JTBrowne
Consulting

Maritime Electric Company, Limited

Energy Cost Adjustment Mechanism

June 1, 2020

Costing &
Regulatory Consulting

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Phone: 416-251-3204
Email: john.browne@bell.net
2045 Lakeshore Blvd. W. #809
Toronto, Ontario M8V 2Z6

INTRODUCTION

On September 27, 2019; the Island Regulatory and Appeals Commission (Commission) issued its Order UE 19-08 dealing with a rate application by Maritime Electric Company, Limited (MECL). In this order, the Commission stated that it had concerns with MECL's Energy Cost Adjustment Mechanism (ECAM), and as a result, it stated:

> *… the Commission requires MECL to undertake a thorough and comprehensive review of the ECAM as it currently exists, including the expenses and accounts that are currently collected through the ECAM, and the practice of deferring a portion of energy supply costs for collection from future ratepayers.*[1]

To assist in its review, MECL has asked me as a CPA, CA and economist with experience in addressing regulatory issues[2] to provide an opinion on its ECAM. In particular, the Company asked me to review its ECAM as proposed in MECL's "Maritime Electric Company, Limited; Comprehensive Review of the Energy Cost Adjustment Mechanism; June 1, 2020" (MECL Report) and provide an opinion as to whether it is consistent with established regulatory principles and practices.

In developing my opinion, I have relied on information about MECL, the ECAM and the costs included in the ECAM that was provided to me by MECL. I was not asked to verify this information and did not undertake the work necessary to provide a professional opinion on the validity of the information.

The next section of this report provides a summary of my understanding of the proposed ECAM. This is followed by sections that discuss its consistency with established regulatory principles and established regulatory practice. The last section sets out my opinion.

As set out in the Opinion section, based on the discussion in this report, the ECAM proposed in the MECL Report is consistent with established regulatory principles and practice.

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[1] Commission; Order UE 19-08; September 27, 2019; para. 160.

[2] A copy of my resume has been attached as Appendix JTBC-1.

ENERGY COST ADJUSTMENT MECHANISM

The ECAM is a mechanism that provides MECL the opportunity to recover the actual amounts of certain specific costs related to the supply of energy: no more, and no less. These costs consist mostly of amounts paid to third parties for energy and capacity, fuel used to generate energy at MECL facilities and maintenance costs for the Government-owned facilities associated with the Maritime Interconnection.

ELECTRICITY SUPPLY

Almost all the energy MECL sells to its customers is acquired from third parties:

- it has a contractual entitlement to capacity and energy from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau");
- it has agreements for the purchase of capacity and system energy from New Brunswick Energy Marketing delivered via four submarine cables leased from the Province of Prince Edward Island;
- it has agreements with the PEI Energy Corporation to purchase all the energy produced by certain wind farms with a capacity of 92.5 MW; and
- it purchases a minor amount of other renewable energy from third parties.

In addition, MECL maintains 130 MW of on-Island generating capacity. However, it usually has the highest incremental cost and as a result is rarely used. Table 1 sets out the amount of energy acquired from each source in 2019 and 2018.

Table 1

MECL ENERGY SUPPLY SOURCES	2019	2018
Point Lepreau	15.9%	16.0%
New Brunswick Energy Marketing	62.1%	61.4%
Renewable Energy	21.9%	22.4%
Third Party	99.9%	99.8%
MECL (Gross)	0.1%	0.2%
	100.0%	100.0%

As described in the MECL Report, the third-party energy is provided under long term contracts. Although the contracts set out the pricing for energy, the average cost per kWh can vary. For example:

- There can be penalties where actual energy required and purchased differs from the estimated amount.
- Each source has a different cost. As a result, changes in the availability of energy from each source and / or the demand for energy may change the relative amounts from each source, and therefore the average cost per kWh.

For example, in 2019 MECL's average cost of energy covered by the ECAM[3] was $0.09169 per kWh, compared to a budget of $0.09152. This difference represented an increase from budget of 0.19% and 1.21% of pre-tax income. However, in 2018 the actual cost per kWh was $0.09290 compared to a budget of $0.09363. This represented a decrease from budget of 0.78% and 5.03% of pre-tax income.

[3] As it existed in 2019.

RORA

Combined with MECL's Rate of Return Adjustments (RORA) account, the variability in amounts paid to third parties for energy supplies can negatively impact its expected return on equity.

To the extent that earnings in any year exceed MECL's allowed rate of return on equity, the difference is credited to the RORA account. The balance is then returned to customers as directed by the Commission. Although excess earnings are returned to customers, deficiencies are not recovered.

Differences between the actual and estimated amounts paid to third parties for energy supplies can result in either excess or deficient earnings. With the RORA account, the possibility of excess earnings offsetting the possibility of deficient earnings will not be available. As a result, there is at least the possibility that over time MECL will not have an opportunity to earn its allowed rate of return.

CRITERIA FOR ECAM RELATED ACCOUNTS

As described in the MECL Report, the Company has reviewed its accounts related to the supply of energy and included in the ECAM those accounts (ECAM Related Accounts) that meet two criteria:

- The account and changes in the costs included therein are largely outside the control of the Utility; and
- The potential variance from forecast, individually or in aggregate, may have a significant or material impact on customer rates or the Company's earnings in a particular year.

In considering the second condition, the company has taken a long-term perspective. The ECAM is not a temporary measure and therefore the Company did not limit its view to next rate setting period.

Using the accounts proposed in the MECL Report, the amount of ECAM costs in 2020 is estimated to be $128,717,684. This represents 56.2% of estimated revenues and over 6 times estimated pre-tax income.

