In the Matter of
Enbridge Gas Inc. 2024 Rebasing Application
OEB File Number: EB-2022-0200

Pre-Filed Evidence of
Patrick Bowman and Hayitbay Mahmudov on Depreciation Related Matters
Exhibit M – OEB Staff Depreciation

Submitted to: Ontario Energy Board

On behalf of: Ontario Energy Board Staff

Prepared by: Patrick Bowman and Hayitbay Mahmudov,
InterGroup Consultants Ltd.

April 21, 2023

InterGroup
CONSULTANTS

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1.0 INTRODUCTION

This testimony has been prepared for the Ontario Energy Board Staff ("OEB Staff") by or under the direction of Patrick Bowman[1] and Hayitbay Mahmudov, both of InterGroup Consultants Ltd. ("InterGroup"). InterGroup was retained to conduct an independent assessment of Enbridge Gas Inc.'s ("Enbridge Gas") evidence on proposed depreciation in Enbridge Gas's 2024 Rebasing Application (EB-2020-0200), including the depreciation study prepared by Enbridge Gas's expert Concentric Advisors ("Concentric") on the annual depreciation accrual rates and amounts applicable to the original cost of gas utility plant, as of December 31, 2021. InterGroup's assessment includes a review of the depreciation methodology, useful lives, depreciation rates, depreciation expense and net salvage methodology.

InterGroup was also asked to review and comment on the depreciation calculations provided by Concentric using a 2050 economic planning horizon, and the underlying assumptions in those calculations.

In preparing the current testimony, InterGroup has primarily relied on the evidence on the record of file number EB-2022-0200 including Enbridge Gas's Application and responses to the information requests. InterGroup has also reviewed the previous depreciation studies prepared by the former Enbridge Gas Distribution ("EGD") and Union Gas ("Union") as they relate to recommendations regarding the now amalgamated operations.

References to other sources are provided in footnotes where appropriate.

This submission focuses on depreciation proposals and analysis conducted on the company plant as of December 31, 2021, consistent with the depreciation study provided by Enbridge Gas[2]. Estimates and impacts of InterGroup's proposals are measured using this same reference point. The impacts on test year 2024 will generally be slightly larger, due to ongoing additions of plant. In cases where estimates have been provided for 2024 figures rather than December 31, 2021, these are specifically noted in the report.

[1] Services provided by Bowman Economic Consulting, Inc.
[2] Application, Exhibit 4, Tab 5, Schedule 1.

2.0 QUALIFICATIONS

InterGroup is an independent, multi-disciplinary firm based in Winnipeg, Manitoba. For more than 45 years, InterGroup has provided a wide range of consulting services to clients across Canada. InterGroup's rate regulation clients include private-sector, Crown and municipal utilities, government departments, consumer associations, and utility regulators. InterGroup has extensive experience with all elements of utility regulatory review processes including issue scoping, drafting and responding to information requests, preparing expert evidence, providing expert testimony at oral hearings, drafting argument and reply argument and providing advice to utility regulators.

InterGroup staff have direct and specific experience in multiple Canadian jurisdictions with respect to regulatory depreciation matters, including analysis of utilities' depreciation studies and proposals.

A sample of the previous relevant work of Mr. Bowman and Mr. Mahmudov is provided below. Further information is provided in the respective resumes of Mr. Bowman and Mr. Mahmudov included in Appendix A.

Mr. Bowman is an associate of InterGroup, having joined the company in 1998 and serving as a Principal Consultant until 2022. Mr. Bowman has a Master's Degree in Natural Resources Management from the University of Manitoba, where he focused on matters of natural resource economics, and is a member of the Society of Depreciation Professionals. He has testified on utility depreciation matters in six of Canada's provinces and territories since 2004. Mr. Bowman has led the management of either depreciation evidence (when operating on behalf of the utility) or the review of depreciation evidence (when operating on behalf of an intervenor) and has testified on matters of depreciation before multiple regulators. This includes the following examples:

- For the Alberta Utilities Consumer Advocate:
    - Provided expert advice as well as support in the negotiated settlement on depreciation matters for AltaLink 2017-18 GTA (Proceeding 21341) and in the 2019-2020 GTA (Proceeding 23848), which included oral testimony, as well as the Review and Variance of Decision 23848-D01-2020, which was Proceeding 25769/25870. Led the UCA intervention into matter related to changes to the AltaLink approach to accruing for net salvage.
    - Provided expert evidence and analysis on depreciation matters in ATCO Pipelines 2017-18 General Rate Application (GRA) (Proceeding 22011). Mr. Bowman also provided expert witness and strategic support on all areas of the ATCO Pipelines 2019–2020 GRA (Proceeding 23793).
    - Provided strategic support and evidence where necessary on depreciation matters in AltaGas 2018 Depreciation Application (Proceeding 24161), ATCO Gas 2018 Depreciation Application (Proceeding 24188), ATCO Electric 2018 Depreciation Application (Proceeding 24195), ATCO Electric Transmission 2020-2022 GTA

Depreciation (Proceeding 24964), and AltaLink 2022-2023 GTA (Proceeding 26509), and depreciation Generic Proceeding 25560.

- Provided expert advice as well as support in the negotiated settlement on depreciation matters for EPCOR Distribution & Transmission Inc. 2023-2025 Transmission Tariff Application (Proceeding 27675). Submitted written expert testimony on depreciation matters.
- Provided expert advice as well as support in the negotiated settlement on depreciation matters for ENMAX Power Corporation 2023-2025 Transmission General Tariff Application (Proceeding 27581). Submitted written expert testimony on depreciation matters.
- Provided expert evidence on depreciation related to utility acquisition and valuation affecting FortisAlberta in AUC proceeding 23972.

- For the Manitoba Industrial Power User's Group (MIPUG), led the intervention in the Manitoba Hydro 2012/13 GRA, and later the 2015/16 GRA on matters of depreciation impacts, policy and approach and provided expert testimony. Currently providing expert evidence before the Manitoba Public Utilities Board on matters of Manitoba Hydro depreciation as part of the 2023/24 GRA.
- For Yukon Energy Corporation, provided analysis and support of regulatory proceedings and appeared before the Yukon Utilities Board as expert on regulatory matters, including depreciation in various proceedings since the utility's 2005 Required Revenues and Related Matters Application.
- For Association of Major Power Consumers of BC (AMPCBC), provided expert witness testimony including depreciation in the BC Hydro 2020/21 Revenue Requirement Application, and evidence focused on depreciation matters, in the BC Hydro 2023-2025 Revenue Requirements Application.
- For Industrial Customers of Newfoundland and Labrador Hydro, prepared analysis and evidence on regulatory matters, including depreciation, for Newfoundland Hydro's 2017 GRA hearing, and participated in the negotiated settlement on depreciation matters. Also addressed matters of depreciation in respect of expert evidence regarding options to address rate mitigation associated with Muskrat Falls in 2019.
- For Northwest Territories Power Corporation, provided support to senior utility staff in preparation of depreciation studies in the utility's 2006/08 and 2012/14 GRAs, and matters of depreciation approach and impacts from acquisition of utility property from Northland Utilities Limited in Hay River, NWT (ongoing).

Mr. Mahmudov joined InterGroup in 2009 and is currently a Principal Consultant with the company. Mr. Mahmudov has a Master's Degree in Economics from the University of Manitoba, and a Bachelor of Science from the Andijan Institute of Engineering and Economics. Mr. Mahmudov provided review and analysis related to depreciation matters, including analysis of utilities' depreciation studies and depreciation consultant evidence; preparation of information requests (interrogatories); preparation of expert evidence; responses to interrogatories from other parties in a number of regulatory proceedings, including:

- For the Alberta Utilities Consumer Advocate, provided support in review and analysis related to depreciation matters, including analysis of utilities' depreciation studies and depreciation consultant evidence; preparation of information requests (interrogatories); preparation of arguments and expert evidence; responses to interrogatories from other parties in the following proceedings:
    - AltaGas 2018 Depreciation Application (Proceeding 24161)
    - ATCO Gas 2018 Depreciation Application (Proceeding 24188)
    - ATCO Electric 2018 Depreciation Application (Proceeding 24195)
    - ATCO Electric Transmission 2020-2022 General Tariff Application (GTA) (Proceeding 24964). Prepared and submitted expert evidence on depreciation matters.
    - Altalink Management Ltd. ("AltaLink" or "AML") 2022-2023 GTA (Proceeding 26509)
    - EPCOR Distribution & Transmission Inc. 2023-2025 Transmission Tariff Application (Proceeding 27675). Prepared and submitted expert evidence on depreciation matters.
    - ENMAX Power Corporation 2023-2025 Transmission General Tariff Application (Proceeding 27581). Prepared and submitted expert evidence on depreciation matters.
- Provided technical support to Northwest Territories Power Corporation's (NTPC) depreciation consultants (Gannett Fleming and Concentric Advisors) in preparing NTPC's depreciation study for the 2012/14 GRA and 2016/19 GRA. The support included preparing NTPC's asset base continuity for depreciation study purposes; analyzing preliminary depreciation study findings; identifying issues and working with the consultant to address those; calculate NTPC's forecast depreciation expense for revenue requirement purposes.
- Provided technical support to Qulliq Energy Power Corporation's (QEC) depreciation consultants (Gannett Fleming and Concentric Advisors) in preparing QEC's depreciation study for the 2010/11 GRA and 2018/19 GRA. The support included preparing QEC's asset base continuity for depreciation study purposes; analyzing preliminary depreciation study findings; identifying issues and working with the consultant to address those; and calculate QEC's forecast depreciation expense for the revenue requirement purposes.

3.0 SUMMARY OF FINDINGS

The analysis summarized in this report addresses the below findings. Note that the impacts quantified for each recommendation are high level estimates of the change in annual depreciation compared to the Enbridge Gas's proposals. Each impact is quantified independent of other recommendations (i.e. the impact only compares to Enbridge Gas's proposal for that one aspect, keeping the group procedures (e.g., ELG, ASL) the same).

Equal Life Group Procedure:

Depreciation is a component of revenue requirement that reflects the costs associated with allocating the capital investment of the utility over its life. Typically, these costs are recorded and analyzed for a group of similar assets, as part of an asset account (for example, meters).

In order to determine the depreciation expense for a group, it is necessary to use methods that can analyze the life expectations of the group of assets. There are different ways to conduct this analysis, which is described as the group depreciation 'procedure' to be applied. The selection of a group procedure can have material impacts on the calculation of depreciation expense to be recorded each year.

Concentric proposes to adopt a new procedure that is part of the methodology of calculating depreciation rates, known as Equal Life Group ("ELG"). The procedure was not used by either EGD or Union previously, and results in higher depreciation expense in the 2024 Rebasing[3] than the more commonly used Average Service Life ("ASL", also known as Average Life Group "ALG").[4] In addition, ELG is premised on highly accurate input data and does not match well with the concept of designing rates to reflect the average life performance of assets organized into groups (e.g., a set of trucks, or a set of pipes).

1. The proposed transition to the ELG procedure at this time is problematic for three reasons:
    a. The purported increased precision of ELG is likely not supported in this case, given limitations on data and the merging of the accounts of two utilities. In contrast the ASL approach is well-accepted, pervasive in North America, and somewhat less sensitive to issues with capital asset data. Assertions that ELG can improve intergenerational equity also do not reflect the premise of group accounting – that some individual assets will last for shorter periods and some will last longer, yet the average performance across the group will be experienced by all generations of ratepayers. ELG excessively burdens the early or current generations of ratepayers with costs that do not reflect average or expected asset group performance.

[3] As discussed further in this submission, theoretically ELG results in higher depreciation expense early in an asset's life, and lower depreciation expense later. However, in practice this is not the case when looking at the utility as a whole, since the newest asset's will typically be the most costly, and it is these assets that are responsible for much of the depreciation expense in a given year. As a result, ELG typically leads to higher depreciation expense every time a new study is performed, compared to alternatives.
[4] EGD used the ASL procedure and Union used a different approach known as Generation Arrangement.

b. The financial impact of a transition to ELG is significant for go-forward depreciation calculations. This impact is compounded by the implicit need to address the fact that, as a more aggressive procedure, the ELG calculations indicate accumulated depreciation results in a large shortfall, and also must be recovered over a shorter period than using the ASL procedure. These three factors (faster depreciation, showing a larger current shortfall, and with a shorter period to recover the shortfall) combine to drive the large effect of adopting ELG.

c. The justification for adopting ELG due to a pending energy transition is misdirected. The issue of energy transition is a significant matter of policy that should be addressed directly through decisions of the regulator, not through the selection of a technical change in depreciation methodology.

2. Concentric has made a sound conclusion that Generation Arrangement is not an appropriate procedure to be used for Enbridge Gas at this time.

3. The continued use of the ASL/ALG procedure for calculation of depreciation rates, as previously applied to EGD, does not appear to have any notable limitations at this time. The procedure has been successfully used by EGD in the past and appears to generate sound calculations of depreciation rates for fixed assets that can readily and accurately be applied in this proceeding. ASL is a widely accepted and the most widely used procedure in North America[5] that results in a high degree of alignment between the performance of a group of assets, the service value provided by the assets, and the costs included in revenue requirement each year.

Asset Life Parameters:

In preparing depreciation estimates, the costs of the original investment in assets are allocated over a period representing the expected life of the asset group. Depreciation studies consider multiple inputs to attempt to estimate these life parameters, including establishing the estimated mean life (in years), and the variability expected around the mean (known as the dispersion). The establishment of appropriate asset life parameters is required regardless of the group procedure used by the utility (ASL or ELG, though the selected dispersion is of lesser impact under ASL), and the selection of life parameters is independent of which group procedure is to be used.

If asset lives are set too short, ratepayers will face depreciation expenses that are excessive, and the assets will remain in service long after they have had their costs fully recovered from customers. If asset lives are too long, many of the assets may be retiring from service well before being fully amortized, leading to losses on disposal, or back-ended depreciation expense increases to recover earlier shortfalls.

The life and dispersion parameters proposed in utility depreciation studies are typically rooted in three factors. First, actuarial analysis of plant; second, interviews with management and operations staff from the utility; and third, comparison to peer utilities.

[5] EB-2022-0200, Exhibit I.4.5-STAFF-173(d)

In the area of actuarial analysis, Concentric compared the asset retirement history by account to various depreciation life curve combinations – known as the Iowa survivor curves. The Iowa curves reflect a combination of the average life of the asset group, and the dispersion about the mean life. An Iowa curve is a way of depicting how the expected surviving complement of an asset group decreases with age.

Concentric also considered the management and operational perspectives shared by Enbridge Gas staff, and the Iowa curves used by Enbridge Gas's peer utilities.

In general, the focus of InterGroup's review was on accounts of material size, or where Concentric was proposing life and dispersion parameters that are material changes to the existing approved parameters, or were outside the range used by peers. The current application proposes that most accounts retain their currently approved life and dispersion parameters, or involve modest changes that are generally supported by the data and updated retirement history.

However, when reviewed against the three factors typically considered in utility depreciation studies (actuarial analysis of plant; interviews with management and operations staff from the utility; and comparison to peer utilities), there are six accounts where the proposed life estimates by Concentric do not reflect the best matching of parameters to observed life characteristics and the other noted factors. Other life and dispersion combinations provide better estimates for these six accounts:

1. Account 452.00: A life parameter of Iowa 45-R2.5 appears to be a better estimate for Account 452.00 for the current review. The expected impact of this finding is a reduction of approximately $0.3 million to Enbridge Gas's 2024 forecast depreciation expense.
2. Account 456.00: A life parameter of Iowa 44-R4 appears to be a better estimate for Account 456.00 for the current review. The expected impact of this finding is a reduction of approximately $1.5 million to Enbridge Gas's 2024 forecast depreciation expense.
3. Account 457.00: A life parameter of Iowa 40-R2.5 appears to be a better estimate for Account 457.00 for the current review. The expected impact of this finding is a reduction of approximately $0.4 million to Enbridge Gas's 2024 forecast depreciation expense.
4. Account 465.00: A life parameter of Iowa 70-R4 appears to be a better estimate for Account 465.00 for the current review. The expected impact of this finding is a reduction of approximately $7 million to Enbridge Gas's 2024 forecast depreciation expense.
5. Account 475.21: A life parameter of Iowa 61-R3 appear to be better estimates for Account 475.21 for the current review. The expected impact of this finding is a reduction of approximately $7 million to Enbridge Gas's 2024 forecast depreciation expense. However, a life parameter of Iowa 70-R3 better fits the experienced data, the operations interviews from 2016, and the lives adopted by Enbridge Gas's peers. This parameter would lead to a reduction of approximately $15 million. Of the two options, 70-R3 appears a better fit overall.
6. Account 475.30: A life parameter of Iowa 65-R3 appears to be a better estimate for Account 475.30 for the current review. The expected impact of this finding is a reduction of

approximately $5 million to Enbridge Gas's 2024 forecast depreciation expense. However, a life parameter of Iowa 70-R4 better fits the operations interviews from 2016, and the lives adopted by Enbridge Gas's peers. This parameter would lead to a depreciation expense reduction of approximately $9 million. However, actuarial data was not analyzed for a Iowa 70-R4 and it is likely less robust than Iowa 65-R3 when compared to Enbridge Gas's recorded retirement experience.

Constant Dollar Net Salvage Calculation Methodology:

Utility depreciation is intended to recover the service value of each group of assets over the life of the group. The service value comprises the original cost to purchase or install the asset, plus the cost to remove or decommission the asset at its end of life ("cost of removal"), less any amounts received for selling off the remaining pieces or scrap ("salvage"). The sum of cost of removal and salvage are typically termed "net salvage" and must be estimated during the life of the asset's service since they will not be known with certainty until the asset is retired and removed from service.

Enbridge Gas proposes that net salvage be collected from customers during the life of the asset as it is used. The cost is proposed by Enbridge Gas to be allocated to the periods during the asset's life using a method known as Constant Dollar Net Salvage ("CDNS"), a continuation of the approach of EGD prior to the current application. The basic premise of CDNS is that the total amount to be collected for future net salvage costs is determined, and that amount should be recovered equally across the years of service, measured in "constant dollars" rather than equally in nominal dollars. The dollars are made constant by use of a discount rate reflecting inflation, or some higher discount rate tied to a cost of capital.

The use of CDNS and the choice of a discount rate are effectively trade-offs between the accruals that are collected today from customers, and those that must occur in the future. The use of a higher discount rate means lower collections for net salvage today, and higher collections for net salvage in the future. The simplest version of CDNS only discounts for inflation, and this approach ensures customers pay for net salvage on a straight-line real economic basis.

Any discount rate higher than inflation is effectively crediting current customers for the time value of money, at the expense of future customers. This crediting can be justified to the extent that the early accruals or collections yield benefits to future customers. The benefits reflect the fact that accrual balances that arise early in the asset's life function benefit the future customers by being applied as an offset to future rate base. So long as the early collected funds are used as an offset to rate base, as is proposed by Enbridge Gas, then future customers will have a lower net rate base due to the contributions of the earlier customers, which will lead to lower future revenue requirements. Using the CDNS approach combined with a discount rate tied to the return on rate base can help achieve fairness among the different generations of customers.

1. The use of CDNS retains consistency with the EGD practice in previous proceedings, and is therefore well suited to use in this proceeding. In addition, CDNS is a method that appropriately recognizes there is a time value of money, and a cost of capital to the funds being provided. Enbridge Gas's proposal to continue to use CDNS is well-supported.

2. While CDNS is an appropriate approach to accruing net salvage, Concentric's CDNS calculations are not accurate. The Concentric calculation of CDNS contains a procedural complication as illustrated in Exhibit I.4.5-IGUA-14 Attachment 1. While the Net Salvage requirement in column H of Exhibit I.4.5-IGUA-14 Attachment 1 is accurate, it is already in dollars-of-the-day for when the retirement will occur in the future. It is not necessary to further inflate these dollar values before discounting them to the current day, as is part of the Concentric calculations. Further, Concentric also applies an equal CDNS net salvage percentage to each vintage, which is not correct. The accruals rate for old vintages under CDNS are by definition higher than for earlier vintages.
3. Correction of the noted Concentric issues will likely lead to a higher required accrual for CDNS if retaining the same proposed Credit-Adjusted Risk Free ("CARF") discount rate. Once corrected, the annual net salvage expense increases by approximately $3-$14 million (depends on whether comparing to the Concentric ELG study or the ASL analysis).
4. To reflect the benefits of funds provided by earlier generations of customers, as an offset to rate base, the discount rate to be used may be better matched to the weighted average cost of capital financing rate base, rather than the 3.75% CARF rate. This would reduce the CDNS Net Salvage annual accrual by approximately $25 million.

Net Salvage Parameters:

Enbridge Gas has provided, as part of the Concentric Depreciation Study, an analysis of net salvage amounts expected to be required in the future to remove the assets once they are retired. Concentric has proposed to change the net salvage estimates (parameters) for a number of accounts as compared to the currently approved level.

Review of Enbridge Gas's evidence suggests that Concentric's proposal with respect to the net salvage parameters is not well supported for six of the asset accounts, as summarized below. In particular, the findings with respect to these accounts raise concerns with the peer information used for these accounts; accuracy of the retirement data; and the judgment used to establish the proposed net salvage rates.

It is also important to note that Enbridge Gas's net salvage analysis is working with a very short record for many of the largest accounts, often only since 2010 or later. Also, it is possible that the merging of the data from the two utilities has proven more problematic in the case of salvage, as the data alignment and quality is significantly more unstable than the capital asset data used to assess life.

1. Account 465.00: It is appropriate to maintain the currently approved Union rate of negative 15% to form the basis of the CDNS calculations for Account 465.00, which is also aligned with the current rates for the peer utilities reviewed. The expected impact of this finding is a reduction of approximately $2 million compared to Enbridge Gas's 2024 forecast depreciation expense.
2. Account 466.00: It is appropriate to maintain the currently approved Union rate of negative 5% to form the basis of the CDNS calculations for Account 466.00, which is higher than

the current rates negative 2% for the peer utilities reviewed. The expected impact of this finding is a reduction of approximately $1 million compared to Enbridge Gas's 2024 forecast depreciation expense.

3. Account 467.00: It is appropriate to maintain the currently approved Union rate of negative 10% to form the basis of the CDNS calculations for Account 467.00, which is higher than the current rates for two of the three peer utilities reviewed. The expected impact of this finding is a reduction of approximately $1 million compared to Enbridge Gas's 2024 forecast depreciation expense.
4. Account 473.02: It is appropriate to use an estimate of negative 40% net salvage estimate to form the basis for the CDNS calculations until a proper retirement record is established for Account 473.02. The expected impact of this finding is a reduction of about $5 million compared to Enbridge Gas's 2024 forecast depreciation expense.
5. Account 475.21: A negative 40% net salvage estimate is appropriate as a basis for CDNS calculation for Account 475.21, which is consistent with the actual retirement experience for this account (still significantly higher than most of the reviewed peer utilities' rate of negative 25%). The expected impact of this finding is a reduction of approximately $40 million compared to Enbridge Gas's 2024 forecast depreciation expense.
6. Account 475.30: A negative 25% net salvage estimate is appropriate as a basis for CDNS calculation for Account 475.30, which is consistent with the actual retirement experience for this account and aligned with majority of the reviewed peer utilities' approved rate of negative 25%. The expected impact of this finding is a reduction of approximately $20 million compared to Enbridge Gas's 2024 forecast depreciation expense.

