Matter No. M12619

In the Matter of

EVIDENCE OF

JOHN D. WILSON

ON BEHALF OF

THE CONSUMER ADVOCATE

Grid Strategies, LLC

MARCH 2, 2026

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I. Identification & Qualifications

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the Vice President of Grid Strategies LLC, Bethesda, MD.

Q: Summarize your professional education and experience.

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods. I have been employed by Grid Strategies since 2023, and previously I performed similar duties as an employee of Resource Insight.

Prior to entering consulting in 2019, I was deputy director of regulatory policy at the Southern Alliance for Clean Energy ("SACE") for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of pro-spective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, prudency review, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Attachment 1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than seventy-five times before utility regulators in twelve US states and Nova Scotia, and appeared numerous additional times before various regulatory and legislative bodies.

Q: Have you previously provided evidence in other matters before this Board?

A: Yes. I have filed evidence in over twenty-five matters. I have also assisted the Consumer Advocate in preparing comments and developing positions in numerous proceedings and stakeholder processes.

Q: On whose behalf are you providing evidence?

A: My evidence is sponsored by the Nova Scotia Consumer Advocate.

II. Introduction and Summary

Q: Please summarize NS Power's application.

A: NS Power is seeking Board approval of 20 capital work orders and the 2026 capital routine program with total project investment of $284 million.[1] Together with capital projects under $1,000,000 and Point Aconi projects that do not require NSUARB approval, carryover spending, capital routines, and subsequent submittal items, NS Power's overall 2026 capital budget amount is $702.1 million.[2]

Some of the other key information that NS Power has submitted includes its Capital Expenditure Justification Criteria (CEJC) Update (Appendix D), Mersey Update (Appendix E), Path to 2030 Update (Appendix F), and Five-Year Reliability Plan Update (Appendix G).

Q: What is the purpose of your testimony?

A: I have reviewed most of the issues identified by the Board as well as the specific projects that NS Power seeks approval in its Annual Capital Expenditure Plan for 2025. I have not identified any specific projects that should be rejected by the Board.

In my evidence, I will discuss cost minimization opportunities related to distribution routines, projects without risk matrices, and reliability-related projects. In those discussions, I do raise questions about the total proposed budget and other details for some projects included in the 2026 ACE Plan.

I will also discuss my review of updates to the CEJC, Mersey Hydro report, and Path to 2030 report.

Q: Please summarize your recommendations.

A: The Board should:

1. Revise its reporting requirement for the Work Management and Scheduling & Dispatch project by directing NS Power to estimate quantified benefits to specific capital projects (including routines) and operating expenses and extending the annual reporting requirement by one year. (Section III.A)

[1] Exhibit N-1, *2026 ACE Plan*, p. 14.

[2] *Id.,* p. 15.

2. Direct NS Power to provide a report on whether the Maximo/Salesforce capabilities could be extended to improve operational efficiency and cost minimization in areas where it is not currently scoped for use. (Section III.A)

3. Direct NS Power to adopt the use of an equivalent to the Basis of Schedule for routines in which the work is not "reactive in nature." (Section III.A)

4. Direct NS Power to revise its internal work orders for work done in customer-driven routines to identify the type of customer. (Section III.B)

5. Direct NS Power to monitor external factors driving costs in customer-driven routines. (Section III.B)

6. Reduce the contingency amount for projects filed in this plan to 10% if they do not have a risk matrix filed in the application. (Section IV)

7. Direct NS Power to, in the future, file a risk matrix with any project that has a contingency amount of more than 10%. (Section IV)

8. Ensure that the ongoing third-party review of the Five-Year Reliability Plan considers the effectiveness of the New Distribution Right of Way projects and the larger issue of outages caused by tree contacts. (Section V.A)

9. Obtain an inventory of NS Power's spare equipment to identify whether there is sufficient volume to consider whether a more cost-effective spare inventory pooling option could be available. (Section V.B)

10. Accept NS Power's clarification to the definition of "scope change" in the CEJC and further revise the CEJC to include a requirement for NS Power to file information when it identifies a change to deliverables, boundaries, and/or detailed tasks that it believes **may** result in a budget increase above a Board-specified threshold, followed by a Board decision as to whether NS Power should file a revised application or ATO. (Section VI.A)

11. Approve NS Power's other revisions to the CEJC. (Section VI.B)

12. Revise the CEJC to reflect the Board's determination that the $1 million capital expenditure threshold applies regardless of funding source. (Section VI.C)

13. Revise the CEJC definition of a "related project" to include units that can be substituted for one another in the normal course of business. (Section VI.C)

I also recommend that in the future, NS Power should make two changes to its tree contact reliability metrics (Figures 65-69): removing tree contacts due to adverse weather from these metrics and verifying that its published trendlines exclude year-to-date data in the final year.

Finally, in my reviews of updates to the Mersey Hydro and Path to 2030 report, I offer comments without recommendations for the Board's consideration.

III. Distribution Routines

A. Enhancing cost minimization in capital routines

Q: Does NS Power appear to track person-hours for distribution routines?

A: No, except for D005 – Unplanned Replace Deteriorated Equipment.[3]

Q: Is the lack of data on regular and overtime person-hours of concern?

A: Yes. Several of the distribution routines have substantial overtime labour forecasts, and it is unclear whether NS Power has any internal practices for minimizing the use of overtime.

To be sure, it is reasonable for NS Power to use an "overtime-based model." NS Power explains that, "The variability of trouble / outage calls requiring a response after regular working hours limits the benefit of having a 24/7 shift in most of the province."[4] This is particularly relevant to D005 – Unplanned Replace Deteriorated Equipment, which will usually require an immediate, unplanned response.

But a reasonable model may still be managed inefficiently. The use of overtime labour should be tracked internally, and available for reporting, for the purpose of identifying trends in excessive use of overtime (e.g., for tasks that could be completed during regular hours) and for the purpose of identifying opportunities to schedule personnel and resources for alternative shifts where sustained work is required outside of regular working hours.

For example, the forecast overtime labour for new customer distribution routines D061 and D062 is about 30% of the forecast regular & term labour budget. Similarly, for regulatory replacements (D006), the overtime labour budget is 49%.[5] Given that new customer and regulatory replacements work can be planned at some level,[6] where work is required to be performed outside of scheduled hours at this scale, it may be feasible to schedule alternative shifts for some of this work. This could be revealed by tracking this work and identifying whether staff or contractor labour could justify incurring the costs of maintaining staffing on these schedules (potentially on a seasonal basis).

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[3] Exhibit N-3, CA RIR-7(a); Exhibit N-6, NSEB RIR-31(b).

[4] Exhibit N-3, CA RIR-7(c).

[5] Calculated from Exhibit N-3, CA RIR-7(a).

[6] Noting that in 2025, forecast spending was substantially below budget. Exhibit N-1, 2026 ACE Plan, p. 62; and Exhibit N-6, NSEB RIR-32(b).

Q: Is there any further evidence that NS Power lacks internal controls to ensure effective planning of resources to minimize costs?