CALCULATION

Base rates reflect the estimated amounts for the ECAM accounts (ECAM Costs). At the end of each month, differences between the estimated and actual ECAM Costs are debited or credited to the ECAM account. The balance in the ECAM account at the end of each year (i.e., December 31) is then recovered from customers, or returned to them,

through a rate rider. The rate rider recovers the balance over a twelve-month period beginning on March 1st of the following year. March 1st is also the date that MECL's base rates are reset. In particular:

- MECL calculates the amount per kWh for the estimated ECAM Costs that go into the determination of base rates.
- Each month, it calculates the actual amount per kWh that is charged to the ECAM Related Accounts.
- The difference is multiplied by the actual sales and then debited or credited to the ECAM account.
- The amount of the rate rider billed to customers each month is credited to the ECAM account.
- The balance in the ECAM account at the end of each year is divided by the estimated kWh sales in the 12-month period beginning the following March 1st.
- Beginning on March 1st, the above amount is multiplied by actual sales for each customer and is added (or subtracted) to their monthly bill for 12 months.

In years between rate hearings, the rate rider will still be reset on March 1st to recover the balance in the ECAM account at the end of the previous year. However, MECL will continue to report on variances between forecast and actual costs throughout the preceding year so that the Commission has the opportunity to review the variances prior to the automatic rate rider reset.

REGULATORY PRINCIPLES

The primary regulatory principle is that rates must be just and reasonable – where "just and reasonable" considers the legitimate interests of both customers and the regulated entity. Unfortunately, "just and reasonable" tends to be a vague concept and other regulatory principles help to establish what is "just and reasonable" in a particular situation. In the case of the ECAM, the relevant principles are the cost of service standard, intergenerational equity, and rate stability and predictability.[4]

COST OF SERVICE STANDARD

In establishing just and reasonable, the most significant principle is the cost of service standard. Under this standard, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

As discussed in Appendix 2, the importance of this principle has been recognized by the Supreme Court of Canada:

> *... a key principle in Canadian regulatory law is that a regulated utility must have the opportunity to recover its operating and capital costs through rates ...* [5]

The cost of service does not require that a regulated entity be guaranteed a fair return, only that it has an opportunity to earn it. In most cases, rates are set prospectively, based on estimated future costs. If the entity over-recovers, it normally keeps the excess; if it under-recovers, it bears the deficiency.

The opportunity to earn a fair return implies that the possibilities of under and over-earning are offsetting. Roughly speaking, this means that a regulated utility should expect, on average, to earn a fair rate of return.[6]

MECL's ECAM is not only consistent with the cost of service standard but helps to achieve the requirements of this standard.

For the ECAM Related Accounts, differences between the estimated costs used in setting rates and the actual costs are deferred. The deferred amounts are then recovered from /

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[4] These principles are discussed in more detail in Appendix 2 - Regulatory Principles.

[5] ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission); 2015; SCC 45; para. 61. [ATCO v. AUC]

[6] Using more technical language, allowed rates should provide an expected rate of return equal to the fair rate of return, where the expected rate of return is equal to the average of the possible rates of return weighted by the probability of their occurrence.

returned to customers through a rate rider. The end result is that MECL receives an opportunity to recover the actual ECAM Costs – no more, no less.

Without the ECAM and the RORA, MECL's realized rate of return on equity would tend to vary from its allowed rate – being both higher and lower. Over time, it would be expected that the over and under earnings would tend to be offsetting. However, with the RORA, earnings above the allowed rate of return on equity would be returned to customers while deficiencies would be borne by the utility and its investors. As a result, over time, MECL would tend to earn less than its allowed rate of return. By deferring differences between estimated and actual ECAM Costs, MECL has a better opportunity to recover its costs and earn a fair return as required by the cost of service standard.

INTERGENERATIONAL EQUITY

Under the principle of intergenerational equity, customers in each period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to customers in another period. This principle is consistent with setting just and reasonable rates within each period.

The ECAM is inconsistent with the principle of intergenerational equity. Differences between the estimated and actual cost of providing service in one period are reflected in the rates charged to customers of another.

As discussed in the next section, there are advantages associated with deferring amounts that are largely outside the control of a regulated entity so that it has an opportunity to recover the actual amount of a cost, rather than an estimate – no more and no less. Appendix 3 provides several examples where it at least appears that Canadian regulators have concluded that these advantages outweigh the deviation from the principle of intergenerational equity in setting just and reasonable rates.

Where amounts are deferred, they should be recovered from, or returned to customers as soon as is reasonable from the perspective of setting just and reasonable rates. Changes in customers and their relative usage increases over time. Therefore, the sooner deferred amounts are reflected in rates, the less the concerns over intergenerational equity; and the longer amounts are deferred, the greater the justification required.

With the ECAM, differences between estimated and actual costs build up over a 12-month period and are recovered within the following 14-months (i.e., 12-months after a two-month period)[7]. Customers and their relative usage are unlikely to change

[7] The actual amounts collected from customers, or returned to customers under the ECAM rate rider are debited or credited to the ECAM account. However, differences between the actual and estimated amounts are assumed to be insignificant.

significantly from one year to the next. Therefore, the ECAM does not represent a significant breach of the principle of intergenerational equity.

RATE STABILITY AND PREDICTABILITY

The principle of rate stability and predictability requires that rates remain stable and predictable – at least to the extent practical. It may, therefore, justify smoothing out changes in rates to avoid sharp rate increases or temporary fluctuations.

This principle recognizes that it is usually easier for ratepayers to deal with gradual and predictable rate changes.

Shortening the period over which costs are deferred under the ECAM would be more consistent with the principle of intergenerational equity; however, it would require more frequent changes in rates (including the rate rider). Shortening the period in which the ECAM balance was amortized and recognized in rates, such as over one month, would also be more consistent with the principle of intergenerational equity, since it would result in an earlier recovery or return of the ECAM balance; however, it would tend to increase rate instability, since the rate rider would be reflected in only certain months and would have a larger impact on rates.

Deferring amounts over 12-months, and then amortizing the balance over 12-months (after a two-month period), is a reasonable compromise between the principle of intergenerational equity and the principle of rate stability and predictability.

