BEFORE THE

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT **and** **IN THE MATTER OF AN APPLICATION by NOVA SCOTIA POWER INCORPORATED for approval of an Extra Large Industrial Dispatchable Above-the-Line Tariff applicable to Port Hawkesbury Paper**	**Matter No.** **M12661**

Evidence of

Colin T. Fitzhenry and Michael P. Gorman

On behalf of

Port Hawkesbury Paper LP

February 20, 2026

BRUBAKER & ASSOCIATES, INC.

Project 12002

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Evidence of Colin T. Fitzhenry and Michael P. Gorman

Q PLEASE STATE YOUR NAMES AND BUSINESS ADDRESS.

A Colin T. Fitzhenry and Michael P. Gorman. Our business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A We are consultants in the field of public utility regulation. Mr. Fitzhenry is a Principal and Mr. Gorman is a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic, and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A and Appendix B to this evidence.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A We are testifying on behalf of Port Hawkesbury Paper LP ("PHP"), who is a customer of Nova Scotia Power Incorporated ("NS Power," or "Company").

Q HAVE YOU PREVIOUSLY PREPARED EVIDENCE AND TESTIFIED BEFORE THE NOVA SCOTIA ENERGY BOARD ("BOARD") OR ITS PREDECESSOR?

A Yes. Mr. Gorman has filed testimony before the predecessor Nova Scotia Utility and Review Board in Matter Nos. NS Power P-881, P-886, 5463 and 6540. In addition, Mr. Gorman has filed testimony before Energy and Utilities Board in the province of Alberta and the National Energy Board. While Mr. Fitzhenry has not previously filed testimony in Nova Scotia, he was engaged by PHP in Matter No. 11475 (NS Power

Cost of Service Study Process) and was actively involved in that process for PHP during 2024 and 2025.

Q HAVE YOU REVIEWED THE APPLICATION FOR AN EXTRA-LARGE INDUSTRIAL DISPATCHABLE ("ELID") ABOVE-THE-LINE ("ATL") TARIFF FOR PHP FILED BY NS POWER ON DECEMBER 29, 2025?

A Yes.

I. TESTIMONY SUMMARY

Q PLEASE SUMMARIZE YOUR RECOMMENDATION ON THE PROPOSED ELID ATL TARIFF?

A Our recommendation and findings are summarized as follows:

- NS Power's proposed design of the ELID Tariff and proposed charges and credits are imbalanced and over-charge PHP for its cost of providing service.
- PHP recommends the ELID Tariff rate charges be designed to reflect the firm and interruptible services that NS Power is providing to NS Power. The ELID should include a capacity charge for the 8 MW of firm demand service under the tariff, and provide recovery of non-firm power supply cost associated with the interruptible power service above the firm service.
  - The firm service Capacity Charge for the ELID should be based on the allocated capacity cost to PHP by including its 8 MW of firm demand in the NS Power Three Coincident Peak ("3-CP") Demand Allocation in its cost of service study.
  - The interruption demand service will not impose resource capacity cost on NS Power because this demand will be served only on an as-available basis. Hence, NS Power can avoid incurring the cost of resource capacity additions to serve the interruptible demand. Therefore, no Capacity Charge will be justified for interruptible demand, but NS Power's cost of serving the interruptible demand can be recovered in the ELID energy charge, which is designed to recover both fuel/energy power supply, and a portion of NS Power's non-fuel cost of service. Under this ELID design, the ELID will not require an interruptible credit for NS Power interruptible power supply above PHP's firm demand of 8 MW. The ELID Energy Charge is designed to recover

both fuel and power energy supply. Hence, the non-fuel ELID energy charge will fairly compensate NS Power for its supply of interruptible power service to PHP above its firm power service.

- NS Power's proposed design of the ELID does not reasonably reflect the firm and interruptible service provided to PHP under the proposed ELID Tariff. PHP does not support the Company's ELID rate design. If the Board prefers NS Power's proposed design of the ELID, albeit not being cost based, it should be adjusted to reflect NS Power's cost of servicing PHP.
    - NS Power proposes to price the PHP capacity charge by including a 65 MW contribution to the ATL system 3-CP allocation. This allocates 65MW of firm capacity to the ELID Capacity Charge. PHP's service with NS Power is stated to be only 8 MW of firm service, and interruptible demand service for demands above 8 MW.
    - If the ELID capacity charge is designed to include the cost of firm demand service for a 65 MW tariff capacity, then the interruptible credit should be applied to 57 MW of the 65 MW service that will be interruptible. NS Power is able to avoid incurring the cost of adding resource capacity additions to serve this interruptible demand. This interruptible credit should be priced at NS Power's estimated marginal cost of capacity of $13.107/KVA, and updated in the next GRA filing to reflect the current cost of capacity.
    - Including this interruptible credit in NS Power's proposed ELID rate design is fair and reasonable to all customers, including PHP. This interruptible credit leaves all ATL customers economically indifferent if NS Power either adds new resource capacity to provide firm service to all of PHP's load, or NS Power pays an interruptible credit to PHP to supply most of its load on an interruptible basis and avoid the cost of resource capacity additions. .
- Under the Company's proposed ELID rate design, the Revenue-to-Cost ("R/C") ratio would be 1.04373 and results in an over-recovery of 4.373% above the cost to serve PHP. While an R/C ratio exceeding 1.0 can be a valid tool to mitigate the impact of shifting Cost-of-Service ("COS") models on other classes, that justification does not apply here. PHP is in a new above-the-line customer class and has not previously benefited from below or above cost rates or model changes in the Cost-of-Service Study ("COSS") that disadvantaged other classes. Therefore, we recommend an equitable R/C ratio of 1.0, ensuring PHP pays exactly its cost to serve without subsidizing or being subsidized by other classes.
- We recommend updating the ELID tariff to incorporate revised 2026 and 2027 energy sales forecasts for PHP. Aligning the tariff with current usage assumptions ensures that energy cost allocations and revenues accurately reflect PHP's actual cost of service. By reflecting the total system energy usage upfront, these adjustments establish more accurate per-unit rates.

II. NS POWER'S PROPOSED ELID TARIFF

Q PLEASE DESCRIBE NS POWER'S PROPOSED ELID TARIFF FOR PHP.