A: Yes, NS Power does not utilize a Basis of Schedule practice, or its equivalent, for its capital routine projects. A Basis of Schedule practice "build[s] the project schedule to help ensure that timelines are met and resources are planned in advance of the work commencing."[7]

For many routines, NS Power's explanation for not using a Basis of Schedule practice is reasonable. NS Power states:

> No equivalent process occurs, as the routine program is made up primarily of small scale, like for like replacements that happen over a short period of time where scheduling generally does not vary considerably or are reactive in nature and do not undergo pre-planning activities.[8]

This is certainly true for routines such as D005 (Unplanned Replacement Deteriorated Equipment) and D008 (Provincial Storm).

But for most other routines, the work is not "reactive in nature" (immediate), although some is required "within a prescribed time."[9] For example, the Regulatory Replacements (D006) budget is forecast based on "the volume of work forecasted by the Provincial Department of Public Works and Municipal governments across the Province that will impact NS Power plant."[10]

In these cases, an equivalent practice to a Basis of Schedule could be useful. The standard Basis of Schedule document is probably far more complex than many distribution routine projects might require, including a number of indirect schedule activities such as environmental management and archaeology that would be highly unusual for most distribution routine work.[11] But for direct schedule activities such as general work and site prep, a practice that requires pre-planning of resources could be useful to avoid unnecessary overtime, delay-related costs due to unavailable equipment, and procurement inefficiencies.

In the aggregate, particularly for distribution routines where immediate response is not typically required, the use of an equivalent practice to the Basis of Schedule could help

[7] Exhibit N-3, CA RIR-8.
[8] Exhibit N-3, CA RIR-8.
[9] Exhibit N-6, NSEB RIR-38(b).
[10] Exhibit N-9, M12012, NSUARB RIR-29(a).
[11] Exhibit N-5, M11458, CA RIR-5, Attachment 8.

to either reduce overtime labour or identify an opportunity to schedule labour on an alternate shift to meet the requirements for this work.

Q: Has NS Power documented any efficiency improvements in distribution routine work?

A: Yes. In May 2025, NS Power reported on the initial impacts of its Work Management and Scheduling & Dispatch project, which upgraded deployment of IBM Maximo and Salesforce software. In that report, NS Power indicated that its transactions per labour hour increased significantly enough to result in $2.7 million in benefits, well above the $0.8 million projected for year 1 of the project.[12]

These savings were achieved through outcomes such as enhancing "operational efficiency by eliminating redundant trips and unnecessary site visits."[13]

Q: Is there a potential for further efficiency improvements in distribution routine work?

A: Yes. One area is with contractor management. In its May 2025 report, NS Power states:

> Scheduling and dispatch of work for pole-setting contractors in the new system has been implemented. Ongoing training and change management is being provided to contractors, however the expected benefits for year 1 have not yet been realized due to:
>
> 1. Initial change management efforts focused mainly on internal stakeholders (schedulers and field resources) and not on contractors.
>
> 2. Contractors facing challenges with the new scheduling tools, partly due to varying levels of general technology familiarity.
>
> Ongoing training and change management with contractors are continuing to ensure improvements and future realization of benefits.[14]

Other potential areas for efficiency improvement were discussed in the M10400 proceeding that approved the Maximo/Salesforce upgrades. In evidence I provided in that proceeding, I compared NS Power's implementation of Maximo/Salesforce with that of SCE,

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[12] Exhibit N-1, M12253, M10400 CI46075 – IT – T&D WAM Phase 2 – Work Management and Scheduling & Dispatch Application Benefits Report, p. 3.

[13] Exhibit N-1, M12253, M10400 CI46075 – IT – T&D WAM Phase 2 – Work Management and Scheduling & Dispatch Application Benefits Report, p. 3.

[14] Exhibit N-1, M12253, M10400 CI46075 – IT – T&D WAM Phase 2 – Work Management and Scheduling & Dispatch Application Benefits Report, p. 4.

and suggested that "the software acquired in the proposed project might help reduce costs related to vegetation management, transmission work and tracking the unplanned replacement of deteriorated equipment."[15]

Q: Is it possible that the Maximo/Salesforce software is addressing your concern about the lack of a practice equivalent to the Basis of Schedule?

A: Yes, it seems possible that comprehensive application of a work asset management system that includes NS Power labour, contractors, and key equipment could even be superior to a project-by-project planning practice that closely resembles the Basis of Schedule.

Q: What are your recommendations for the Board?

A: I have three recommendations to enhance cost minimization in capital routines. First, I recommend that the Board revise its reporting requirement for the Work Management and Scheduling & Dispatch project in two respects:

1. The Board should direct NS Power to include in its annual report, beginning in 2027, an estimate of how the quantified benefits apply to specific capital projects (including routines) and to relevant categories of operating expenses. This would provide the Board with context to understand how this project is helping to control costs of the Five-Year Reliability Plan as well as other areas of interest.

2. The Board should extend the annual reporting requirement by one year, through 2028, with a final report in late 2028 or early 2029. Given the slower-than-expected rollout of contractor management, tracking the evolution of those benefits over several years would better verify success in contractor management efficiency improvements and create opportunities for lessons learned that could enhance software use practices.

Second, I recommend that the Board direct NS Power to provide a report on whether the Maximo/Salesforce capabilities could be extended to improve operational efficiency and cost minimization in areas where it is not currently scoped for use, including but not limited to vegetation management, transmission work and tracking the unplanned replacement of deteriorated equipment. NS Power could provide this information in its rebuttal evidence, a compliance filing subsequent to the Board's decision in this proceeding, or in its 2027 ACE Plan. If NS Power identifies further opportunities for operational efficiencies using this software, it should be encouraged to proceed towards a "Phase 3" project expeditiously.

Third, I recommend that the Board direct NS Power to adopt the use of an equivalent to the Basis of Schedule for routines in which the work is not "reactive in nature," or take

[15] Exhibit N-10, M10400, Evidence of John D. Wilson, p. 15.

other measures to identify opportunities to either reduce overtime labour or schedule labour on an alternate shift to meet the requirements for planned work that must occur outside of regular hours. This practice could be an extension of the Maximo/Salesforce capabilities.

While I have developed these recommendations primarily with respect to distribution routines, the Board should not limit their application to distribution routines where the same benefit may be obtained in other routines (e.g., transmission as noted in the discussion of Maximo/Salesforce capabilities).

B. Forecasting New Customer-Driven Work Volumes

Q: Please summarize NS Power's commitments to collect data that would better inform new customer-driven work volumes.

A: In the 2024 ACE Plan proceeding, NS Power committed to "continue to assess how this data could be obtained," noting that if obtained, the data could potentially be "utilized for the purposes of planning at the substation or circuit level, [or] for budgeting purposes." The categories of data that it committed to continue to assess included:

> (a) new customers by single-family, multi-unit, and residential addition categories; (b) increased load capacity at existing residential and commercial sites; (c) unmetered services, such as streetlights; and (d) external factors driving costs, including supply chain issues, shifts in the regular/overtime labour breakdown due to other utility programs.[16]

This commitment was made in response to concerns I raised in evidence regarding NS Power's explanation of the variance between its Load Forecast Report and the trends used to forecast new customer-driven work volumes. For example, NS Power claimed that "Detached garages and other similar new customer claims … [and] Unmetered services (such as streetlights and area lights) and large renovations" are the source of the variance.[17]

Q: Has NS Power kept that commitment?

