Initiatives to align these functions across the enterprise are ongoing and are part of the overall corporate merger integration and not managed directly by the Applicants. There are, however, a number of shared services such as Finance, Law, Human Resources, Information Technology, Supply Chain Management, Real Estate Services, Government Relations and Enterprise Safety & Operational Reliability that are resident at EGD and Union, which provide utility-specific shared services. The utility specific shared services rely on several smaller systems and software. The initial review has identified applications such as utility billing financial analysis, IT service requests and real estate services as potential integration opportunities."*

Question:
For each of 2016 and 2017, for each of Enbridge Inc. and Spectra, please provide the actual costs for the corporate office functions.

a. Please provide the annual apportionment to the each of the respective utilities.
b. Please provide a forecast of all of the above costs for 2019.

Response

a. EGD and Union decline to provide the Enbridge Inc. and Spectra corporate office function costs as the costs are not relevant to this proceeding. Please see the response to CCC Interrogatory #15 found at Exhibit C.CCC.15.

b. Please see the response to FRPO Interrogatory #11(b) found at Exhibit C.FRPO.11.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: EB-2017-0306 B1, TAB 1, pg. 33 and Attachment 4

Preamble: "*The Enbridge corporate office functions began to integrate and optimize at the close of the Enbridge Inc. and Spectra Energy merger in Q1, 2017. Initiatives to align these functions across the enterprise are ongoing and are part of the overall corporate merger integration and not managed directly by the Applicants. There are, however, a number of shared services such as Finance, Law, Human Resources, Information Technology, Supply Chain Management, Real Estate Services, Government Relations and Enterprise Safety & Operational Reliability that are resident at EGD and Union, which provide utility-specific shared services.*
The utility specific shared services rely on several smaller systems and software. The initial review has identified applications such as utility billing financial analysis, IT service requests and real estate services as potential integration opportunities."

Question:

For each of 2016 and 2017 and for each of EGD and UGL, please provide the actual costs for each of the identified shared services.

a. Please provide the annual apportionment to each of the respective corporate parents including those listed in Attachment 4.
b. Please provide a forecast of all of the above costs for 2019.

Response

a) Below are the actual costs for each of the identified shared services. Please note that EGD and Union figures are not comparable as the utilities had different corporate cost allocation models.

EGD Information:

SHARED SERVICES (000'S)	2016 ACT	2017 ACT	Notes
REWS (Real Estate Services plus Workplace Services)	10,084	8,822	
FINANCE & REGULATORY	19,802	15,096	**Note 1**
HUMAN RESOURCES	121,837	91,826	
INFORMATION TECHNOLOGY	22,197	22,102	
LEGAL	4,145	4,786	
SUPPLY CHAIN MANAGEMENT	4,101	4,431	
Gross O&M	182,165	147,063	
DLC & A&G Capitalization	37,745	31,402	
Net O&M	144,420	115,661	

GENERAL NOTE

2016 actuals are adjusted based on the post-reorganizational structure to ensure consistency against 2017 actuals.

NOTE 1

2017 Actuals do not include a $8.7M US GAAP Differal Gross Up amount which is reported as a balance sheet item.

Union Information:

Group	2016 Actual	2017 Actual
Finance	27,305,868	26,497,188
IT	31,066,552	33,737,935
CRES	20,701,308	21,370,873
Legal	1,805,897	1,795,803
ECS Indirect*	3,507,305	2,956,202
HR	95,946,227	97,003,744
Affliate Revenue	- 15,905,086	- 15,842,379
Affliate Expense	22,008,191	22,610,354
Total Gross Costs	**186,436,262**	**190,129,720**
Indirect Capitalization	- 44,477,172	- 44,014,729
Total Net Costs	**141,959,089**	**146,114,991**

**ECS Indirect includes: Supply Chain, Global Fleet Services, and Corporate EH&S*

b) Please see applicant response FRPO Interrogatory #11b), found at C.FRPO.11.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 3

Preamble: *"As the Applicants are not part of this annual Board process, this Application proposes an inflation factor and productivity factor that are modelled on Price Cap IR."*

Union Gas has been under a price cap with an inflation adjustment factor which has been used as a productivity factor. With that productivity factor limiting inflationary rate increases, we would like to understand how Union has performed financially relative to the Board approved return on equity.