Energy Transition:

In Appendix 1 of the 2021 depreciation report[6], Concentric provides an analysis linked to a 2050 economic planning horizon. Concentric is not recommending adoption of a 2050 economic planning horizon at this time, but has provided calculations to indicate the impact if a 2050 truncation date were to be adopted (the analytical approach assuming all assets are of no further utility use as of the year 2050). The 2050 Economic Planning Horizon scenario prepared by Concentric is mathematically sound but fails to address multiple issues and unknowns that are implicitly intertwined with the analysis. The rates derived are not appropriate for use in setting depreciation expense at this time.

Estimated Impact of Findings on Depreciation Expense

Table 1 provides estimated impact of InterGroup's findings on Enbridge Gas's 2024 forecast depreciation expense.

[6] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 316 of 451.

Table 1: Estimated Impact of Findings on Enbridge Gas's Proposed Depreciation Expense

Line no	Finding/Recommendation	Estimated Impact on Enbridge Gas's Proposed Depreciation for 2024 ($M) [1]		Note/Explanation
	Depreciation Rates Estimate Procedure			
1	Use of ASL/ALG procedure rather than ELG procedure	-81.4		Exhibit 1.4.5-Staff-170 Attachment 1
	Subtotal		**-81.4**	
	Asset Life Parmeters			
2	Use of life parameter of Iowa 45-R2.5 for Account 452.00	-0.3		Note 2
3	Use of life parameter of Iowa 44-R4 for Account 456.00	-1.5		Note 2
4	Use of life parameter of Iowa 40-R.25 for Account 457.00	-0.4		Note 2
5	Use of life parameter of Iowa 70-R4 for Account 465.00	-7.0		Note 2
6	Use of life parameter of Iowa 70-R3, or at a minimum Iowa 61-R3 for Account 475.21	-15 (at 70-R3); -7 (at 61-R3)		Note 2
7	Use of life parameter of Iowa 70-R4, or at a minimum Iowa 65-R3 for Account 475.30	-9 (at 70-R4); -5 (at 65-R3)		Note 2
	Subtotal		**-21.2 to -33.2**	
	CDNS Calculation Methodology			
8	Correct CDNS net salvage rate calculation (compared to Concentric ELG or ALG analysis)	+2.9 (vs. ELG); +14.0 (vs. ALG)		Attachment 1 to InterGroup's evidence
9	Use CDNS discount rate based on return on rate base 5.87% rather than 3.75% CARF rate [3]	-24.9		Attachment 2 to InterGroup's evidence
	Subtotal		**-10.9 to -22.0**	
	Net Salvage Parameters			
10	Maintain the currently approved Union rate of negative 15% for Account 465.00	-2.0		Note 4
11	Maintain the currently approved Union rate of negative 5% for Account 466.00	-1.0		Note 4
12	Maintain the currently approved Union rate of negative 10% for Account 467.00	-1.0		Note 4
13	Use negative 40% net salvage estimate for Account 473.02	-5.0		Note 4
14	Use negative 40% net salvage estimate for Account 475.21	-40.0		Note 4
15	Use negative 25% net salvage estimate for Account 475.30	-20.0		Note 4
	Subtotal		**-69.0**	

Notes:

1. The impacts quantified for each recommendation are high level estimates. Each impact is quantified independent of other recommendations (i.e. impact only compares to Enbridge Gas's proposal for that one aspect). Therefore, the impacts are not additive and the adoption of a recommendation could change the impact quantified for another recommendation. All estimates, except finding #1, were quantified by InterGroup.
2. Based on the life estimate difference from proposed and plant balances as per Exhibit I.4.5-IGUA-25 Attachment 3.
3. Return on rate base of 5.87% as per Exhibit 5, Tab 2, Schedule 1, Attachment 6, page 1.
4. Based on calculated CDNS rate difference from proposed and plant balances as per Exhibit I.4.5-IGUA-25 Attachment 3.

4.0 EQUAL LIFE GROUP PROCEDURE

In preparing the consolidated depreciation study for the operations of Enbridge Gas, Concentric reviewed the methodologies used by EGD and Union Gas in their previous depreciation studies, and "made recommendations to be applied to the combined assets of Enbridge Gas."[7] Among the matters considered was the group procedure to be applied to calculation of depreciation rates (and consequently depreciation expense). In this regard, "procedure" refers to a set of methods to turn estimates of the service life of assets (sometimes referred to as life and dispersion estimates, or Iowa curves) into an annual expense. Three such procedures are addressed in the filing:

1) The **Equal Life Group ("ELG")** procedure now recommended by Concentric.
2) The **Average Service Life ("ASL")**, or **Average Life Group ("ALG")** procedure used in the last approved depreciation studies for EGD. For simplicity, and to help distinguish from the similarly acronymed ELG, this submission refers to the second procedure as ASL.
3) The **Generation Arrangement** procedure used in the last approved depreciation studies for Union (also known as Vintage Group). While Generation Arrangement is generally considered its own procedure, in the final stages of the analysis, Generation Arrangement applies calculations to determine the depreciation accrual rates that are normally the same as ASL (applied to each vintage), but also can use ELG methods.

Concentric notes that the Generation Arrangement procedure is rarely used by Concentric and is uncommon as a procedure in Canada.[8] Concentric also notes that the procedure is poorly suited (or introduces inaccuracies, or excessive reliance on simulated data) for utilities which do not have complete retirement records for all plant existing and retired, such as Enbridge Gas. On these matters, Concentric's characterization of the Generation Arrangement procedure is reasonable. Generation Arrangement is also more typically used for telephone utilities rather than energy.[9] For theses reasons, consistent with Concentric's conclusion, the Generation Arrangement does not merit further consideration for use by Enbridge Gas.

The remaining two procedures – ELG and ASL – are further addressed below.

4.1 BACKGROUND ON GROUP PROCEDURE (ELG VERSUS ASL)

The ASL procedure applies a set of mathematics that is intuitively aligned with the expectations of a group of assets having a clearly estimated average service life. For example, The ASL depreciation rate, in its simplest form, for an asset with a 40 year life is 2.5%/year (or depreciating 1/40th of the asset each year). In general, this 2.5%/year rate continues to be operative throughout the asset's life, whether it lasts 20 or 40 or 60 years.[10]

[7] EB-2022-0200, Exhibit 4 Tab 5. Schedule 1, page 5 of 20.
[8] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 14-16 of 451.
[9] National Association of Regulatory Utility Commissioners (NARUC), Public Utility Depreciation Practices. August 1996. Page 131.
[10] Where asset performance varies from projected, there can be a variance or "true-up" applied to adjust the rate to address past shortfalls or surpluses. But the core rate for go-forward assets remains as indicated.

Inherent in the use of the ASL Group Procedure is the concept of an asset group. This classification ("componentization") entails taking the utility's assets and grouping them with like assets which are expected to have similar average lives. Every group depreciation methodology requires such componentization or else the very concepts of average lives and actuarial analysis cannot be completed.

In order to know if an asset group is performing according to the projected life estimates, the depreciation study will provide both an average life (i.e., 40 years), and a dispersion. The dispersion addresses the characteristics as to how the asset is expected to perform in relation to its average life. For example, a symmetrical dispersion of high mode will portray that for the same average 40-year life the asset group will see many retirements between years 35 and 45, while a low mode may portray that the assets will see more retirements at 20 and 60 years (i.e., the retirement probability curve would have larger shoulders). Depreciation practice assigns these dispersions a value to indicate the degree of modality (or tightness) exhibited, typically from 0 to 5. Asymmetrical dispersions are also possible, skewed either to the right or left. Thus, a life estimate could be 40-S4, indicating a 40-year average service life, with a symmetrical dispersion and a relatively high mode. This nomenclature is sometimes known as an "Iowa curve" due to the origination at Iowa State University.

For the ASL procedure, the selection of a dispersion is typically of very limited importance. The dispersion is mostly needed to indicate if the asset group is showing excess early or late retirements, so that this variance can be quantified. The variance can then be amortized if desired, typically over the remaining life of the assets in the group.

It must be noted that the ASL procedure inherently includes recognition that some assets will retire earlier than the 40-year average, and some later, and this is not, in and of itself, an indictment of the 40-year life estimate, nor is it a loss on retirement. It is simply a component of the estimation approach. The ASL procedure inherently results in early retirements being effectively amortized over the remaining life of the assets in the group.

The ELG procedure is a significantly more complicated refinement on the ASL procedure noted above. Where ASL is applied to a group of assets as a whole, ELG first slices each group of assets into tiers that are expected to have equal lives. So, while ASL has a group for Meters, ELG implicitly creates a group for Meters expected to live 1 year, and a separate group for Meters expected to live 2 years, and so on. ELG then creates a separate rate for each of these subgroups of theoretical equal life.

One complication arises in knowing how to slice the overall asset investment in a class into the differing estimated lives. The answer is reliance on the Iowa curve. The Iowa curve can indicate, say for a 40-year average life asset, what percentage should be assumed to retire in year 1, and in year 2, etc. up to years 70 or higher. However, this introduces a new and significantly more sensitive set of assumptions into the preparation of depreciation estimates – not only does the utility require a good estimate of how long the assets will live on average, but it also requires a detailed knowledge of just how the retirements will vary around the average. Solid estimates can be made of dispersion and the appropriate Iowa curve for assets with very good actuarial data, however this requires the data to be sound in multiple ways that can be challenging for utility assets:

1) First the data generating the actuarial analysis has to include a large enough set of individuals. This may be true in some accounts (e.g., meters, of which Enbridge Gas has many individuals) but may not be true for all accounts.
2) Second, the data has to be relatively complete through a large part of the asset's life cycle (e.g., for a 60-year life asset, one would need records over about 100 years to capture the dispersion experience). For most utility assets that are relatively long-lived, this is not typically available. It can be achieved with assets like trucks and computers, for example, which have shorter life cycles.
3) Third, the data from the past record has to be representative of future performance. Again, with longer life cycles, and changing technology, this can be difficult to achieve.

It can be challenging enough to review asset performance under the above limitations to come up with reasonable estimates of average asset lives, particularly when relying on the merging of the asset records of two utilities. The confidence related to knowing the correct dispersion as well, to the point where this is relied upon to introduce more purported precision in the depreciation estimates, can be far more challenging. Some approaches can be used to help correct for this issue, including looking at peers to effectively broaden the set of data being considered, but this too introduces its own imprecision, as peers may have different climate, maintenance practices, types of assets, etc.

For this reason, the purported greater degree of accuracy under ELG, dependent upon selecting the correct dispersion, is not well-founded in the case of many gas utility asset classes. In this case, assertions of the greater precision of ELG are less well-founded given Concentric has already ruled out the Generation Arrangement procedure due to data limitations.

In terms of the mathematics of calculating the costs under each procedure, Concentric has presented a comparison of the costs of ASL and ELG, as follows:

Excerpt from Concentric 2021 Depreciation Study[11]

The difference in calculation of depreciation expense derived from ELG and ALG can best be explained with the use of a simple example.

Assume one plant account with a total cost of $2,000 is comprised of two subgroups of assets, each with an original cost of $1,000. The first group has a life of 5 years, while the second group has a life of 15 years.

Under both procedures the average life of this plant account would equal 10 years (15 + 5)/2. With the ALG procedure this average life would be used to determine the depreciation accruals for the first 5 years as follows:

($2,000 / 10 years) = $200 per year

The accrual for years 6 through 15 would be as follows:

($1,000 / 10 years) = $100 per year

Under the ELG procedure, the expense for each sub group is determined and then added together. Therefore for the first 5 years, the accrual would be as follows:

($1,000 / 5 years) + ($1,000 / 15 years) = $267 per year.

The accrual for years 6 through 15 would be as follows:

($1,000 / 15 years) = $67 per year.

The following table sets out the differences in the two methods:

Average Life Group Procedure				Equal Life Group Procedure			
Year	Accruals ($)	Retirements ($)	Acc. Deprn Balance ($)	Year	Accruals ($)	Retirements ($)	Acc. Deprn Balance ($)
1	200		200	1	267		267
2	200		400	2	267		534
3	200		600	3	267		801
4	200		800	4	267		1,068
5	200	1,000	0	5	267	1,000	335
6	100		100	6	67		402
7	100		200	7	67		469
8	100		300	8	67		536
9	100		400	9	67		603
10	100		500	10	67		670
11	100		600	11	66		736
12	100		700	12	66		802
13	100		800	13	66		868
14	100		900	14	66		934
15	100	1,000	0	15	66	1,000	0

[11] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 15 of 451.

In the example above Concentric considers two assets of average age of 10, under both the ELG and ASL (ALG) procedures. Concentric's portrayal attempts to indicate that the costs of these two assets included in revenue requirement under ASL ($200/year; $100/year) would lead to an insufficient accrual of accumulated depreciation as compared to ELG ($267/year; $67/year). Concentric's example is suggesting that ASL has set a depreciation expense that is too low in the first 5 years, such that customers in the last 5 years must pay more, which Concentric indicates is an issue for inter-generational equity. Concentric suggests that there is better intergenerational equity when customers pay $267/year for the two assets in service in years 1-5 and $67/year for the one asset in service for years 6-15.

The Concentric example portrayed above is flawed for two reasons:

1) The analysis portrays a sort of terminal account, where there is no turnover or reinvestment.
2) The analysis does not consider the Service Value of the group of assets in question, for which ratepayers are fundamentally paying via depreciation expense. Service value can be understood mathematically (e.g., "The service value of the plant, for depreciation purposes shall be its cost less its estimated net salvage value"[12]) or by the notional concept of the capacity to deliver the services provided by the group of assets (e.g., trucks, or mains). Depreciation is the process of allocating the service value of a group of assets over the life of the group, not just the original cost of each individual asset.

Concentric also fails to note that at the outset these assets are not distinguishable. They are, for example, two meters of the same quality and composition. One may be hit by some external event (e.g., a collision with garden equipment) in year 5, and another may be retired for corrosion in year 15, but at the outset, one does not know whether this will occur, or at which age, or to which meter. All one knows at the beginning is that the meters will live an average of 10 years, with some symmetrical dispersion (and even this is an estimate). It is important to note that this uncertainty is true under ASL or ELG.

In order to address the above concerns, a more appropriate example of a continuing property account the following example is provided:

[12] For example, OEB Uniform System of Accounts for Class A Gas Utilities (April 1, 1996), Appendix A, 5A.

Figure 1: Depreciation Expense ELG versus ASL

Depreciation Expense for 4 Trucks, at 2.5 year average life, over 5 years.

			Capital spent						
	year		0	1	2	3	4	5	
Truck number				unit 1 replaced at end of year	unit 2 replaced	unit 3 replaced	unit 4 replaced	all retire at end of year	
1	retires 1, 5		100,000.00	100,000.00					
2	retires at 2, 5		100,000.00		100,000.00				
3	retired at 3, 5		100,000.00			100,000.00			
4	retires at 4, 5		100,000.00				100,000.00		
2.5 yr average life									
Depreciation expense									Total
	ASL	Gross Book		400,000.00	400,000.00	400,000.00	400,000.00	400,000.00	
				40%	40%	40%	40%	40%	
	ASL depreciation			160,000.00	160,000.00	160,000.00	160,000.00	160,000.00	800,000.00
	ELG	GBV 1 year old		400,000.00	100,000.00	100,000.00	100,000.00	100,000.00	
		rate		52.08%	52.08%	52.08%	52.08%	52.08%	
		GBV 2 year old		-	300,000.00	100,000.00	100,000.00	100,000.00	
		rate		36.11%	36.11%	36.11%	36.11%	36.11%	
		GBV 3 year old		-	-	200,000.00	100,000.00	100,000.00	
		rate		29.17%	29.17%	29.17%	29.17%	29.17%	
		GBV 4 year old		-	-	-	100,000.00	100,000.00	
				25.00%	25.00%	25.00%	25.00%	25.00%	
	ELG depreciation			208,333.33	160,416.67	146,527.78	142,361.11	142,361.11	800,000.00
Added Cost of ELG									
	NBV ASL		400,000.00	340,000.00	280,000.00	220,000.00	160,000.00	0	
	NBV ELG		400,000.00	291,666.67	231,250.00	184,722.22	142,361.11	0	
	cumulative added cost of ELG			48,333.33	48,750.00	35,277.78	17,638.89	0	

Development of rates	
ASL rate	
1/2.5=	**40%**
ELG rate	
age of vehicle	
1	100%
	50%
	33.3%
	25%
	208.3%
	/4
	52.1%
2	50%
	33.3%
	25%
	108.3%
	/3
	36.1%
3	33.3%
	25%
	58.3%
	/2
	29.2%
4	**25.0%**

In the above example, the asset in question that is providing service to customers is a fleet of four trucks, with an average service life of 2.5 years. Hence, to provide service for five years, eight individual trucks will ultimately be required. At the time of retirement, each asset is replaced with a new truck, because the utility requires four trucks at a time to fulfill its service to customers. The example ignores inflation and mid-year calculations for simplicity.

In the top of the table, the pattern of replacements is noted. As one truck retires at the end of year one, it is replaced by a second, which is assumed to last for four years. Similarly, the second truck retires at the end of year two, and replaced with a truck that lasts three years, etc. By the end of five years, the full fleet is retired, all trucks lasted an average of 2.5 years, and all original cost will have been recovered. Note that this is a valid group of assets – similar equipment grouped with an equivalent estimated service life, uncertainty as to which individuals may last how long, and with a pattern of dispersion about the average life.

On the right-hand side are the calculations of the depreciation rates for ASL and ELG. For ASL, the rate is simple – it is 40% (1 / 2.5 years). For ELG, the rate depends on the age or vintage of the vehicle. For vehicles in their first year, the rate would be 52.1%. This is because they will have a 25% slice assumed to retire at year one (100% depreciation rate needed), a 25% slice that retires at year two (50% depreciation rate needed), a 25% slice that retires at year three (33.3% depreciation rate needed) and a 25% slice that retires at year four (25% depreciation rate needed). The composite rate then for a first-year vehicle is 52.1% ((100%+50%+33.3%+25%) / 4).

If the vehicle survives to year two, then there is a 1/3 chance of retiring when it is two years old (a 50% rate) a 1/3 chance of retiring when it is three years old (a 33.3% rate) and a 1/3 chance of retiring when it is four years old (a 25% rate) leading to a composite depreciation rate for vehicles in their second year of 36.1%.

The same pattern applies to vehicles in their third and fourth year. Note that to properly apply ELG then, it is important to calculate the depreciation rate <u>annually</u> to suit the vintage of the assets in service. In practice, utilities typically only periodically update the depreciation study. Utilities also typically further hybridize the ELG depreciation rates by age to a single rate applied to the entire group of assets – a further oversimplification which serves to undermine the purported accuracy of the ELG procedure.

Taking these rates and applying them to the fleet of trucks shown in Figure 1, the ASL approach leads to customers facing depreciation expense of $160,000 per year. This same value is maintained throughout the five years. The result is fair for rate setting purposes since each generation of customers received the same overall service (the service of four trucks) and paid the same in revenue requirement. In this manner, the ASL procedure leads to a fair and equal allocation of costs over time for the services provided.

Under ELG however, the depreciation expense declines from $208,333 in the first year to $142,361 in the final two years. This decline occurs despite the same service value being provided in each year noted (four trucks worth of service). So, customers in the first year of the analysis were paying considerably more for the service of four trucks than customers in the last year. This is the basis for conclusions that ELG leads to a sort of front-end loading of depreciation expense.

Comparing the two examples underlines the inaccurate interpretation espoused by Concentric's assertion that[13]:

> …the ALG grouping procedures results in depreciation accruals that in later years contain an incremental component of depreciation expense to compensate for the lower levels of accruals in early years.

The above interpretation by Concentric is effectively suggesting that the assets from the "early years" that retired before the average life underperformed, and this underperformance should be

[13] EB-2022-0200, Ex.1.4.5-STAFF-173, page 3.

fully ascribed to the customers served in the early years. This is antithetical to the concept of an asset group, which fully contemplates that some assets will last shorter and some will last longer, and neither represents any form of under- or over-performance ascribable to one generation of ratepayers or another. As demonstrated in Figure 1 above, the early years ratepayers did not leave a problem to later (or future) ratepayers – both faced the same depreciation expense for the same complement of used and useful assets.

4.2 SUITABILITY OF ELG AND ASL TO ENBRIDGE GAS

For reasons outlined above, the ELG procedure is widely considered a more complicated and calculation-intense procedure for depreciation than ASL. It is also less intuitive. For example, consider the Concentric analysis to calculate the depreciation rate for account 453.00 (Underground Storage – Wells) as set out in the following table.[14]

[14] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 200 of 451.

Table 2: Concentric Depreciation Rate Calculation – Account 453.00

Enbridge Gas Distribution

Account #: 453.00 - Underground Storage - Wells

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2005	1,360,580.25	689,168	541,710	0.3063	1,227,044	25.85	47,473	16.5
2006	996,980.51	478,262	375,931	0.2901	920,144	26.50	34,717	15.5
2007	571,778.84	258,700	203,347	0.2736	539,965	27.16	19,879	14.5
2008	1,208,898.37	513,466	403,602	0.2568	1,167,966	27.82	41,984	13.5
2009	1,775,954.26	704,289	553,595	0.2398	1,755,145	28.48	61,635	12.5
2010	11,625,733.52	4,277,734	3,362,446	0.2225	11,751,008	29.13	403,398	11.5
2011	926,645.91	314,031	246,839	0.2049	957,800	29.78	32,164	10.5
2012	3,611,156.89	1,117,196	878,154	0.1871	3,816,350	30.42	125,458	9.5
2013	1,210,191.93	338,119	265,773	0.1689	1,307,477	31.05	42,109	8.5
2014	2,286,760.05	569,263	447,460	0.1505	2,525,328	31.67	79,748	7.5
2015	2,024,005.52	441,236	346,827	0.1318	2,284,380	32.26	70,809	6.5
2016	7,066,060.81	1,318,234	1,036,177	0.1128	8,149,702	32.83	248,271	5.5
2017	539,683.06	83,421	65,572	0.0935	636,016	33.35	19,073	4.5
2018	11,744,935.60	1,432,717	1,126,165	0.0738	14,142,252	33.80	418,417	3.5
2019	499,285.70	44,291	34,814	0.0536	614,257	34.14	17,994	2.5
2020	8,527,709.20	465,244	365,698	0.0330	10,720,324	34.24	313,070	1.5
2021	24,979,214.43	475,069	373,420	0.0115	32,099,559	33.68	953,155	0.5
TOTAL	143,144,394.64	63,662,026	50,040,540		136,047,173		5,515,552	

As shown in the above excerpt from the Concentric 2021 Depreciation Study, the calculation of the depreciation rate for account 453.00 (Underground Storage – Wells) takes into account the remaining Original Cost investment in each vintage (e.g., 2021) and a measure of accumulated depreciation by vintage (Calculated Accumulated Depreciation, which is the amount that the Iowa curves suggest should be accrued, Allocated Accumulated Depreciation, which is the amounts Enbridge Gas has actually recorded, and an Accumulated Depreciation factor which is the percentage of the original plant that has now been depreciated, inclusive of net salvage). It also shows the "ELG remaining life" towards the right-hand side of the page.