A: No. NS Power stated that, "at this time, neither revised methodologies nor methods of capturing the data outlined above are being considered."[18] NS Power justifies this based on "observed success in 2025 with the new forecasting methodology developed for these

[16] Exhibit N-16, M11458, NS Power Rebuttal Evidence, p. 17.

[17] Exhibit N-15, M11458, Evidence of John D. Wilson, p. 27.

[18] Exhibit N-3, CA RIR-32(a).

routines, which has resulted in no ATO being required for a New Customer routine for the first time in a number of years."[19]

Q: How would these data be useful?

A: In addition to forecasting new customer distribution routine costs, the information described above would be useful as:

- An input in NS Power's long-term load forecast,
- As an input into distribution circuit planning (e.g., advance notice of needs to upgrade substation transformers or circuit capacity, allowing for least-cost planning and procurement),
- For purposes of improved cost allocation, and
- For purposes of improved rate design.

Most of these data could be collected through internal work orders, which have not been recently changed, and would not be onerous. It would be fairly obvious to NS Power field technicians whether new customer work related to single-family, multi-unit, residential addition, increased load capacity, or unmetered services. Collecting and storing this information would not be onerous.

It could be somewhat more complex to analyze external factors driving costs, but a strong cost minimization management approach would seek to understand the factors driving costs and determine whether they are external and not subject to control or potentially subject to some degree of management and cost minimisation.

Q: What is your recommendation regarding collection of new customer data?

A: I recommend that the Board direct NS Power to revise its internal work orders for work done in customer-driven routines to identify whether the work was done for:

- New customers by single-family, multi-unit, residential addition, single-customer commercial, or multi-customer commercial categories;
- Increased load capacity at existing residential and commercial sites; or
- Unmetered services, such as streetlights.

I further recommend that the Board direct NS Power to monitor external factors driving costs, including supply chain issues and shifts in the regular/overtime labour breakdown due to other utility programs (e.g., storm recovery requiring overtime due to making up customer-driven work to meet service expectations). The Board may wish to express an expectation that where significant impacts from these factors are identified as a

[19] Exhibit N-3, CA RIR-32(a).

cost-driver in an ATO or where the ACE Plan is showing a significant budget increase, that NS Power should have supporting data that demonstrate the significance of the cost-driver and show evidence that NS Power used best practices to minimize costs despite the cost-driver.

IV. Contingency for Projects without Risk Matrices

Q: What contingency amount does NS Power use for transmission projects that do not have risk matrices prepared?

A: NS Power appears to routinely include a 15% contingency in transmission line and transformer project budgets where no risk matrix is prepared. In this proceeding, five of the seven CIs (C0080110, C0070909, C0080109, C0053214, and C0053234) have a 15% contingency with no risk matrix.

In a previous proceeding, NS Power explained that transmission line replacement projects with a 15% contingency "are routine in nature and do not present a higher level of cost risk," further pointing out that, "There are contracts with set pricing in place to control the costs of executing the work," and that "While outage windows for transmission lines can fluctuate, this typically does not have a material impact on completion timelines or overall cost."[20]

Similarly, in this proceeding, NS Power justifies the lack of a risk matrix and detailed schedule on the basis that, "NS Power has significant experience completing and the risks to the project are well understood, as they are generally very consistent across all transformer addition projects."[21]

The only risk matrix provided for a transmission project is for the L6536 Switch Replacements project (C0070586), which has a 20% contingency.[22]

Q: What conclusion do you draw from this review?

A: It appears that NS Power may have a de facto policy of not utilizing a risk matrix or detailed schedule for transmission projects unless it wishes to apply a contingency higher than 15%.

[20] Exhibit N-5, M11458, CA RIR-17.

[21] Exhibit N-3, CA RIR-16(d).

[22] Incidentally, I did not find any reason to challenge the 20% contingency based on the information supplied in the application, Exhibit N-1, 2026 ACE Plan, CI C0070586.

Q: If your deduction is correct, is a policy to not utilize a risk matrix or detailed schedule for projects with a 15% contingency reasonable?

A: No. If these projects are so well understood and so consistent, then a much smaller contingency amount should be utilized. If, on the other hand, it is common for these projects to go well over budget, then a risk matrix should be prepared in order to manage the risks that cause overspending.

It should be understood that a key part of minimizing costs for capital projects is a proactive approach to risk management. Where NS Power believes that its capability to manage risks is well established without following a formal practice, then it should not be using a large contingency in its budget.

Q: What is your recommendation on reasonable contingency for projects without a risk matrix?

A: I recommend that the Board reduce the contingency amount for projects filed in this plan to 10% if they do not have a risk matrix filed in the application. Going forward, the Board should direct NS Power to file a risk matrix with any project that has a contingency amount of more than 10%. The Board should only allow NS Power to exceed a 10% contingency without a risk matrix in cases where NS Power identifies a narrowly-defined risk that is unique to the project (e.g., a specific inspection or study that is incomplete) and does not otherwise necessitate a risk matrix being prepared.

Q: Could a smaller contingency budget increase the number of ATO proceedings?

A: Yes, a possible consequence of the Board adopting my recommendation is that there could be slightly more ATO proceedings. From a cost minimization perspective, that would be a good thing, as the evidence in the ATO proceeding would identify risks that lead to overspending in transmission and other capital projects, increasing the opportunity to manage those risks more effectively in the future.

For example, the L6549 transmission line replacements and upgrades project approved in the 2019 ACE plan had an estimated cost of $2.2 million that included a 10% contingency.[23] Due to a significant increase in full structure replacements, the Board approved NS Power's ATO for $4.0 million (an 81% increase).[24] The increase in full structure

[23] Exhibit N-1, M08984, 2019 ACE Plan, CI C0011339 – L6549 – Replacements and Upgrades Phase 2, p. 3.
[24] Board Decision, M11707 (August 20, 2024).

replacements occurred due to analysis of LiDAR data that identified ground clearance requirements,[25] resulting in an "unconventional design that lead to the procurement of non-standard material which had longer lead times,[26] and delayed the project by nearly four years.[27]

As a result of this experience, NS Power stated that it:

> … revised its approach to transmission line projects similar to this one and to the extent possible, now aims to complete additional preliminary engineering ahead of filing, including LiDAR analysis to minimize additional scope that may arise during the detailed engineering process, additional access planning to identify where additional swamp matting may be required, and using this additional information to inform the initial project estimates.[28]

This is precisely the type of budget risk that could be identified in advance and for which planning could ensure that procurement and resource scheduling occurs after the risk has been mitigated.