CONCLUSION

MECL's proposed ECAM, including the criteria for including accounts in the ECAM, is consistent with established regulatory principles. Moreover, with the RORA, it will help ensure that MECL has an opportunity to recover its costs of providing regulated service (including a fair return) – no more, and no less, as required by the cost of service standard..

The ECAM does breach the principle of intergenerational equity. However, it does not represent a significant breach and can be justified by the benefits it provides to customers and MECL.

REGULATORY PRACTICE

The ECAM is a variance deferral account that helps deal with uncertainty associated with energy costs that are largely outside MECL's control.

NORMAL PRACTICE

Regulated rates are normally set prospectively based on estimated costs (including a fair return) and estimated demand. The regulated entity charges the allowed rates and keeps the resulting earnings. Since actual costs and demand may vary from the estimated amounts, realized earnings may provide more or less than a fair return.

With realized returns based on actual costs, there is an incentive for the regulated entity to manage its costs efficiently. If a regulated entity could pass on any differences between estimated and actual costs, this incentive would be lost. However, where costs are outside the control of a regulated entity, the entity lacks the ability to manage the costs and any incentive to do so will have no effect.

DEFERRAL ACCOUNTS

There are situations where there is material uncertainty as to amounts that should go into the determination of rates. These amounts are usually costs, but might also include revenues, gains, or losses[8]. To deal with the uncertainty, regulators may exclude the amounts from consideration in setting current rates; defer the amounts when they are incurred; and include the actual amounts in determining future rates once the actual amounts are known.

Deferral accounts have been widely used by the regulators of Canadian utilities. For example, in a 2016 decision dealing with Newfoundland and Labrador Hydro, the Newfoundland & Labrador Board of Commissioners of Public Utilities stated:

> *In appropriate circumstances deferral accounts are sound regulatory tools to address earnings volatility associated with certain costs outside of the utility's control. In the Board's view deferral accounts can contribute to a stable and predictable regulatory environment to the benefit of both the utility and its customers. A financially strong utility which is not unduly burdened by significant costs outside of its control will have*

[8] For simplicity, only costs will be considered in the remainder of this discussion.

> *access to necessary financing at reasonable costs and will be in the best position to provide safe and adequate reliable service at the lowest possible rates.*[9]

With a deferral account, a regulated entity still has an opportunity to recover its costs of providing service and only one opportunity. However, instead of an opportunity to recover the estimated amount of a cost, it has an opportunity to recover the actual amount.

Deferred amounts are usually limited to amounts that are largely outside the control of the regulated entity and which could have a material impact on earnings.

- Setting rates based on estimated costs provides an incentive for the regulated entity to manage the costs since differences between the actual and estimated amounts will be reflected in its earnings. However, where a cost is largely outside the control of the entity, there is limited opportunity (if any) to manage the cost.

- If the deferred amount does not have the potential to have a material impact on earnings, whether it is deferred or not will not be significant.

The main problem with deferral accounts is that they are inconsistent with the principle of intergenerational equity. They result in costs being recovered through rates in a period other than the one for which the costs were incurred.

VARIANCE DEFERRALS

Variance deferrals are a common form of deferral accounts. With these deferrals:

- An estimate of the cost is included in determining rates.

- Differences between the actual and estimated amounts are deferred and included in a variance account.

- The balance in the variance account is subsequently included in the determination of future rates.

The end result is that the regulated entity has an opportunity to recover the actual amount of the cost, and only the actual amount.

The advantage of a variance deferral is that current rates reflect an estimate of the cost and only the difference between the actual and estimated cost is deferred. As a result, since at least part of the cost is included in the determination of rates in the period for

[9] Newfoundland & Labrador Board of Commissioners of Public Utilities; Order No. P.U. 49(2016); December 1, 2016; pg. 115.

which the costs were incurred, such accounts are more aligned with the principle of intergenerational equity.

Canadian regulators have approved a number of variance accounts that are similar to the ECAM. They often defer differences between the actual and estimated cost of the commodity that a utility sells (i.e., electricity or gas), or at least a significant portion of the cost of that commodity (e.g. fuel costs). As stated by the Newfoundland & Labrador Board of Commissioners of Public Utilities:

> *The approval of supply related cost deferral and recovery mechanisms is common practice in regulatory jurisdictions across Canada. ...*[10]

Appendix 3 provides several other examples. In these cases, the deferred costs relate to amounts paid to a third party and are largely outside the control of the regulated entity.

BENEFITS

Deferral accounts, including variance accounts, can provide several possible advantages:

- They reduce the risk to the regulated entity and therefore tend to reduce the fair rate of return that the entity should be given an opportunity to recover and the interest rates it is required to pay.

- They reduce the possibility of significant losses that could jeopardize the regulated entity's financial viability. This could make it difficult to raise the capital necessary to finance regulated operations, or even jeopardize the continued existence of the regulated entity.

- They reduce the possibility that the regulated entity may recover from customers significantly more than the cost of providing service.[11]

- They tend to reduce the time, effort and associated cost spent on supporting and arguing over the estimated amounts covered by the deferral account. This is because the regulated entity will have an opportunity to recover the actual cost, and only the actual cost, regardless of the estimate used in setting rates.[12]

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[10] Newfoundland & Labrador Board of Commissioners of Public Utilities; Order No. P.U. 49(2016); December 1, 2016; pg. 115.

[11] With the RORA, this is not a concern with MECL.

[12] Identifying the best estimate is usually still a concern for the regulator, the regulated entity, and the entity's customers. However, the future adjustment to actual amounts reduces the potential impact on the entity and its customers.

- In some cases, such deferrals are necessary if the regulated entity is to have an opportunity to recover its costs of providing service. This could occur where the possibility of an unusual cost was not considered in setting rates e.g., a significant increase in costs due to storm damage. It would also occur where the cost can vary and the entity must bear the risk of any underestimate, while being required to return any overestimate.

To mitigate the impact on intergenerational equity, the deferred amounts should be recognized in rates as soon as is reasonably practical. This increases the probability that the customers who pay for the related costs are the same as those for whom the costs were incurred.