A NS Power is requesting approval of an Extra Large Industrial Dispatchable ("ELID") Tariff for PHP, to be available on, or before, January 1, 2027, following the termination of the Extra Large Industrial Active Demand Control ("ELIADC") Tariff under which PHP is currently taking service from NS Power. The ELIADC service will expire at year-end 2026.[1]

NS Power states that the ELID is based on the Large Industrial ("LI") Tariff under which the Company's ATL LI customers are served. The proposed ELID includes a new rider, the Dispatchable Rider ("DR"), as a component of ELID service to PHP. The DR is similar to the Active Demand Control under NS Power's current ELIADC service to PHP. Under Rider DR, NS Power will dispatch PHP's load (this includes the right to curtail PHP demands on the NS Power system above a stated 8 MW firm demand level) in response to system conditions that will allow NS Power to reduce system power supply cost and to ensure service reliability.[2] NS Power notes that:

> Under this Rider, NS Power has a general duty to serve just as it does to other ATL customers but will dispatch PHP's load in response to system conditions to reduce the cost to serve PHP and enable the system cost savings created by PHP's load flexibility to be credited to PHP.[3]

Under the ELID Tariff, PHP will have firm demand rights of 8 MW, and NS Power will have the right to dispatch or curtail NS Power's load above the firm demand when necessary to reduce its system power supply cost and to prioritize service reliability to other NS Power firm service customers over serving PHP's interruptible load above its 8 MW firm demand.

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[1] Application at 3.
[2] *Id*.
[3] *Id*. at 3.

This Tariff dispatch and interruptible right creates material resource capacity savings to NS Power, and power supply benefits to ATL customers. NS Power acknowledges that PHP peak period demands could range between a low demand of 8 MW and a high demand of 160 MW[4]. NS Power can use this dispatch right to reduce PHP load when doing so will reduce its energy or power supply cost, and to curtail PHP's demands above 8 MW during its peak-demand periods if NS Power's resource capacity is not adequate to serve the ATL firm demand. Hence, the ELID dispatch and curtailment rights for the PHP's demands above 8 MW allow NS Power to reduce system energy costs and to avoid the cost of adding additional production and transmission resource capacity that would otherwise be needed to serve a higher ATL firm peak demand if PHP full 3-CP demands were served as firm load. Further, NS Power states that it will require the PHP load to be interrupted within 10 minutes of a request by NS Power, which will allow NS Power to hold this interruption right as Operating Reserves, as needed for system reliability.[5]

Q HOW IS NS POWER PROPOSING TO PRICE SERVICE UNDER THE ELID?

A NS Power states that its proposed ELID rate is patterned after its LI tariff. We have provided a comparison of its Large Industrial Tariff Rate pricing and the ELID in Table 1 below.

[4] *Id.* at 5.
[5] Application Attachment 1 at 5.

Table 1

Nova Scotia Power
Large Industrial Rate Comparison - 2027 Rates

Description		Large Industrial Interruptible (Transmission)	Extra Large Industrial Dispatchable (ELID)
Customer	$/Mo		$10,000
Fuel	$/Kwh	$0.0746	$0.0885
Non-Fuel	$/Kwh	$0.0224	$0.0239
Total	$/Kwh	**$0.0970**	**$0.1124**
Demand	$/Kva	$10.068	$14.310
Interruptible Credit	$/Kva	$7.667	$7.667
ELID Priority Credit	$/Kva	$0.000	$0.767
Total w/Credits	$/Kva	**$2.401**	**$5.876**

Source: Application Attachment 1, 2027 Prices Excel Sheet N-1.

NS Power states the **ELID Customer Charge** is designed to recover costs incurred to dispatch this PHP load and administer the ELID tariff.[6]

The **ELID Energy Charge** will apply to all delivered energy to PHP in excess of the subject Energy Amount deemed to have been provided, pursuant to the Power Sales Agreement issued under section 4 AA of the Electricity Act.[7] Energy credit will be estimated at year end for production supply estimated savings achieved as a result of the DR dispatch of PHP's load.[8]

[6] Application at 3 and 4.
[7] *Id.* at 7.
[8] *Id.* at 8.

The **ELID Demand Charge** will be based on a “PHP demand determinant” set, as part of the GRA process, fuel adjustment Mechanism or other related proceeding,[9] and a stated demand price of $14.31/KVA-month in 2027.[10] The “PHP demand determinant” will be based on the GRA cost of service and the NS Power assumed PHP 3-CP demand contribution it makes to NS Power’s system peak. NS Power states that this makes the demand charge to PHP a “fixed charge.”[11] This designation as a “fixed charge” distinguishes the demand charge to PHP from the demand charges to other ATL LI customer demand charges that are based on metered demands and demand prices.

NS Power states that the **ELID Interruptible Service and Credit** are, for the most part, the same as the LI Interruptible Rider (“LIIR”) terms, except that the PHP’s interruptible service will have priority interruption service; that is, it will be subject to interruption before LIIR customers are interrupted. Therefore, NS Power proposes the PHP interruption credit to be at a 10% premium to the LIIR interruption credit.[12]

Q HOW WILL NS POWER PROPOSE TO PASS ON THE BENEFITS OF THE DR AND INTERRUPTIBLE SERVICE TO PHP?

A There will be two credits made to PHP cost of service. First**,** NS Power will provide a billing determinant demand charge credit equal to the same interruptible credit available to LIIR customers of $7.667/KVA plus a 10% priority interruption credit premium. The premium interruptible credit reflects NS Power’s proposal to interrupt ELID before the LIIR customers per NS Power's proposed Order of Interruptibility.[13]

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[9] *Id.* at 5.
[10] *Id.* at 6.
[11] *Id*.
[12] *Id.* at 8.
[13] *Id*. at 7.

Second, NS Power opines that PHP load will be dispatched via the dispatchable Rider in response to high-cost marginal power supply periods. This PHP load dispatch curtailment during these high marginal-cost power supply periods will reduce NS Power's power supply charges to the benefit of PHP, without changing its power supply costs to ATL customers, including PHP.[14] PHP will receive a power supply credit from the DR based on NS Power's estimated modeled power supply savings realized due to the PHP dispatched load.

Q DO YOU AGREE WITH NS POWER THAT THE ELID IS STRUCTURED TO CREDIT TO PHP ALL COST SAVINGS CREATED BY NS POWER'S ABILITY TO DISPATCH PHP'S FLEXIBLE LOAD?