Question:
Using the actual inflation rate incorporated into the establishment of annual rates, for each of the IR years, in tabular fashion, please provide:

a. The inflation factor approved by the Board for rates
b. The effective productivity factor for each of the years of 2014 to 2017 (i.e., 60% of the inflation determined for that year).
c. The Board-approved percentage rate of return on equity
d. The actual percentage rate of return on equity

Response

a- d) Please see Table1 provided on the following page.

Table 1
2014 – 2017 Price Cap Index Factors and Return on Equity

Line No.	**Particulars**	**2014** (1)	**2015** (2)	**2016** (3)	**2017** (4)
1	Inflation factor	1.27%	2.05%	1.99%	1.66%
2	Productivity factor (60% of line 1)	0.76%	1.23%	1.19%	1.00%
3	Price Cap Index (line 1- line 2)	0.51%	0.82%	0.80%	0.66%
4	Board-approved return on equity	8.93%	8.93%	8.93%	8.93%
5	Actual return on equity	10.69%	9.89%	9.24%	9.15%

Notes:

(1) Price cap index factors from EB-2013-0365, Rate Order, Working Papers, Schedule 1, line 6. Return on equity figures from EB-2015-0010, Exhibit A, Tab 2, p. 3.

(2) Price cap index factors from EB-2014-0271, Rate Order, Working Papers, Schedule 1, line 6. Return on equity figures from EB-2016-0118, Exhibit A, Tab 2, p. 4.

(3) Price cap index factors from EB-2015-0116, Rate Order, Working Papers, Schedule 1, line Return on equity figures from EB-2017-0091, Exhibit A, Tab 2, p. 3.

(4) Price cap index factors from EB-2016-0245, Rate Order, Working Papers, Schedule 1, line 6. Actual return on equity figure is expected to be included in the Application and Evidence for EB-2018-0105, but is draft at this time and may change.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Preamble: While EGD was under price cap, its custom IR methodology, that methodology was based on embedded productivity between forecasted costs and those applied for. Ultimately, the Board approved different costs.

Question:
Using the difference between the forecasted costs in EGD's EB-2012-0459 application for each of the first 3 years and the resulting Board-approved costs, please provide:

a. The inflation factor which represents the forecasted cost increases for each year of forecasted costs between 2014-2016.
b. The effective inflation factor determined using Board-approved costs for rates
c. The effective productivity factor for each of the years of 2014 to 2016 (i.e., the difference between the forecasted inflation (a.) and approved inflation (b).)
d. The Board-approved percentage rate of return on equity
e. The actual percentage rate of return on equity

Response

a- c) The forecasted and resulting Board approved costs within the EB-2012-0459 Custom IR mechanism and application cannot be used to calculate effective inflation and productivity factors which are elements resident in Price Cap IR mechanisms and formulas. As such, we will not provide these calculations.

d -e) Please see the response to LPMA Interrogatory #18 found at Exhibit C.LPMA.18.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 3

Preamble: *"The Applicants propose a materiality threshold of $1.0 million, which is consistent with the threshold for electric distributors"*.

We would like to understand better the requested reduction in materiality threshold if a Z-factor were part of the ratemaking construct.

Question:
For each utility, please provide their current Board-approved materiality threshold and what percentage that threshold represents relative to the currently approved revenue requirement for that utility in 2018.

a. Beyond, consistency with the threshold for electric distributors, what principled reasons support this reduction in materiality threshold from the existing levels?

Response

Please see the response Board Staff Interrogatory #23 found at Exhibit C.STAFF.23.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 9

Preamble: *"Further, over the deferred rebasing period Amalco expects to experience increasing cost pressures, such as line locates, potential stricter pipeline safety regulations, increased municipal infrastructure activity that impacts natural gas infrastructure (e.g. roads, bridges, etc.) and depreciation increases even when managing maintenance capital expenditures to the level of depreciation."*

We would like to understand better how these cost pressures are different from those experienced in the past.

Question:
In tabular fashion, please provide:

a. The number of locates performed annually by each utility between 2013 to 2017
b. The annual actual costs associated with provision of those locates
c. What productivity improvements has each utility put in place over the recent IRM period and which year were they implemented

---

Response

a. Locates Performed Annually

Union Information

Year				
2013	2014	2015	2016	2017
314,251	349,403	399,954	399,315	436,197

EGD Information

Year				
2013	2014	2015	2016	2017
526,898	595,867	612,065	637,568	790,026

b. Annual Actual Costs

Union Information

Year				
2013	2014	2015	2016	2017
$ 11,528,587	$ 12,257,626	$ 13,116,670	$ 12,331,190	$ 13,323,353

EGD Information

Year				
2013	2014	2015	2016	2017
$ 16,703,551	$ 16,749,880	$ 17,397,795	$ 17,173,488	$ 20,170,200

c. Productivity Improvements during IRM Period

Union did not track productivity information for line locates.