RECOVERY OF DEFERRED AMOUNTS

In recovering (or returning) deferred amounts to customers (i.e., amortizing the deferral), regulators often consider (at least implicitly) two regulatory principles: intergenerational equity and the principle of rate stability. Consistent with the former, the deferred amounts should be reflected in rates as soon as is reasonable so that the customers who pay for the costs will be the same as those for whom the costs were incurred. However, the shorter the period over which a deferral is amortized, the larger the impact on rates and the larger the potentially negative impact on rate stability and predictability.

For variance accounts dealing with energy supply costs; deferral and amortization of the deferral frequently occurs within a period of two years. As noted in Appendix 3, there are examples where the amortization of deferred amounts is updated quarterly, semi-annually, or annually, although the amortization is often based on a 12-month period. For example, in a recent decision, the Ontario Energy Board (OEB) discussed the Quarterly Rate Adjustment Mechanism (QRAM) for Enbridge Gas

> *The QRAM is intended to strike a balance between ensuring that consumers are receiving appropriate price signals which reflect natural gas market prices, and protecting the interest of consumers that purchase their gas from the distributor by reducing, to some extent, the volatility in the price of natural gas. Natural gas commodity prices charged by Enbridge Gas are based on:*
>
> - *A market price forecast for the commodity over the next 12 months.*
> - *A true-up between actual and forecast commodity prices for prior periods as actual costs are passed on to customers without a mark-up. By design, the*

> *QRAM includes smoothing of price volatility by spreading this difference over a 12-month period.*[13]

Where rates are changed between rate hearings, they are often subject to regulatory review. In some cases, the change is approved on an interim basis and is subject to review at a future hearing.

CONCLUSION

MECL's proposed ECAM, including the criteria for including accounts in the ECAM, is consistent with established regulatory practice.

The ECAM is a variance account that collects the difference between the estimated and actual amount of supply related costs that are largely outside the control of the Company. The deferred amounts are subsequently amortized and reflected in future rates. Such accounts are often used by the regulators of Canadian utilities.

Under the ECAM, the deferred amounts are collected and amortized within a period of approximately 2 years (i.e., 2 years and two months). This is consistent with Canadian utility practice.

[13] OEB; Decision and Interim Rate Order EB-2019-0273; December 19, 2019; pg. 3.

OPINION

Based on the discussion in the previous sections, the ECAM proposed in the MECL Report, including the criteria for including accounts in the ECAM, is consistent with established regulatory principles and practice. Moreover, with MECL's RORA account, the ECAM helps to achieve the requirements of the cost of service standard: i.e., provide MECL an opportunity to recover its costs of providing regulated service including a fair return.

RESUME - JOHN T. BROWNE

Summary: John Browne has been assisting clients in applying regulatory principles and resolving financial, accounting and costing issues related to rate regulation for over 35 years. Prior to establishing his own practice 20 years ago, he was a consultant with Deloitte and Touche LLP, the last seven years as a partner.

He has directed and worked on a wide range of studies for rate-regulated entities that have dealt with accounting and cost allocation principles, the determination of rate base, cost of service determination, product costing/pricing, rate of return, capital structure, and methods of regulation.

He has appeared as an expert witness on accounting, costing and financial issues before the following regulatory tribunals: Canadian Radio-television and Telecommunications Commission, Canadian Transport Commission, the Alberta Public Utilities Board / the Alberta Energy and Utilities Board, the Manitoba Public Utilities Board, Newfoundland and Labrador Board of Commissioners of Public Utilities and the Nova Scotia Board of Commissioners of Public Utilities.

Education / Professional Qualifications:

- Bachelor of Commerce - Queen's University
- Master of Arts (Economics) - Queen's University
- Chartered Professional Accountant, Chartered Accountant

Committees/ Publications

Mr. Browne was Chairman of the Canadian Institute of Chartered Accountants ("CICA") Study Group that produced the CICA research report "Financial Reporting by Rate Regulated Enterprises".

He authored or co-authored the CA Magazine articles "A Matter of Principles - Part I" "A Matter of Principles - Part II" and "Regulatory Assets". These articles dealt with accounting by rate-regulated enterprises.

He co-authored the Deloitte & Touche publication "Basics of Canadian Rate Regulation" and authored the Deloitte & Touche monograph "The Contractual Pitfalls of Relying on GAAP". He has also authored a number of papers for distribution to clients and potential clients such as "Fundamentals of Rate Regulation" (an update of "Basics of Canadian Rate Regulation") and "Comments on Deferral Accounts to Deal With Uncertainty".

Key Clients: Mr. Browne's major clients have included: Newfoundland Power Inc., Nova Scotia Power Inc., New Brunswick Power Corporation, Maritime Electric Company Limited, Hydro Quebec, Ontario Hydro, Manitoba Hydro, SaskPower, Edmonton Power, Ottawa Hydro, Canadian Electricity Association, Ontario Energy Board, Atco Gas, Enbridge, Newfoundland Telephone Company Ltd., Bell Canada, Manitoba Telephone System, Saskatchewan Telecommunications, AGT/TELUS, Teleglobe, Telesat Canada, Southwestern Bell Telephone Company, New York Telephone, The Telecommunication Authority of Singapore and Dhiraagu (Maldives).

Selected Assignments:

- Completed a survey of Canadian regulators to determine what they viewed as their objectives and how they interpreted those objectives.
- Assisted Ontario Hydro Services Company (currently Hydro One), one of the successor companies of Ontario Hydro, in understanding its regulatory options by researching and providing advice on a number of regulatory issues related to transfer pricing, structural organization, accounting for income taxes, relationships with affiliated companies, performance-based regulation, etc.
- Participated in the in the Ontario Energy Board consultation process dealing with the transition to IFRS. As part of this participation, made a presentation on proposed principles to guide the development and maintenance of regulatory accounting policies (RAP) and a framework for evaluating proposed changes in RAP.
- Advised the Canadian Electricity Association in the preparation of a paper dealing with the recognition of regulatory assets and liabilities. The assistance included organizing and drafting the report and advising on issues covered in the paper.
- Prepared a draft for the framework and principles section of a utility's cost manual.
- Researched and analysed the issue of a deferral plan for the introduction of a new plant into rate base. Prepared evidence on the issue for Nova Scotia Power and appeared as an expert witness. Subsequently prepared evidence and appeared as an expert witness on changes to the deferral of the costs on the plant due to changes in circumstances.