A No. We do not dispute the lower power supply benefits that can be realized by dispatching the PHP interruptible load. However, we do dispute NS Power's claims that non-power supply savings created by the DR are being fully passed to PHP. Rather, the ELID design does not allocate PHP a reasonable, let alone fair, share of the non-fuel interruptible benefits created by the DR and the interruptible ELID load.

NS Power's proposal under the ELID Tariff is imbalanced and also ignores the fact that PHP incurs production delays and likely increased operating cost in order to provide NS Power the right to dispatch PHP's load and to interrupt PHP down to the firm demand level with only 10 minutes' notice.

[14] *Id*. at 9-10.

Q PLEASE DESCRIBE THE NON-FUEL SAVINGS CREATED BY THE DR COMPONENT OF THE ELID.

A NS Power's ability to dispatch PHP load allows it to curtail PHP's demands above the 8 MW firm demand when it does not have the system resource capacity that is needed to serve ATL customers' coincident firm demands during peak-demand periods and/or during system emergencies. Without this PHP demand curtailment right, NS Power would need to invest in additional generating capacity to serve its ATL system coincident firm demands. Therefore, NS Power's ability to curtail PHP demand allows it to avoid investing in additional production and transmission capacity that would otherwise be needed to serve its ATL system's coincident firm peak demand and demands during system emergencies. This avoided production and transmission capacity cost is material and is not fully incorporated into NS Power's proposed ELID Tariff rate charges. Rather, the avoided production and transmission capacity costs savings created by NS Power's ability to dispatch the PHP load above 8 MW are partially allocated to other ATL customers under NS Power's proposed ELID Tariff design.

Q DOES NS POWER RECOVER PORTIONS OF ITS GENERATING RESOURCE COST THROUGH THE ELID ENERGY CHARGE?

A Yes. NS Power uses a System Load Factor ("SLF") methodology to functionally allocate generating resource cost to demand and energy.[15] This uniform SLF approach calculates the portion of costs classified as "energy" by dividing the average annual demand by the demand during system coincident peak hours, applying this same standard to all generation assets including wind, hydro, and steam. This means that

[15] M11175, Cost of Service Study Process, NS Power, September 18, 2025, Page 13.

under the ELID Tariff, PHP will support the cost recovery of a significant portion of generating resource cost through the ELID energy charge.

Q DOES NS POWER RESOURCE PLANNING IDENTIFY HOW PRODUCTION RESOURCE CAPACITY IS IDENTIFIED TO SERVE THE ATL PEAK DEMAND?

A. Yes. NS Power's resource planning design specifies targeted resource reliability to achieve a loss of load expectation of 0.1 days/yr. This expected ability to serve load is based on estimating the effective capacity rating of its generating resources (which differs from the resources' nameplate capacity rating), relative to its ATL customer "Firm Peak Load Net of DSM," plus a planning reserve margin of 21%.[16]

Q ARE THE INTERRUPTIBLE SERVICE AS CONTAINED IN THE ELID AND THE LIIR COMPARABLE?

A No. The LIRR interruptible service is limited to system reliability support. In contrast, the ELID tariff provides interruption for economic and reliability purposes. Also, the ELID is interrupted ahead of the LIRR in NS Power's proposed order of interruption. The ELID allows NS Power to interrupt the PHP supply as a dispatch resource that will be used to produce system power supply savings. The ELID is also subject to interruptions at the discretion of NS Power if needed to reliably serve its ATL firm customers' peak demands during peak demand periods and/or during system emergencies.

In contrast, under the LIRR tariff, customers can only be interrupted for "16 hours a day and 5 days per week to a maximum of 30% of the hours per month,

[16] Novia Scotia Power Inc, Overview of PRM Study, August 7, 2019, at 20-21.

and 15% of the hours per year." [17] The LIIR interruptible service is not used as a dispatch resource, and has limited hours of interruption.

Q HOW SHOULD THE ELID TARIFF BE CHANGED TO MORE EQUITABLY REFLECT PHP'S FIRM AND INTERRUPTIBLE SUPPLY?

A The ELID provides both firm service and interruptible service to PHP. The cost of firm service is based on NS Power's COS, which allocates the cost of its production and transmission resource portfolio capacity costs across its customer rate classes to align with its cost to service its customers.

PHP firm demand service will contribute 8 MW to NS Power firm ATL peak demand. Hence, the firm 8 MW demand charge should reflect the PHP allocated cost of including its 8 MW peak demand in NS Power's 3-CP capacity cost allocation used within its COS. As discussed previously, PHP's interruptible demand in excess of its firm service demand will be paid for by the non-fuel cost included in the ELID energy rate. No interruptible credit would be needed in this ELID pricing structure.

This ELID pricing structure is cost-based because it requires PHP to pay NS Power the cost of resource capacity needed to serve its firm peak demand, plus the Planning Reserve Margin ("PRM"). The interruptible demand in excess of the firm demand level does not cause NS Power to incur additional resource capacity to serve firm demand, because the interruptible load can be curtailed during periods where NS Power's resource capacity is not sufficient to serve the interruptible load.

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[17] NS Power Large Industrial Tariff, page 5 of 6.

Q IF NS POWER'S PROPOSED ELID TARIFF RATE DESIGN IS PREFERRED BY THE BOARD, HOW SHOULD IT BE MODIFIED TO REFLECT NS POWER'S COST OF PROVIDING SERVICE TO PHP?

A If NS Power's structure of the ELID is adopted, PHP will pay for NS Power's cost of resource capacity needed to service 65 MW of firm demand. However, PHP will only impose 8 MW of firm peak demand on the Company, and the 57 MW difference will be subject to interruption at the discretion of NS Power. The Company will interrupt PHP when it does not have adequate resource capacity to meet the firm service customers' peak demands during its winter peak season, or during system emergencies. As such, the PHP interruptible demands will be dispatched or curtailed during peak periods and will enhance NS Power's resources available to reliably service its firm service customers. This dispatch right to curtail PHP's load during peak periods is equivalent to adding an additional resource capacity supply that would otherwise be needed to provide reliable firm service to ATL customers' if PHP's interruptible service were not offered. Under the Company's proposed ELID design, the interruptible credit should be the same as the avoided cost of adding resource capacity. NS Power estimates that its marginal cost of adding new peaking capacity is $13.107/KVA in 2020. The interruptible credit should be set equal to this avoided cost capacity addition of $13.107/KVA and should be applied to all demand above 8 MW up to the 65 MW of demand cost the Company proposed to include in the ELID Demand charge. In addition, as will be discussed in greater detail later in the testimony, NS Power should update the interruptible credit to reflect its current cost of capacity.