In this case, as shown in the upper right-hand side, the asset group has a 45-year average life, with a dispersion of R2.5. However, the very recent investment (vintage 2021, only 0.5 years old as of the study) shows an ELG Remaining Life of 33.68 years. This difference is due to the aggressive nature of the ELG procedure. An asset placed in service with an average life of 45 years, in its first year is considered under ELG to have an average life of only 33.68 years. The ELG procedure will calculate an accrual on this vintage equal to recovering the entire investment for this new plant over this 33.68 year period (or, as shown in the table, $0.953 million per year, inclusive of -30% salvage).

This indicates the basis for assertions that ELG is not intuitive and is more aggressive than needed for an asset that will, on average, be expected to live 45 years. For this reason, ELG is generally considered to drive higher depreciation expense in the early years of an asset's life.

In contrast, an ASL calculation of the same asset group would report that 45 years on average is available to recover the cost of the 2021 vintage. Not only is this approach intuitive, it is also directly consistent with the OEB's Uniform System of Accounts ("USoA"), as follows[15]:

> The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations, and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various provisions for the respective assets in the group.
>
> …
>
> When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service life is shorter or longer than the average service life, accumulated depreciation attributable to an asset at the time of retirement under such circumstances is equal to the cost, except for that portion reasonably assumed to be recoverable through salvage realization. Assets remaining in use after reaching the average life expectancy are not regarded as fully depreciated until actual retirement.

[15] OEB Uniform System of Accounts for Class A Gas Utilities (April 1, 1996), Appendix A, 5B.

The above excerpt highlights the adherence of the ASL procedure to the OEB System of Accounts. Namely, the ASL procedure leads to depreciation expense that is the "weighted average of the various provisions for the respective assets in the group". ASL is premised on the fact that there will be "variations in the service lives of the assets constituting the group, even among assets of the same class".

As depreciation expense is only seeking to allocate the original cost across the full asset life, any procedure (such as ELG) that leads to higher depreciation in the early years can be assumed to lead to lower depreciation later in an asset's life. However, this assumption is often incorrect when applied on a group basis. For example, with the impacts of inflation (newer assets being generally more expensive in nominal dollar terms than old assets) and with a general expansion of utility investment over time, then the ELG estimates could very well indicate a higher total expense in every year. In other words, the ELG proposition for customers is not to pay more now in order to pay less later – it can easily be pay more now to pay more later.[16] Indeed, every ELG study of utility property that Intergroup has reviewed, from any utility, has shown a higher expense for ELG than for ASL using the same life and dispersion estimates, regardless of the status of the utility in its asset life curves or maturity.

The situation becomes more complicated for a utility that previously used ASL, and proposes to move to ELG. Under the Whole Life technique, the depreciation study first looks at what accumulated depreciation should exist for the account (the Calculated Accumulated Depreciation in Table 2 above), given each asset's age and life and dispersion, and calculates what depreciation expense is needed to finish amortizing the original cost. Then, the technique looks at whether the actual accumulated depreciation today is equal to the calculated (i.e., the theoretically correct) amount of accumulated depreciation (the Calculated Accumulated Depreciation versus the Allocated Actual Booked Depreciation in Table 2 above), and if it is not the same, it will amortize the difference (shortfall or surplus, known as a true-up) over a period selected by the depreciation policies – typically the weighted average remaining life of the assets (the ELG Remaining Life in Table 2 above). In the case of Enbridge Gas, the following consolidated accumulated amortization balances are provided by Concentric:[17]

[16] This is confirmed as an adverse effect of ELG in the depreciation literature, for example at NARUC, Public Utility Depreciation Practices, August 1996, page 178: "In a growing account however, a crossover point may never occur."
[17] ASL values from EB-2022-0200, Exhibit I.4.5-Staff-173, Attachment 1, page 3 of 3 (summation required); ELG values from EB-2022-0200, Exhibit I.4.5-Staff-173, Attachment 3, page 4 of 6.

Table 3: Accumulated Depreciation (Shortfall)/Surplus Under Different Procedures

$millions	Booked Accumulated Amortization	Calculated Accumulated Amortization	(Shortfall)/ Surplus
ASL	7,125.7	7,757.5	(631.8)
ELG	7,125.7	8,358.2	(1,232.5)

Table 3 shows that if the depreciation estimates are performed using the ASL procedure as of December 31, 2021 the actual accumulated depreciation that is recorded of $7,125.7 million is below the calculated amount ($7,757.5 million) by $631.8 million. This shortfall would be amortized over the average remaining life of the assets under ASL.

Under ELG, the same actual accumulated depreciation is recorded, but the calculated accumulated depreciation is $8,358.2 million, indicating a shortfall of $1,232.5 million.

Table 3 indicates that under either ELG or ASL, there is a current shortfall of accumulated depreciation. Under ASL this shortfall is $631.8 million (approximately 9%). However, under ELG, the shortfall is $1,232.5 million (approximately 17%). This variance reflects the more aggressive nature of ELG, as applied to the current complement of Enbridge Gas's assets. In short, the proposal to use the ELG procedure today is not only increasing costs for ongoing depreciation, it is also seeking to effectively recover back from customers an additional $600.7 million related to past periods (the difference between $1,232.5 million shortfall under ELG and $631.8 million shortfall under ASL).

This large shortfall difference is further driving costs because of the period on which the shortfall is amortized, as follows:[18]

[18] ASL/ASL per EB-2022-0200, Exhibit I.4.5-Staff-173, Attachment 1, page 2 of 2; ELG/ASL per EB-2022-0200, Exhibit I.4.5-Staff-173, Attachment 3, page 2 of 6. ELG/ELG per EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 41 of 451.

Table 4: Total Depreciation Expense for 2021 Study Year

Procedure Going Forward	Shortfall to be Amortized ($millions)	Remaining Life Used for Amortization	Resulting Annual Depreciation Expense (based on assets in service as of Dec 31, 2021) ($millions)
ASL	$631.8	ASL	$713.8
ELG	$1,232.5	ASL	$729.2
ELG	$1,232.5	ELG	$786.5

Table 4 highlights that the change from ASL to ELG drives $15.4 million in additional annual expense (from $713.8 million to $729.2 million), reflecting the higher shortfall of $1,235.5 million that Enbridge Gas is proposing, so long as the added shortfall continues to be amortized over the ASL remaining life.

This is compounded by also applying the ELG procedure to calculate the average remaining life. In fact, this impact is the larger component of the change to ELG, totalling a further $57.3 million (from $729.2 million to $786.5 million). These estimates of the impact are linked to the 2021 study – in the test year the impacts will be larger due to newer capital additions that were not included in the 2021 study (the 2024 estimated combined impact is $81.4 million/year)[19]

The large ELG shortfalls are not only a function of the ELG procedure itself. They are also a function of the fact that ELG is proposed to be applied today after a period where ELG was not applied in the past. While ELG is a more costly form of depreciation, transitioning to ELG, including catching up on past periods, exacerbates the impact considerably particularly if the period used for the variance true-up is also shortened (as is proposed by Enbridge Gas).

It should also be noted that the hybrid approach (use ELG for calculating depreciation expense, but ASL remaining lives for amortizing variances (surplus/shortfall) is used at times by regulated utilities. In particular, the Alberta Utilities Commission has approved this approach for ATCO Pipelines in Alberta.[20]

4.3 RATIONALE FOR ADOPTING ELG

The Enbridge Gas Application provides a generic exposition of what it views as the merits of ELG, namely:[21]

a) Enhances the generational equity for customers;

[19] EB-2022-0200, Exhibit I.4.5 Staff-170 Attachment 1.
[20] AUC Decision 22011-D01-2017. Note that in that decision, the ASL procedure is called the "Broad Group" (or "BG") procedure – the two are the same.
[21] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, page 6.

> b) Provides superior matching of the depreciation expense to the consumption of assets providing service to customers; and
>
> c) More accurately reflects the actual useful life of the assets used.

This represents a common textbook list of the assertions about the benefits of ELG. However, as noted in previous sections, these benefits are significantly in dispute (e.g., the result is only more accurate to the extent data is of a high enough quality to model actuarial results accurately; assertions of superior matching and generational equity do not bear out when considering continuing property accounts and the service value actually provided by the group of assets, etc.). For this reason, ELG remains in far less use among utilities in North America than ASL.

In the case of Enbridge Gas, Concentric was asked about the specific foundation for the recommendation to adopt the ELG procedure. The response is as follows:[22]

> Overall, Concentric views that the use of the ELG procedure for this EGI study has two significant advantages as compared to the use of the ALG procedure. Firstly, the use of the ELG procedure was the best available match to the historic procedures approved for Union Gas. Secondly, given the potential changes in use of fossil fuels and the unknown impact of such change on the Enbridge Gas system, the use of the ELG procedure best reduced the future risk of intergenerational inequity.

On the matter of the match to the previous Union Gas methods, this is not well-founded. The Generation Arrangement procedure is not the same as ELG. Generation Arrangement slices the group of plant into vintages based on installation date (i.e., the entire complement of each type of plant installed in a given year) and then analyzes each vintage individually, while ELG slices the assets based on future expected performance. Further, Generation Arrangement can be applied using either ASL or ELG for the purposes of estimating the future performance of the vintage groups[23], and Union used ASL not ELG.

Further, Generation Arrangement has been rejected for this study as the plant data is not of sufficient quality to permit continued use of Generation Arrangement. If precedence is to be a material consideration, continuation of the use of ASL/ALG which was the previous approach for EGD would be a closer adherence to a past method than extrapolating from Generation Arrangement as a justification for ELG.

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[22] EB-2022-0200, Exhibit I.4.5-Staff-173(c).

[23] The NARUC manual Public Utility Depreciation Practices describes the Generation Arrangement application as follows: "Therefore, the generation arrangement is used with both the whole life and remaining life techniques. The process can also be used with the ELG procedure (see Chapter XII). The generation arrangement allows some vintages in a category to be studied under the ELG procedures, and some vintages in the category may also be studied under other procedures using either the whole life or remaining life techniques" (page 131). In the case of Foster's Associates study last completed for Union, the analysis was completed using ASL (also called Whole Life). This can be seen, for example, by reference to Exhibit EB-2011-0210, Ex. D2, pdf page 217 of 325, where a given account (in this case Meters) is shown to have the most recent vintage (2010) with an average life of 25 years, which matches the Iowa curve life for the account (25-L1.5). Had an ELG procedure been used to analyze the vintage groups, the average life reported would have been much shorter than 25.

On the second rationale, adoption of ELG does not bear a clear linkage to addressing the noted energy transition policy issues. There are multiple utilities, such as electrical utilities, who do not face obsolescence risk but use ELG, and an even greater complement of utilities which do face obsolescence risk that use ASL (including basically all US gas utilities).[24] ASL is not a procedure based on artificially deferred asset cost collection – it matches the depreciation of the asset group to the service it provides in each year.

Further, energy transition is a major topic that encompasses the issues of obsolescence, the rights and risk-sharing regarding recovery of capital investment, stranded assets, and potential new fuels and future alternative utility plant uses. This policy issue merits a proper vetting and a broad consistent policy approach. Adopting ELG as an obscure means to accelerate capital recovery and reduce utility investor exposure to energy transition appears to be a poor justification. Energy transition is a matter that is best addressed directly rather than indirectly. The topic of energy transition is further addressed in Section 8 of this report.

4.4 FINDINGS

1. The proposed transition to the ELG procedure at this time is problematic for three reasons:
    a. The purported increased precision of ELG is likely not supported in this case, given limitations on data and the merging of the accounts of two utilities. In contrast the ASL approach is well-accepted, pervasive in North America, and somewhat less sensitive to issues with capital asset data. Assertions that ELG can improve intergenerational equity also do not reflect the premise of group accounting – that some individual assets will last for shorter periods and some will last longer, yet the average performance across the group will be experienced by all generations of ratepayers. ELG excessively burdens the early or current generations of ratepayers with costs that do not reflect average or expected asset group performance.
    b. The financial impact of a transition to ELG is significant for go-forward depreciation calculations. However, this impact is compounded by the implicit need to address the fact that, as a more aggressive procedure, the ELG calculations indicate accumulated depreciation is both in a large shortfall, and also must be recovered over a shorter period than using the ASL procedure. These three factors (faster depreciation, showing a larger current shortfall, and with a shorter period to recover the shortfall) combine to drive the large effect of adopting ELG.
    c. The justification for adopting ELG due to a pending energy transition is misdirected. The issue of energy transition is a significant matter of policy that should be addressed directly through decisions of the regulator, not through the selection of a technical change in depreciation methodology.
2. Concentric has made a sound conclusion that Generation Arrangement is not an appropriate procedure to be used for Enbridge Gas at this time.

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[24] EB-2022-0200, Exhibit I.4.5-Staff-173(d)

3. The continued use of the ASL/ALG procedure for calculation of depreciation rates, as previously applied to EGD, does not appear to have any notable limitations at this time. The procedure has been successfully used by EGD in the past and appears to generate sound calculations of depreciation rates for fixed assets that can readily and accurately be applied in this proceeding. ASL is a widely accepted and the most widely used procedure in North America[25] that results in a high degree of alignment between the performance of a group of assets, the service value provided by the assets, and the costs included in revenue requirement each year.

[25] EB-2022-0200, Exhibit I.4.5-STAFF-173(d)

5.0 ASSET LIFE PARAMETERS

This section reviews the proposed parameters for life and dispersion proposed by Enbridge Gas.

In preparing depreciation estimates, the costs of the original investment in assets are allocated over a period representing the expected life of the asset group. Depreciation studies consider multiple inputs to attempt to estimate these live parameters, including establishing the estimated mean life, and the variability expected around the mean (the dispersion). The establishment of appropriate asset life parameters is required regardless as to the group procedure used by the utility (ASL or ELG, though the selected dispersion is of lesser impact under ASL), and the selection of parameters is independent of which group procedure is to be used.

If asset lives are set too short, ratepayers will face depreciation expenses that are excessive, and the assets will remain in service long after they have had their costs fully recovered from customers. If asset lives are too long, the assets may be retiring from service well before being fully amortized, leading to losses on disposal or back-ended depreciation expense increases to recover earlier shortfalls.

The life and dispersion parameters proposed in utility depreciation studies are typically rooted in three factors. First, actuarial analysis of plant; second, interviews with management and operations staff from the utility; and third, comparison to peer utilities.

In the area of actuarial analysis, Concentric compared the asset retirement history by account to various depreciation life curve combinations - the Iowa survivor curves.

An Iowa curve is a way of graphing how the survival of an asset decreases with age. It typically starts with a relatively small risk of retirement, and slow decline in the graph. Then, over time, the decline becomes steeper as the probability of retirement grows with age. Finally, the curve levels off over time as there are few individuals left in the population who will tend to have anomalously long lives.

In general, in the current application Concentric proposes that most accounts retain their current approved life and dispersion parameters, or involve modest changes that are generally supported by the data and updated retirement history.

There are several accounts where the proposed life estimates by Concentric do not reflect the best matching of parameters to observed life characteristics. Other life and dispersion combinations provide better estimates for these accounts. There are also accounts where Concentric's recommendation are not generally aligned with peer utilities range.

For major accounts not listed in this section, no problematic issues were identified that merited a finding for a different life and dispersion combination. For small accounts, the impact of life and dispersion changes would be extremely small and these accounts were reviewed in only a cursory way.[26]

[26] In this regard, small accounts would include those with a surviving original cost less than $100 million.

5.1 ACCOUNT 452.00 - UNDERGROUND STORAGE - STRUCTURES AND IMPROVEMENTS

The currently approved life parameter for Account 452.00 is Iowa 45-R1.5 for EGD.[27] For Union, a life-span method was applied to this account.[28] Concentric proposes this account to use Iowa 40-R3.[29]

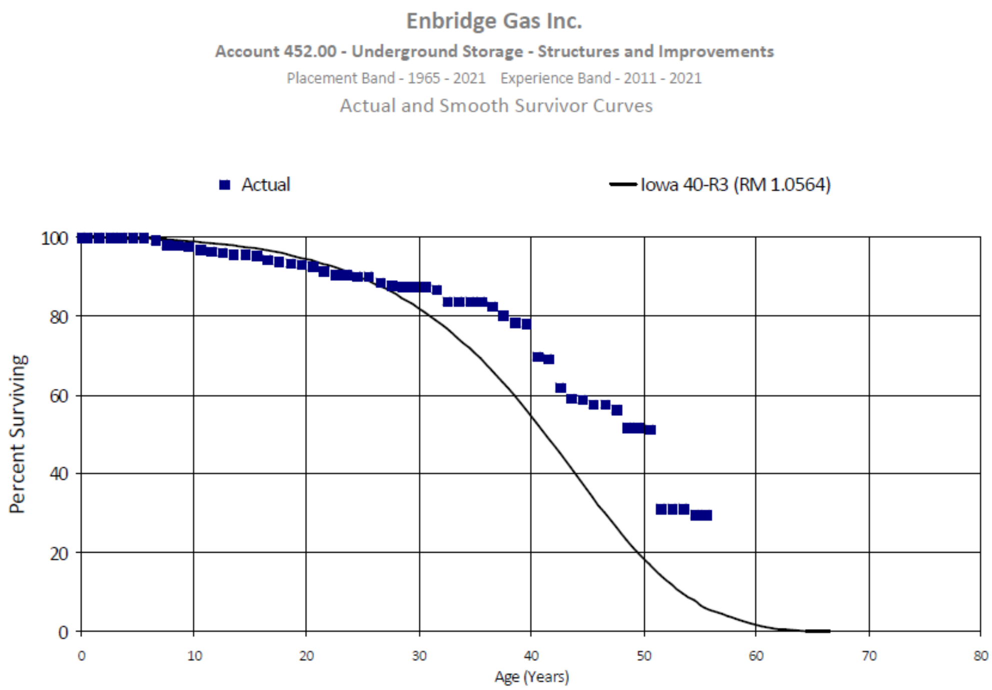
It appears an Iowa 45-R2.5 is better suited to the account.

Concentric does not provide detailed discussion of arriving at the proposed life parameter recommendation for Account 452.00 and only one Iowa curve was included in the depreciation study retirement analysis – Iowa 40-R3 with a residual measure of 1.0564 (Residual Measure is an indication of goodness-of-fit) [30]. At 40 years, the proposed life is a significant reduction to the previously approved EGD life parameter for this account of 45 years.

This account has a good retirement history with a placement band of 1965-2021 (assets installed in this year are analyzed) however, the experience band is limited to 2011-2021 (retirement events within these years are the only events considered). The review of the proposed Iowa 40-R3 indicates that it is notably behind the observed data after approximately 90th percentile surviving as shown in Figure 2.

[27] EB-2011-0354, EGD 2010 Depreciation Study, Schedule 1
[28] EB-2011-0210, Union 2011 Depreciation Study, page 10
[29] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 889 of 1382
[30] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 869 of 1382

Figure 2: Enbridge Gas Proposed Life Curve Illustration – Account 452.00



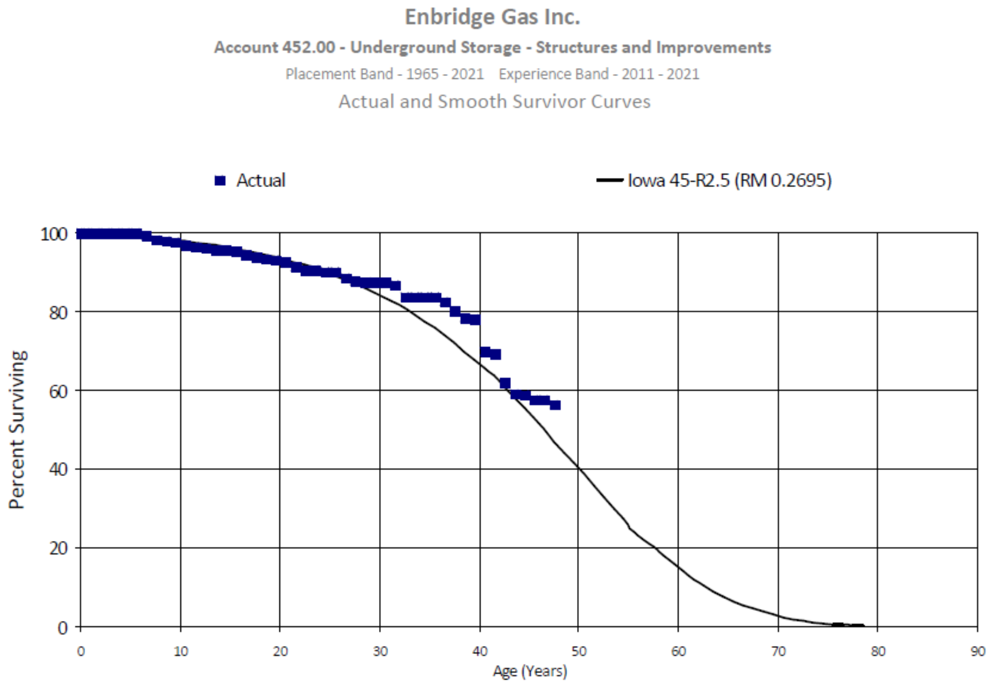
In response to the OEB Staff interrogatory, Concentric provided additional life/curve combinations that were considered as part of the study from the retirement rate analysis, which shows that for Account 452.00 Concentric's analysis only included same life parameters (Iowa 40-R3, Iowa 40-R2.5 and Iowa 40-R4) and did not test curves that have better fit to the observed data.[31]

In an interrogatory, OEB Staff requested Concentric to provide alternative life and dispersion curve for this account for Iowa 45-R2.5 excluding vintages with exposures below 1% of total exposures, which is the widely used practice followed by Concentric.[32] This approach attempts to remove trivial data for vintages that are immaterial to the overall investment.

Concentric provided the requested analysis for Account 452.00 for Iowa 45-R2.5, which is reproduced in Figure 3.[33]

[31] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 4
[32] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 869 of 1382
[33] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1.

Figure 3: Iowa 45-R2.5 Life Curve Illustration – Account 452.00



The depreciation literature notes two typical methods to identify an Iowa curve that best fits the observed data – visual fitting and mathematical fitting to the observed data.[34]

The review shows Iowa 45-R2.5 curve is a better visual fit for Account 452.00 compared to Concentric's recommended parameter under both methods (i.e., the blue dots representing actual retirements more closely align with the projected retirement shown by the black line). On mathematical fitting, Iowa 45-R2.5 has a residual measure of 0.2695 compared to 1.0564 for Iowa 40-R3.[35] This is a significant reduction, which indicates improvement.