- Researched and analysed the issues of phase-in and risk sharing for Edmonton Power's Genesee plant and prepared a recommendation that was submitted to the utility's regulator. Expert testimony was also provided.
- Researched, analysed, and presented a recommendation that an electric utility should be allowed to defer tax costs so that the utility could avoid a rate increase followed by a rate decrease.
- Provided a written opinion for Nova Scotia Power Inc. on its regulatory treatment of amounts related to an income tax dispute. The report dealt with past taxes that had not been recovered in allowed rates, future taxes that may not be payable, and the use of deferral accounts.
- Prepared a report for Nova Scotia Power Inc. that addressed the utility's plan to use market-related value in determining its pension expense. This plan would result in smoothing the impact of pension expense on rates. The report provided an opinion on whether the plan was consistent with generally accepted accounting principles and established regulatory principles.
- Provided a written opinion for Newfoundland Power on accounting and regulatory issues related to future employee benefits and the company's hydro production equalization reserve. The opinion was included in the company's rate submission.
- Advised New Brunswick Power Distribution and Customer Service Corporation on regulatory issues related to a proposed fuel deferral account.
- Prepared two reports for Nova Scotia Power Inc.: the reports addressed the recovery of unrecovered costs of a retired generating station. The utility's proposal included the recognition of a deferral account for both the unrecovered costs and the related capitalized financing costs.
- Provided a written opinion on a proposal by a not-for-profit electric system operator to deal with surpluses and deficits. In preparing the opinion, the treatment of surpluses and deficits by other not-for-profit independent electric system operators was reviewed.
- Analysed the issue of the appropriate accounting and regulatory treatment of Nova Scotia Power Inc's defeasance program. Prepared evidence and appeared as an expert witness on the issue.

REGULATORY PRINCIPLES

Regulators must review and set rates in accordance with their empowering legislation, which generally provides limited guidance on how to set rates. The legislation often states little more than that rates should be just and reasonable. As a result, regulators frequently refer to established regulatory principles to guide their judgment in determining what is appropriate in a particular case.

No single authority sets regulatory principles. Instead, principles become established through their general acceptance. Although the regulatory principles are sometimes reflected in the regulators empowering legislation.

In the context of the ECAM issue, four regulatory principles are relevant: just and reasonable; prudence, intergenerational equity and rate stability and predictability.

JUST & REASONABLE

The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be just and reasonable, or words to that effect. For example:

- The preamble to the Prince Edward Island Electric Power Act starts with: "*WHEREAS the rates, tolls and charges for electric power should be reasonable, publicly justifiable, and non-discriminatory;*" .[1]

- The Newfoundland & Labrador "Electric Power Control Act, 1994" states that it is the declared policy of the province that the rates to be charged, either generally or under specific contracts, for the supply of power within the province "should be reasonable and not unjustly discriminatory".[2]

- The British Columbia "Utilities Commission Act" states that, in setting a rate under the Act, the Commission must have due regard to the setting of a rate that is not unjust or unreasonable.[3]

This principle applies to both customers and regulated entities. It requires a balancing of the legitimate interests of both parties.

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1 Prince Edward Island; Electric Power Act .

2 Newfoundland and Labrador; Electrical Power Control Act, 1994; para. 3 (a) (i).

3 British Columbia; Utilities Commission Act, [RSBC 1996] Chapter 473; para 60 (1) (b) (i).

Unfortunately, "just and reasonable" is a vague and subjective concept. It provides an overall direction to regulators but little specific guidance. The other regulatory principles help to establish what is just and reasonable.

COST OF SERVICE STANDARD

At the heart of rate regulation is the cost of service standard, sometimes referred to as the revenue requirement standard. After "just and reasonable" it is the most important regulatory principle.

Under the cost of service standard, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

This standard does not require that a regulated entity be guaranteed a fair return, only that it has an opportunity to earn it. In most cases, rates are set prospectively, based on estimated future costs. If the entity over-recovers, it normally keeps the excess. If it under-recovers, it bears the deficiency.

The opportunity to earn a fair return implies that the possibilities of under and over-earning are offsetting. Using more technical language, allowed rates should provide an expected rate of return equal to the fair rate of return, where the expected rate of return is equal to the average of the possible rates of return weighted by the probability of their occurrence[4].

The cost of service standard is consistent with what is expected to occur in a competitive market, where the prices for goods and services tend to equal the cost of providing them, including a fair return. This is important since it is often argued that rate regulation is a proxy for competition[5] and it tends to be withdrawn where there is adequate competition to protect customers.

This standard also reflects fairness and the necessity to offer adequate incentives for providing regulated services.

- In fairness, a regulated entity's investors should have the opportunity to recover their costs, including a fair return, just as they would if they were to invest in a non-regulated entity. However, customers should not have to provide investors with the

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[4] For example, if there is a 40% probability of an 8% return, and a 60% probability of a 12% return, the expected return is 10.4%: (8% x 40%) + (12% x 60%) = 10.4%.

[5] For example, in a 2001 decision the Ontario Energy Board ("OEB") stated: *The Board notes that the general role of the regulator is to act as a proxy for competition….* (OEB; Enbridge Gas Distribution Inc., RP-2001-0032; December 13, 2002; para. 5.11.49)

opportunity to earn more than they could expect from investing in non-regulated operations of similar risk.