A more recent example is the 76V-T1 Transformer Replacement (C0055557). The Board originally approved this project with a budget of $2.5 million, including a 15% contingency. NS Power justified the contingency stating, "Risks are well understood and the majority of costs are well known."[29] However, in this case NS Power appears to have insufficiently inspected the condition of wooden transmission structures at the substation and failed to anticipate the need for ground wells to handle fault currents. As a result, NS Power filed an ATO for a budget of $3.2 million (29% increase).[30] In this case, NS Power did not state that it has revised its approach to transformer replacement projects similar to this tone to inform the initial project estimates.

Filing of ATOs that identify the motivation for the development of improved planning and risk management practices should be encouraged by the Board.

[25] Exhibit N-1, M11707, CI C0011339 – L6549 – Replacements and Upgrades Phase 2 (ATO), p. 2.
[26] Exhibit N-3, M11707, NSUARB RIR-15.
[27] Exhibit N-2, M11707, NSUARB RIR-5(b).
[28] Exhibit N-2, M11707, NSUARB RIR-11.
[29] Exhibit N-1, M11168, CI C0055557 – 76V-T1 Transformer Replacement, p. 4.
[30] Exhibit N-1, M12204, CI C0055557 – 76V-T1 Transformer Replacement (ATO), p. 2, 4.

V. Reliability-Related Projects

A. New Distribution Right of Way Phase 11 (CI C0080266)

Q: Please summarize the New Distribution Right of Way project.

A: NS Power describes the project as follows:

> This project is to establish new rights-of-way (6 meters of clearance, wherever feasible) for distribution feeders, where rights of way had not previously existed. NS Power targets circuits where current vegetation management maintenance practices have limited impact on preventing off right-of-way tree contacts and their negative influence on reliable operation of NS Power's distribution system. The new rights-of-way will primarily be established adjacent to the road right-of-way edge, where most distribution feeders are currently located and bordered by vegetation.

Q: Does it appear that NS Power is targeting circuits with higher tree contact rates?

A: No. The circuits selected for this project appear to be simply typical in this respect.

As shown in Table 1, I reviewed NS Power's tree contact event data for the circuits targeted in this project and compared them to the systemwide data. Tree contacts are responsible for roughly one-quarter of outage events on both the overall system as well as for the circuits selected for this project. I also analyzed the tree contact outage event rate weighted by circuit length, which resulted in tree contacts being responsible for just 19% of outage events.[31]

Table 1: Tree Contact Events for Project Circuits vs Systemwide

Year	C0080266 Projects[32]			Systemwide[33]		
	Total Outage Events	Tree Contact Outage Events	Percent of Total	Total Outage Events	Tree Contact Outage Events	Percent of Total
2021	1,551	365	24%	11,158	2,173	19%
2022	3,639	1,038	29%	26,614	8,006	30%
2023	2,627	695	26%	19,064	4,709	25%
2024	1,681	338	20%	11,484	1,943	17%
2025	1,634	317	19%	13,094	2,492	19%
Total	**11,132**	**2,753**	**25%**	**81,414**	**19,323**	**24%**

[31] Circuit length obtained from Exhibit N-1, 2026 ACE Plan, CI C0080266, p. 1-2.

[32] Exhibit N-6, NSEB RIR-129, Attachment 1 EO; and Exhibit N-8, CA RIR-19 Revised.

[33] Exhibit N-6, NSEB RIR-52.

Q: Did you include tree contacts during adverse weather events in your calculations?

A: No. NS Power's calculation of tree contacts during adverse weather events is based on an estimate that "up to 40% Adverse Weather events can be further attributed to tree contacts," as "originally provided by NS Power's subject matter experts in 2019."[34] While NS Power states that it "continues to be confirmed by subject matter experts based on field reviews of large events coded as adverse weather," it acknowledges that it "does not specifically collect additional data … to determine further attribution to tree contacts."[35] And further, "If clear evidence of a tree contact is found … the event would be coded as Tree Contact."[36]

While I do not doubt that some percentage of outage events coded as Adverse Weather result from tree contacts, it does not appear to me that the estimate is precise enough to support analysis of trends in tree contacts or help identify circuits that should be prioritized for vegetation management activities such as the New Distribution Right of Way projects.

Q: Should the Board be concerned about the effectiveness of the New Distribution Right of Way projects?

A: Perhaps, but it may be too soon to say. Since 2016, NS Power's four reliability metrics related to tree contacts continue to remain relatively flat or even decreasing.[37] Considering that it is not evident that there have been impacts due to the previous ten phases of this project on reducing tree contact contribution to reliability, this raises concerns that the program is ineffective.

On the other hand, in its 2025 ACE Plan, NS Power reported changes to its vegetation management practices. Previously, NS Power had cleared or managed vegetation almost exclusively in the defined right-of-way (ROW). Over the past two years, NS Power has implemented new practices that go beyond targeting only trees that show signs of poor health, and is now considering factors including tree species (especially poplar and black spruce), tree canopy density, slope, and soil depth. NS Power's foresters are responsible for verifying trees beyond the defined ROW that should be removed and then landowners are worked with.

[34] Exhibit N-3, CA RIR-24(c).

[35] Exhibit N-3, CA RIR-24(d-e).

[36] Exhibit N-3, CA RIR-24(d-e).

[37] The trendlines in NS Power's Figures 65-69 appear to include the 2025 October YTD in the calculation, which skews the trend downward.

Considering that these changes have only been effective for a limited period, it is too soon to say whether the New Distribution Right of Way projects may have a positive effect on reliability.

Q: What are your recommendations related to this project and the larger issue of outages caused by tree contacts?

A: At this time, I do not recommend that the Board direct modification of the New Distribution Right of Way projects.

Instead, this topic should be examined in the ongoing third-party review of the Five-Year Reliability Plan.

I do recommend that NS Power make two changes to its tree contact reliability metrics (Figures 65-69). First, NS Power should remove tree contacts due to adverse weather from these metrics. It may be useful to continue to include this information in other contexts, but the imprecision of the 40% estimate may skew the total data to give a false trendline.

Second, NS Power should verify that its published trendlines exclude year-to-date data in the final year so that the trendlines are correctly presented.

Q: Do you have any other comments on NS Power's vegetation management program?

A: Yes. In a response to an information request, NS Power seems to suggest that it was able to "exceed the planned kms" of trimming and removal of trees through a number of good work practices and cost minimization activities.[38] However, NS Power then goes on to explain that what happened is that it shifted resources, and therefore costs, from capital (routine D010 or the New ROW Phase 10 or 11 project work) to operating expense tree trimming work.[39] While this reflects an efficient reallocation of resources in response to circumstances that limited the capital projects, I would hope that the good work practices and cost minimization activities described in the information response reflect the ongoing practices of NS Power and not a recent innovation.

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[38] Exhibit N-1, 2026 ACE Plan, Appendix G, Figure 5, p. 16; and Exhibit N-3, CA RIR-26(a).

[39] Exhibit N-1, 2026 ACE Plan, Appendix G, Figure 5, p. 16; and Exhibit N-3, CA RIR-26(b-c).

B. Spare Transformers

Q: Please describe the role of spare transformers in supporting reliability.