Accordingly, a life parameter of Iowa 45-R2.5 appears to be a better estimate for Account 452.00 for the current review.

5.2 ACCOUNT 456.00 – UNDERGROUND STORAGE – COMPRESSOR EQUIPMENT

Account 456.00 relates to compressor stations located at the underground storage facilities on both the EGD and Union system, and makes up 3.15% of Enbridge Gas's asset base as of the 2021 Depreciation study with $682.2 million investment.[36]

[34] Wolf F. K. and Fitch W. C., Depreciation Systems, Iowa State University (1994), pages 46-47.
[35] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1, page 1 of 23.
[36] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 874 of 1382

The currently approved life parameter for this account is Iowa 35-R2.5 for Union and 40-R2 for EGD. Concentric proposes a life parameter for this account at Iowa 40-R4.[37]

An Iowa 44-R4 shows better adherence to the inputs available, and is therefore recommended in this report.

In supporting its recommendation for and Iowa 40-R4, Concentric's analysis compares the proposed life parameter of Iowa 40-R4 to the currently approved life parameters for the EGD and Union and finds that the proposed life parameter shows a lower residual measure of 0.7496. Concentric also notes that discussions with EGI operational and management staff indicated that the Iowa 40-R4 is a good representation of the historical life and future expectations[38]. However, the current management meeting notes provided by Concentric indicate that this is not generally supported. While there is reference to Siemens giving the C plant at Dawn an estimated 40-year life, the plant is from 1984 and replacement is likely over the next 10 years[39] (i.e., closer to 45 years than 40 years). Other examples are provided of plants, such as Crowland, that are 50-60 years old[40].

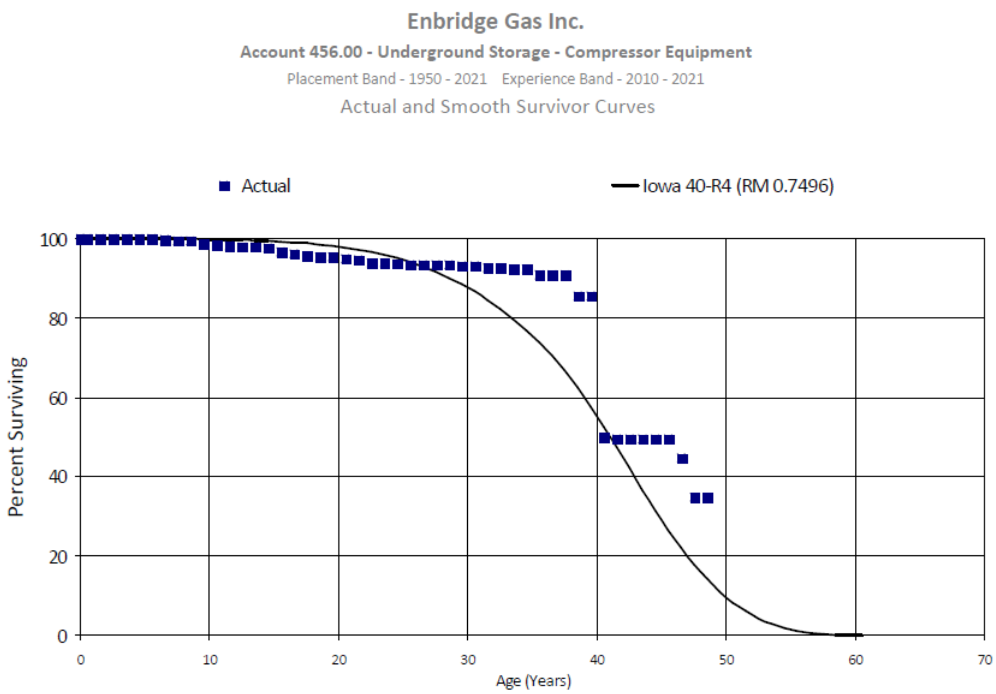
In a draft 2016 study, Gannett Fleming indicated:[41]

> Interviews with company management indicate that an extension to the life of this account is reasonable at this time. The currently approved Iowa 40-R2 is not a good fit to the historical data, nor does it represent the expectations of company management. As the Iowa 45-R3 is consistent with operational staff interviews, and historic indications, the Iowa 45-R3 is forecast to be representative of the anticipated future retirement activity and is recommended in this study. This account will require careful monitoring and may need to have a further life extension in future studies.

The proposed Iowa curve illustration prepared by Concentric for this account in the current study is reproduced in Figure 4.

[37] Ibid
[38] Ibid
[39] EB-2022-0200, Ex. I.4.5-Staff-71 Attachment 5 page 4.
[40] EB-2022-0200, Ex. I.4.5-Staff-71 Attachment 5 page 4.
[41] EB-2022-0200, Ex. I.4.5-Staff-172, Attachment 1, page 23-24.

Figure 4: Enbridge Gas Proposed Life Curve Illustration – Account 456.00

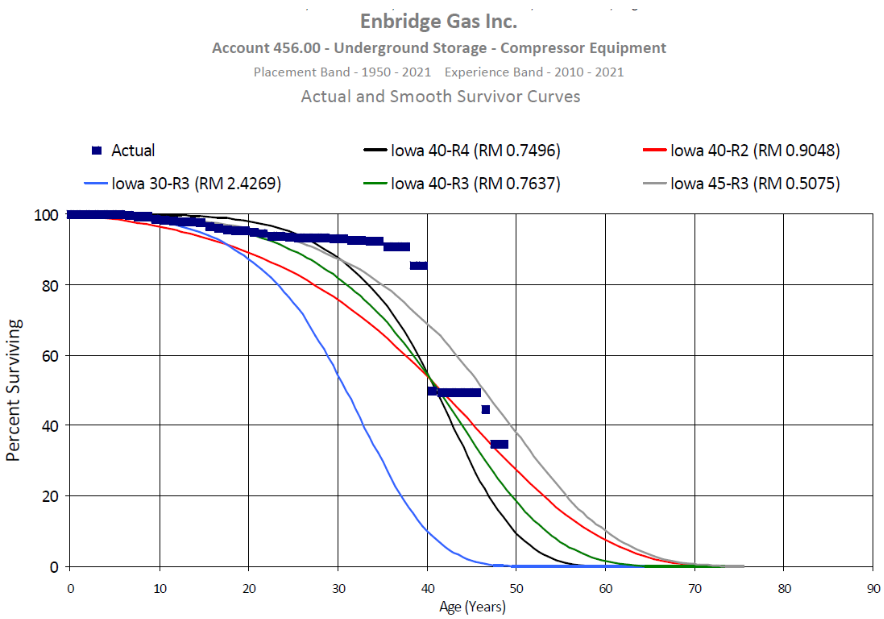


However, in response to the OEB Staff information response, Concentric provided additional life/curve combinations that were considered as part of the study from the retirement rate analysis.[42]

The review shows that there are better matching survivor curves compared to the proposed Iowa 40-R4 curve. In particular, Iowa 45-R3 has a residual measure of 0.5075 compared to 0.7496 for Iowa 40-R4, as well as a superior visual fit to the retirement history compared to the proposed Iowa 40-R4 curve.[43] This is illustrated in Figure 5.

[42] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 4; and Exhibit I.4.5-STAFF-177 Attachment 1.
[43] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 4, page 29 of 112.

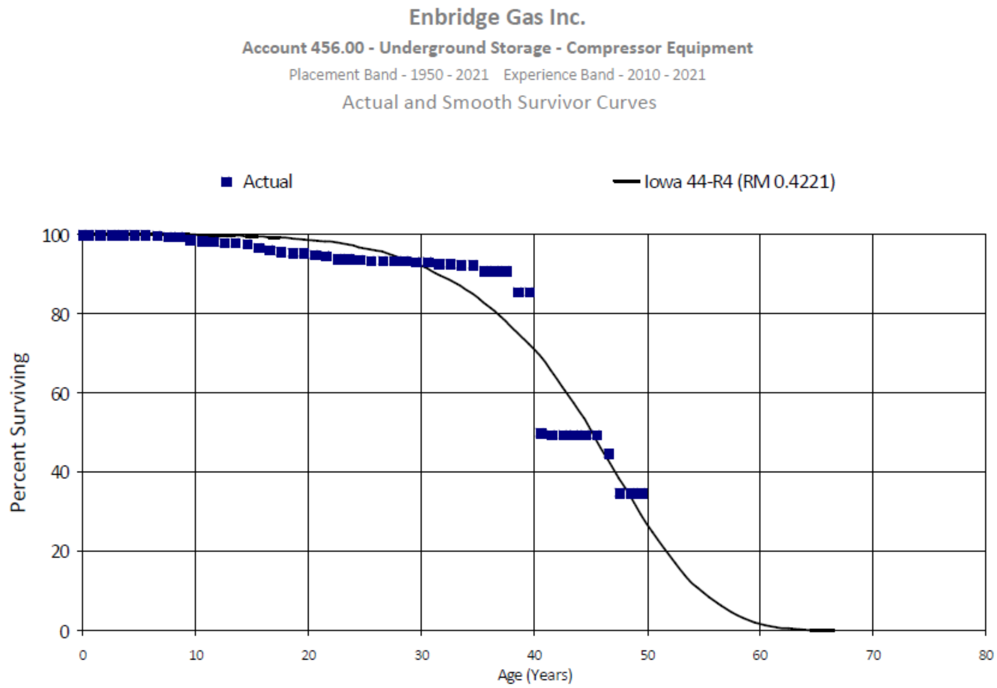
Figure 5: Alternative Life Curves Illustration – Account 456.00



Further, Iowa 44-R4 that was requested in an OEB Staff interrogatory has an even lower residual measure of 0.4221 compared to 0.7496 for Iowa 40-R4, as well as a superior visual fit to the retirement history compared to the proposed Iowa 40-R4 curve as shown in Figure 6.[44]

[44] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1, page 4 of 23.

Figure 6: Iowa 44-R4 Life Curve Illustration – Account 456.00



The Concentric proposal is not supported by its retirement analysis and no other justification for such expectation was provided in the evidence filed by Enbridge Gas in this proceeding.

Accordingly, a life parameter of Iowa 44-R4 appears to be a better estimate for Account 456.00 for the current review.

5.3 ACCOUNT 457.00 – UNDERGROUND STORAGE – REGULATING AND MEASURING EQUIPMENT

The currently approved life parameter for Account 457.00 is 30-R1.5 for EGD and 30-R3 for Union.[45] Concentric proposes a life parameter for this account at Iowa 35-R3.[46]

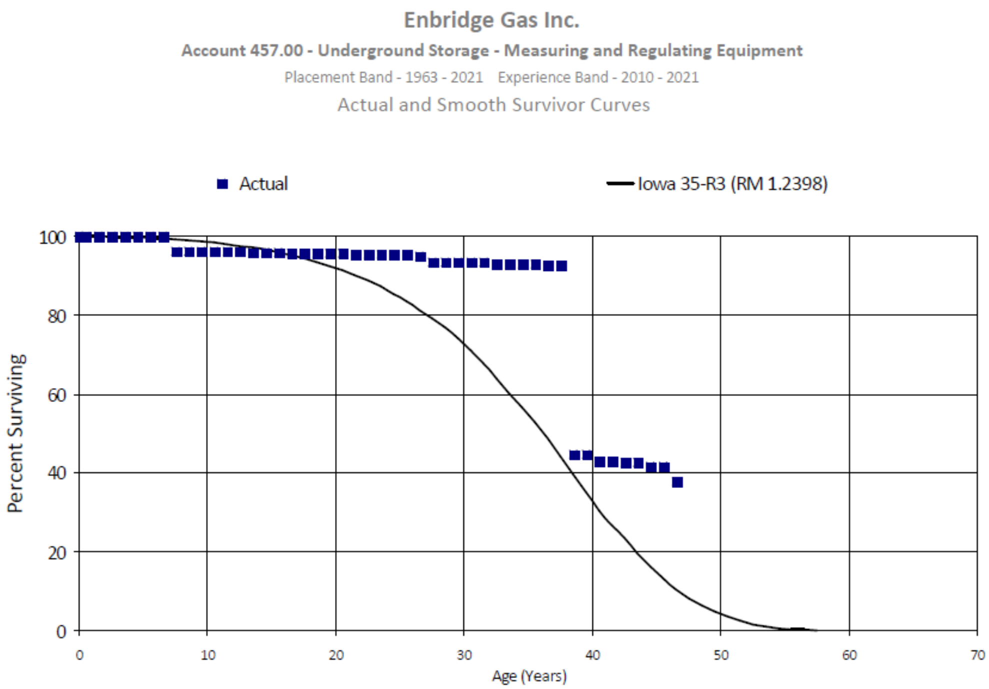
However, an Iowa 40-R2.5 is a better match to the data and inputs available.

Concentric does not provide detailed discussion of arriving at the proposed life parameter recommendation for Account 457.00 and only one Iowa curve was included in the depreciation study retirement analysis – Iowa 35-R3 with a residual measure of 1.2398 (see Figure 7).

[45] EB-2011-0354, EGD 2010 Depreciation Study, Schedule 1; EB-2011-0210, Union 2011 Depreciation Study, page 27

[46] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 889 of 1382

Figure 7: Enbridge Gas Proposed Life Curve Illustration – Account 457.00



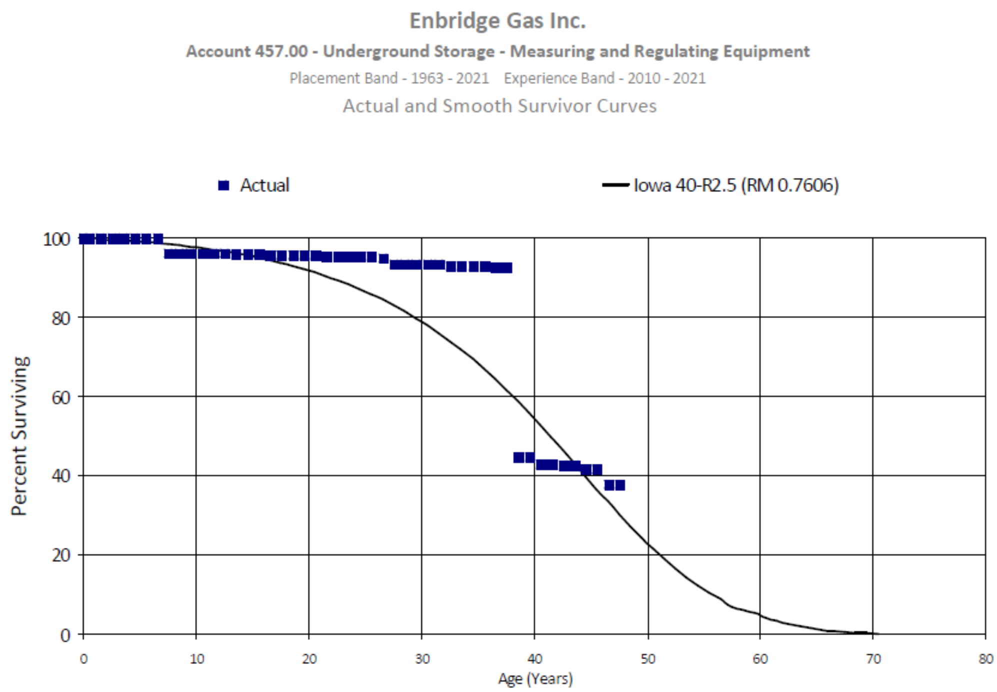
However, in response to the OEB Staff interrogatory, Concentric provided additional life/curve combinations that were considered as part of the study from the retirement rate analysis, which shows that for Account 457.00 Concentric's analysis only included same life parameters (Iowa 35-R3 and Iowa 35-R4) and did not test curves that have better fit to the observed data.[47]

In an interrogatory, OEB Staff requested Concentric to provide alternative life and dispersion curve for this account for Iowa 40-R2.5 excluding vintages with exposures below 1% of total exposures, which is the widely used practice followed by Concentric.[48]

Concentric provided the requested analysis for Account 452.00 for Iowa 40-R2.5, which is reproduced in Figure 8.[49]

[47] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 4.
[48] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 869 of 1382
[49] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1.

Figure 8: Iowa 40-R2.5 Life Curve Illustration – Account 457.00



The review shows Iowa 40-R2.5 curve is a better fit for Account 457.00 compared to Concentric's recommended parameter. In particular, Iowa 40-R2.5 has a residual measure of 0.7606 compared to 1.2398 for Iowa 35-R3, as well as a superior visual fit to the retirement history compared to the proposed Iowa 35-R3 curve.[50]

Accordingly, a life parameter of Iowa 40-R2.5 appears to be a better estimate for Account 457.00 for the current review.

5.4 ACCOUNT 465.00 – TRANSMISSION PLANT – MAINS

The assets in account 465.00 typically relate to large diameter pipelines primarily used to transport natural gas from receipt points (i.e. compressor stations, custody transfer stations) to delivery locations (i.e. distribution networks or other transmission pipelines) along the pipeline relates to compressor stations located at the underground storage facilities on both the EGD and Union system and makes up 12.86% of Enbridge Gas's asset base as of the 2021 Depreciation study with $2,783.3 million investment.[51]

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[50] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1, page 1 of 23.
[51] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 875 of 1382

The currently approved life parameter for this account is Iowa 55-R4 for Union and there is no EGD account for transmission mains.[52] Union had a draft study prepared in 2019 that recommended the life be extended to 60-R4, but this was not implemented[53].

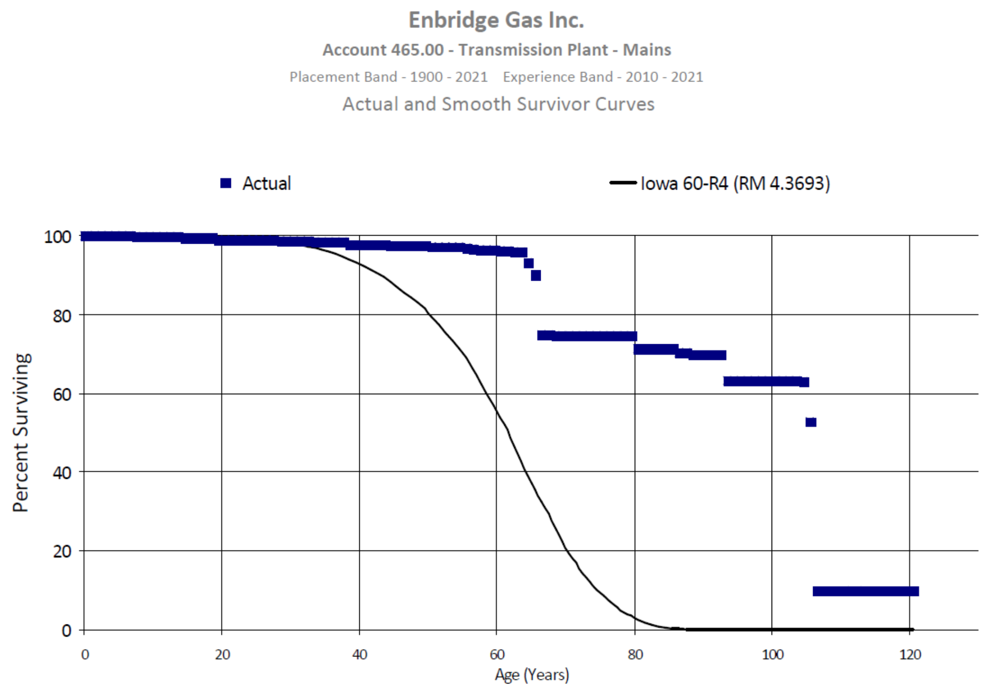
Concentric proposes a life parameter for this account at Iowa 60-R4.[54]

Based on the history of this account, the experience of Enbridge Gas's peers and the data available regarding retirements that have occurred, an Iowa 70-R4 is better suited to the account.

In supporting its recommendation Concentric's analysis compares the proposed life parameter of Iowa 60-R4 to the currently approved life parameters for Union and finds that the proposed life parameter shows a lower residual measure of 4.3693 (vs 4.8604 for Iowa 55-R4). This is a very high residual measure, indicating a poor fit to the experienced retirement data. Concentric also notes that discussions with Enbridge Gas operational and management staff indicated that the Iowa 60-R4 is a good representation of the historical life and future expectations, however there is no discussion of transmission plant lives in the management meeting minutes provided by Concentric.[55] The proposed Iowa curve illustration prepared by Concentric for this account is reproduced in Figure 9.

[52] Ibid
[53] EB-2022-0200, Ex I.4.5-Staff-172, Attachment 3, page 30 of 49.
[54] Ibid
[55] EB-2022-0200, Ex. I.4.5-Staff-173, Attachment 1, page 14 of 20.

Figure 9: Enbridge Gas Proposed Life Curve Illustration – Account 465.00

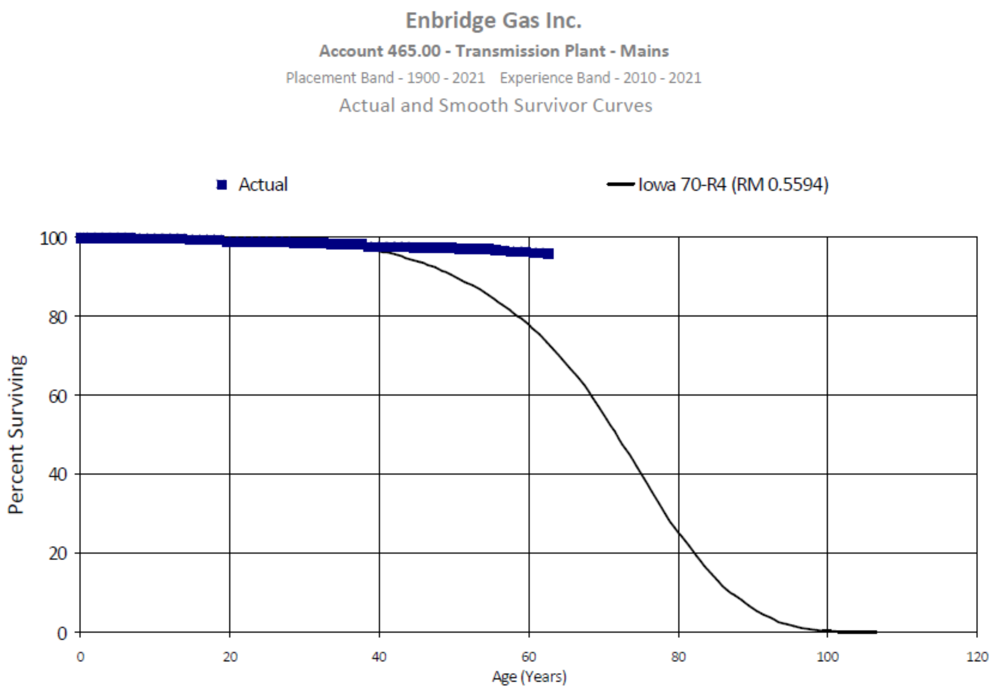


In an interrogatory, the OEB Staff requested Concentric to provide alternative life and dispersion curve for this account for Iowa 70-R4 excluding vintages with exposures below 1% of total exposures, which is the widely used practice followed by Concentric.[56]

Concentric provided the requested analysis for Account 465.00 for Iowa 70-R4, with data truncated at the 1% exposures to remove trivial transactions. This is reproduced in Figure 10.[57]

[56] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 869 of 1382.
[57] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1.