- From an incentive viewpoint, unless investors have a reasonable opportunity to recover their costs, which includes a fair return, it will be difficult to attract the investment necessary to provide regulated operations. However, the opportunity to recover costs, including a fair return, should provide an adequate incentive to attract necessary funding.

The cost of service standard is applicable to all regulatory methodologies, including incentive-based methods. A regulated entity may earn more or less than a fair return, and incentive-based methods increase the possible differences between realized earnings and a fair return. However, the issue is that a regulated entity should have a reasonable **opportunity** to earn a fair return, which implies that the possibilities of under and over-earning are offsetting.

The importance of this standard has been recognized by regulatory authors and the Supreme Court of Canada.

In "The Regulation of Public Utilities" Charles Philips Jr. stated that the standard, which he referred to as the revenue requirement standard, was at the heart of rate regulation:

> *The basic standard of rate regulation is the revenue-requirement standard, often referred to as the rate base-rate of return standard. Simply stated, a regulated firm must be permitted to set rates that will both cover operating costs and provide an opportunity to earn a reasonable rate of return on property devoted to the business. …*[6]

In "Principles of Public Utility Rates" by Bonbright et al., the authors recognized the cost of service as the basic standard of fairness:

> *… one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of costs of service, often qualified by the stipulation that the relevant cost is necessary, true (i.e., private and social) cost or cost reasonably or prudently incurred.*[7]

Indeed, the book has a chapter titled "Cost of Service as a Basic Standard of Reasonableness".

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[6] Phillips, Charles F. Jr.; The Regulation of Public Utilities; (Public Utilities Reports, Inc.; July 1993); pg. 176.

[7] Bonbright, James C., Danielsen, Albert L., Kamerschen, David R.; Principles of Public Utility Rates (Public Utilities Reports, Inc.; March 1988); pg. 109.

In a 2015 Supreme Court of Canada (SCC) decision dealing with ATCO Gas and Pipelines Ltd (ATCO), the majority opinion stated:

> *… a key principle in Canadian regulatory law is that a regulated utility must have the opportunity to recover its operating and capital costs through rates …* [8]

And in another 2015 decision dealing with Ontario Power Generation Inc (OPG), the majority opinion stated:

> *In order to ensure that the balance between utilities' and consumers' interests is struck, just and reasonable rates must be those that ensure consumers are paying what the Board expects it to cost to efficiently provide the services they receive, taking account of both operating and capital costs. In that way, consumers may be assured that, overall, they are paying no more than what is necessary for the service they receive, and utilities may be assured of an opportunity to earn a fair return for providing those services.*[9]

PRUDENCE STANDARD

The prudence standard modifies the cost of service standard and is sometimes viewed as being part of it. The prudence standard requires that customers be charged only for prudently incurred costs.

As the majority stated in the 2015 SCC dealing with ATCO:

> *… This is not to say that the Commission is not required to consider consumer interests. These interests are accounted for in rate regulation by limiting a utility's recovery to what it reasonably or prudently costs to efficiently provide the utility service.*[10]

Imprudent costs are not necessary to provide regulated services. In a competitive market, companies are generally unable to recover them. If they attempted to, they would usually lose customers to more efficient competitors. Also, where an entity is unable to recover imprudent costs, it has an incentive to manage itself efficiently.

Prudency is determined by considering whether management decisions were consistent with what a reasonable person with appropriate competence would have decided in a similar situation. This should not be done in hindsight. A regulated entity's management

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[8] ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission); 2015 SCC 45; para. 61. [ATCO v. AUC]

[9] Ontario (Energy Board) v. Ontario Power Generation Inc.; 2015 SCC 44; para 20. [OEB v. OPG]

[10] ATCO v. AUC; para. 61.

can be expected to rely only on information reasonably available to it when it makes its decisions. In addition, it is generally assumed that management has acted prudently unless evidence exists to the contrary.

In a 2002 decision, the Ontario Energy Board set out four principles concerning the issue of prudence which reflect general practice:

- *Decisions made by the entity's management should generally be presumed to be prudent unless challenged on reasonable grounds.*
- *To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the entity at the time the decision was made.*
- *Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.*
- *Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.*[11]

INTERGENERATIONAL EQUITY

The principle of intergenerational equity helps to determine when costs should be recovered. Under this principle, customers in a given period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to customers in another period. This principle is consistent with setting just and reasonable rates within each period.

For example, a regulated entity is usually not allowed to recover in current rates the cost of financing projects under construction. It's incurring this cost to provide service to future customers, not customers in the current period. Instead, the return is capitalized and recovered through depreciation over the period in which the assets are used to provide service.

Combined with the cost of service standard, the principle of intergenerational equity requires that rates within a period should cover the costs of providing service in that period, but only that period.

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[11] Ontario Energy Board; Enbridge Gas Distribution Inc., RP-2001-0032; December 13, 2002; para. 3.12.2.

This principle's importance depends on the periods involved. Customers in one year tend to be the same as those in the next and their relative usage generally doesn't vary that much from year to year. Having customers in one year pay more as a result of costs incurred to provide service in the previous year would not be as serious a breach of this principle as it would be if they had to pay more because of service provided to customers 10 years earlier. In the first case, it is more likely that the costs will be borne by those that benefited from their incurrence, and in proportion to the benefits they received.

If costs can't be recovered in the period for which they were incurred, it's generally best to recover them in a period as close as possible to the one for which they were incurred.

RATE STABILITY AND PREDICTABILITY

The principle of rate stability and predictability also helps to establish when costs should be recovered. It requires that rates remain stable and predictable – at least to the extent practical. It may, therefore, justify smoothing out changes in rates to avoid sharp rate climbs or temporary fluctuations. This principle recognizes that it is usually easier for ratepayers to deal with gradual and predictable rate increases.

The principle's intent is to establish only when costs are recovered, not the amounts actually recovered. In practice, it does affect the amounts recovered because the timing of cost recovery affects financing costs. Where costs are deferred, the deferred amount must be financed, and regulated entities are entitled to recover the additional financing costs under the cost of service standard.