Other ATL firm customers will be indifferent to this interruptible credit because it represents the same additional cost to NS Power and its firm ATL customers by aligning the amount of resource capacity that is needed to serve the ATL firm peak demand. That is, NS Power can align its resource capacity with its ATL customers' firm demand by either: 1) adding additional resource capacity that would be needed to serve a larger ATL firm demand, or 2) incur a cost to reduce its ATL firm demand by paying an interruptible credit that reduces the firm demand PHP places on the ATL system. The cost of adding new resource capacity and the cost to reduce the ATL firm demand will have the same impact on NS Power's cost for firm service to ATL customers. Hence, ATL firm customers will be economically indifferent for these two resource options. .

Q IS NS POWER'S PROPOSED ELID TARIFF RATE REASONABLE?

A. No. NS Power's proposed ELID capacity charge and interruptible credit are imbalanced and overcharge PHP for its cost of providing service to PHP. The ELID Tariff pricing should be modified as explained above.

III. DEMAND COST ALLOCATION

Q PLEASE DESCRIBE NS POWER'S PROPOSED DEMAND-RELATED COST ALLOCATION UNDER THE ELID.

A The proposed resource capacity cost to the ELID Tariff is based on NS Power's system embedded COSS methodology, which allocates demand-related costs to the class based on the classes' contribution to NS Powers Three Coincident Peaks ("3-CP") during the winter peak period demands. The NS Power 3-CP occurs during the winter months of December, January, and February. The 3-CP demand is the sum of the coincident ATL customers' single largest hourly system peak demand in each month being included in the system 3-CP demand allocation. For PHP, NS Power proposes to include its actual demands during the two-year period to be included in the system

3-CP demand. Because PHP was not required to curtail load during some of the peak demand periods, its 3-CP contribution includes both its firm demand of 8 MW, and the amount of interruptible demand that was not interrupted or dispatched down in the historical period.

For the 2026 and 2027 test years, the Settlement Agreement assumes for modelling purposes a PHP 3-CP demand of 65 MW, which consists of PHP's 8 MW firm demand service, and 57 MW of its interruptible demand service.[18]

Q PLEASE PROVIDE YOUR UNDERSTANDING OF HOW THE 65 MW 3-CP DEMAND LEVEL WAS DETERMINED BY NS POWER.

A During the General Rate Application Settlement Discussions that took place in 2024 and 2025, it was determined that PHP's average metered 3-CP demand during 2022 and 2023 was approximately 65 MW. We have shown the date and times of these historical CPs in Table 2 below.

[18] Application at 5-6.

TABLE 2

Nova Scotia Power
Summary of PHP Historical 3-CPs
(2033-2023)

Date	Hour	NSP Demand (kW)	PHP Demand (kW)
1/11/2022	1800	2,215,698	70,056
2/15/2022	1900	2,112,013	91,871
12/13/2022	1800	1,973,475	111,230
1/12/2023	900	1,915,457	10,860
2/4/2023	1200	2,467,302	9,219
12/22/2023	1800	2,040,914	98,756
Average		2,120,810	65,332

Source: Cost of Service Study (NSUARB M11475)
NSPI Response to PHP Data Request, Request DR-13.

As can be seen from Table 2, the average of the 2022 and 2023 PHP demands at the winter CPs is 65,332 kW, or approximately 65 MW. However, the actual PHP 3-CP values used in the N-1 excel workpaper supporting the Application are 67,790 kW in 2026 and 67,801 kW in 2028 to account for line losses.

Further, PHP's demand at the time of all these CPs was primarily informed by the system operator, meaning whether PHP's demand was 9.2 MW, as it was on February 4, 2023, or 111.2 MW as it was on December 13, 2022, was based on the dispatch level set by the system operator. This is a function of the Active Demand Control ("ADC") operations used to control PHP's load. Under the Dispatchable Rider, the utility manages PHP's load in response to real-time system conditions, causing demand to fluctuate significantly. Because of these wide swings, the Application states that relying strictly on metered data would not provide a fair allocation of demand-related costs.[19] Consequently, the 65 MW determinant was selected as a representative level of system usage, ensuring that demand-related cost recovery remains predictable and fixed throughout the billing year.

Lastly, there is a clear outlier among the historical system CPs during the 2022-2023 period shown in Table 2. Specifically the peak recorded on February 4, 2023, at hour 12:00 is significantly higher than any other CPs during this period. During this hour, system demand reached 2,467,302 kW, exceeding the period's average by 346,492 kW due to record-breaking low temperatures that NS Power described as the most extreme conditions seen in nearly 20 years.[20] Amidst this event, PHP's demand was dispatched down to approximately 9 MW, its lowest recorded level during any coincident peak in that two-year window. This deep reduction effectively halted mill production, allowing the utility to prioritize available power for residential heating and emergency services. This event underscores the value of PHP's curtailable/interruptible service provided to NS power and its ability serve its ATL customers' firm demands. This event also demonstrates that the 65 MW PHP billing determinant that is used for the 3-CP cost allocation does not reflect the service to PHP, as the capacity available to PHP's fluctuates based on NS Power's System Operator's dispatch instructions that prioritize providing reliable service to the ATL firm customers over the interruptible service that is provided in large part to PHP. Please refer to the Direct Evidence of Bevan Lock and John Esaiw for additional information about how the Company operates during peak demand events.

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[19] Application at 6.

[20] https://www.nspower.ca/about-us/articles/details/articles/2023/02/06/you-asked-we-answer-what-happened-this-past-weekend-with-the-extreme-temperatures.

Q HOW SHOULD PHP'S DEMANDS BE REFLECTED IN A 3-CP DEMAND ALLOCATION BASED ON COST CAUSATION PRINCIPLES?