EGD Information

	Year			
EGD Locates Productivity Savings	2014	2015	2016	2017
OOC Notification Fees		85,000	280,000	286,850
LAC Member Growth	100,000	108,000	84,600	342,020
ALA Growth	340,000	1,900,000	2,340,000	2,956,500
Sewer Safety Program RFP			246,000	272,900
Dedicated Locator				3,826,521
Total	440,000	2,093,000	2,950,600	7,684,791

As part of the performance measurement framework required by the Board in its July 17, 2014 Decision with Reasons for EB-2012-0459, the Board required reporting of the EGD's productivity initiatives relative to what was identified in EGD's evidence.

The productivity commitments embedded in the Company's forecasts included the management of locate cost pressures from the passage of Bill 8. The EGD productivity savings noted in the table above are included in the Annual Productivity Report filed as of part of the annual ESM application through the custom IR term.

Narratives of each of the locate productivity savings areas are provided below:

OOC Notification Fees

Ontario One Call (OCC) charges a fee to EGD for all locate requests. EGD Damage Prevention has a major presence and involvement on the OOC committee. Through EGD's influence, effort and involvement, more utilities joined OOC and making its operations more efficient enabling OOC to reduce its fees because of increased revenue and reduced general overhead costs.

LAC Member Growth

Locate Alliance Consortium (LAC) is group of facility owners working towards a cost efficient locate process with standardized terms & conditions and consistent quality & outcomes. With more Utilities joining the Consortium, the locate price from locate Service Providers becomes lower by coordinated Enbridge locate requests along with other Utility requests.

ALA Growth

Alternative Locate Agreement (ALA) is an agreement between EGD and an excavator who has been vetted and approved to do locates. This allows the excavator to complete their project without a field locate.

Sewer Safety Program RFP

Negotiated vendor contract renewal savings

Dedicated Locator

A new initiative in 2017, where Enbridge worked with industry partners to develop a Dedicated Locator model for large capital projects. This created an ownership approach for the Excavators by having dedicated locators embedded within the Excavator's crew at the cost of the project owner. The Excavators benefit by having greater flexibility on their projects by having direct control over their locate resources that results in cost savings beyond the cost incurred for locates. These productivity savings are reliant on excavator participation and represents a mutually beneficial opportunity to drive efficiency on large capital infrastructure projects.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 9 and EB-2017-0102

Preamble: "*Normalized Average Consumption/Average Use Adjustment* *The Applicants are proposing to continue to adjust rates annually to reflect the declining trend in use.*"

We would like to understand better the differences in the respective average adjustment methodologies and Amalco's proposed approach upon merger.

Question:
Please describe the differences between the two utilities NAC methodologies.

a. In the view of the utilities, what are the pros and cons of each?
b. Is it expected that the current methodology would stay in place for the respective franchise areas? If so, why?
c. If not, which is proposed. Please provide the supporting rationale.

Response

a- c) EGD's Board-approved average use forecast methodology applies econometric regression models that utilize heating degree days, natural gas prices, economic variables, etc. as driver variables.

Union's Board-approved NAC forecast methodology applies the most recent actual NAC available, weather-normalized to the forecast year. The most recent actual NAC available at the time of rate adjustment is the two years' prior to the forecast year.

The weather-normals used in the NAC forecasts are obtained using Board-approved methodologies.

The current AU/NAC methodologies have been effective at each utility. No changes are proposed as part of this application. If Amalco considers future changes to AU/NAC, the proposal will be included as part of a future rate proceeding.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 9 and EB-2017-0102

Preamble: "*Normalized Average Consumption/Average Use Adjustment The Applicants are proposing to continue to adjust rates annually to reflect the declining trend in use.*"

We would like to understand better the differences in the respective average adjustment methodologies and Amalco's proposed approach upon merger.

Question:
For EGD's establishment of rates and AUTVA true-up, please provide:
a) The revenue classifications used to establish baseload for general rate
b) The monthly budget baseload use per unlocked meter for each classifications
c) How does Enbridge explain the incremental baseload for these classes in the heating season? Please provide a comprehensive explanation including tests run to ensure that the budgeted baseload is in fact baseload for these revenue classifications.