A: According to NS Power, it has added a new transformer to strengthen its "fleet of spares" in support of "system reliability and long-term asset sustainability."[40]

Q: Are there potentially more cost-effective methods of ensuring access to spare transformers and other critical, long-lead-time equipment?

A: Yes. Spare inventory pooling is a utility industry practice in which an inventory of equipment assets are purchased and stored for use by subscribing industry partners to "expedite the restoration of critical, long lead-time transmission equipment following significant grid outages."[41]

The electric utility industry has four programs to share spare critical equipment, including transformers, to supply replacement of equipment damaged in catastrophic events. Such collaborative action is advantageous because the cost and physical characteristics of large power transformers present challenges to stockpiling by individual transmission owners. The specialized requirements for transportation and storage; purchase cost; and financial carrying cost for large power transformers is a disincentive for speculative purchase and ownership of spare equipment.[42] For example, in 2021, NS Power estimated the cost to deploy a spare transformer, including disassembly, transport, design and installation to be $1.4 million, in addition to the transformer's estimated $3.0 million cost.[43]

One such program is Grid Assurance, a company that a number of US utilities created and subscribed to in order to mitigate the high cost of physical stockpiling, providing its subscribers with immediate access to spare units in certain emergency circumstances. Subscribers to the sparing service identify a required quantity of each class of transmission

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[40] Exhibit N-1, 2026 ACE Plan, Appendix G, p. 41.

[41] Grid Assurance, https://gridassurance.com/.

[42] US Government Accountability Office, *DOE Could Better Support Industry Efforts to Ensure Adequate Transformer Reserves* (August 2023), p. 11-12.

[43] Note that the $3.0 million cost was estimated to be the same whether the transformer was placed in service immediate or placed in storage, as the cost of commissioning is similar for each delivery option. Exhibit N-3, CA RIR-9(c, f), Matter No. M09920.

equipment, then Grid Assurance purchases an "optimal quantity" of each type of spare equipment based on subscribers' "collective identified needs."[44]

Another benefit of programs like Grid Assurance is experience in determining the optimal quantity of equipment to procure based on subscribers' collective needs, which reduces the risk that subscribers would procure too much equipment considering that they do not know exactly what equipment they may need in the future.

And further, such programs simplify financial treatment of carrying and, if necessary, storage costs. Rather than bearing the full cost of delivery and storage of surplus deliveries on an individual basis, spare inventory pooling demonstrates how those costs can be shared.

Q: Are there challenges for NS Power to participate in existing spare inventory pooling programs?

A: In response to an information request, NS Power stated:

> NS Power has previously investigated spare inventory pooling opportunities … but did not find that it was a more effective approach than existing sparing strategies given the potentially high costs. While pooling arrangements can be beneficial, such programs can not necessarily guarantee that the required spares will always be available in the pool and that they would be released to NS Power in a timely manner. For spares stored in the US …, border crossings could create additional complications. Overall effectiveness would depend on the ability for the program to procure and maintain suitable spare assets, replace spares as they are used by other members, and the logistics of obtaining a suitable spare by the impacted utility. Further study would ultimately be necessary …

I agree these are reasonable concerns, especially regarding spares stored in the US.

Q: What is your recommendation regarding spare inventory pooling?

A: The Board should obtain an inventory of NS Power's spare equipment to identify whether there is sufficient volume to consider whether a more cost-effective option could be available. I recommend that the Board request the following data:

- Equipment type
- Number of units in storage (or on order)
- Date of acquisition for each unit
- Original cost of each unit
- Estimated book cost of each unit
- Annual storage cost per unit, including required maintenance

[44] In addition to purchasing, securely storing, and maintaining the spare equipment in as-new condition, Grid Assurance assists its subscribers with delivery of the equipment for installation. Spare units are available in the event of physical attack, cyber-attack, an electromagnetic pulse, or catastrophic event such as severe weather or earthquake. FERC, Order on Petition for Declaratory Order, Docket EL16-20, paras 12, 14.

- Estimated unit installation cost, exclusive of procurement costs

The scope of the request should include all inventory for items that are typically stored for at least two years, thus excluding spare equipment that is routinely rotated into service such as meters, pole-mounted distribution transformers, and the like. The Board may also wish to set a cost threshold such as estimated current market price of at least $250,000 or a delivery threshold of at least one year.

If, after considering this information, the Board determines that a spare inventory pooling program could be beneficial, it should direct NS Power to report back on the topic in its next ACE Plan application.

VI. CEJC Updates

Q: Please summarize the scope of the updates to the Capital Expenditure Justification Criteria (CEJC).

A: NS Power is proposing revisions to the CEJC to address a definition of scope change, revision to the underspend FIN threshold, the timeline to file a FIN filing, and several other clarifications or updates.

A. Scope Change Definition

Q: How does NS Power describe the purpose of its proposed definition of "scope change"?

A: NS Power states,

> The purpose of this proposed definition is to find the proper balance in what should require an updated project application to the NSEB when changes occur to a project, and to avoid filing a significant number of scope change applications when a project is still being completed as intended, but experiences potentially minor variances in what was originally included in the application.[45]

NS Power further clarifies that its proposed definition is not intended to alter the type of information that "should be in a project scope statement from being included in the project application."[46]

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[45] Exhibit N-6, NSEB RIR-152(a).

[46] Exhibit N-6, NSEB RIR-152(b).

Q: What is NS Power's view of the risk of adding detail to the scope, consistent with some other definitions of scope?

A: NS Power states that if "scope change" included changes in deliverables, boundaries, and/or detailed tasks, roughly 70-80 of 200 projects filed over the last 5 years would have required a scope change, resulting in a significant regulatory burden on NS Power, the NSEB, and regulatory stakeholders, with costs borne by NS Power customers.[47]

Q: Has NS Power suggested any further changes to its definition of scope change?

A: Yes, in response to an information request, NS Power suggested that the ambiguity in its original proposal could be resolved by adding further language, bolded (as in the original):

> Scope Change: A project is considered to have had a scope change when the stated intent from the original capital application of the project description has been changed. **A change in intent would occur when the alternative defended under the Why do this Project This Way section of the application changes.**[48]

NS Power further justifies this additional language as follows:

> In each application, the intent of the project is defended as the best alternative under the *Why do the Project This Way* section. This includes justifications such as why refurbishment is more beneficial than replacement, why a Software as a Service solution is better than an on-premises solution or where completing component replacement on a transmission line is preferred to fully replacing the line or reconductoring the line. NS Power believes that this update will provide additional clarity and remove subjectivity to that existed prior to the update.[49]

Q: Does NS Power's proposed addition resolve the ambiguity?

A: No, it merely shifts the ambiguity from a change in "stated intent" to a change in the "alternative defended." For example, in response to a hypothetical presented in an information request, NS Power found that a scope change would not be triggered where a project involving refurbishment of a dam and dyke is revised to include significant civil work on an adjacent (second) dyke.[50] In its response, NS Power also pointed out that "additional work such as this that is added to the project has a high likelihood of driving additional costs for the project, thus triggering an Authorization to Overspend (ATO) application, and resulting regulatory process to confirm its prudency."