A PHP's firm peak demand will require NS Power to incur resource capacity costs to reliably serve its ATL customers system coincident firm peak demand, and should be reflected in a 3-CP production cost allocator. However, PHP's interruptible demand does not require NS Power to incur resource capacity costs, because this interruptible demand can be curtailed when NS Power does not have sufficient capacity resources to serve its peak demand. Therefore, PHP's interruptible demands are served on an as-available basis, do not impact the NS Power cost of system resource capacity costs, and, therefore, should not be included in the 3-CP resource capacity allocator.

As noted above, NS Power resource adequacy planning is based on its "firm peak demand" and the Company must have a sufficient amount of resource capacity that is needed to serve its firm peak demand plus a planning reserve margin. Because NS Power resource planning does not plan for the effective generating capacity to be needed to serve interruptible peak demands, it is not consistent with cost causation to include PHP's interruptible demands in the development of a 3-CP system resource capacity allocator. Including interruptible demand in the PHP contribution to the system 3-CP allocator, results in the allocation of firm resource capacity cost to PHP for its interruptible service demand. This is not reasonable and over allocates capacity costs to PHP, particularly when the interruptible credit is set at an arbitrarily low value and below the avoided capacity cost price.

A similar cost-causative relationship exists regarding the transmission system. Transmission planning, specifically Steady-State Power Flow Analysis, is designed to ensure the grid satisfies N-1 contingency requirements, maintaining safe thermal and voltage limits even if a major component trips during the year's highest demand. It is our understanding that these reliability studies assume that PHP's demand is minimal during system peaks. Because PHP's load is not a driver for additional transmission investment or capacity expansion, principles of cost-based rate-making support a minimal demand allocation that reflects this lack of cost causation.

Q DOES THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS ("NARUC") ELECTRIC UTILITY COST ALLOCATION MANUAL SUPPORT THESE COST-CAUSATIVE PRINCIPLES?

A Yes, the NARUC Electric Utility Cost Allocation Manual is regarded as a reliable reference for utility COSS. The NARUC Electric Utility Cost Allocation Manual provides a theoretical foundation that supports the use of cost based demand allocation of infrastructure costs. At its core, the manual emphasizes the principle of cost causation, which dictates that costs should be allocated to the specific customers or classes that cause the utility to incur those costs.

NS Power does not include interruptible demands when forecasting the amount of resource effective capacity needed to reliably serve its firm peak demand. Again, interruptible demands do not "cause" the need for incremental capacity additions or infrastructure expansion. Under the NARUC framework, if a customer's usage does not drive the utility's investment decisions or cost incidence, this limited or non-existent cost causation is considered in apportioning the utility's costs across rate classes and is fair and equitable to all customers.[21]

Furthermore, while the NARUC manual supports the use of CP methodologies, such as the 3-CP approach, it also allows for flexibility in how those determinants are set to ensure they reflect the actual cost to serve a specific customer, or class of

[21] NARUC Electric Utility Cost Allocation Manual at 41.

customers.[22] For a dispatchable industrial customer whose load is controlled by the System Operator to protect the grid during emergencies, the manual's principles of "fairness"[23] and "equity"[24] justify using a lower demand determinant. This approach aligns with the manual's objective of apportioning costs in a manner that recognizes the unique operational constraints and system benefits provided by large, flexible loads.

Q HOW DO YOU RECOMMEND THE 3-CP DEMAND ALLOCATOR BE DEVELOPED TO ENSURE FAIR COST BASED TREATMENT TO ALL NS POWER ATL CUSTOMERS, INCLUDING PHP, IN THIS PROCEEDING?

A We recommend that PHP's 3-CP demand of 8 MW be reflected in the 3-CP capacity cost allocator. A 3-CP allocator based on customers' firm demands aligns NS Power's resource planning cost to reliably serve its customers' firm and interruptible demands.

Q WHAT ARE THE RATE IMPLICATIONS FOR PHP IF THE BOARD ACCEPTS YOUR PROPOSED WINTER MONTH SYSTEM COINCIDENT DEMAND FOR PHP?

A NS Power provided an updated COSS for 2026 and 2027 based on a reduction in PHP's total demand coincident with the winter system peaks reduced from 65 MW to 8 MW in Undertaking U-3.[25] Based on these results PHP's rate would be reduced by approximately $6.5 million in 2026[26] and $9.4 million[27] in 2027. These reductions more

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[22] *Id.*
[23] *Id.* at 149.
[24] *Id.*
[25] 2026-2027 General Rate Application (NSEB M12451), Undertaking U-3.
[26] "N-75(C)(i) Response to Undertaking U-03 Att 01 PCON EO.xlsx" provided in response to Undertaking U-3.
[27] "N-75(C)(iii) Response to Undertaking U-03 Att 03 PCON EO.xlsx" provided in response to Undertaking U-3.

accurately reflect appropriate cost causation principles, which NS Power's Application does not.

IV. INTERRUPTIBLE CREDIT

Q DESCRIBE THE PHP INTERRUPTIBLE SERVICE CREDIT?

A The PHP Interruptible Service Credit is a component of the ELID Tariff that provides a monthly reduction in demand charges when the customer's load is curtailed. According to NS Power, the Application largely adopts the terms of the Settlement Agreement. For the 2026 and 2027 years, the proposed interruptible credits for the Large Industrial Customer Tariff were set at $7.638 per kVA in 2026 and $7.667 per kVA in 2027, respectively. NS Power proposed to apply these demand credits to the ELID with a priority credit 10% addition to reflect the Company's proposed Order of Interruptibility.[28] Under the NS Power proposed Order of Interruptibility, the ELID will be interrupted before interruptions to Large Industrial Tariff customers.

Q DOES THE ELID PROVIDE PHP FULL CREDIT FOR SYSTEM RESOURCE CAPACITY SAVINGS CREATED BY ITS INTERRUPTIBLE OR 'NON -FIRM' LOAD TO PHP?

A No, it does not provide a full credit for PHP's willingness to be interruptible above its 8 MW firm base demand, and NS Power's ability to avoid the incremental cost of additional production resource capacity that would otherwise be needed to serve a higher ATL system firm peak demand. These avoided production and transmission capacity costs are material. Specifically, NS Power's avoided production capacity cost

[28] *Id.* at Attachment 1 at 7.

ranges from its embedded production and transmission cost of $14.310/KVA[29] (the proposed ELID demand charge for 2027), to its marginal production capacity cost estimated to be $13.107/KVA[30]. This marginal production capacity cost is the same as NS Power's estimated cost of adding additional natural gas peak production capacity[31] needed to serve its ATL system's firm peak demand in 2020.