Figure 10: Iowa 70-R4 Life Curve Illustration – Account 465.00



The review shows Iowa 70-R4 curve is a better fit for Account 465.00 compared to Concentric's recommended parameter showing, a significantly lower residual measure of 0.5594 compared to 4.3693 for Iowa 60-R4, as well as a superior visual fit to the retirement history compared to the proposed Iowa 60-R4 curve.[58] The data also shows that outside of some trivial transactions, there has been effectively no retirements in this account through 60+ years of exposures. Concentric's 60-R4 projects that almost half of the plant would be retired by year 60, which is inconsistent with the data.

While Concentric states that discussions with Enbridge Gas operational and management staff indicated that the Iowa 60-R4 was a good representation of the historical life and future expectations for this account, Enbridge Gas staff notes that there has never been a segment over approximately 100 meters replaced due to a condition of the pipeline, and that the pipe as a whole is in good condition.[59]

Further, the life parameter of 60 years recommended by Enbridge Gas is not aligned with the peer utilities reviewed by Concentric which show a much longer life estimates of 65-70 years.[60]

[58] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1, page 1 of 23.
[59] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 5, page 14 of 20.
[60] EB-2022-0200, Exhibit I.4.5-IGUA-26 Attachment 1.

As such, a longer life estimate appears supported for this account. Accordingly, a life parameter of Iowa 70-R4 appears to be a better estimate for Account 465.00 for the current review.

5.5 ACCOUNT 475.21 – MAINS – COATED & WRAPPED

The investments in Account 475.21 relate to steel pipelines that transport gas to individual services or other distribution mains and make up 15.34% of Enbridge Gas's asset base as of the 2021 Depreciation study with $3,320.4 million investment.[61]

The currently approved life parameter for this account is Iowa 55-R4 for Union and Iowa 61-R3 for EGD.[62] Concentric proposes a life parameter for this account at Iowa 55-R3.[63]

However, the Concentric recommendation is well outside the experience of peers and the information Enbridge staff provided in 2016, and there is better support for an Iowa 70-R3.

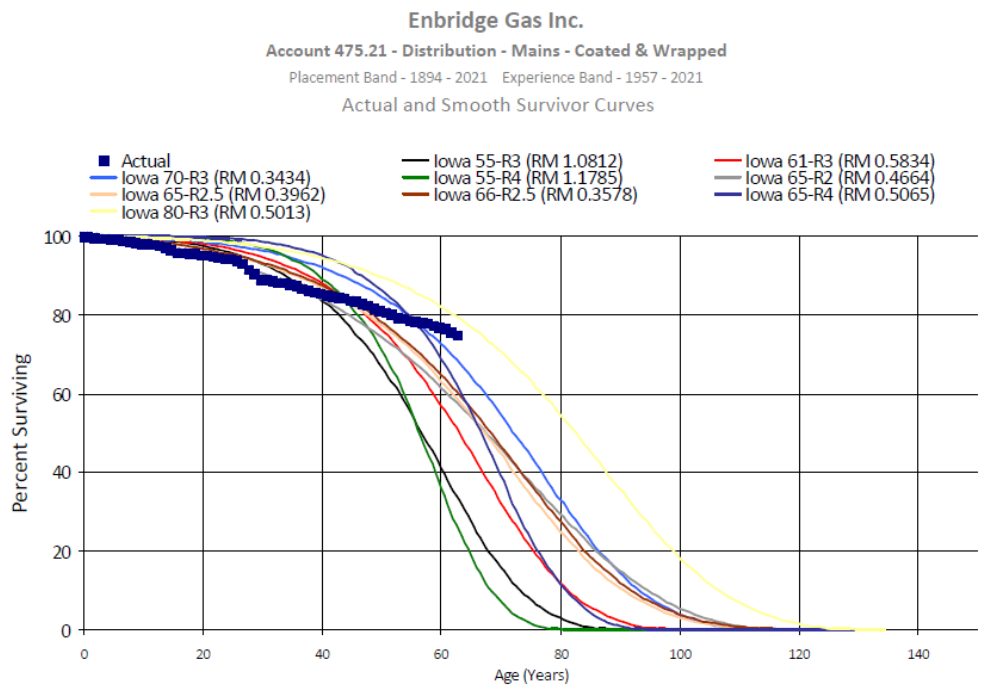
In their 2016 draft report for EGD, Gannett Fleming recommended a 70-R3, noting that operations staff were supportive of the lengthening:[64]

> Gannett Fleming interviews with Operations and Engineering staff have indicated that coated steel mains are primarily used within the Enbridge system on installations where pipe of 8 inches or greater diameter is required. It was also indicated that all coated steel mains within the system are protected with cathodic control systems. Consistent with the retirement rate analysis, the internal company experts felt that the currently approved 61-year average service life should be lengthened.
>
> As the Iowa 70-R3 is consistent with operational staff interviews and the historic data, the Iowa 70-R3 is forecast to be representative of the anticipated future retirement activity. Consequently, an extension of the currently approved 61-year average service life to 70 years is reasonable.

Concentric's retirement rate analysis provided in the response to the OEB Staff interrogatory shows a residual measure of 1.1785 for an Iowa 55-R4 (currently approved for Union Gas) and a residual measure of 0.5834 for an Iowa 61-R3 (currently approved for EGD).[65] In contrast the proposed Iowa 55-R3 shows a residual measure of 1.0812, a notably larger residual than a longer life Iowa 61-R3. This analysis is reproduced in Figure 11.

[61] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 880 of 1382
[62] Ibid
[63] Ibid
[64] EB-2022-0200, Exhibit I.4.5-Staff-172 Attachment 1, page 20 of 188.
[65] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 4, page 82 of 112

Figure 11: Life Curve Illustrations – Account 475.21



Concentric states that an Iowa 55-R3 provides a superior visual fit through the age of 40.5 years.[66] The depreciation study however does not discuss an Iowa 66-2.5 curve estimate for this account, which actually shows better visual fit through the age of approximately 50 years, as well as a lower residual measure of 0.3578. The best fit, however, is achieved by 70-R3, at a residual measure of 0.3434.

Concentric states that discussions with Enbridge Gas's operational and management staff indicated that the historical fit of Iowa 55-R3 was a reasonable expectation for the assets in this account and that the Iowa 55-R3 was within the span of peer Canadian pipeline utilities that ranges from 55–80 years.[67] However, review of the peer utilities comparators provided by Concentric indicated that there are no utilities that have a life estimate of 55 years for this account. The correct span of peer Canadian pipeline utilities ranges from 65 to 80 years – much longer life estimates than that proposed by Concentric.[68]

Based on the evidence on record, the proposed life parameter of Iowa 55-R3, which is a notable reduction to the currently approved EGD life parameter, does not appear supported by the historical retirement data of Enbridge Gas, the discussion with operations staff in 2016, or the peer analysis.

[66] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 880 of 1382.
[67] Ibid
[68] EB-2022-0200, Exhibit I.4.5-IGUA-26 Attachment 1

The retirement rate analysis and peer review show that it is more appropriate at a minimum to maintain the currently approved EGD's life curve of Iowa 61-R3 for this account. A better actuarial fit is achieved by adopting 70-R3 in concordance with the operations staff input in 2016 and within the range of peers. Of the two options, 70-R3 appears a better fit overall.

5.6 ACCOUNT 475.30 – MAINS – PLASTIC

The investment in this account represents 16.08% of Enbridge Gas's asset base as of the 2021 Depreciation study with $3,480.1 million investment that relate to plastic pipelines that transport gas to individual services or other distribution mains.[69]

The currently approved life parameter for this account is Iowa 60-L2 for Union and Iowa 65-R3 for EGD.[70] Enbridge Gas proposes to approve the life parameter for this account at Iowa 60-R4.[71]

However, there is better support for an Iowa 65-R3, though a 70-R4 would also be within the range of peers and EGD's past evidence.

In their 2016 draft report for EGD, Gannett Fleming recommended a 70-R4, noting that operations staff were supportive of the lengthening.[72]

> As the Iowa 70-R4 is consistent with operational staff interviews, the Iowa 70-R4 is forecast to be representative of the anticipated future retirement activity and is recommended in this study.

Concentric states that the currently approved life parameter for the Union account is an Iowa 60-L2 with a residual measure of 1.7968 and an Iowa 65-R3 for the EGD account with a residual measure of 0.3571 and that the Iowa 60-R4 was considered against the observed data after harmonization with a residual measure of 0.5515.[73] Concentric also states that the proposed Iowa 60-R4 is within a Canadian peer comparison where the average service life ranges from 60-80 years and that based on the above, Concentric recommends the Iowa 60-R4 to represent the future expectations for the investment in this account.[74]

In an interrogatory, OEB Staff requested Concentric to provide alternative life and dispersion curve for this account for the currently approved and proposed Iowa curves (60-L2, 65-R3 and 60-R4), excluding vintages with exposures below 1% of total exposures, which is the widely used practice followed by Concentric.[75]

Concentric provided the requested analysis for Account 475.30, which is reproduced in Figure 12.[76]

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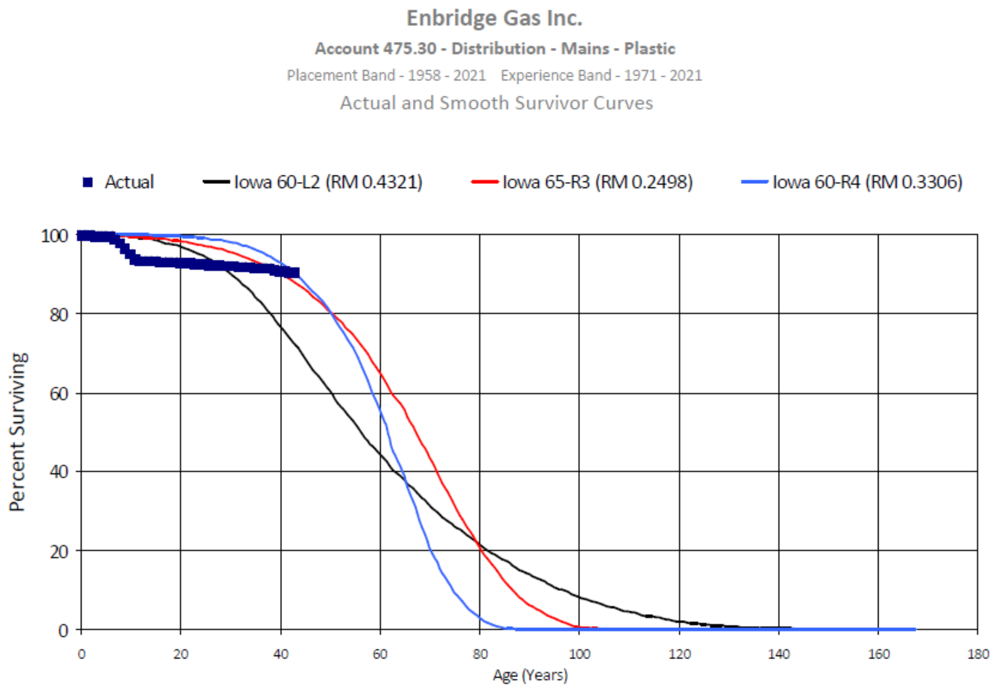
[69] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 881 of 1382
[70] Ibid
[71] Ibid
[72] EB-2022-0200, Exhibit I.4.5-Staff-172 Attachment 1, page 19 of 188.
[73] Ibid
[74] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 881 of 1382
[75] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 869 of 1382
[76] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1

Figure 12: Iowa Life Curve Illustrations – Account 475.30



The review shows that the Iowa 65-R3 curve, currently approved for EGD, is a better fit for Account 475.30 compared to Concentric's recommended reduced life parameter of Iowa 60-R4 showing a lower residual measure of 0.2498 compared to 0.3306, as well as a superior visual fit to the retirement history.[77] However, the visual and actuarial record is of limited value in this case given the long lived nature of plastic distribution mains and the relatively short experience band with any material exposure (just over 40 years). There is also no useful information in the utility management interviews from this study, with no conclusions regarding life provided.[78]

Also note that Concentric states that the Iowa 60-R4 is within a Canadian peer comparison where the average service life ranges from 60-80 years. However, this is not the case. Review of the peer utilities comparators provided by Concentric indicated that there are no utilities that have a life estimate of 60 years for this account. The correct span of peer Canadian pipeline utilities ranges from 65 to 80 years – much longer life estimates than proposed by Enbridge Gas.[79]

Based on the evidence on record, there appears to be no rationale, supported by data or otherwise, for shortening the life estimate for this account as proposed by Enbridge Gas.

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[77] EB-2022-0200, Exhibit I.4.5-STAFF-177 Attachment 1, page 18 of 23
[78] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 5, page 12 of 20
[79] EB-2022-0200, Exhibit I.4.5-IGUA-26 Attachment 1

The retirement rate analysis and peer review show that it is more appropriate at a minimum to maintain the currently approved EGD's life curve of Iowa 65-R3 for this account (Account 475.30). However, adopting Iowa 70-R4 from the 2016 Gannett Fleming study would place Enbridge Gas into the middle range of peers and in a range consistent with the recommendations of operations staff. However, actuarial data was not analyzed for a Iowa 70-R4 and it is likely less robust than Iowa 65-R3 which was compared to Enbridge Gas's recorded experience.

5.7 FINDINGS

InterGroup's findings with respect to the asset life parameters, based on the review of the evidence on record, are summarized below.

1. Account 452.00: A life parameter of Iowa 45-R2.5 appears to be a better estimate for Account 452.00 for the current review. The expected impact of this finding is a reduction of approximately $0.3 million to Enbridge Gas's 2024 forecast depreciation expense.
2. Account 456.00: A life parameter of Iowa 44-R4 appears to be a better estimate for Account 456.00 for the current review. The expected impact of this finding is a reduction of approximately $1.5 million to Enbridge Gas's 2024 forecast depreciation expense.
3. Account 457.00: A life parameter of Iowa 40-R2.5 appears to be a better estimate for Account 457.00 for the current review. The expected impact of this finding is a reduction of approximately $0.4 million to Enbridge Gas's 2024 forecast depreciation expense.
4. Account 465.00: A life parameter of Iowa 70-R4 appears to be a better estimate for Account 465.00 for the current review. The expected impact of this finding is a reduction of approximately $7 million to Enbridge Gas's 2024 forecast depreciation expense.
5. Account 475.21: A life parameter of Iowa 61-R3 appear to be better estimates for Account 475.21 for the current review. The expected impact of this finding is a reduction of approximately $7 million to Enbridge Gas's 2024 forecast depreciation expense. However, a life parameter of Iowa 70-R3 better fits the experienced data, the operations interviews from 2016, and the lives adopted by Enbridge Gas's peers. This parameter would lead to a reduction of approximately $15 million. Of the two options, 70-R3 appears a better fit overall.
6. Account 475.30: A life parameter of Iowa 65-R3 appears to be a better estimate for Account 475.30 for the current review. The expected impact of this finding is a reduction of approximately $5 million to Enbridge Gas's 2024 forecast depreciation expense. However, a life parameter of Iowa 70-R4 better fits the operations interviews from 2016, and the lives adopted by Enbridge Gas's peers. This parameter would lead to a depreciation expense reduction of approximately $9 million. However, actuarial data was not analyzed for a Iowa 70-R4 and it is likely less robust than Iowa 65-R3 which was compared to Enbridge Gas's recorded experience.

6.0 CDNS CALCULATION METHODOLOGY

6.1 BACKGROUND ON NEGATIVE NET SALVAGE AND CDNS

Utility depreciation is intended to recover the service value of each group of assets over the life of the group. The service value comprises the original cost to purchase or install the asset, plus the cost to remove or decommission the asset at its end of life ("cost of removal"), less any amounts received for selling off the remaining pieces or scrap ("salvage"). The sum of cost of removal and salvage are typically termed "net salvage" and must be estimated during the life of the asset's service since they will not be known with certainty until the asset is retired and removed from service. Typically for utilities, net salvage is negative, reflecting the fact that it costs more to decommission and remove utility plant than can be secured by selling off the residual pieces (hence, the concept of "negative net salvage").

There are multiple ways a utility can recover negative net salvage from customers, and treat the balances recorded. This can encompass the following:

1) Balance to be collected - The estimate of the balance to be collected from customers during the life of an asset ties to estimates of the cost of removal and how those costs will be accounted for. If the costs will be applied to the asset being removed, then they are normally collected in some manner from the customer who used the asset. Many utilities however allocate the cost to remove utility assets as a capital cost of the next generation of assets being installed (when the removal is concurrent with a replacement asset being installed), and this lessens the amount of net salvage that must be collected from customers during the current generation of the assets. Enbridge Gas proposes to collect net salvage during the life of the asset, rather than the life of the replacement, which is understood to be consistent with both EGD and Union Gas.

2) When the amounts are collected - If net salvage is to be collected during an asset's life, then there are multiple ways to determine the dollar value to be ascribed to each year. The "traditional method" mimics depreciation expense – typically a straight-line method. Other approaches attempt to levelize for inflation or the cost of capital (e.g., using constant dollars). Finally, discounted liability approaches can be used, such as are applied in accounting for Asset Retirement Obligations ("ARO"s) which have the effect of accruing for salvage costs primarily very near the end of an asset's life. Enbridge Gas proposes to use a constant dollar approach, continuing the approach of EGD. Union Gas previously used the traditional method.

3) How the pre-collected funds are used in the period before the retirements occur - As the collection of net salvage amounts occurs prior to the incurrence of the cost to remove the asset, the use of the collected funds in the interim can vary. Typically, these funds are considered a simple offset to rate base (e.g., as a regulatory liability). However, externally invested funds can also be used, where the cash collected is invested in a defined account where it can earn a return and parties can be sure the funds are available for decommissioning. This is atypical for utility assets for securely franchised utilities who

operate as a going-concern, but has been used for very large potential future liabilities such as nuclear plants. Enbridge Gas proposes to retain the approach where funds are an offset to rate base.

With regard to #1, Enbridge Gas proposes to recover the costs during the entire life of the asset (rather than alternatives that may allocate salvage costs to the next generation of facilities to be installed on the same site), and for #3, Enbridge Gas proposes to treat the balances as an offset to the utility investment (rather than, for example, as a segregated investment fund holding the cash that has been collected).

With respect to #2, Enbridge Gas proposes that the allocation of net salvage to the periods during which the asset is being used should be calculated using a method known as Constant Dollar Net Salvage ("CDNS"). This is a continuation of the general approach of EGD prior to the current application. The basic premise of CDNS is that the total amount to be collected for future net salvage costs is determined, and that amount should be recovered equally across the years of service, measured in "constant dollars" rather than equally in nominal dollars. The values collected over the span of years that the asset is in service are such that the amount recovered from each successive year is somewhat larger in nominal terms than the nominal value recovered in the previous year.

The CDNS method is a refinement on what is often termed the "traditional method", which was previously used by Union Gas. Under this approach one estimates the dollars required at end-of-life, and divides this amount by the life, to come up with an equal annual nominal dollar value of accrual required. For example, under the traditional approach, an asset installed today that costs $1 million, amortized over 50 years would lead to an amortization expense of $20,000 per year for the life component before addition of net salvage. If that asset had an estimated negative net salvage percentage of -50%, that would mean that $500,000 in future dollars would be required (i.e., the dollars in effect 50 years from now). The negative net salvage accrual would occur over the same 50 years at $500,000 / 50 years = $10,000 per year. Under the traditional approach, the -50% estimate includes <u>both</u> the costs to remove <u>and</u> all estimates of inflation on those costs for 50 years.

The traditional method suffers from the fact that it entirely ignores the time value of money in the accrual. The $10,000 accrued in year one does not have the same impact on customers as the same $10,000 accrued in year 49. In addition, if the funds collected are on offset to rate base, the customers in year 49 not only pay a smaller real accrual, but also benefit from the earlier generation's investment in the balance offsetting rate base.

The intent of CDNS is that it corrects for this problem. The simplest version of CDNS would adjust the collection amount only for inflation, such as in the following example.

> Assume an asset that lasts 3 years, and with inflation equal to 2%. Assume the amount of net salvage needed at the end of 3 years is $300 (i.e., future dollars needed total $300, including the effects of inflation up to that time).
>
> In year one, the accrual would be a calculated value, while year two would be 102% of the year-one value, and year three would be 102% of the year-two value (i.e.,

104.04% of the year-one value). This would lead to equal real economic accruals each year.

The amount to be accrued would be 100% of the year-one value + 102% + 104.04%, or a total of 306.04% of the year-one value ($300 / 306.04% = $98.03).

The resulting accruals would therefore be as follows, in nominal dollars:

year 1	$98.03
year 2	$99.99
year 3	$101.99
total	$300.00

This approach results in annual accruals that are equal in real, constant dollar (i.e., inflation-adjusted) terms. The accruals are not equal in nominal dollar terms, reflecting that $98.03 in year one is equal to $101.99 in year 3, due to inflation. Note that the $300 was not the estimate of the cost to remove the asset today – it is the estimate of the nominal cost to remove the asset 3 years from now, so it already includes an estimate for inflation

The options for value used to discount the nominal dollar accruals (2% in the above example) are not limited to inflation. For example, in this case Enbridge Gas recommends that the nominal dollars be discounted based on the Credit Adjusted Risk Free (CARF) cost of capital (3.75%), such that the dollars collected in each year not only grow with inflation, but also grow to recognize that dollars collected in earlier years have a time-value-of-money adjustment included. The purpose of the adjustment was described by Mr. Kennedy as follows:[80]

> It also recognizes the fact that the company is putting in its pocket today $1.3 billion in dollars of the day that it has got quite potential to do other things with. It has the potential to use that money in its working capital to reduce its credit.
>
> It has the ability to use that money in a number of ways. It can invest it so it can grow.
>
> …
>
> And theoretically it uses that money in a manner that can either reach its credit matrix, it can do, you know, what it needs to do to invest in new capital and earn a return on that. So the company has that money in its pocket today.

The use of CDNS and the choice of a discount rate are effectively trade-offs between the accruals that are collected today from customers, and those that must occur in the future. The use of a higher discount rate means lower collections today, and higher collections in future. The simplest version of CDNS only discounts for inflation, and this approach ensures customers pay for net salvage on a straight-line real economic basis. Any discount rate higher than inflation is effectively crediting current customers for the time value of money, at the expense of future customers. This

[80] Final Transcript EB-2022-0200 TC4 March 27, 2023 page 32.

crediting can be justified to the extent that the early accruals or collections yield benefits to future customers. The benefits reflect the fact that accrual balances that arise early in the asset's life function benefit the future customers by being applied as an offset to future rate base. So long as the early collected funds are used as an offset to rate base, as is proposed by Enbridge Gas, then future customers will have a lower net rate base due to the contributions of the earlier customers, which will lead to lower future revenue requirements. Future customers may pay more in real terms for their salvage accruals, but their tolls for utility service are lower than they would have been because of all the funds put up by earlier generations of ratepayers acting as a credit against rate base.