Response

a) Baseload is established for each General Service heating revenue class on the basis of the average of each class' July and August consumption. Monthly seasonality factors derived from the associated non-heating classes are applied on the average summer load to develop the seasonal baseload for the heating class.

Heating Revenue Class	Heating Revenue Class Description	Associated Non-Heating Revenue Class	Non-Heating Revenue Class Description
10 (Rate 1)	Residential Space Heating	60 (Rate 1)	Residential General Use
20 (Rate 1)	Residential Space Heating, Water Heating, Other Uses	61 (Rate 1)	Residential Water Heating
12 (Rate 6)	Apartment Space Heating	86 (Rate 6)	Apartment Water Heating & General Uses
48 (Rate 6)	Commercial Space Heating	79 (Rate 6)	Commercial Water Heating & General Uses
73 (Rate 6)	Industrial Space Heating	83 (Rate 6)	Industrial Water Heating &

b) Please see attachment.

c) Incremental baseload that is inherent in winter and spring months is due to lower ground temperatures reducing customers' inlet water temperatures. More energy is required in the winter months to achieve and maintain a constant water temperature compared to other times of the year.

The Company's weather normalization methodology was established in EBRO 465 and refined in EBRO 473 where baseload is defined as the average of July and August consumption. Seasonality factors as described in part a) are then applied to derive the annual baseload consumption for associated heating classes. This methodology has been applied consistently since its approval in 1992.

Average Baseload per Customer (m^3) - Central Region

Rate Class	Revenue Class	Revenue Class Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	10	Residential Space Heating	35.6	35.6	35.4	34.4	31.8	30.4	28.0	27.8	29.8	31.3	33.6	33.8	387.6
1	20	Residential Space Heating, Water Heating, Other Uses	76.2	79.8	76.2	74.3	68.0	60.5	52.0	49.2	50.9	58.0	64.3	70.9	780.3
6	12	Apartment Space Heating	5,954.3	6,321.1	6,096.2	5,607.9	5,226.3	4,502.6	3,917.3	3,518.0	3,937.0	4,343.8	5,070.0	5,410.9	59,905.4
6	48	Commercial Space Heating	498.5	498.6	488.3	478.9	451.4	433.5	415.1	414.6	419.6	445.5	465.0	483.3	5,492.2
6	73	Industrial Space Heating	3,528.7	2,843.8	3,066.4	2,495.4	2,334.6	1,957.9	2,496.9	2,590.8	2,648.9	2,421.7	3,170.7	3,340.6	32,896.3

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0307, Exhibit B, Tab 1, Pages 9 and 12

Preamble:
"Further, over the deferred rebasing period Amalco expects to experience increasing cost pressures, such as line locates, potential stricter pipeline safety regulations, increased municipal infrastructure activity that impacts natural gas infrastructure (e.g. roads, bridges, etc.) and depreciation increases even when managing maintenance capital expenditures to the level of depreciation. ***In addition, economists currently believe the Canadian economy will be exposed to increasing interest rates over the next decade".(*****emphasis added).**

And

"Over the deferred rebasing period there is the potential for changes which could impact Amalco that would be outside of the direct control of management. As indicated above, interest rates are poised to increase. If there is a material impact on Amalco's ability to earn its allowed ROE, Amalco may address this through an application to the Board."

We would like to understand better Amalco's proposal for handling interest rate risk.

Question:
Is Amalco using interest rate risk to support a deferred re-basing period or is it proposing rate risk as a Z-factor?

a. If the latter, is Amalco proposing a $1M threshold as noted earlier?
b. If not, what is the proposed threshold or criteria to qualify for Z-factor?
c. Given the answers above, if interest rate risk is eligible for Z-factor protection, how does it contribute to the need for a 10-yr deferred rebasing. Please explain fully.

Response

a- c) The Applicants are not using interest rate risk to support the proposed ten year deferred rebasing period. Please see the response to Board Staff Interrogatory#4 found at Exhibit C.STAFF.4 for an understanding of why a ten year deferred rebasing is best for

Amalco and ratepayers. Please also see the responses to Board Staff Interrogatory #23 found at Exhibit C.STAFF.23 and SEC Interrogatory #10 found at Exhibit C.SEC.10 for further discussion on Z factors.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 12

Preamble: "*The Consolidation Handbook provides the ICM option for funding incremental capital investments during the deferred rebasing period. Capital projects related to the amalgamation will be funded and managed by Amalco as an integral part of supporting achievement of synergies through the deferred rebasing period*"

We would like to understand better how Amalco proposes to reduce systemic cross-subsidization.