In its Application, NS Power states it uses an Annual Levelized Avoided Peaker Cost of $160.44/kW, which is consistent with what was used for the 2026-2027 GRA. However, NS Power's capacity costs have increased significantly since the $160.44/kW avoided cost figure was established. The benchmark of $160.44/kW for the Annual Levelized Avoided Peaker Cost is fundamentally based on the 2020 Integrated Resource Plan (and the associated 2019 Supply Options Study conducted for NS Power by E3). This value represents the Levelized Cost of Capacity for a "proxy" 100 MW Simple Cycle Combustion Turbine using 2019 nominal dollars.

Under the proposed ELID, PHP receives a credit of $7.667/KVA, which is well below NS Power's avoided production capacity cost, in the range of $14.31/KVA to $13.107/KVA. Under the ELID as proposed, PHP would pay an interrupted capacity charge of $6.643/KVA ($14.31 less a credit of $7.667) for interruptible demands that do not contribute to NS Power's "Firm Peak Load" resource capacity obligation, and do not contribute to NS Power resource capacity costs. Hence, PHP will be paying a subsidy to NS Power for the cost of resources that are needed to provide reliable "firm" service to other ATL customers. This resource capacity subsidy included in the proposed ELID tariff is not reasonable.

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[29] *Id*. at 6 for 2027.
[30] *Id*. at 8 footnote 5.
[31] Nova Scotia Power, 2020 Integrated Resource Plan (IRP), Final; Assumptions Set, March 11, 2020.

Under the proposed ELID Tariff, PHP will pay a capacity charge based on a full allocated cost of resource capacity needed to serve PHP's assigned 3-CP demands (65 MW), which includes both its firm 8 MW demand and 57 MW of interruptible demand. But despite the 3-CP allocation of 65 MW of firm capacity used to set the ELID Capacity charge, PHP is only entitled to 8 MW of firm demand service. The interruptible credit on the 57 MW of interruptible service should be set at NS Power full avoided cost of adding new resource capacity additions, $13.107/KVA.

Q IF THE ELID INTERRUPTIBLE CREDIT WAS SET AT NS POWER'S AVOIDED CAPACITY COST OF $13.107/KVA, WOULD PHP PAY ANY CAPACITY COST FOR ITS INTERRUPTIBLE SERVICE?

A Yes. The proposed ELID 2027 energy charge of $0.1124/KWh[32] exceeds NS Power's average fuel cost in the LI tariff of $0.08299/kWh.[33] Hence, NS Power will collect non-fuel margins in the ELID energy rate for all PHP energy purchases from NS Power. The energy rate recovers a large percentage of NS Power non-fuel costs, which are predominantly production, transmission, and related administration charges. Under this approach, PHP would also pay the difference between the proposed demand charge of $14.310/kVA and the credit of $13.107/KVA.

Q HAS NS POWER'S CAPACITY COST INCREASED SINCE THE CURRENT ESTIMATE OF THE AVOIDED COST OF A PEAKING UNIT HAS BEEN CALCULATED IN THE ELID TARIFF?

A Yes, NS Power's capacity costs have increased significantly since the $160.44/kW avoided cost figure was established. The benchmark of $160.44/kW for the Annual

[32] Application, Attachment 1, page 2 of 8 for the energy charge.
[33] NS Power Excel Workpaper N-1.

Levelized Avoided Peaker Cost is fundamentally based on the 2020 Integrated Resource Plan ("IRP") and the associated 2019 Supply Options Study conducted for NS Power.

Since this estimate was established, NS Power's capacity costs have experienced a significant upward trend. In the 2023/2024 Evergreen IRP process and the 2025 IRP Action Plan and Roadmap Update, NS Power and independent consultants like Synapse Energy Economics have explicitly stated that market costs for peakers and other supply-side options have increased compared to the 2020 data.[34] These increases are driven by several factors, including global supply chain inflation for turbine equipment, higher financing costs, and a transition toward more expensive dual-fuel units (natural gas and hydrogen or oil) required to meet new provincial reliability and clean energy standards.

Q IS NS POWER'S NEED FOR RESOURCE CAPACITY TO SERVE PEAK DEMAND EXPECTED TO CHANGE GOING FORWARD?

A Yes. The obligation for NS Power to retire its remaining coal-fired generation by 2030 is a primary driver for an anticipated increase in capacity costs. Currently, coal provides a significant portion of the province's firm capacity, and its accelerated phase-out creates a substantial "capacity gap."[35]

To bridge this substantial gap, the utility must invest in a complex mix of fast-acting natural gas generation, long-duration battery storage, and enhanced transmission interconnections like the Salisbury-Onslow reliability tie.[36] Further, dispatchable capacity additions options may be constrained by limitations in firm

[34] Nova Scotia Power 2023 Evergreen Integrated Resource Plan; Nova Scotia Power Integrated Resource Plan Action Plan Update 2025.
[35] Nova Scotia Clean Power Plan 2023.
[36] NS Power 10-Year System Outlook 2025.

natural gas delivery supply, as noted by NS Power in its most recent Overview of PRM Study.[37]

Dispatchable capacity and load resources are needed to perform a load following function to supplement NS Power intermittent generation resources. NS Power describe the reliability benefit of operating reserves to be:

> Operating reserves represent the quantity of reserves that must be maintained and which NSPI will shed load to maintain –these values are less than the typical operating reserves that are held by NSPI which can decrease in extreme grid conditions. Operating reserves are necessary to be able to quickly react to unexpected grid conditions that might otherwise result in significant grid problems if operating reserve are not available.[38]

In Summary, not only does NS Power acknowledge the significant benefit of dispatchable capacity and operating reserves, but NS Power is expected to invest in additional capacity resources in the near-term to be able to continue to reliably serve its customers. The value of the interruptible demand that PHP provides will continue to increase on the system as NS Power undergoes this energy transition.

Q IS NS POWER'S ELID PROPOSED INTERRUPTIBLE CREDIT REASONABLE?