Given the funds in this case are proposed to be used as an offset to rate base, there may be a stronger link to a discount rate tied to the effective returns these early investments will drive (i.e., setting the discount rate equal to the average return on rate base). However, this would be a much higher discount rate than EGD used in the past, which would lead to much lower accruals today as part of revenue requirements, which is illustrated in Table 7 of section 6.2.[81]

6.2 ISSUES WITH THE ENBRIDGE PROPOSAL

While CDNS is a well-founded methodology and is based on a sounder economic rationale than the more common traditional method of collecting net salvage, the details of the calculation by Concentric are problematic.

There are two issues with the Concentric calculation approach, as set out below.

To prepare their estimates, Concentric goes through two steps:

- First, Concentric calculates what is effectively a traditional salvage percentage for each account. This gives the estimate of the total future nominal net cost to remove the assets at the time the work is estimated to be completed. This is set out at section 7 of the Concentric report.[82]
- Second, Concentric turns the traditional salvage percentage into a CDNS percentage that is applied to each asset vintage.[83] This is done by inflating the original cost of the asset and the net salvage to what is purported to be a common base, calculating a new "Adjusted" Net Salvage Rate by vintage (by adding more inflation), discounting this estimate at the 3.75% rate, and applying this adjusted net salvage requirement (in total across all vintages) to the total original cost of the asset to come up with a single percentage to be used in determining the annual depreciation rates.

The two problems with this approach are as follows:

First, converting a traditional net salvage into a single flat percentage that is considered the CDNS percentage fails to reflect that CDNS accruals are designed to change with the vintage make-up of

[81] According to the Gannett Fleming report from June 2013, EB-2012-0459, Ex. D2, Tab 1, Schedule 1, page II-13, the EGD discount rate was equal to the Canadian AAA bond rate, or 2.38%.
[82] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, starting at page 155 of 451.
[83] Provided in EB-2022-0200, Exhibit I.4.5-IGUA-14 Attachment 1.

the account, and with time. A 60-year-old vintage should not be driving salvage at the same percentage rate as a new asset. Even if the intent is to get, say, 50% of the original value in the CDNS balance, as noted earlier in this section, this would be consistent with a smaller accrual for recent vintages and a larger accrual for older vintages closer to the end of life. CDNS is not appropriately modelled as an equal percentage for the entire class.

Second, the Concentric mathematics also inappropriately inflate what is already a future value estimate of removal cost to come up with a grossly overstated future removal cost, in coming up with the CDNS estimates. This can be seen in the following table extracted from the IRR responses:[84]

Table 5: CDNS Calculation by Concentric – Account 466.00

Account 466		
Cost of Removal Estimate	0.1	
Average Age of Retirements	23.56	24
Canada Long term Bond rate =	3.75	
Future Inflation Rate =	2	

Age	Vintage	Original Cost	R/L	Net Salvage Requirement	Adjusted Original Cost	Adjusted Net Salvage Rate	Future Salvage Requirement	Discounted Salvage Requirement			
51	1970	5,225,157.68		$ 522,515.77	22,043,633.96	0.02	$522,515.77	$522,515.77	6.8	1.6	4.21875
49	1972	6,694,440.19		$ 669,444.02	27,212,464.67	0.02	$669,444.02	$669,444.02	6.3	1.54	4.064935065
33	1988	3,767,639.42	3.06	$ 376,763.94	6,401,652.82	0.06	$400,300.25	$357,653.32	1.9	1.13	1.699115044
31	1990	29,064,577.31	3.76	$ 2,906,457.73	46,663,312.19	0.06	$3,131,126.81	$2,726,373.68	1.8	1.09	1.605504587
28	1993	4,270,487.16	5.16	$ 427,048.72	6,507,409.01	0.07	$472,992.56	$391,161.12	1.6	1.05	1.523809524
27	1994	6,598,676.71	5.73	$ 659,867.67	10,250,371.59	0.06	$739,155.54	$598,582.47	1.6	1.03	1.553398058
26	1995	11,074,974.21	6.35	$ 1,107,497.42	17,105,900.76	0.06	$1,255,896.40	$994,098.33	1.6	1.01	1.544554455
25	1996	41,359,020.59	7.00	$ 4,135,902.06	63,692,891.71	0.06	$4,750,851.42	$3,671,594.50	1.5	1	1.54
20	2001	2,237,627.66	10.66	$ 223,762.77	3,196,610.94	0.07	$276,353.93	$186,651.91	1.4	0.98	1.428571429
17	2004	1,108,053.64	13.14	$ 110,805.36	1,481,173.74	0.07	$143,736.49	$88,610.12	1.3	0.98	1.336734694
15	2006	6,339,908.87	14.91	$ 633,990.89	8,151,311.40	0.08	$851,748.89	$491,959.02	1.3	0.98	1.285714286
14	2007	81,039,112.91	15.82	$ 8,103,911.29	101,712,356.00	0.08	$11,085,349.64	$6,191,809.25	1.2	0.98	1.255102041
13	2008	80,181,083.22	16.75	$ 8,018,108.32	98,180,918.23	0.08	$11,171,842.29	$6,030,093.29	1.2	0.98	1.224489796
12	2009	1,978,036.78	17.69	$ 197,803.68	2,422,085.85	0.08	$280,783.38	$146,400.25	1.2	0.98	1.224489796
11	2010	5,756,021.34	18.64	$ 575,602.13	6,930,719.57	0.08	$832,586.95	$419,190.39	1.2	0.98	1.204081633
10	2011	17,185,515.58	19.60	$ 1,718,551.56	19,991,314.04	0.09	$2,533,529.31	$1,231,286.36	1.1	0.98	1.163265306
9	2012	33,368,237.21	20.58	$ 3,336,823.72	38,475,620.46	0.09	$5,015,622.00	$2,351,200.09	1.1	0.98	1.153061224
8	2013	1,949,552.75	21.55	$ 194,955.28	2,228,060.29	0.09	$298,723.02	$135,121.68	1.1	0.98	1.142857143
7	2014	6,525,504.74	22.54	$ 652,550.47	7,257,959.35	0.09	$1,019,675.49	$444,723.51	1.1	0.98	1.112244898
6	2015	203,461,376.38	23.53	$ 20,346,137.64	224,222,741.32	0.09	$32,422,314.91	$13,634,647.04	1.1	0.98	1.102040816
5	2016	153,100,505.79	24.52	$ 15,310,050.58	167,160,756.32	0.09	$24,880,140.99	$10,088,451.09	1.1	0.98	1.091836735
4	2017	235,646,157.74	25.51	$ 23,564,615.77	252,478,026.15	0.09	$39,052,671.16	$15,268,422.75	1.1	0.98	1.071428571
3	2018	2,388,189.10	26.51	$ 238,818.91	2,510,035.48	0.10	$403,700.48	$152,129.90	1	0.98	1.051020408
2	2019	620131.22	27.50	$ 62,013.12	639,114.83	0.10	$106,902.61	$38,843.24	1	0.98	1.030612245
1	2020	1,757,876.43	28.50	$ 175,787.64	1,793,751.46	0.10	$309,095.90	$108,251.08	1	0.98	1.020408163
0	2021	62,362,174.13	29.50	$ 6,236,217.41	62,362,174.13	0.10	$11,184,750.86	$3,775,523.74	1	0.98	1
		1,005,060,038.76		100,506,003.88	1,201,072,366.28		$153,811,811.06	$70,714,737.91			
				0.10	1.20		0.15	$0.07			

As shown in the above table, Account 466 uses a traditional net salvage estimate of 10% (reported as 0.1 under "Cost of Removal Estimate" at the top of the page). As a traditional net salvage estimate, this value should properly include all inflation between the date an asset is installed and the date it is taken down – in this case an average of 30 years (the account is an Iowa 30-R4, and column "R/L" indicates remaining life of the asset installed in each vintage). Looking at the most recent vintage (2021), Concentric takes the 10% estimate ($62.362 million of investment with an estimate cost of $6.236 million to remove 29.5 years from now) and further inflates the Future Salvage Estimate to $11.184 million. This inflation step is not needed – the traditional approach

[84] EB-2022-0200, Exhibit I.4.5-IGUA-14 Attachment 1, Account 466. Note this was refiled without changes in EB-2022-0200, Exhibit JT4.4, Attachment 1, page 10 of 18.

10% estimate already includes all inflation to the future date of removal[85]. Concentric also overly discounts this value. The result is an inappropriate mix of dollar vintages in the Concentric calculations.

To properly apply CDNS, Concentric should take the already inflated future value ($6.236 million for 2021 in Table 5) and divide by the sum of annual accruals that should make up the total removal cost over the life of the asset, as follows:

> 100% + (100% + 3.75%)^1 + (100% + 3.75%)^2 + … + (100% + 3.75%)^30
>
> This total yields 5682%.
>
> $6.236 million divided by 5682% yields a year-one accrual of $109,760. Since this is a year-one vintage, this is the appropriate accrual. In year two, the appropriate accrual for this vintage (assuming no retirements) will be $109,760 x 1.0375 which equals $113,876, etc. with the same escalation occurring for each of the next 30 years.
>
> Similarly, the calculated accrued depreciation for this vintage will total the sum of all accruals that should have happened to date for the assets of the vintage that remain in service as of the date of the calculation. For example, in year 3, the total accrued deprecation for net salvage on this complement of assets should be $109,760 + $113,876, or $223,636.

For vintages that have a longer average life due to being of advanced age, the calculation would be slightly extended. For example, the 33 year-old vintage from 1988 still has an expected remaining life of 3 years, meaning the sum shown above would continue through year 36 for the plant that remained in service from that vintage.

When this approach is repeated for each vintage in each asset class that has a net salvage estimate, the annual accrual (whole life) can be calculated and compared to the Concentric estimates, as follows:

[85] This wan confirmed in EB-2022-0200, Exhibit I.4.5-STAFF-176(a), as follows: "The traditional method has an embedded inflation component within the calculation, as the salvage percentage is calculated from dividing the actual cost of removal (net of gross salvage proceeds), which is expressed in the dollar value as at the time of the retirement transaction, by the original cost dollars which are expressed in the value of the dollar at the time of the original installation of the asset. <u>Therefore, the net salvage percentage has an embedded historic rate of inflation over the period from when the asset was originally installed to the year in which it was removed</u>."

Table 6: Estimate of Annual CDNS Accrual Compared to Concentric Estimate ($)

($) Account	Calculated CDNS	Concentric CDNS ELG	*difference*
452	407,970	257,459	*150,511*
453	1,052,073	1,043,285	*8,788*
455	277,120	313,450	*(36,330)*
456	1,119,329	1,052,399	*66,930*
457	508,012	304,347	*203,665*
462	181,863	168,224	*13,639*
463	18,215	12,410	*5,805*
464	2,983	2,988	*(5)*
465	6,062,772	5,809,203	*253,569*
466	2,478,357	2,407,980	*70,377*
467	1,645,595	1,544,429	*101,166*
473.01	4,441,562	4,023,042	*418,520*
473.02	23,466,911	22,305,952	*1,160,959*
475.21	28,717,183	27,193,689	*1,523,494*
475.3	23,151,821	23,125,032	*26,789*
477	1,326,276	2,401,727	*(1,075,451)*
Total	94,858,041 annual	91,965,617 annual	*2,892,424*

Table 6 above emphasizes that the use of the CDNS as proposed above calculates slightly higher net salvage accruals than proposed by Concentric, when using the ELG procedure. The table focuses on only the annual Whole Life accruals and do not take into account true-ups (the amortization of accumulated depreciation variances that occur over the remaining life of the assets, as discussed in Section 4).

It should be noted that the CDNS calculation above is not sensitive to the procedure used (ELG or ASL).[86] As a result, the same CDNS accrual of $94.858 million would be recommended by this approach under the ELG or the ASL procedure.

The approach taken by Concentric is sensitive to whether ELG or ASL is used. Under ELG (as shown above), Concentric's net salvage expense would be higher than under ASL. As a result, the impact

[86] This is because the CDNS calculation is always based on the ASL remaining life. See: Final Transcript EB-2022-0200 TC4 March 27, 2023 page 16.

of the revised CDNS calculation as compared to Concentric's ASL estimates would be even larger. Unfortunately, the Whole Life accruals for ASL were not provided, so the comparison above cannot be completed precisely for comparing the CDNS per this report to Concentric's ASL estimates, but it is expected that applying the above approach under a scenario where the Concentric ASL procedure is otherwise used would show a net salvage expense approximately $14 million higher than Concentric would calculate.[87]

Also note that Table 6 above only calculates the estimate of CDNS for this report based on the annual requirement ($94.858 million), it does not further consider the sufficiency or true-up of booked accrued depreciation amounts. This estimating of true-up for booked accumulated net salvage balances versus calculated balances is not possible without more detailed access to the Concentric models, which was not provided. However, it can be inferred that after correcting for this effect, the Concentric approach is leading to CDNS accrual estimates that are too low for a 3.75% cost of capital rate, particularly under an ASL procedure.

Finally, the selection of the discount rate is a very significant factor in calculating the CDNS accrual in any given year. For example, adjusting the discount rate can change the annual accrual across a wide range, from 0% (effectively the traditional approach) to 2% (constant real dollars, i.e., only levelized for inflation), 3.75% (CARF, as proposed) up to 5.87% (the full weighted average return on rate base) as illustrated in Table 7. While the effects on annual costs are significant, the principle against which the rate is selected is a policy question regarding trade-offs between existing customers and future customers. There is no further definitive technical insight to guide this decision. However, the approach that most directly recognizes the full value of the net salvage funds that will be collected from current ratepayers, which will be credited against the rate base in future rate cases, is the 5.87% discount rate.

[87] The ELG and ASL accruals for Remaining Life were provided by Concentric (i.e., inclusive of true-up), and suggest that ASL accruals are approximately $11 million lower than ELG accruals under Concentric's approach. As a result, the Concentric accruals to net salvage appear to be understated by approximately $2.892 million per year for their ELG calculations, and by potentially upwards of $14 million per year for their ASL calculations. [Supporting calculations for these values are provided in an Excel document filed concurrent with this submission]

Table 7: Annual CDNS Accrual Under Various Discount Rates ($)

	Calculated CDNS Annual Accrual ($) [1]			
	At 0% Discount Rate	At 2% Discount Rate	At 3.75% Discount Rate	At 5.87% Discount Rate
Total	160,755,441	122,221,765	94,858,041	69,963,017

Note:
1. Calculations provided in InterGroup Evidence Attachments 1 through 4.

6.3 FINDINGS

1. The use of CDNS retains consistency with the EGD practice in previous proceedings, and is therefore well suited to use in this proceeding. In addition, CDNS is a method that appropriately recognizes there is a time value of money, and a cost of capital to the funds being provided. Enbridge Gas's proposal to continue to use CDNS is well-supported.
2. While CDNS is an appropriate approach to accruing net salvage, Concentric's CDNS calculations are not accurate. The Concentric calculation of CDNS contains a procedural complication as illustrated in Exhibit I.4.5-IGUA-14 Attachment 1. While the Net Salvage requirement in column H of Exhibit I.4.5-IGUA-14 Attachment 1 is accurate, it is already in dollars-of-the-day for when the retirement will occur in the future. It is not necessary to further inflate these dollar values before discounting them to the current day, as is part of the Concentric calculations. Further, Concentric also applies an equal CDNS net salvage percentage to each vintage, which is not correct. The accruals rate for old vintages under CDNS are by definition higher than for earlier vintages.
3. Correction of the noted Concentric issues will likely lead to a higher required accrual for CDNS if retaining the same proposed Credit-Adjusted Risk Free ("CARF") discount rate. Once corrected, the annual net salvage expense increases by approximately $3-$14 million (depends on whether comparing to the Concentric ELG study or the ASL analysis).
4. To reflect the benefits of funds provided by earlier generations of customers, as an offset to rate base, the discount rate to be used may be better matched to the weighted average cost of capital financing rate base, rather than the 3.75% CARF rate. This would reduce the CDNS Net Salvage annual accrual by approximately $25 million.

7.0 NET SALVAGE PARAMETERS

Enbridge Gas has provided, as part of the Concentric Depreciation Study, an analysis of net salvage amounts and a proposal to change the net salvage accruals for a number of accounts.

As discussed above, the approach to developing CDNS net salvage rates proceeds from analyses performed by Concentric to first estimate the traditional net salvage parameter, and then convert the traditional parameter to a CDNS parameter. This section focuses on the development of the traditional net salvage parameters.

Concentric states that the net salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the natural gas industry, and comparisons of the service life and net salvage estimates from Concentric's studies of other gas utilities. [88]

Concentric has proposed the net salvage rates to form the basis for the CDNS calculations to several accounts as shown in Table 8.

Table 8: Concentric Proposed Traditional Net Salvage Parameters in the Current Depreciation Study[89]

Account	Description	Proposed Net Salvage Percent Under Traditional Method
452.00	Underground Storage Plant - Structures and Improvements	-15%
453.00	Underground Storage Plant - Wells	-50%
455.00	Underground Storage Plant - Field Lines	-15%
456.00	Underground Storage Plant - Compressor Equipment	-10%
457.00	Underground Storage Plant - Regulating and Measuring Equipment	-20%
462.00	Transmission Plant - Compressor Structures and Improvements	-10%
463.00	Transmission Plant - Measuring Regulating Structures and Improvements	-10%
464.00	Transmission Plant - Equipment	-10%
465.00	Transmission Plant - Mains	-25%
466.00	Transmission Plant - Compressor Equipment	-10%
467.00	Transmission Plant - Measuring and Regulating Equipment	-25%
473.01	Distribution Plant - Services - Metal	-50%
473.02	Distribution Plant - Services - Plastic	-50%
475.21	Distribution Plant - Mains - Coated and Wrapped	-80%
475.30	Distribution Plant - Mains - Plastic	-80%
477.00	Distribution Plant - Measuring and Regulating Equipment	-15%

[88] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 873 of 1382
[89] EB-2022-0200, Exhibit I.4.5-IGUA-14, Attachment 1.

Review of Enbridge Gas's evidence suggests that Concentric's proposal with respect to the net salvage rates is not well supported for several accounts discussed below. In particular, the findings raise concerns with the peer information used for these accounts; accuracy of the retirement data; and reasonableness of the proposed net salvage rates.

At the outset, it is important to note that the net salvage analysis is working with a very short record for many of the largest accounts, often only since 2010 or later. Also it is possible that the merging of the data from the two utilities has proven more problematic in the case of salvage, as the data alignment and quality is significantly less coherent than the capital asset data used to assess life. Examples are given of this effect in the following sections.

7.1 ACCOUNT 465.00 – MAINS

Concentric proposes to use a negative 25% net salvage estimate to form the basis for the CDNS calculations in respect of Account 465.00.[90] Currently, the approved net salvage is negative 15% for Union Gas and no net salvage rate for EGD.

Concentric states that that the historical net salvage activity in the account ranged from negative 985 percent to negative one percent when looking individually at each year[91] and that the three-year band ranges from negative six percent to negative 763 percent, while the five-year band has ranged from negative nine percent to negative 129 percent.[92] The full depth band indicates negative 83 percent.[93]

However, review of the retirement and cost of removal data raises some significant concerns. In particular, the net salvage analysis shows that the highest removal costs took place in 2019 ($4.7 million) and 2021 ($5.1 million). However, no asset retirement is shown for either 2019 or 2021. Enbridge Gas does not explain why there were such a high net salvage cost in 2019 and 2021 when no assets were retired.[94] Of the 11-year record used to assess this account, there are only notable retirement costs in three (2019, 2020,-2021), totalling approximately $15 million of the $17 million incurred since 2010. This large spending occurred at a time when minimal assets were actually being retired. Prior to this three-year period, the spending on net salvage in this account supported a negative 12% ratio.

When the misaligned 2019 and 2021 net salvage amounts are removed from the analysis, the cumulative band indicates negative 35 percent as compared to negative 83 percent stated by Concentric.

Further, Concentric states that Canadian peer comparison of approved net salvage values indicates a range from negative 20 percent to negative 30 percent, which is incorrect.[95] In particular, the peer review purports to show AltaGas at the highest negative net salvage rate of -30%.[96] However,

[90] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 875 of 1382
[91] Looking at a single year to determine a ratio between retirements and salvage is a highly inferior way to assess net salvage, since the spending to remove assets often occurs in a later year than the retirement of the asset.
[92] Ibid
[93] Ibid
[94] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3
[95] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 875 of 1382
[96] EB-2022-0200, Exhibit I.4.5-IGUA-26 Attachment 1

the approved net salvage rate for AltaGas for this account is -15%, not -30% as shown in the peer review.[97] Accordingly, the correct peer review range is from negative 15 percent to negative 20 percent.

Considering the concerns with the retirement and cost of removal record accuracy for this account and the peer utilities' net salvage levels, it appears more appropriate to maintain the currently approved Union rate of negative 15% form the basis of the CDNS calculations for Account 465.00, which is aligned with the current rates for the peer utilities reviewed. The expected impact of this finding is a reduction of approximately $2 million to Enbridge Gas's 2024 forecast depreciation expense.

7.2 ACCOUNT 466.00 – COMPRESSOR EQUIPMENT

Concentric proposes to use a negative 10% net salvage estimate to form the basis for the CDNS calculations in respect of Account 466.00.[98] Currently, the approved net salvage is negative five percent for Union Gas and no net salvage rate for EGD.

Concentric states that that the historical net salvage activity in the account ranged from positive 151 percent to negative 199 percent when looking individually at each year and that the three-year band ranges from negative 106 percent to positive 16 percent, while the five-year band has ranged from over 15 percent to negative 125 percent.[99] The cumulative band indicates negative 28 percent.[100]

However, review of the retirement and cost of removal data shows that highest removal costs took place in 2019-2021 with each year showing a cost of removal of $1.03 million to $1.04 million each year. However, no asset retirement is shown for any of 2019-2021 and there are limited asset retirements in 2015-2018. Enbridge Gas does not explain why there were such a high net salvage cost (of precisely the same dollar value) in 2019-2021 when no assets were retired.[101]

Absent the 2019-2021 net salvage amounts, the cumulative band indicates positive three percent as compared to negative 28 percent stated by Concentric. This positive three percent is closely aligned with the currently approved rates for peer utilities reviewed which Concentric notes indicate negative two percent.[102]

Considering the concerns with the retirement and cost of removal record accuracy for this account, as well as the peer utilities net salvage levels, it appears more appropriate to maintain the currently approved Union rate of negative 5% form the basis of the CDNS calculations for Account 466.00. Note that a negative 5% rate is higher than the current rates of negative 2% for the peer utilities reviewed. The expected impact of this finding is a reduction of approximately $1 million to Enbridge Gas's 2024 forecast depreciation expense.