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[47] Exhibit N-5, IG RIR-9(a-b).

[48] Exhibit N-3, CA RIR-1.

[49] Exhibit N-6, NSEB RIR-149(b).

[50] Exhibit N-3, CA RIR-2.

Examples of projects where alternatives may have been overlooked at an early stage are the L6549 transmission line replacements and upgrades 76V-T1 transformer replacement projects discussed in Section IV, both of which involved significant changes to the project definition and budget, could have been the subject of proceedings to review alternatives. In the case of the transmission line, no alternative routings or upgrades to existing alternative transmission paths appear to have been considered. In the case of the transformer, further alternatives were explored in Board IRs.

Q: What concerns do you have with this remaining ambiguity?

A: In my opinion, this ambiguity has the potential to undermine the intent of Section 35 of the *Public Utilities Act*. The Act requires each capital item in excess of $1 million to obtain approval from the NSEB.

While I am not a lawyer, it appears to me that the intent of the capital project approval process is to significantly reduce the necessity of reviewing completed projects to determine if they are inappropriately justified or imprudent, and thus subject to partial or full exclusion from NS Power's rate base. The capital project approval process does not replace the Board's authority to review project costs for prudency, but it provides NS Power with increased confidence in its opportunity to recover capital costs (thus reducing regulatory risk) and regulatory stakeholders with a more meaningful opportunity to identify improvements or alternatives to proposed capital projects in a timely manner.

NS Power's views on the scope change definition suggest that it would shift a meaningful scope of Board oversight from more proactive capital project approval proceedings to retrospective proceedings such as the ATO application where changes to the project can be reviewed "to confirm its prudency" (as quoted above).

On the other hand, I recognize the validity of NS Power's concern regarding a requirement to file an updated scope every time deliverables, boundaries, and/or detailed tasks are changed.

Q: Do you have a recommendation for the Board to refine NS Power's proposed definition of scope change?

A: Yes. I recommend that NS Power's clarification be accepted and that the CEJC be further revised to include a two-step process that focuses on the potential that NS Power may be proceeding with a sub-optimal alternative, while leaving the question of prudency of costs to existing processes.

First, upon identifying a change to deliverables, boundaries, and/or detailed tasks that NS Power believes **may** result in a budget increase above a Board-specified threshold (e.g., double any applicable ATO threshold), NS Power should file a brief letter in the proceeding in which the project was approved (which may be reopened if necessary) with the following information:

1. The identified change to deliverables, boundaries, and/or detailed tasks.
2. NS Power's current estimate of the potential budget increase relative to the previously-approved budget, which may be expressed in percentage terms as an order of magnitude without detailed support.
3. Whether or not NS Power has identified any new alternatives to the proposed project as a result of the information which led to the identified change; and, if so, a brief description of the alternative and a general statement as to the reason the alternative was not selected.
4. Whether or not NS Power intends to file a revised capital project application or ATO application prior to proceeding with project construction or implementation (as applicable).

Second, the Board, on its own or in response to any regulatory intervenor, may respond to the letter by identifying a reason that NS Power should more formally evaluate some other alternative. The evaluation would then be included in a revised capital project application or ATO application as directed.[51]

In my opinion, this approach would avoid the regulatory burden described by NS Power and focus the attention of any additional proceedings on circumstances where (a) the potential for a more cost-effective or otherwise desirable alternative may be identified through the regulatory process, without creating multiple proceedings in which prudency of project costs is litigated.

[51] Note that in my proposal, the initial notification by NS Power is based on the possibility ("may") of exceeding the Board-specified threshold. If NS Power later determined that the budget does not exceed the Board-specified threshold, my proposal is that any proceeding that has been initiated or directed should continue notwithstanding.

B. Other NS Power CEJC Proposed Revisions

Q: What is your opinion of the other proposed revisions to the CEJC?

A: I support the other revisions as proposed.

C. Additional Recommended CEJC Revisions

Q: Do you have any further proposed revisions to the CEJC?

A: Yes, I recommend two further revisions to the CEJC not directly related to any proposals from NS Power.

First, I recommend that the introduction be revised to reflect the Board's decision in M12012 that, "NS Power is directed to submit any future capital expenditures that exceed $1 million for approval to the Board, regardless of the source of funding."[52] Specifically, I recommend the following additional language (bolded) to Section 2.0 (Introduction), as follows.

> NS Power is a public utility, subject to the provisions of the Public Utilities Act (the Act). NS Power is subject to general supervisory oversight of the NSEB (previously the UARB). Prior to October 30, 2019, each capital item in excess of $250,000 required approval by the Board. Section 35 of the Act was amended on that date to raise this limit to $1,000,000 for "large scale public utilities", **regardless of the source of funding,**[2] which is defined under the Act as a public utility with an annual revenue of one hundred million dollars or more. Accordingly, NS Power can carry-out capital work on projects of $1,000,000 or less in value without Board approval. The Board can perform periodic audits to ensure that the criteria are being properly applied. Projects found to be inappropriately justified or imprudent can be excluded from NS Power's rate base.[53]
>
> **[2]2025 ACE Plan Board Decision (August 19, 2025) NS Power M12012.**

I note that NS Power views reflecting this Board decision in the CEJC as not "providing additional value at this time."[54] I disagree, as it provides a material reference for future users of the CEJC that is not immediately evident, given the disagreement over this point in the 2025 ACE Plan proceeding.

Second, I recommend changing the definition of a "related project" to include units that can be substituted for one another in the normal course of business. Examples could

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[52] Board Decision, 2025 ACE Plan, M12012, para. 204.

[53] Exhibit N-1, 2026 ACE Plan, Appendix D, p. 9. Additional proposed language in bold.

[54] Exhibit N-3, CA RIR-3.

include work on any of the rotating LM6000 engines, procurement or refurbishment of substantially identical transformers, and the like. This would be a relatively small change to the CEJC and the language change below is suggested by NS Power in response to an information request (added language in bold, removed language in strikethrough):

> Related Projects approved or having taken place in the past 2 years, current year or anticipated for the next 2 years including the projects' estimated costs. When multiple projects relate to the same asset **(or an asset that can be used to replace this asset in the normal course of operations)**, or initiative they should be considered related and listed in the project description. ~~grouped as a package.~~[55]

VII. Comments on the Mersey Hydro Update

Q: What are your general views on the Mersey Hydro Update?

A: Consistent with views that I have expressed to the Board in prior ACE Plan proceedings, I am concerned that NS Power does not have a strong plan for protecting customers from excessive costs when dealing with the potential redevelopment or decommissioning of the Mersey Hydro project.

Currently, NS Power is continuing to invest significant sums to "ensure the continued safe operation" of Mersey facilities while it has deferred a full application for either redevelopment or decommissioning.[56] While I do not dispute what appear to be necessary projects given the circumstances, it is unfortunate that this project was not more definitively defined years ago.

Q: How do the three alternatives discussed in the net present value (NPV) analysis compare?

A: From an investment perspective, redevelopment requires by far the greatest expenditure.[57] Redevelopment requires a nominal investment of $1.2 billion, compared to just $512 million for full decommissioning.[58]

[55] Exhibit N-3, CA RIR-4.