A. No. Under the proposed ELID, the interruptible credit will not remove the cost of resource capacity needed to serve firm customers from the cost of providing PHP interruptible service. The interruptible credit should reflect the avoided cost savings to NS Power that is created when PHP's demands are curtailed above its firm demand service of 8 MW. The avoided cost benefit to NS Power and its firm service ATL customers is the cost that is avoided by interrupting PHP rather than investing in new production resource capacity. NS Power estimates its marginal cost of adding

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[37] *Id*. at page 18.
[38] *Id.* at 20.

production resource capacity during its 3-CP peak periods to be $13.107/KVA.[39] Hence, to the extent the Board approves the use of a demand charge applicable to PHP's interruptible load, the ELID interruptible credit should be based on this avoided cost. NS Power's firm service customers will be economically better off either by paying $13.107/KVA to PHP or by adding new capacity resource additions to the NS Power resource portfolio. If PHP is allocated demand costs exceeding its 8 MW firm peak demand level, it should receive an interruptible credit that fully reflects the system benefits provided by its interruptible load.

V. REVENUE-TO-COST RATIO

Q WHAT IS NS POWER PROPOSING IN TERMS OF AN R/C RATIO FOR PHP'S NEW ABOVE-THE-LINE ("ATL") TARIFF?

A According to NS Power's COSS, the Revenue to Cost ("R/C") ratios applicable to PHP is 1.04373. This means that the ELID rate is designed to collect revenue 4.373% greater than NS Power's cost to serve PHP.

Q IS IT APPROPRIATE TO APPLY AN R/C RATIO GREATER THAN 1.0 TO A CUSTOMER TRANSITIONING FROM A MARGINAL COST RATE TO AN ATL TARIFF?

A No. Applying a R/C ratio greater than 1.0 to a customer transitioning from a marginal cost-based rate to an ATL tariff is generally considered inappropriate because it violates the fundamental regulatory principle of cost causality. In utility rate-making, the primary objective of an Embedded Cost of Service Study ("ECOSS") is to ensure that each customer class pays for the specific assets and operating expenses it

[39] Application at 8 footnote 5.

imposes on the system. When a regulator sets an R/C ratio above 1.0, they are intentionally over-collecting from that customer to subsidize other classes. While this is sometimes done for residential protection, applying it to a customer already undergoing a structural shift to a full-cost tariff creates an inequitable "double hit." The transition to an ATL tariff is designed to capture a fair share of fixed overhead; adding a premium on top of that shift means the customer is no longer paying their fair share, but is instead being used as a revenue generator for the utility's other obligations. Other customer classes with a positive R/C ratio indicates that these customer classes have benefited from the changes made to the COSS. However, in this instance, this is not applicable to PHP since they were not previously served at a cost-based rate under previous COSS models.

Q WHAT DO YOU RECOMMEND THIS BOARD APPROVE AS THE APPROPRIATE R/C RATIO APPLICABLE TO PHP IN THIS PROCEEDING?

A We would recommend that an R/C ratio of 1.0 be applied to PHP's rate calculation under the proposed ELID tariff. PHP would be in a new customer class and has not previously been costed through the COSS on an above-the-line basis. Therefore, we recommend an equitable R/C ratio of 1.0, ensuring PHP pays its cost to serve without subsidizing or being subsidized by other classes.

VI. FORECASTED ENERGY REQUIREMENTS

Q WHAT IS NS POWER PROPOSING IN TERMS OF PHP'S FORECAST ENERGY REQUIREMENTS IN 2026 AND 2027 IN CALCULATING PHP'S NEW ABOVE-THE-LINE TARIFF?

A NS Power has established specific forecast energy consumption levels for PHP to calculate the proposed embedded costs, energy costing, and billing determinants for the 2026-2027 test years. For the 2026 calendar year, the assumed energy consumption for PHP in the General Rate Application (GRA) COSS is 810.5 GWh. For 2027, the forecast requirement drops significantly to 304.3 GWh. This substantial reduction in the 2027 forecast is primarily attributed to the anticipated displacement of NS Power electricity supply by energy generated from the Goose Harbour Lake Wind Farm (PHPW) under a Power Purchase Agreement.

The energy charges proposed for these years (9.977 cents per kWh for 2026 and 11.240 cents per kWh for 2027) apply to energy supplied to the customer in excess of the "Subject Energy Amount" deemed provided through the Power Sales Agreement associated with the wind farm. Under this structure, the Subject Energy Amount is deemed to be delivered to the facility before any regulated tariff energy is supplied by NS Power. Furthermore, the company notes that these ultimate energy charges remain subject to potential changes depending on the outcome of ongoing court proceedings regarding PHP's responsibility for costs related to the Maritime Link Federal Loan Guarantee.

Q WHAT DO YOU RECOMMEND THIS BOARD APPROVE AS THE APPROPRIATE ENERGY REQUIREMENTS FOR CALCULATING PHP'S NEW ABOVE-THE-LINE TARIFF IN THIS PROCEEDING?

A We would recommend that the proposed ELID tariff reflect the current forecast energy sales as provided in PHP's direct evidence. These forecasted energy sales figures more accurately reflect the likely energy sales to PHP in the applicable years. Aligning the tariff with current usage assumptions ensures that energy cost allocations and revenues accurately reflect PHP's actual cost of service. By reflecting the total system energy usage upfront, this establishes more accurate per-unit rates.

VII. CONCLUSION

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A In conclusion, Mr. Fitzhenry and Mr. Gorman recommend several modifications to Nova Scotia Power Inc.'s proposed ELID Tariff to better align with cost-causation principles. Their primary recommendations include designing the capacity charge to reflect PHP's actual 8 MW firm demand rather than the proposed 65 MW, adjusting the interruptible credit to match Nova Scotia Power's marginal cost of capacity at $13.107/kVA, and applying a revenue-to-cost ratio of 1.0 to prevent PHP from subsidizing other customer classes. Additionally, they urge the Board to adopt updated 2026 and 2027 energy sales forecasts to ensure that rate allocations accurately reflect PHP's expected usage following the integration of the Goose Harbour Lake Wind Farm.

Q DOES THIS CONCLUDE YOUR EVIDENCE?

A Yes, it does.