[97] Alberta Utilities Commission Decision 24161-D03-2019, p. 23-24
[98] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 876 of 1382
[99] Ibid
[100] Ibid
[101] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3
[102] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 876 of 1382

7.3 ACCOUNT 467.00 – MEASURING AND REGULATING EQUIPMENT

Concentric proposes to use a negative 25% net salvage estimate to form the basis for the CDNS calculations in respect of Account 467.00.[103] Currently, the approved net salvage is negative 10 percent for Union Gas and no net salvage rate for EGD.

Concentric states that that the historical net salvage activity in the account ranged from negative three percent to over negative 7,000 percent when looking individually at each year and that the three-year band ranges from negative four percent to over negative 2,000 percent, while the five-year band has ranged from negative seven percent to negative 413 percent.[104] The cumulative band indicates negative 47 percent.[105]

With respect to the individual year net salvage percentages variation, note that the negative 7,000 percent quoted by Concentric is related to a single retirement of $10,000 in 2020, and a cost of removal of $730,973 in this same year.[106] While the cost of retirement in 2020 is only 0.1% of the cumulative retirement to 2021, the cost of removal amount is 22% of the cumulative cost of removal to 2021. Enbridge Gas does not explain the reasons why the 2020 cost of removal is so high to remove an asset worth only $10,000 (if this is the suggestion in the data), however this cost of removal seems likely to be related to a different asset retired in earlier years, in which case the negative 7,000 percent quoted by Concentric is inaccurate and not informative. Note that this account records significant spending in 2019-2021, but no significant asset retirements since 2013-2014.

Secondly, the net salvage analysis shows a cost of removal of $788,253 in 2021 (24% of the cumulative cost of removal to 2021) with no asset retirement reported in this year. Enbridge Gas does not explain why there was such a high net salvage cost in 2021 when no assets were retired.[107]

Absent the problematic 2021 net salvage amount, the cumulative band indicates negative 36 percent as compared to negative 47 percent.

Further, Concentric states that Canadian peer comparison of approved net salvage values indicates a range from negative seven percent to negative 75 percent, which is incorrect.[108] In particular, the peer review shows AltaGas at the highest negative net salvage rate of 75%.[109] However, the approved net salvage rate for AltaGas for this account is -35%, not -75% as shown in the peer review.[110] Other than AltaGas, the peer review shows only two utilities which have net salvage rates in this account – FortisBC at negative five percent and PNG at negative seven percent. Accordingly, the correct peer review range is from negative five percent to negative 35 percent.

[103] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 877 of 1382
[104] Ibid
[105] Ibid
[106] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3
[107] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3
[108] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 877 of 1382
[109] EB-2022-0200, Exhibit I.4.5-IGUA-26 Attachment 1
[110] Alberta Utilities Commission Decision 24161-D03-2019, p. 23-24

Considering the concerns with the retirement and cost of removal record accuracy for this account and the peer utilities net salvage levels, it appears more appropriate to maintain the currently approved Union rate of negative 10% form the basis of the CDNS calculations for Account 467.00. Note that a negative 10% rate is already higher than the current rates for two of the three peer utilities reviewed. The expected impact of this finding is a reduction of approximately $1 million to Enbridge Gas's 2024 forecast depreciation expense.

7.4 ACCOUNT 473.02 – SERVICES - PLASTIC

Concentric proposes to use a negative 50% net salvage estimate to form the basis for the CDNS calculations in respect of Account 473.02.[111] In the last public depreciation studies filed for EGD and Union Gas, the traditional net salvage rates for this account was negative 45% for EGD and negative 40% for Union Gas.[112]

Concentric states that the historical net salvage activity since 2010 in the account has a wide range from over negative 1,000 percent to over positive 1,000 percent when looking individually at each year and that the three-year band ranges from negative 51 percent to over negative 1,300 percent, while the five-year band has ranged from negative 49 percent to over negative 1,100 percent.[113] The cumulative band indicates negative 168 percent.[114]

Concentric states that Canadian peer comparison of approved net salvage values indicates a range from negative 60 percent to negative 125 percent and Concentric recommends that a negative 50 percent net salvage estimate be used to form the basis of the CDNS calculations for this account.[115]

Firstly, note that peer review includes only five utilities, of which the reported net salvage values for three utilities are indicated as "requested", as compared to approved parameters.[116] However, for Gazifere, which is included in the peer review, the referenced values appear to be from a 2008 depreciation study, from La Regie de L'Energie proceeding R-3724-2010.[117] Note that review of this depreciation study shows different net salvage rates for Gazifere than shown in the Concentric peer review. In particular, for Account 473, the requested net salvage rate was -115%, and not -125% as shown in Concentric's peer review.[118]

Further, of the remaining two utilities which show approved net salvage parameters, AltaGas shows an incorrect approved rate. The approved net salvage rate for AltaGas for this account is -50%, not -100% as shown in the peer review.[119]

[111] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 879 of 1382
[112] EB-2011-0354, Exhibit D2, Tab 2, Schedule 1, EGD Depreciation Study; EB-2011-0210, Exhibit D2, Union Gas Depreciation Study, Statement E
[113] Ibid
[114] Ibid
[115] Ibid
[116] EB-2022-0200, Exhibit I.4.5-IGUA-26 Attachment 1
[117] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 1297 of 1382
[118] Gazifere 2008 Depreciation Study, page III-4; available at http://www.regie-energie.qc.ca/audiences/3724-10/Demande_3724-10/B-1_GI-3Doc1_3724_4mars10.pdf
[119] Alberta Utilities Commission Decision 24161-D03-2019, p. 23-24

Further, the review of the historical retirement and net salvage information for this account identified that the net salvage amounts for this account simply repeats the same amounts as shown for Account 473.01 (Distribution Services – Metal) all the way to 2020, inclusive, but a much lower regular retirement amounts resulting in very high net salvage percentages quoted by Concentric.[120]

When requested to reconcile this data inconsistency in the technical conference, Concentric provided the following response in the undertaking:[121]

> In the preparation of the net salvage analysis, Concentric considered the accounts 473.01 and 473.02 together as the cost of removal information was not available for the accounts separately. When the depreciation study was filed, the cost of removal information was included in the net salvage analysis for both accounts. This was done because it was not possible to separate the two values. In the interest of transparency, Concentric has attached a net salvage analysis with the dollars of retirement together for both accounts as Attachment 1.

The combined net salvage analysis for accounts 473.01 and 473.02 provided by Concentric in Attachment 1 to the undertaking in EB-2022-0200, Exhibit JT4.6 shows that the cumulative band is negative 55 percent. Note however, that Concentric indicated the cumulative band of negative 69 percent in recommending a negative 50 percent rate for Account 473.01 – it was not based on a negative 55 percent retirement rate analysis.

Further, while Concentric states that the cost of removal information was not available for accounts 473.01 and 473.02 separately, this contradicts previous depreciation studies filed for Union Gas, which show separate net salvage analysis and proposal for each account.[122] It is also important to note that Union Gas assets make up approximately 37% of the total assets in Account 473.02.

As such, the net salvage analysis for Account 473.02 does not appear to be based on accurate historical information and should not be relied upon in determining the traditional net salvage parameter for this account.

Also note that historical regular retirements to the end of 2021 are shown at $96.7 million, as compared to the account gross plant in-service balance of $4,458.9 million (only 2% of the gross plant in service).[123] At the Enbridge Gas proposed net salvage rate (50% traditional converted to CDNS adjusted 26%), the account will accrue $28.3 million annually, more than has been spent on salvage activities on this account in any year.[124]

Considering lack of reliable data specific for Account 473.02 for net salvage analysis, it would be appropriate to use the currently approved rate of negative 40% for Union Gas to form the basis for the CDNS calculations until a proper retirement record is established for this account. Use of a

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[120] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3
[121] EB-2022-0200, Exhibit JT4.6
[122] EB-2011-0210, Exhibit D2, Union Gas Depreciation Study, Statement E.
[123] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3 and Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 879 of 1382
[124] EB-2022-0200, Exhibit I.4.5-IGUA-25 Attachment 3; Account 473.02 balance column (a) multiplied by column (e).

negative 40% net salvage estimate to form the basis for the CDNS calculations is expected to reduce Enbridge Gas 2024 depreciation expenses by about $5 million.

7.5 ACCOUNT 475.21 – MAINS – COATED AND WRAPPED

In respect of Account 475.21 Concentric proposes to use a negative 80% net salvage estimate to form the basis for the CDNS calculations.[125]

Concentric states that that the historical net salvage activity since 2010 in the account has a wide range from negative 21 percent to negative 366 percent when looking individually at each year and that the three-year band ranges from negative 51 percent to negative 174 percent, while the five-year band has ranged from negative 34 percent to negative 53 percent.[126] Concentric states that the cumulative band indicates negative 80 percent.[127]

Firstly, note that the cumulative band actually indicates negative 52 percent net salvage ratio for the account and not 80 percent as stated by Concentric.[128] Further, even the 52 percent net salvage ratio is calculated incorrectly, as it omits the year 2010 data from the summation of the retirements and net salvage amounts. When full data range shown in the depreciation study (2010 to 2021) is included in the summation, the correct cumulative band indicates negative 46 percent as compared to negative 80 percent stated by Concentric.

Secondly, Concentric states that its peer review shows peer utilities net salvage rates range from negative 25 percent to negative 90 percent.[129]

Note that peer review includes five utilities, of which the reported net salvage values for three utilities are indicated as "requested", as compared to approved parameters, and the only peer utility which Concentric's peer review table shows at -90% is Gazifere. However, review of Gazifere's 2008 depreciation study shows the requested rate of -70% for this account, and not -90% as shown in Concentric's peer review.[130]

Further, of the remaining two utilities which show approved net salvage parameters, AltaGas shows incorrect approved rate. The approved net salvage rate for AltaGas for this account is -25%, not -75% as shown in the peer review.[131]

Accordingly, of the reviewed five peer utilities, three (FortisBC, AltaGas, and PNG) show a net salvage rate of -25% and two utilities (ATCO Gas and Gazifere) show a net salvage rate of -70% - all below the level proposed by Enbridge Gas.

The net salvage accrual at the proposed approved net salvage rate based of -80%, adjusted for CDNS calculation as provided by Concentric (-42%), is $40.1 million per year for the 2024 forecast

[125] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 880 of 1382
[126] Ibid
[127] Ibid
[128] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 1025 of 1382
[129] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 880 of 1382
[130] Gazifere 2008 Depreciation Study, page III-4; available at http://www.regie-energie.qc.ca/audiences/3724-10/Demande_3724-10/B-1_GI-3Doc1_3724_4mars10.pdf
[131] Alberta Utilities Commission Decision 24161-D03-2019, p. 23-24

plant balance. [132] By comparison, since the start of the account retirement history in 2010 the highest ever net salvage historical expense recorded was $15.0 million in 2021, with majority of the expenses in the range of $2-$5 million.[133]

Based on this evidence, there is no basis to use a negative 80% net salvage estimate to form the basis for the CDNS calculation in this review. A negative 40% net salvage estimate is more appropriate for Account 475.21, which is consistent with the actual retirement experience for this account. Note that a negative 40% traditional net salvage rate would still be significantly higher than the approved rates for majority of the peer utilities reviewed, which are at negative 25%. The expected impact of this finding is a reduction of approximately $40 million to Enbridge Gas's 2024 forecast depreciation expense.

7.6 ACCOUNT 475.30 – MAINS – PLASTIC

Enbridge Gas proposes to use a negative 80% net salvage estimate to form the basis for the CDNS calculations for Account 475.30.[134] This is the same rate as proposed for Account 475.21.

Concentric states that that the historical net salvage activity since 2010 in the account has a wide range from negative five percent to negative 703 percent when looking individually at each year and that the three-year band ranges from negative 12 percent to negative 334 percent, while the five-year band has ranged from negative 12 percent to negative 252 percent with the cumulative band indicating negative 23 percent.[135]

However, similar to Account 473.21, the cumulative band of negative 23 percent net salvage ratio is calculated incorrectly, as it omits year 2010 data from the summation of the retirements and net salvage amounts. When full data range shown in the depreciation study (2010 to 2021) is included in the summation, the correct cumulative band indicates negative 20 percent.

Concentric also states that its peer review shows net salvage rates from negative 25 percent to negative 90 percent.[136] However, as explained in section 7.5 of this evidence:

- the only peer utility which Concentric's peer review table claims is at -90% is Gazifere, which actually shows the requested rate of -70% for this account, and not -90% as shown in Concentric's peer review.[137]
- AltaGas also shows incorrect approved rate. The approved net salvage rate for AltaGas for this account is -25%, not -75% as shown in the peer review.[138]

[132] EB-2022-0200, Exhibit I.4.5-IGUA-25 Attachment 3; Account 475.21 balance column (a) multiplied by column (e).
[133] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3
[134] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 881 of 1382.
[135] Ibid
[136] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, Depreciation Study, pdf page 866 of 1368.
[137] Gazifere 2008 Depreciation Study, page III-4; available at http://www.regie-energie.qc.ca/audiences/3724-10/Demande_3724-10/B-1_GI-3Doc1_3724_4mars10.pdf
[138] Alberta Utilities Commission Decision 24161-D03-2019, p. 23-24.

Accordingly, of the reviewed five peer utilities, three (FortisBC, AltaGas, and PNG) show a net salvage rate of -25% and two utilities (ATCO Gas and Gazifere) show a net salvage rate of -70% - all below the level proposed by Enbridge Gas.

The net salvage accrual at the proposed approved net salvage rate based off -80%, adjusted for CDNS calculation as provided by Concentric (-38%), is $30.0 million per year for the 2024 forecast plant balance.[139] By comparison, since the start of the account retirement history in 2010 the highest ever net salvage historical expense recorded was $9.9 million in 2016, with the last five years net salvage expense ranging from $0.3 million to $6.7 million.[140]

Based on this evidence, using a negative 80% net salvage estimate to form the basis for the CDNS calculation in this review is too aggressive, inconsistent with the actual retirement experience and is not aligned with peer utility rates. A negative 25% net salvage estimate is more appropriate as a basis for CDNS calculation for Account 475.30, which is consistent with the actual retirement experience for this account and is similar to the approved rates for majority of the peer utilities reviewed, which are at negative 25%. The expected impact of this finding is a reduction of approximately $20 million to Enbridge Gas's 2024 forecast depreciation expense

7.7 FINDINGS

1. Account 465.00: It is appropriate to maintain the currently approved Union rate of negative 15% to form the basis of the CDNS calculations for Account 465.00, which is aligned with the current rates for the peer utilities reviewed. The expected impact of this finding is a reduction of approximately $2 million compared to Enbridge Gas's 2024 forecast depreciation expense.
2. Account 466.00: It is appropriate to maintain the currently approved Union rate of negative 5% to form the basis of the CDNS calculations for Account 466.00, which is higher than the current rates negative 2% for the peer utilities reviewed. The expected impact of this finding is a reduction of approximately $1 million compared to Enbridge Gas's 2024 forecast depreciation expense.
3. Account 467.00: It is appropriate to maintain the currently approved Union rate of negative 10% to form the basis of the CDNS calculations for Account 467.00, which is higher than the current rates for two of the three peer utilities reviewed. The expected impact of this finding is a reduction of approximately $1 million compared to Enbridge Gas's 2024 forecast depreciation expense.
4. Account 473.02: It is appropriate to use an estimate of negative 40% net salvage estimate to form the basis for the CDNS calculations until a proper retirement record is established for Account 473.02. The expected impact of this finding is a reduction of about $5 million compared to Enbridge Gas's 2024 forecast depreciation expense.

[139] EB-2022-0200, Exhibit I.4.5-IGUA-25 Attachment 3; Account 475.21 balance column (a) multiplied by column (e).
[140] EB-2022-0200, Exhibit I.4.5-STAFF-171 Attachment 3.

5. Account 475.21: A negative 40% net salvage estimate is appropriate as a basis for CDNS calculation for Account 475.21, which is consistent with the actual retirement experience for this account (still significantly higher than most of the reviewed peer utilities' rate of negative 25%). The expected impact of this finding is a reduction of approximately $40 million compared to Enbridge Gas's 2024 forecast depreciation expense.
6. Account 475.30: A negative 25% net salvage estimate is appropriate as a basis for CDNS calculation for Account 475.30, which is consistent with the actual retirement experience for this account and aligned with majority of the reviewed peer utilities' approved rate of negative 25%. The expected impact of this finding is a reduction of approximately $20 million compared to Enbridge Gas's 2024 forecast depreciation expense.

8.0 ENERGY TRANSITION

In Appendix 1 of the 2021 depreciation report[141], Concentric provides an analysis linked to a 2050 economic planning horizon. Concentric is not recommending adoption of a 2050 economic planning horizon at this time, but has provided calculations to indicate the impact if a 2050 truncation date were to be adopted.

Concentric notes the following[142]:

> While future retirements that are caused by physical forces of retirement such as wear and tear and changes in technology of the assets will continue, it is reasonable to anticipate that the utilization of large groups of assets may change due to the implementation of climate change legislation. Consistent with the reduction in the utilization of the assets, it could be assumed that large scale retirement of assets may be required in the periods between now and 2050. Common depreciation practice is to deal with the anticipated large scale retirements through the introduction of an economic planning horizon within the depreciation rate calculations. However, at this time the future impacts of the relevant climate change legislation have not been sufficiently studied, nor have specific programs been put into place that would provide indications of the changes in the utilization levels.

A review of Appendix 1 indicates Concentric has prepared an updated depreciation study using the same apparent parameters as the main study, but with introduction of an effective truncation at the year 2050. In short, all assets are assumed to continue to perform exactly as otherwise projected, but in the event that they are not ot retired by 2050, all remaining assets will retire at that date. A new schedule of straight-line depreciation is calculated for each asset group to ensure straight-line recovery of all investments in the available time period to 2050.

Appendix 1 indicates no issue of concern with respect to the mathematics. If projections were that all assets would retire at 2050, and the intent was that the investor utility would be given a full opportunity to recover all capital costs, then the included calculations would achieve this result, within the accuracy of estimation inherent in any depreciation study.

At the same time, it must be noted that the mathematics as presented implicitly incorporated a long list of assumptions that may or may not represent the best estimates or policy intent with regard to energy transition, including the following:

- There is an assumption of no residual operating value of the assets. For example, at 2050 there is no assumed use of any utility assets for distribution of Renewable Natural Gas ("RNG") or any form of hydrogen.
- The calculations make an assumption of no excess net positive salvage given the truncation. For example, for assets being retired at that date for energy transition reasons,

[141] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 316 of 451.
[142] EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 19 of 451.

but which would remain in good physical condition (e.g., compressors, structures, tools, equipment, etc.) there is an assumption that they would have no greater salvage value than a similar asset retirement of an entirely worn-out or end-of-life unit. For a number of Enbridge Gas's assets, this is not a reasonable assumption, as only partially used equipment could well have a positive salvage value (e.g., compression equipment).

- The underlying assumption in the calculations is that the utility operator is entitled to a complete recovery of their invested capital, which has been invested in now stranded utility assets. This may or may not be an assumption in accord with the policy regarding energy transition in the province.
- The estimates are predicated on the fact that there is no rolling system retirement or transition. For example, there are no retirements occurring in any way other than the normal fashion in 2049, but then a full retirement in 2050 with no further value beyond that date. This is likely not a scenario that is credible for a major energy system in the province.

For these reasons, the estimates are at best indicative of impacts of adopting a 2050 truncation date, but do not fully and properly account for multiple complicated and highly speculative conditions that would accompany any energy transition. For this reason, it is appropriate that Concentric elected to include the estimates but not recommend their use in setting depreciation parameters for this proceeding.

Findings

The 2050 Economic Planning Horizon scenario prepared by Concentric is mathematically sound but fails to address multiple issues and unknowns that are implicitly intertwined with the analysis. The rates derived are not appropriate for use in setting depreciation expense at this time.

APPENDIX A: Resumes

PATRICK BOWMAN

Principal Consultant
Bowman Economic Consulting Inc.

161 Rue Hebert
Winnipeg, Manitoba
R2H 0A5 CANADA

AREAS OF EXPERIENCE:

- Utility Regulation and Rates, including Depreciation
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), Prescott College (Arizona), 1994

PROFESSIONAL EXPERIENCE:

Bowman Economic Consulting Inc., Winnipeg, Manitoba

2020 – current – Principal Consultant

Conduct consulting assignments as Principal Consultant of new economic consulting firm, focused on utility regulation.