Question:
How will capital overheads and other General Allocations be adjusted to ensure that the fully loaded cost of capital related to the amalgamation is not being cross-subsidized by capital applied for through an ICM?

a) Please explain fully.
b) Please provide a sample numeric illustration.

Response

a), b) Amalco Day 1 structure and corresponding capitalization policy has not yet been defined. The company will review the eventual policy and ensure consideration that amounts included in future ICM applications will not include such cross subsidization.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 24

Preamble: "*Relocations Mains Variance Account and Replacement Mains Variance Account - EGD's accounts will not continue at the expiry of the term of the custom incentive regulation period. Costs related to capital expenditures will be managed under the Price Cap through the d*

Question:
What is the budgeted amount currently embedded in rates for each utility?

a. Please provide the actual annual expenditures for each utility for each year since 2013.

Response

Included within EGD's 2018 rates is the impact of $12.6 million in forecast relocation mains capital spending, and $5.1 million in forecast miscellaneous replacement mains capital spending. The table below shows EGD's expenditures for replacement mains and relocation mains:

(in millions CAD)	2013 Act	2014 Act	2015 Act	2016 Act	2017 Act	2018 IR Bud
Total Replacement Mains	16.3	26.5	12.8	18.9	16.1	5.1
Total Relocation Mains	22.2	0.8	5.0	13.8	3.5	12.6
Total	38.5	27.3	17.7	32.7	19.6	17.7

The table on the following page shows Union's expenditures for replacement mains and relocation mains:

	(in millions CAD)	**2013 Board Approved**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 Plan**
*	Leakage Replacements	7.4	7.4	9.8	4.5	4.6	4.5	9.9
**	General Replacements	27.9	19.2	30.4	36.6	47.0	56.7	59.0
1	Total Replacement Mains	35.3	26.6	40.2	41.1	51.6	61.2	68.9
***	Municipal Replacements	12.2	12.2	17.1	30.5	20.8	26.3	20.8
2	Total Relocation Mains	47.5	38.8	57.3	71.6	72.4	87.5	89.7
3	Total							

* Replacements of main due to leakage includes cost of pipe, related fittings and installation. *(SAP Priority Type D)*
** Replacements of main other than leakage or municipal work includes cost of pipe, related fittings and installation.
*** Replacements of main due to municipal conflict includes cost of pipe, related fittings and installation. *(SAP Priority Type C)*

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 2

Preamble: In early 2017, Union generated a customer engagement workbook for which one of the outcomes sought was stated as "*Union Gas must submit a business plan that focuses on the cost effective delivery of outcomes that matter to customers. What are the outcomes that you care about?*"

We would like to understand better the investment and outcomes of Union's initiative.

Question:
Please provide the following information on the outcomes of this initiative:

a. The total cost of developing and implementing this initiative
b. The number of customers that completed the workbook
c. The top five outcomes that were identified and what Union has planned and/or implemented as a result.

Response

a) In preparation for rebasing, Union worked with a consultant to undertake comprehensive customer engagement to further understand the needs and preferences of customers. Due to the diversity of Union's customer base, engagement was targeted to residential general service customers, commercial/industrial general service customers, contract customers and storage and transportation customers. The total costs were approximately $0.350 million.

b) Approximately 10,000 general service customers and 50 contract customers completed the online workbook. Union held in-person meetings with approximately 40 strategic and storage and transportation customers.

c) The top five outcomes were price, safety, reliability, providing dependable and responsive customer service, and making good use of the money customers pay. Union shared the results throughout the company to ensure a further understanding of the needs and preferences of customers. In particular, Union used the findings from this customer engagement as an input to the asset management planning process. Union also provided information on the results to the customers that participated.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 3

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 29

Preamble:

"For purposes of applying the rate setting mechanism in an annual rate application, Amalco will use approved regulated service offerings, cost allocation methodologies and rate design during the deferred rebasing period."

And EB-2014-0261, Exhibit A, Tab 10, Page 5, Table 10-1

And EB-2013-0074, Section 10, Page 7

"Adding the rate base and operating costs associated with the Project as Dawn-Parkway transmission costs to the 2013 Board-approved cost allocation study results in the re-allocation of cost components that are functionalized based on rate base and O&M. As a result of the additional transmission rate base and operating costs associated with the Project, indirect costs (general plant, administrative and general expenses, and general operations and engineering costs), and taxes (income taxes, deferred taxes and property taxes) are re-allocated from distribution, storage and other transmission-related functional classifications to the Dawn-Parkway functional classification. The shift in indirect costs to the Dawn-Parkway functional classification is approximately $3.3 million, as provided at Schedule 10-2, column (f)."