The principle of rate stability and predictability may require costs to be collected from customers in periods other than those for which they were incurred. Therefore, it is inconsistent with the principle of intergenerational equity. Despite that, it's justified because it recognizes the adverse impact on customers where they must adjust to significant rate increases or short-term rate fluctuations.

As time passes, the makeup and relative usage of a customer group changes. Therefore, the longer the period that costs are deferred, the more serious the breach of the principle of intergenerational equity. As a result, when the principle of rate stability and predictability is applied, deferred costs should be recovered over as short a period as is reasonable. Similarly, if, to avoid a sharp rate increase, costs are recovered before a period for which they will be incurred, the intervening period should also be as short as reasonably possible.

EXAMPLES OF VARIANCE DEFERRALS

There are several instances where Canadian regulated entities have deferred differences between the actual and estimated amount of costs related to the commodity that they sell.

British Columbia Hydro and Power Authority (BC Hydro)

As indicated in BC Hydro's audited financial statements, that were included in its "2018/19 Annual Service Plan Report", the Company maintains three regulator approved cost of energy variance accounts[1]. A description of these accounts was presented in its "Fiscal 2020 to Fiscal 2021 Revenue Requirements Application".

> *BC Hydro has three Cost of Energy Variance Accounts that capture the differences between forecast and actual revenues and energy costs: the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account.*[2]
>
> *The purpose of the three Cost of Energy Variance Accounts is to defer the differences between forecast and actual revenues and energy costs for recovery or refund to ratepayers in future periods. These differences are non-controllable and can be positive or negative. ...*[3]

FortisBC Energy Inc.

FortisBC Energy Inc. has two regulator approved deferral accounts to deal with variances in the cost of the commodity it sells. As described in the Company's financial statements:

> *There are two primary deferral mechanisms in place to decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the impacts of weather and other changes on use rates.*
>
> *The first mechanism relates to the recovery of all gas supply costs through deferral accounts that capture variances (overages and shortfalls) from forecasts in costs incurred and amounts recovered through rates. Balances to be either refunded to or recovered from customers are determined via quarterly application and review by the BCUC. Currently under this mechanism, there are two separate deferral accounts:*

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1 BC Hydro; 2018/19 Annual Service Plan Report; pg. 70.

2 BC Hydro; Fiscal 2020 to Fiscal 2021 Revenue Requirements Application; pg. 7-23.

3 BC Hydro; Fiscal 2020 to Fiscal 2021 Revenue Requirements Application; pg. 7-24.

the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA").[4]

FortisAlberta Inc.

FortisAlberta has a variance account to deal with differences between actual and estimated transmission costs. This deferral does not deal with the cost of the commodity in distributes, however it is similar in that it provides the utility with an opportunity to recover the actual amount of a third-party cost related to the commodity that it sells..

This account (AESO Charges Deferral Account) was described in the Company's audited financial statements for the years ended December 31, 2018 and 2017:

These balances represent the difference in revenue collected and expenses incurred for transmission-related items that are expected to be collected or refunded in future customer rates. To the extent that the amount of actual costs incurred is different from revenue collected in rates for these items, the difference is deferred as a regulatory asset to be collected or a regulatory liability to be refunded in future rates. As at December 31, 2018, the regulatory asset primarily represented the under collection of the AESO charges deferral account for 2016 and the regulatory liability primarily represented the over collection of the AESO charges deferral account for 2017 and 2018.[5]

MANITOBA HYDRO-ELECTRIC BOARD (MANITOBA HYDRO)

Manitoba Hydro sells both electricity and gas. In the case of its gas operations (Centra Gas), it has a variance account to provide the Company an opportunity to recover the actual cost of the commodity it sells. As described in the audited financial statements contained in the Company's 2019 annual report:

Purchased gas variance accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. Purchased gas variance accounts are reflected as a regulatory debit or credit depending if the amounts represent a recovery from or a refund to the customers, respectively.[6]

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[4] FortisBC Energy Inc.; Consolidated Financial Statements For the years ended December 31, 2019 and 2018; pg. 17.

[5] FortisAlberta Inc.; Audited Financial Statements For the years ended December 31, 2018 and 2017; pg. 17.

[6] Manitoba Hydro-Electric Board 68th Annual Report For the year ended March 31, 2019: pg. 86.

As the Manitoba Public Utilities Board (MPUB) stated in a recent regulatory decision dealing with Centra Gas:

> *Centra's Primary Gas rate is subject to quarterly amendment (February 1, May 1, August 1, and November 1)…. Quarterly Primary Gas rate setting does not involve a public hearing, reflecting the formulaic nature of the Rate Setting Methodology and furthering the objective of least-cost regulation. Public reviews of Primary Gas rates are conducted at periodic Cost of Gas or General Rate Application hearings.*[7]
>
> …
>
> *Centra tracks differences between the previously approved Primary Gas rate (and its underlying gas costs) and the actual cost of purchases it incurs. … When the actual cost of gas is greater than what was forecasted, a positive balance accrues in the PGVA, which is then collected from customers. When the actual cost of gas is less than what was forecasted, a negative balance accrues in the PGVA and this is refunded to customers. A Primary Gas rate rider is used to account for these differences between forecasted and actual costs of Primary Gas.*
>
> *A Primary Gas rate rider recovers from or repays to customers the balance in the PGVA, with interest. Utilization of the PGVA and rate rider ensures that customers' costs are adjusted so that customers are paying for the actual cost of gas with no mark-up or discount. The Primary Gas rate rider is determined by dividing the accumulated balance in the PGVA by the volumes Centra forecasts to flow in the upcoming twelve months, … If the PGVA balance is not brought to zero with the rate rider, the remaining balance will be included in the calculation of future rate riders.*[8]

ONTARIO ELECTRICITY MARKET

In purchasing electricity in Ontario, customers can choose between competitive service suppliers and the Regulated Price Plan (RPP). Each distribution utility is required to offer the RPP to its customers.