Member, Society of Depreciation Professionals

InterGroup Consultants Ltd., Winnipeg, Manitoba
1998 – 2022 – Research Analyst/Consultant/Principal/Senior Associate

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in eight Canadian provinces and territories and international. Prepared evidence and expert testimony for regulatory hearings. Assisted in utility capital and operations planning to assess impact on rates and long-term rate stability.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

Government of Northwest Territories, Yellowknife, Northwest Territories
1996 – 1998 Land Use Policy Analyst

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	Northwest Territories Power Corporation (NTPC)	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000 - 2002	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001 - 2002	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony on all areas of Revenue Requirement, including Depreciation	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2006 - 2008	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008 - 2009	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation, Support to Legal Counsel	BCUC	BC Municipal Electrical Utilities	2009 - 2010	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009 - 2010	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010 - 2011	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
Newfoundland Hydro	Depreciation Methodology	Analysis, Support of Expert Witness, Advisor to Legal Counsel	NLPUB	Newfoundland Industrial Customers	2012	No
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2015	Yes

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council
Newfoundland Hydro	2017 General Rate Application	Pre-Filed Testimony and Negotiated Settlement, including Depreciation	NLPUB	Newfoundland Industrial Customers	2017 - 2018	No - Negotiated Settlement
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on Depreciation matters	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016 - 2017	No - Negotiated Settlement
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence on Depreciation matters	AUC	UCA	2016 - 2017	No - Written Process only
Manitoba Hydro	2017/18 and 2018/19 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2017 - 2018	Yes
ATCO Pipelines	2017-18 GRA Review and Vary	Analysis and Case Preparation for SCADA Depreciation	AUC	UCA	2017 - 2018	No
ATCO Pipelines	2019-20 General Rate Application	Analysis, Preparation of Intervenor Evidence including Depreciation	AUC	UCA	2018	No - Written Process only
Altalink Management Limited	2019-21 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters, Preparation of Intervenor Evidence and Expert Testimony	AUC	UCA	2018	Yes
Newfoundland Hydro	Cost of Service Methodology	Analysis and Case Preparation	NLPUB	Newfoundland Industrial Customers	2018	No
ATCO Pipelines	Keephills Transmission Facilities Assessment	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - 2019	No - Written Process only
Manitoba Hydro	2019/20 Electric Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2019	Yes
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2019 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2019	Presentation to Council
ATCO Electric Distribution	Distribution Depreciation	Analysis and Case Preparation	AUC	UCA	2019	No
AltaGas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
ATCO Gas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
Nalcor Energy, Newfoundland and Labrador Hydro	Muskrat Falls Rate Mitigation Hearing	Analysis, Preparation of Intervenor Evidence and Expert Testimony. Included Depreciation Rate Mitigation Options	NLPUB	Newfoundland Industrial Customers	2019	Yes
Kinder Morgan Canada (Jet Fuel) Inc.	2019 Tariff Filing Application	Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories and draft issues for evidence	BCUC	Vancouver Airport Fuel Facilities Corporation (VAFFC)	2019 - 2021	No
BC Hydro	Fiscal 2020 to 2021 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence	BCUC	Association of Major Power Consumers of BC (AMPCBC)	2019-2020	Yes
FortisAlberta	Town of Fort Macleod RCN-D Valuation Application	Analysis, Preparation of Intervenor Evidence on Depreciation and Valuation matters	AUC	UCA	2019-2020	No - Written Process only
Manitoba Public Insurance	2021 General Rate Application	Review insurer evidence, draft IRs and prepare evidence on regulatory and rate setting principles	MPUB	Taxicab Coalition	2020	Yes
ATCO Gas	2020 Cost of Service and Phase II Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2020	No - Written Process only
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2021 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2020	Presentation to Council
ATCO Pipelines	Acquisition of Pioneer Pipeline	Review evidence, draft IRs. Evidence	AUC	UCA	2020	No - Written Process only
ATCO Electric Transmission	2020-2022 GTA Depreciation Expert	Analysis and support of intervenor evidence	AUC	UCA	2020-2021	No - Written Process only
Direct Energy Regulated Services (DERS)	2020-2022 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2021	No - Negotiated Settlement
AltaLink Management Ltd.	2022-23 General Tariff Application, and Review and Variance Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process, Preparation of Intervenor Evidence on Depreciation Matters.	AUC	UCA	2021-2022	No - Written Process only
Manitoba Hydro	2021 Interim Rate Application, Review and Variance Application	Analysis, Support of Intervenor position	MPUB	MIPUG	2021	No
NTPC	2022/23 General Rate Application, Interim Rate Application, and Taltson Hydro Major Project Permit Application	Analysis, support preparation of utility filing, responses to IRs on matters of revenue requirement, rate design and depreciation	NWT PUB	NTPC	2022	No
Nelson Hydro	Cost of Service and Rate Design Proceeding and 2022 Revenue Requirements proceeding	Support to Nelson Hydro on preparation of Cost of Service model and specified studies	BCUC	Nelson Hydro	2020-2022	No
Epcor Distribution and Transmission Inc (EDTI)	EDTI Phase II (Cost of Service and Rate Design) Distribution Tariff AUC proceeding 27018	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2022	No - Written Process only
Newfoundland Hydro	Electrification, Conservation and Demand Management	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2021-2022	No - Written Process only
Centra Gas Manitoba	2021 Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence	MPUB	Industrial Gas Users of Manitoba (IGU)	2021-2022	No - Written Process only
BC Hydro	Fiscal 2022 to 2025 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence, primarily focused on depreciation	BCUC	AMPCBC	2022	Yes
DERS	2023 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2023	No - Negotiated Settlement and written process
EDTI	2023-2025 Transmission Facility Owner Revenue Requirement	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement
ENMAX Power Corporation (EPC)	2023-2025 Transmission General Tariff Application	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2024	No - Negotiated Settlement and written process
BC Hydro	2021 Intergrated Resource Plan	Analysis, Preparation of Intervenor Evidence	BCUC	AMPCBC	2023	Pending
Enbridge Gas Inc (EGI)	2024 Rebasing	Analysis, Preparation of Intervenor Evidence	Ontario Energy Board (OEB)	OEB Staff	2023	Pending

InterGroup

CONSULTANTS

HAYITBAY MAHMUDOV

PRINCIPAL AND CONSULTANT

AREAS OF EXPERIENCE:

- Utility Regulation, including Revenue Requirement, Depreciation, Cost of Service and Rate Design
- Economic/Financial Analysis, including Cost-Benefit Analysis and Business Valuation
- Strategic Planning and Assessment
- Public Policy Advisory

EDUCATION:

- Master of Arts (Economics), University of Manitoba, 2003
- Bachelor of Science (Economics), Andijan Institute of Engineering and Economics, 2000

PROFESSIONAL EXPERIENCE:

INTERGROUP CONSULTANTS LTD., WINNIPEG, MANITOBA

2009 – Present – Research Consultant/Consultant/Principal

Strategic Planning and Project Management – Resource Planning and Development

For Qulliq Energy Corporation (QEC) (2014-2021): Project Principal and lead consultant in developing specialized pricing strategy for renewable energy suppliers to sell renewable electricity to QEC as non-utility generators, taking into consideration the findings and recommendations of the Utility Rates Review Council (URRC) in its October 6, 2020 report; Assisted QEC in developing Independent Power Produce (IPP) program policy and the pricing structure. Assisted QEC in the review of the proposed IPP program by the regulator (Utility Rates Review Council); Analyzed plant capacity requirements for Rankin Inlet to serve a major industrial customer planning operations in the community neighbourhood. Analyzed plant capacity requirements for Cambridge Bay and options to serve a new major customer (Canadian High Arctic Research Station). Worked on capital project planning manual development for QEC and organized a training session to QEC's staff.

For Yukon Energy Corporation (YEC) (2009-2011): Worked on a 20-year YEC Resource Planning update for the load forecast and capacity/supply options using a Power System Model, incorporating expected mining development and renewable generation options to meet energy demands in the Territory.

For Northwest Territories Power Corporation (NTPC) (2012-Present): In response to the 2014 extreme low water situation arising on North Slave system, assisted in development of Low Water Response Plan, which sets out action items to address the extreme low water conditions. The document addressed required actions and responsibilities for hydrology status, load forecasts, system dispatch, capital planning, financial planning, regulatory reporting and stakeholder communications. For purposes of the 2014 application for exception to minimum water levels to the NWT Water Board, calculated water turnover rates for the long-term period using a liner regression approach, which were used in determining environmental effects of a drawdown in the lake reservoir. Prepared a business case and major project permit application, including required firm capacity analysis, for the Inuvik LNG Facility project, which allows to displace approximately 40% of diesel usage in the Town with natural gas for power generation. Analysed capacity requirements in the North Slave system to meet energy demands of NICO mining development by adding LNG-based power generation facility to the system. The analysis also reviewed safe and cost-effective LNG supply options and financing options. Analyzed the need for and feasibility of interconnecting North and South Slave transmission systems to utilize surplus power generation capacity in the South Slave to serve major industrial customers in the North Slave system.

For Government of Northwest Territories (2015-2016): For the North Slave Resiliency Study developed, in collaboration with the Manitoba Hydro International, studied and evaluated a range of infrastructure options that can be developed to improve the resiliency of the North Slave system to periodic droughts. Analyzed the electricity rate structure options in order to avoid rate shocks when future droughts occur. The report was presented to the GNWT in April of 2016. The GNWT accepted the recommendations in the report and proposed resources to address hydrology monitoring in the 2016-17 Territorial budget.

Utility and Municipal Regulation

For Northwest Territories Power Corporation (NTPC) (2009-Present): Assisted with the preparation of numerous regulatory filings and applications, including technical analysis related to operations and maintenance expenses, return on utility equity, cost of service, and rate/tariff design. Prepared responses to Information Requests from intervenors (related to sales and generation forecasting, rate design, rate impacts, capital planning, revenue requirement, etc.). Provided technical support to NTPC's depreciation consultants (Gannett Fleming and Concentric Advisors) in their preparation of depreciation study for NTPC for 2012/14 and 2016/19 General Rate Applications. Managed projects on development and submission of 2012/14 and 2016/19 Phase I and Phase II General Rate Applications. Provided hearing support at the public hearings before the Northwest Territories Public Utilities Board for the 2012/14 General Rate Application and Technical Workshop for the 2016/19 General Rate Application. Expert testimony before the Public Utilities Board of NWT on electricity costing and rates related to NTPC's 2016/19 GRA. Major capital projects implementation support related to performing economic analysis, preparation and submission of project permit applications for regulatory approvals. Provided hearing support to a panel of experts at the Mackenzie Valley Land and Water Board public hearing for the regulatory review of NTPC's Bluefish Lake Dam Replacement project. Following the hearing, the Board and relevant Canadian federal agencies approved the capital project implementation. Prepare NTPC's medium and long-term load forecast and calculate firm capacity requirements to assist NTPC in plant capacity planning to meet energy demands by community.

For Qulliq Energy Corporation (QEC) (2009-Present): Managed the development and submission of 2010/11, 2014/15, and 2018/19 Phase I and Phase II General Rate Applications. Provided support in the GRA review process by the regulatory council. Provide support and perform analysis related to QEC's operating budget forecast, load forecast, capital structure, return on equity, amortization expense, cost of service and rate design. Provided technical support to QEC's depreciation consultants (Gannett Fleming and Concentric Advisors) in their preparation of depreciation study for QEC for 2010/11 and 2018/19 General Rate Applications. Provide public awareness support for the rate applications. Prepare QEC's medium and long-term load forecast and calculate firm capacity requirements to assist QEC in plant capacity planning to meet energy demands by community. Prepare semi-annual Fuel Stabilization

Fund rider applications and review support.

For Town of Drumheller (2022): Developed a water and sewer utility rate model that allows systematic calculation of appropriate water and sewer utility rates to charge to ratepayers. Developed rate design reflecting fair cost recovery by customer category and ensuring financial sustainability of the utilities.

For North Salt Spring Waterworks District (2022): Reviewed and recommended the parcel tax structure more fairly reflecting the cost of providing service to different types of customers while maintaining a consistent revenue stream to the District to cover the current and future capital projects.

For Yukon Energy Corporation (YEC) (2009-2011): Provided analytical support during the 2008/2009 Phase I and Phase II General Rate Applications, including responses to Information Requests from intervenors. Performed cost-of-service study analysis, rate design and rate impact analyses. Prepared regulatory year-end financial statement reporting and GRA update filings for submission to the Yukon Energy Board. Performed forecast cash flow analysis to determine financing needs for the capital projects.

For Jamaica Public Service Company Ltd. (JPS) (2018-2021): Coordinated activities related to submission of the 2018 Annual Adjustment Filing under the Performance Based Regulation (PBR) framework with the regulator; led the overall planning and preparation of the submission and coordination with JPS staff as required to complete, review and document the required technical analysis for the submission. Coordinated and provided lead support in the development of JPS's 2019-2024 Rate Case Submission which included drafting of major chapters, technical analysis and support on 5-year business plan and revenue requirement, capital plan, load forecast, tariff design, and stakeholder engagement. Assisted JPS in the 2019-2024 Rate Case review process by the regulator and financial planning under PBR framework, including Annual Adjustment Filing support.

For the Office of the Utilities Consumer Advocate of Alberta (UCA) (2019-Present): Providing support in review and analysis related to depreciation matters, including preparation of arguments and expert evidences in the AltaGas 2018 Depreciation Application (Proceeding 24161), ATCO Gas 2018 Depreciation Application (Proceeding 24188), and ATCO Electric 2018 Depreciation Application (Proceeding 24195). Expert support in the review and analysis, including drafting information requests and issues summary, submission of testimony in the FortisAlberta RCN-D Valuation Application for the Electric Distribution System Assets purchase from the Town of Fort Macleod (Proceeding 23972). Expert support in depreciation matters review of the ATCO Pipelines 2019-2020 GRA Compliance Filing (Proceeding 24817). Provided written testimony on the Depreciation Study and proposed depreciation parameters in the ATCO Electric Transmission 2020-2022 GTA (Proceeding 24964) before Alberta Utilities Commission. Expert support in the review and mediation process, including negotiated settlement analysis, in DERS 2020-2022 DRT and RRT Application (Proceeding 26207). Expert support in the review and mediation process; analysis and submission of testimony in Altalink Management Ltd. 2022-2023 GTA (Proceeding 26509).

Economic/Financial Analysis

For Northwest Territories Power Corporation (NTPC) (2009-Present): Develop business cases for NTPC's capital projects as part of regulatory requirements. The business cases include substantiation of a public need for the project; technical and financial analysis of options, including lifecycle costs and scenarios for reasonable sensitivities; analysis of rate impacts to customers; and complete discussion of risks and mitigation strategies related to the project and recommended option. Participated in NTPC's successful negotiations with a contractor on risk-sharing basis alliance model contract for the Bluefish Lake Dam Replacement project. Prepared distribution system assets estimate and revenue requirement estimate for valuation purposes of the electrical utility providing electricity service to the Town of Hay

River under the franchise agreement. The assignment was performed in order to assist NTPC and the Town in negotiations with the utility to determine purchase price of the utility.

For Qulliq Energy Corporation (QEC) (2009-Present): Major capital projects implementation support related to performing economic analysis, preparation and submission of applications for regulatory approvals.

For City of Swift Current (2013-2014): Assisted the City of Swift Current with an assessment of valuations related to possible rationalization of the electrical franchise/service areas within the city boundaries of Swift Current between the City and the Saskatchewan Power Corporation. Work included preparing a long-term economic forecast for the utility for the purposes of a valuation of the asset base. The economic forecast and valuation approach focused on a staged analysis, including a baseline financial forecast focusing on utility cash- flow and dividends, with reasonable estimates of future capital spending and rate levels.

For Government of Northwest Territories (2013-2020): Performed economic analysis of potential renewable energy projects in the remote diesel communities of the Northwest Territories, including solar, wind, and LNG power generation in order to determine subsidy support required for their implementation. Provided technical support in cost-benefit analysis for potential Transmission line extension from Northwest Territories to Saskatchewan, including sensitivities analysis and rate impacts under different project funding scenarios (2013).

Performed project evaluation (financial and regulatory impacts) of the proposed Fort Providence Transmission Line (2019) and What Ti Transmission Line (2020) constructions.

Public Policy Advisory

For Qulliq Energy Corporation (QEC) (2009-Present): Organize regulatory sessions for QEC's senior management to familiarize them with the regulatory process and policy requirements. Assisted QEC with developing a Net Metering Program policy and guidelines to promote alternative renewable energy generation in Nunavut.

For Government of Northwest Territories (2010-2014): Assisted in the review of electricity regulation, rates and subsidy programs in the NWT, resulting in a report Creating A Brighter Future in 2010. Findings of the report allowed the GNWT to redesign the existing rate structure in the NWT to move from community-specific to a levelized zone-based rates structure. Supported the GNWT in preparation of the materials for the 2012 Energy Charrette, which resulted in the release of a 3-year Energy Action Plan for the NWT in 2013. Supported the GNWT in preparation of the materials for the 2014 Energy Charrette, which proposed alternative energy solutions to reduce the cost and environmental impact of energy generation in the NWT.

For Northwest Territories Power Corporation (2013–2014): Assisted in designing the Net Metering program for the NWT, which promotes customer-owned renewable energy generation (wind and solar) in the NWT and achieve the GNWT Solar Energy Initiative objectives. The program was approved by the NWT Public Utilities Board in 2014.

For Gwich'in Council International (2016-2018): Lead consultant for the study estimating utility and social costs of diesel fuel use in power generation related to GHG emissions and other criteria pollutants. The study focuses on developing a plan for indigenous people of the Canadian North to take action to secure alternative energy sources and reduce current reliance on fossil fuel. Lead consultant on study by Gwich'in Tribal Council funded by INAC, with participation of GNWT and others, on fossil fuel use and costs (and options to reduce this use) for power generation, heating and transportation in Inuvik region communities.

MINISTRY OF FINANCE, TASHKENT, UZBEKISTAN

2005 – 2008 Lead Economist

Member of the Unit for reforming Public Finance Management system of Uzbekistan and introduction of treasury execution of State budget. [Successful implementation of the reform led to official establishment of Ministry of Finance Treasury by the President's decree in February 2007]. Liaised with the World Bank, Asian Development Bank, IMF, and EU Commission and worked on financial, organizational and advisory issues in relation to reforming PFM system of Uzbekistan. Represented Ministry of Finance in the negotiations with the World Bank, ADB and EU. Drafted, as a member of the task force, regulations on transition mechanism to treasury execution of State budget in Uzbekistan and organized training for budget organizations on the new treasury system. Developed, as a member of the task force, the new Budget Classification System, consistent with the international standards, for Uzbekistan [Approved in 2008]. Developed, as a member of the taskforce, functional modules for Treasury Software (Financial Management Information System) to be developed and fully implemented nationwide in 2011 in Uzbekistan. Analyzed results of pilot implementation of treasury execution of State budget in selected regions of Uzbekistan, and prepared proposals on further steps of reforming Public Finance Management system of Uzbekistan. Worked with the World Bank, IMF, ADB and EU experts in order to establish the internal control and audit framework in the Ministry of Finance Treasury [Approved in 2008].

WESTMINSTER INTERNATIONAL UNIVERSITY, TASHKENT, UZBEKISTAN

2006 – 2008 Lecturer/Module Reader

Taught courses in Advanced Microeconomics and International Trade.

MINISTRY OF FINANCE, TASHKENT, UZBEKISTAN

2003 – 2005 Research Associate

Conducted quantitative analysis and econometric modelling of different fiscal policy scenarios for Uzbekistan. Designed and implemented econometric models for forecasting annual and long-term State budget revenues. Conducted analysis of the impacts of demographic, economic and other factors on government spending (such as health care and pension funding) in order to identify expenditure risks and their mitigation measures. Drafted, as a member of the task force, the Law on Funded Pension System of Uzbekistan [Approved by the Parliament in December 2004 and became effective from January 2005]. Conducted analysis of tax policy (direct taxation) and tax compliance, and prepared policy proposals to the Ministry of Finance on changes to tax policy and fiscal planning.

Hayitbay Mahmudov - Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year
Northwest Territories Power Corporation (NTPC)	2010 Rate Rebalancing Application	Analysis and assistance with preparation of application, Revised cost-of-service study runs, Rate design scenarios development.	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2010
NTPC	Bluefish Dam Replacement Project	Technical support; hearing support to a panel of experts at the public hearing.	Mackenzie Valley Land and Water Board	NTPC	2011
Qulliq Energy Corporation (QEC)	2010/11 Phase I General Rate Application	Analysis and Coordination; Lead consultant for preparation of application, including load forecast, depreciation forecast, rate base and revenue requirement; Analysis and assistance in the Council Information Requirement responses preparation.	Utility Rates Review Council (URRC)	QEC	2011
Qulliq Energy Corporation (QEC)	2010/11 Phase II General Rate Application	Analysis and Coordination; Lead consultant for preparation of application, including COS study and rate design; Analysis and assistance in the Council Information Requirement responses preparation.	URRC	QEC	2011
NTPC	2012/13 and 2013/14 Phase I General Rate Application	Analysis; Assistance in preparation of application and company evidence on revenue requirement, including depreciation expense forecast; Analysis and assistance in the Board/interveners Information Requirement responses preparation; Review/critique of intervener evidences.	NWTPUB	NTPC	2012
NTPC	2012/13 and 2013/14 Phase I GRA Compliance Filing	Lead consultant in preparation of the compliance filing, and information requirement responses to the interveners; Assist in the review/critique of interveners arguments; Assist in preparation of company's reply argument.	NWTPUB	NTPC	2013
Qulliq Energy Corporation (QEC)	2014/15 Phase I General Rate Application	Analysis; Lead consultant for preparation of application; Analysis and assistance in the Council Information Requirement responses preparation.	URRC	QEC	2014
NTPC	2012/13 and 2013/14 Phase II General Rate Application	Lead consultant on cost of service study and rate design; Assistance in preparation of company evidence on cost of service study and rate design; Analysis and assistance in the Board/interveners Information Requirement responses preparation; Review/critique of intervener evidences.	NWTPUB	NTPC	2015
NTPC	2016/19 Phase I General Rate Application and Technical Workshop	Lead consultant on revenue requirement, including load forecast, rate base and depreciaiton expense matters; Assistance in preparation of application and company evidence on revenue requirement; Analysis and assistance in the Board/interveners Information Requirement responses preparation; Review/critique of intervener evidences.	NWTPUB	NTPC	2016-2017
NTPC	2016/19 Phase II General Rate Application	Expert testimony; Lead consultant on cost of service study and rate design; Assistance in preparation of application and company evidence on COS study and rate design; Analysis and assistance in the Board/interveners Information Requirement responses preparation; Review/critique of intervener evidences.	NWTPUB	NTPC	2017
Qulliq Energy Corporation (QEC)	2018/19 Phase I and II General Rate Application	Analysis and Coordination; Lead consultant for preparation of application, including COS study and rate design; Analysis and assistance in the Council Information Requirement responses preparation.	URRC	QEC	2018
AltaGas	2018 Depreciation Application	Review and analysis of the depreciaiton application; identify and summarize the applciation issues; draft information requests; assist legal counsel in drafting arguments/reply arguments; support in expert evidence preparation/drafting.	Alberta Utilities Commission (AUC)	UCA	2019
ATCO Electric	2018 Depreciation Application	Review and analysis of the depreciaiton application; identify and summarize the applciation issues; draft information requests; assist legal counsel in drafting arguments/reply arguments; support in expert evidence preparation/drafting.	AUC	UCA	2019
ATCO Gas	2018 Depreciation Application	Review and analysis of the depreciaiton application; identify and summarize the applciation issues; draft information requests; assist legal counsel in drafting arguments/reply arguments; support in expert evidence preparation/drafting.	AUC	UCA	2019
FortisAlberta	Town of Fort Macleod RCN-D Valuation Application	Review and analysis of the RCN-D application; identify and summarize the application issues; submit expert testimony; assist legal counsel in drafting arguments/reply arguments.	AUC	UCA	2019-2020
ATCO Electric Transmission	2020-2022 General Tariff Application	Review and analysis of the depreciaiton study and proposed parameters; identify and summarize issues; draft information requests; submit expert testimony; assist legal counsel in drafting argument/reply argument.	AUC	UCA	2020
Direct Energy Regulated Services (DERS)	2020-2022 DRT and RRT Application	Expert support in the review and mediation process, including negotiated settlement analysis.	AUC	UCA	2021
Altalink Management Ltd. (AML)	2022-2023 General Tariff Application	Review and analysis of the proposed parameters; expert support in the review and mediation process; identify and summarize issues; draft information requests; submit expert testimony; assist legal counsel in drafting arguments/reply arguments.	AUC	UCA	2021
NTPC	2022-23 General Rate Application	Analysis, support preparation of utility filing, responses to IRs on matters of revenue requirement, rate design and depreciation	NWTPUB	NTPC	2022
QEC	2022-23 General Rate Application	Analysis and Coordination; lead preparation of application, including COS study and rate design; responses to IRs on matters of revenue requirement, COS study and rate design.	URRC	QEC	2022
EPCOR Distrubution & Transmission Inc. (EDTI)	2023-2025 Transmission Tariff Application	Review and analysis of the proposed parameters; draft information requests; prepare and submit evidence; Negotiated settlement	AUC	UCA	2023
DERS	2023 DRT and RRT Application	Analysis, review of the application; prepare and submit expert evidence; assist legal counsel in drafting argument/reply argument	AUC	UCA	2023
ENMAX Power Corporation (EPC)	2023-2025 Transmission General Tariff Application	Review and analysis of the proposed parameters; draft information requests; prepare and submit evidence; Negotiated settlement	AUC	UCA	2023

InterGroup

CONSULTANTS

300-259 Portage Avenue
Winnipeg, MB R3B 2A9
www.intergroup.ca