[56] Exhibit N-1, 2026 ACE Plan, Appendix E, p. 5.

[57] The partial decommissioning option is least attractive from every perspective, and is excluded from my discussion for clarity.

[58] These and following figures are from Exhibit N-1, 2026 ACE Plan, Appendix E, Attachment 1.

In net present value terms, the expenditure comparison is a little closer. Redevelopment would cost $560 million NPV compared to $196 million NPV for decommissioning.

From any perspective, these are massively expensive projects for NS Power to undertake – comparable to the current budget for synchronous condensers that I will discuss in Section VIII below.

Of course, there are benefits from redevelopment: in net present value terms, $377 million in energy and $98 million in capacity value, for a total of $475 million.

Q: Is there a clearly best alternative?

A: No. If the Mersey Hydro system were a greenfield power project, it would not be seriously considered: In NPV terms, the cost of $560 million far exceeds the benefit of $475 million.

But of course, Mersey Hydro is not a greenfield power project and the asset must be responsibly managed by NS Power, which means its customers must bear the costs of that management.

Q: Is the NPV analysis reasonably complete?

A: No. The Mersey Redevelopment Project was first identified as a subsequent submittal project in 2017, and retained in each ACE Plan on the same basis until it was moved to deferred status in the 2023 ACE Plan. Yet even after nearly a decade of study, NS Power explains that its current full decommissioning cost estimate is "based on high level metrics and assumptions applied broadly across the Mersey Hydro System, and does not account for the full scope …"[59] Essentially, there is a very high uncertainty to the cost estimate used for full decommissioning, with the hint from NS Power that it expects the actual cost to be even higher than estimated in the NPV analysis.

NS Power does not directly compare the uncertainty in redevelopment cost estimates to the decommissioning cost estimate, but I would expect both to be highly uncertain, especially as critical decisions about either project direction's scope and requirements have not been made.

Q: How will the Mersey Hydro project decision be made?

A: At this point, NS Power is not the key decision maker. Key decisions are the responsibilities of three different institutions.

[59] Exhibit N-6, NSEB RIR-162(b).

The IESO Nova Scotia is now the key planning authority for this decision. NS Power states:

> Active project work on the Mersey Redevelopment remains paused as NS Power awaits the outcome of the ongoing IESO Nova Scotia-led Integrated Resource Plan (IRP) process. The IRP will inform the long-term role of the Mersey Hydro System within the overall provincial resource portfolio and is expected to assess the costs associated with the potential future options for the Mersey Hydro system and determine the appropriate long-term pathway for the system.[60]

One key schedule driver is compliance with the Fisheries Act, administered by Fisheries and Oceans Canada (DFO). At this point, fish passage elements are only estimated at 3 percent of redevelopment costs, but:

> While NS Power has incorporated fish passage construction costs into its capital forecasts, broader requirements—such as the extent of passage infrastructure, sequencing, and DFO expectations for system-wide connectivity—may influence project scope, timelines, and permitting complexity.[61]

A key cost driver is addressing the archaeological sites in the Mersy Hydro System, with a current cost estimate of $352 million, and NS Power notes that "any additional work in the reservoirs could result in a significant escalation of this estimate."[62] The cost for this work is rivaled by the complexity of reaching agreement on just what work should be done: NS Power describes engagement on these topics as follows:

> While active project work on the Mersey Redevelopment remains paused, NS Power continues to build an understanding of requirements resulting from the recent shifts in the environmental regulatory landscape, as well as Mi'kmaq interest and concern with respect to environment, fish passage, and archaeology. NS Power continues to have meaningful conversations with Kwilmu'kw Maw-klusuaqn (KMK), Wasoqopa'q, Bear River and Sipekne'katik First Nations as well as the Department of Fisheries and Oceans (DFO) and the Nova Scotia Government including Nova Scotia Departments of Environment (NSECC), Natural Resources (NSDNR) and Communities Culture Tourism and Heritage (CCTH). NS Power's goal is to achieve a common understanding and agreement on an approach with respect to expectations for archaeology and environment as it relates to the project prior to moving forward and submitting an application for approval.[63]

[60] Exhibit N-6, NSEB RIR-157(a).

[61] Exhibit N-6, NSEB RIR-158(a)(i).

[62] Exhibit N-1, 2026 ACE Plan, Appendix E, p. 13.

[63] Exhibit N-1, 2026 ACE Plan, Appendix E, p. 8.

Q: What do you conclude regarding the Mersey Hydro Update?

A: Unfortunately, I do not have a clear recommendation for the Board. I can only express my concerns about this project, given its potential to unduly burden customers with costs, as it seems apparent that the Mersey Hydro project is not primarily a power infrastructure project at this time. Future power generation, if it occurs, will be merely a significant byproduct of more consequential decisions about the project's fate.

VIII. Comments on Updated Path to 2030 Report

Q: What are your general views on NS Power's updated Path to 2030 Report?

A: I have recently expressed concerns regarding key milestones not being met towards achieving the 2030 targets for coal retirements, carbon reductions, and RES compliance.[64] The report filed in Appendix F provides no reassurance on these points and I continue to encourage the Board to press both NS Power and IESO Nova Scotia to expedite implementation of the necessary actions described in the report.

Q: Are there topics from the Path to 2030 Report that you wish to discuss?

A: Yes. I am concerned that there has not been adequate stakeholder consultation regarding the Synchronous Condensers (ECEI) project (C0072808).

The synchronous condensers project was first presented in the 2025 ACE Plan as a subsequent submittal project with a preliminary budget of $244 million. While synchronous condensers have been discussed as having a potentially important role in wind integration since at least the 2022 IRP, NS Power has only recently identified this technology as its choice to support wind integration.

For example, as recently as 2024, NS Power's IRP Action Plan Update stated that:

[64] Grid Strategies, Review of NS Power's 2025 10-Year System Outlook, filed by the Consumer Advocate in M12386 (October 9, 2025); Grid Strategies, Review of NS Power's 2025 IRP Action Plan and Roadmap Update, filed by the Consumer Advocate in M12247 (August 19, 2025).

> Studies to date find that the loss of inertia from the retirement of thermal generating units can be replaced with a mix of Synchronous Inertial Response from remaining thermal plants and synchronous condensers as well as Fast Frequency Response from the Maritime Link, grid scale batteries, Reliability tie and technology-enabled response from new Inverter Based Resources (IBRs). Studies are ongoing to evaluate new technologies such as grid forming static synchronous compensators (STATCOMs) as potential alternatives to the use of synchronous condensers.[65]

Similarly, the 2024 10-Year System Outlook Report presented synchronous condensers as one of several potential fast acting reactive power sources.[66] The 2025 10-Year System Outlook Report updated this topic to indicate that six synchronous condenser unit locations had been identified, with more expected to support the Green Choice procurement.[67]

This will be a substantial investment by NS Power, with an updated budget of $365 million in the 2026 ACE Plan reflecting the increase to as many as 9 units, due to wind farms with a larger capacity output.[68] This information is not included in the Path to 2030 Report. The report first restates a list of technology options for supporting wind integration (similar to those presented in the 2024 IRP Action Plan Update) and then only briefly mentions the synchronous condenser project as being prioritized for support near two wind farms.[69] It is not clear why information in the Path to 2030 - 2025 Update appears to predate information shared in the 2025 ACE Plan which was, of course, prepared in 2024.