The RPP prices are set by the Ontario Energy Board (OEB) and are intended to reflect the full cost of supply. They are based on estimated costs plus the outstanding difference between actual and estimated costs. As explained in the Regulated Price Plan Manual:

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[7] MPUB; Order No. 10/20 Centra Gas Manitoba Inc.: Primary Gas Rate Application, Effective February 1, 2020; January 23, 2020; pg. 5.

[8] MPUB; Order No. 10/20 Centra Gas Manitoba Inc.: Primary Gas Rate Application, Effective February 1, 2020; January 23, 2020; pg. 8&9.

> *… The RPP supply cost and the accumulated variance between actual and forecast costs (carried by the IESO) both contribute to the base RPP price, which is set to recover the full costs of supply. …*[9]
>
> *New RPP prices are computed at six-month intervals and are the result of an integrated consideration of re-basing and true-ups. Price changes become effective at the beginning of a calendar month.*[10]
>
> *The price resetting determines how much of a price change is needed to recover both the forecast RPP supply cost and the accumulated variance in the IESO variance account over the next 12 months.*[11]

In Ontario, variances between the actual and the estimated cost are held by a separate entity, the IESO. However, the end result is that any difference between the actual and the estimated cost of power is reflected in the future RPP prices charged to customers.

Although the difference between RPP prices and actual cost is carried by the Independent Electricity System Operator (IESO), there can be differences between the RPP prices, and the amounts reflected in rates charged to customers. Toronto Hydro Corporation has a regulator approved variance account so that its actual costs are passed on to customers. As described in the Company's 2018 audited financial statements:

> *…For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC*[12] *to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing amounts to be recovered from or refunded to customers through future rates approved by the OEB. …* [13]

ENBRIDGE GAS INC

Enbridge is the major gas distribution utility in Ontario. As approved by its regulator (OEB), the Company defers differences between the estimated and actual cost of the

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9 OEB; Regulated Price Plan Manual; Issued February 16, 2016; pg. 4.

10 OEB; Regulated Price Plan Manual; Issued February 16, 2016; pg. 37.

11 OEB; Regulated Price Plan Manual; Issued February 16, 2016; pg. 18.

12 LDC refers to the Toronto Hydro-Electric System Limited, which is the local distribution company.

13 Toronto Hydro Corporation Financial Report December 31, 2018; pg. 7.

commodity it distributes, and refunds/collects these differences from customers. As described in the Company's 2019 audited financial statements:

> *Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. The Company has been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process.*[14]

The workings of the Quarterly Rate Adjustment Mechanism (QRAM), was discussed in a recent OEB decision:

> *The QRAM is intended to strike a balance between ensuring that consumers are receiving appropriate price signals which reflect natural gas market prices, and protecting the interest of consumers that purchase their gas from the distributor by reducing, to some extent, the volatility in the price of natural gas. Natural gas commodity prices charged by Enbridge Gas are based on:*
>
> - *A market price forecast for the commodity over the next 12 months.*
> - *A true-up between actual and forecast commodity prices for prior periods as actual costs are passed on to customers without a mark-up. By design, the QRAM includes smoothing of price volatility by spreading this difference over a 12-month period.*[15]

NOVA SCOTIA POWER INC (NSPI)

For NSPI, fuel costs are a significant cost that is largely outside the control of the Company. As approved by its regulator (UARB), differences between the actual and estimated fuel costs are deferred and recovered / returned to customers in a future period. In discussing its fuel adjustment mechanism (FAM), NSPI's 2019 financial statements state:

> *NSPI has a UARB approved FAM, allowing NSPI to recover fluctuating Fuel Costs from customers through annual fuel rate adjustments. Differences between prudently incurred Fuel Costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year. …*[16]

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[14] Enbridge Gas Inc Consolidated Financial Statements December 31, 2019; pg.17.

[15] OEB; Decision and Interim Rate Order EB-2019-0273; December 19, 2019; pg. 3.

[16] Nova Scotia Power Inc Consolidated Financial Statements December 31, 2019 and 2018; pg.18.

NEWFOUNDLAND AND LABRADOR HYDRO (HYDRO)

Hydro has a rate stabilization (RSP) that allows it to defer significant costs associated with the cost of energy it sells (including to Newfoundland Power). This regulator approved plan was described in the Company's 2018 audited financial statements:

> *In 1986, the PUB ordered Hydro to implement the RSP which primarily provides for the deferral of fuel expense variances resulting from changes in fuel prices, hydrology and load and associated interest. Additionally, the RSP also includes costs associated with the island interconnected and isolated systems. Adjustments required in utility rates to cover the amortization of the balance are implemented on July 1 of each year. Similar adjustments required in industrial rates are implemented on January 1 of each year. …* [17]

NEWFOUNDLAND POWER (NP)

NP has a regulator approved Rate Stabilization Account (RSA) that deals with differences between the actual cost of power and the estimated amount used in setting rates. The balance on March 31 of each year is recovered from / returned to customers over a 12-month period beginning with the following July . As described in the Company's 2019 audited financial statements:

> *On July 1 of each year, customer rates are recalculated in order to recover from or refund to customers, over the subsequent twelve months, the balance in the RSA as of March 31 of the current year. The amount and timing of the recovery or refund is subject to PUB approval. In 2019, the annual July 1 rate adjustment was postponed, as ordered by the PUB, to coincide with customer rate implementation as a result of Hydro's 2017 GRA.*
>
> *The RSA passes through, to the Company's customers, amounts primarily related to changes in the cost and quantity of fuel used by Hydro to produce the electricity sold to the Company.*
>
> *The RSA also passes through, to the Company's customers, variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates ("Energy Supply Cost Variance"). …*[18]

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[17] Newfoundland and Labrador Hydro Non-consolidated Financial Statements December 31, 2018; pg. 25.

[18] Newfoundland Power Annual Audited Financial Statements December 31, 2019; pg. 12.