We would like to understand better how these methodologies could have impact given the potential of the two utilities becoming one. In the reference to the facilities build application, EB-2014-0261, reference, Union outlines the impact of the build on in-franchise and ex-franchise Dawn-Parkway Distance Weighted Demands. The EB-2013-0074 reference outlines the re-allocation of distribution, storage and other transmission-related functional classifications and the resulting shift in indirect costs.

We would like to understand better the investment and outcomes of Union's initiative.

Question:

Using the Board-approved methodologies updated for additional Dawn-Parkway builds until 2017, please:

a. Update a Table comparable to Table 10-1 that provides the 2019 Dawn-Parkway distance weighted demands separating Union North, Union South and Ex-franchise but separating Enbridge demands as a separate column for which distance weighted demands are allocated to the capacity requirements under-pinned by current contacts in place for Enbridge.
b. Please show two versions of the above table with one showing Enbridge as ex-franchise and one showing Enbridge as in-franchise treated similarly to Union North.
c. Please provide the resulting rates projected for all rate classes (Union South, North and Enbridge) given the different treatments (Enbridge as in-franchise and Enbridge as ex-franchise) keeping all other proposed parameters and methodologies constant and, if needed, assuming 2% inflation.

To be clear, we are seeking an understanding of the impact on rates with Enbridge territory being deemed in-franchise and treated similarly to Union North from a distance weighted demand basis and attracting cost allocations aligned with Board-approved approaches to Union North.

Response

a. Please see Attachment 1 for the allocation of the Board-approved Dawn-Parkway distance weighted design day demands updated to separate Enbridge Gas Distribution ("Enbridge") from other ex-franchise. The approved allocation is based on the 2013 Dawn-Parkway distance weighted design day demands updated to include the project demands of the capital pass through projects[1].

   Union has not prepared an updated Dawn-Parkway distance weighted design day demand allocation for 2019, as this information is only required to support a 2019 cost of service application.

[1] Union's Dawn-Parkway capital pass through projects include Parkway West (EB-2012-0433), Brantford to Kirkwall/Parkway D (EB-2013-0074), 2016 Dawn-Parkway Expansion (EB-2014-0261) and 2017 Dawn-Parkway Expansion (EB-2015-0200).

b. There are no impacts on the Dawn-Parkway demand cost allocation associated with showing Enbridge as in-franchise. As provided at Attachment 1, the demands to serve Enbridge and the distance those demands are required to travel would not change.

c. Consistent with the response in part b), there are no rate impacts associated with showing Enbridge as in-franchise. Amalco has proposed to maintain separate rate zones for Union North, Union South and Enbridge and set rates for regulated distribution, transmission, and storage services during the deferred rebasing period under the proposed Price Cap IR mechanism.

UNION GAS LIMITED

OEB-Approved Dawn-Parkway Distance Weighted Design Day Demands Updated for Capital Pass Through Project Demands

Line No.	Particulars	Union North In-Franchise	Union South In-Franchise	Enbridge Gas Distribution	Other Ex-franchise	Total
		(a)	(b)	(c)	(d)	(e) = sum (a:d)
	Design Day Demands ($10^6m^3/d$)					
1	2013 OEB-Approved	7	44	59	65	175
2	Parkway Projects	2	-	6	4	11
3	2016 Dawn-Parkway Expansion (1)	1	2	4	5	13
4	2017 Dawn-Parkway Expansion (2)	-	-	5	7	12
5	Total Design Day Demands ($10^6m^3/d$)	10	46	74	81	211
6	Weighted Average Distance (km)	229	89	228	200	187
7	Distance Weighted Demands ($10^6m^3/d$ x km) (line 5 x line 6)	2,302	4,097	16,783	16,155	39,337
8	Distance Weighted Demands (%)	5.9%	10.4%	42.7%	41.1%	100.0%

Notes:

(1) EB-2014-0261, Exhibit A, Tab 10, Table 10-1, line 3. Union North T-service incremental Dawn-Parkway demands of 0.771 $10^6m^3/d$ included in Other Ex-franchise consistent with the EB-2015-0200 presentation.

(2) EB-2015-0200, Exhibit A, Tab 10, Table 10-1, line 3.