Colin T. Fitzhenry

Professional Qualifications and Expert Testimony Listing

Testimony and Regulatory Litigation Support

Mr. Fitzhenry has provided expert testimony in utility regulatory proceedings before state commissions in connection with rate cases and various other utility matters. In addition, Mr. Fitzhenry has participated in settlement hearings at the Federal Energy Regulatory Commission regarding Formula Rate Tariff modifications. His testimony has focused on a number of topics, including capital expenditure prudency, net power cost, multi-year rate plans, service reliability and other utility-related matters. Mr. Fitzhenry has collaborated with outside counsel in the development of litigation strategies supporting rate proceedings, including testimony development, responding to discovery requests from utilities, interveners and commission staff, and in the preparation of legal briefs.

Professional Background

Principal, Brubaker and Associates (January 2026-Present)
Associate, Brubaker and Associates (July 2024-December 2025)
Senior Consultant, Brubaker and Associates (January 2023-June 2024
Associate Consultant, Brubaker and Associates (2021-2022)
Engineer, Brubaker and Associates (2013-2020)
Engineer Intern, Dynegy (2009)

Educational Background

B.S. in General Engineering, University of Illinois Urbana-Champaign

Conference Seminars and Presentations

BAI Fall Seminar, Competitive Procurement: Gas Market Structure, Multiple Years.

Testimony in Utility Regulatory Proceedings

Summary of Testimony in Utility Regulatory Proceedings			
Application	**Commission**	**Docket/Case No.**	**Subject**
Ameren Illinois Company	Illinois Commerce Commission	Docket No. 22-0487	Capital Projects and System Reliability Metrics
Commonwealth Edison Company	Illinois Commerce Commission	Docket No. 22-0486	Capital Projects and System Reliability Metrics
Columbia Gas of Maryland, Inc.	Maryland Public Service Commission	Case No. 9701	Capital Expenditures and STRIDE Investments
Rocky Mountain Power	Public Service Commission of Wyoming	Docket No. 20000-633-ER-23	Net Power Cost and Energy Cost Adjustment Mechanism
Washington Gas Light Company	Maryland Public Service Commission	Case No. 9704	Infrastructure Riders and Capital Expenditures
Georgia Power Company	Georgia Public Service Commission	Docket No. 55378	Integrated Resource Planning
Rocky Mountain Power	Public Service Commission of Wyoming	Docket No. 20000-653-EA-23	Reliability and Power Quality, Service Quality Reports
DTE Gas Company	Michigan Public Service Commission	Case No. U-21291	Capital and Operating Expenditures
Easton Utilities Commission	Maryland Public Service Commission	Case No. 9719	Capital and Power Production Expenditures
PacifiCorp	Public Utility Commission of Oregon	Docket No. UE 434	Net Power Cost and Transition Adjustment Mechanism
Chesapeake Utilities Corporation	Maryland Public Service Commission	Case No. 9722	Capital Expenditures and Operating and Maintenance Expenditures
Baltimore Gas and Electric Company	Maryland Public Service Commission	Case No. 9645	Reconciliation of Mulit-Year Rate Plan
Columbia Gas of Maryland, Inc.	Maryland Public Service Commission	Case No. 9754	Capital Expenditures and STRIDE Investments
Rocky Mountain Power	Public Service Commission of Wyoming	Docket No. 20000-653-EA-24	Reliability and Power Quality, Service Quality Reports
NV Energy	Nevada Public Service Commission	Docket No. 24-05041	Load Forecast
Rocky Mountain Power	Utah Public Service Commission	Docket No. 24-035-04	Net Power Cost
Washington Gas Light Company	Public Service Commission of the District of Columbia	Case No. 1179	Approval for Natural Gas Infrastructure Replacement Plan
Rocky Mountain Power	Public Service Commission of Wyoming	Docket No. 20000-671-ER-24	Net Power Cost and Production Cost Modeling
Washington Gas Light Company	Public Service Commission of the District of Columbia	Case No. 1180	Capital Expenditures and PROJECTpipes Investments
Evergy Kansas Central	Kansas Corporation Commission	Docket No. 25-EKCE-207-PRE	Predetermination of Ratemaking Principles for New Generating Resources
Consumers Energy Company	Michigan Public Service Commission	Case No. U-21806	Capital and Operating Expenditures
Duke Energy Indiana	Indiana Utility Regulatory Commission	Cause No 46193	CPCN to Construct a New Natural Gas Generating Resource and Ratemaking Treatment
Indiana Michigan Power Company	Indiana Utility Regulatory Commission	Cause No 46217	CPCN to Acquire Oregon Clean Energy Center and Ratemaking Treatment
Ameren Illinois Company	Illinois Commerce Commission	Docket No. 25-0382	Reconciliation Capital and Operating Expenditures
DTE Electric Company	Michigan Public Service Commission	Case No. U-21860	Benefit-Cost Analysis and Distribution Investment Programs
Commonwealth Edison Company	Illinois Commerce Commission	Docket No. 25-0383	Reconciliation Capital and Operating Expenditures
Portland General Electric Company	Public Utility Commission of Oregon	UM 2377	HB 3546 Alignment, Direct Access Impact/Green Tariff Ratemaking Options, and the large New Load Direct Access program
Southwestern Public Service Company	New Mexico Public Regulatory Commission	25-00066-UT	CPCN for Eight Self-Build utility-Owned Resources

Curriculum Vitae of

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Occupation

Mr. Gorman is a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Education Background and Work Experience

In 1983, Mr. Gorman received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, he received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. He has also completed several graduate level economics courses.

In August of 1983, Mr. Gorman accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, he performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, he was promoted to the position of Senior Analyst. In this position, he assumed the additional responsibilities of technical leader on projects, and his areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, Mr. Gorman was promoted to Director of the Financial Analysis Department. In this position, he was responsible for all financial analyses conducted by the Staff. Among other things, he conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. He also supervised the development of all Staff analyses and testimony on these same issues. In addition, he supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, Mr. Gorman accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, he worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, Mr. Gorman accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, Mr. Gorman has performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. He also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, Mr. Gorman also has extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. He has participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. He has also analyzed commodity pricing indices and forward pricing methods for third-party supply agreements, and has also conducted regional electric market price forecasts.

In addition to the main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Testimony Sponsorship Before Regulatory Bodies

Mr. Gorman has sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. He has also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate-setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Professional Registration and Organizational Membership

Mr. Gorman earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. Mr. Gorman is a member of the CFA Institute's Financial Analyst Society.