Q: Why is the status of the synchronous condenser project concerning?

A: In contrast to, for example, the NS-NB Reliability Intertie Project, there has been no stakeholder presentation explaining why synchronous condensers have been selected as the best option for wind integration. When the Synchronous Condenser Project application is filed, it should include a thorough analysis of the several technology options.

Yet as I have noted above, time is of the essence in completing wind integration projects in order to meet key 2030 compliance milestones. If the project application fails to make a strong case that the best technology implementation has been selected, the Board will be in the position of having to choose between further delay in meeting 2030 compliance milestones or approving a project that may have significant flaws.

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[65] NS Power, Integrated Resource Plan Action Plan Update (June 2024), p. 46

[66] Exhibit N-1, M11764, 2024 10-Year System Outlook Plan, p. 61.

[67] Exhibit N-1, M12386, 2025 10-Year System Outlook Plan, p. 63.

[68] Exhibit N-1, 2026 ACE Plan, Appendix B; Exhibit N-3, CA RIR-5.

[69] Exhibit N-1, 2026 ACE Plan, Appendix F, p. 29.

Of course, this is all speculation at this point, as NS Power has provided little meaningful information about its evaluation of these technologies in several years.

Q: What recommendation do you have for the Board?

A: Unfortunately, I do not have a clear recommendation for the Board. I can only express my concerns about this important work and hope that NS Power's technology evaluation and project development will yield an excellent project plan for review and, hopefully, approval.

Q: Does this conclude your evidence?

A: Yes.

JOHN D. WILSON

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SUMMARY OF PROFESSIONAL EXPERIENCE

2023–Present **Vice President, Grid Strategies, LLC**. Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric utility prudence, cost allocation and rate design. Designs and evaluates electrification and energy efficiency programs for electric utilities, including cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses generation interconnection, load forecasting, resource planning and procurement strategies for regulated and competitive markets.

2019–23 **Research Director, Resource Insight, Inc.** Same services as above.

2007-19 **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Directed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony to utility regulators. Directed litigation activities, including support of expert witnesses. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

2001–06 **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air quality, including ozone, air toxics, and other industrial, utility, and transportation pollutants. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Science Committee.

2000–01 **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

1997–99 **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

1997 **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

1992-96 **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for assessments of environmental and resource issues in the Rio Grande / Rio Bravo basin and the Greater Houston region. Coordinated and edited book on climate change in Texas.

EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

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"Municipal Coal in Ohio: Implications of PJM's Behind-the-Meter Generation," with Paul Chernick and James Harvey, April 2020.

"Review of Nova Scotia Power's 2020 Integrated Resource Plan," prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M08059, with Paul Chernick, January 2021.

"Implementing All-Source Procurement in the Carolinas," prepared for Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League and Upstate Forever, for submission in NCUC Docket E-100, Sub 165, and SCPSC Dockets 2019-224-E and 2019-225-E, February 2021.

"Intelligent Feeder Project: Comments on Nova Scotia Power's Final Report," prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M09984, June 2021.

"MGCC Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates," joint report prepared by PG&E, Small Business Utility Advocates, CPUC Public

Advocates Office, California Large Energy Consumers Association, and Enel X, CPUC Dockets A.20-10-011 and A.19-11-019, March 2022.

"The Era of Flat Power Demand is Over," with Zach Zimmerman, Grid Strategies LLC, prepared for Clean Grid Initiative, December 2023.

"Generator Interconnection Scorecard: Ranking Interconnection Outcomes and Processes of the Seven U.S. Regional Transmission System Operators," Grid Strategies LLC and Brattle Group, with Richard Seide, Rob Gramlich, and J. Michael Hagerty, February 2024.

"Review of Mississippi Power Company 2024 Integrated Resource Plan," with Michael Goggin, Grid Strategies LLC, prepared for Southern Renewable Energy Association, for submission in MPSC Docket No. 2019-UA-231, June 2024.

"Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid," prepared for Advanced Energy Institute and Solar and Storage Industries Institute, Grid Strategies LLC and Brattle Group, with Rob Gramlich, Richard Seide, Yorgos Raskovic, J. Michael Hagerty, Joe DeLosa III, and Johannes Pfeifenberger, for submission in FERC Docket No. AD24-9, August 2024.

"Independent Transmission Construction Monitor," Grid Strategies LLC, with Rob Gramlich and Yorgos Raskovic, November 2024.

"Strategic Industries Surging: Driving US Power Demand," with Zach Zimmerman and Rob Gramlich, Grid Strategies LLC, prepared for Clean Grid Initiative, December 2024.

"Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers," with Sophie Meyer, Zach Zimmerman and Rob Gramlich, Grid Strategies LLC, prepared for Clean Grid Initiative, November 2025.

"Forecasting for Large Loads: Current Practices and Recommendations," with Sophie Meyer and members of the Energy Systems Integration Group's Large Load Task Force, December 2025.

SELECTED PRESENTATIONS

"Clean Energy Solutions for Western North Carolina," presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

"Energy Efficiency: Regulating Cost-Effectiveness," Florida Public Service Commission undocketed workshop, April 25, 2008.

"Utility-Scale Renewable Energy," presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

"An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

"Building the Energy Efficiency Resource for the TVA Region," presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

"Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

"The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference, February 2010.

"Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South," April 10, 2010.

"Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop, September 2010.

"Energy Efficiency Delivers Growth and Savings for Florida," testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

"Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

"TVA IRP Update," TenneSEIA Annual Meeting, November 19, 2014.

"Views on TVA EE Modeling Approach," presentation with Natalie Mims to Tennessee Valley Authority's Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

"The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast," FERC Eastern Region Technical Conference on EPA's Clean Power Plan Proposed Rule, March 11, 2015.

"Renewable Energy & Reliability," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Challenges to a Southeast Carbon Market," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Solar Capacity Value: Preview of Analysis to Date," Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Southeast Energy and Environmental Leadership Forum, Nicholas Institute for Environmental Policy Solutions, August 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Indiana State Bar Association, Utility Law Section, Virtual Fall Seminar, September 2020.

"Resource Adequacy, Reserve Margin, & Seasonal Planning," 2022 Georgia IRP Training and Roundtable Series, February 2022.

"Six Lessons from the PG&E Real Time Pricing Rate Proceeding," 45th Peak Load Management Alliance Conference, April 2022.

"The Era of Flat Power Demand is Over," EFI Foundation, February 2024.

"The Era of Flat Power Demand is Over," 2024 The Energy Authority Energy Symposium, March 2024.

"RTO Generator Interconnection Scorecard," 2024 The Energy Authority Energy Symposium, March 2024.

"The Era of Flat Power Demand is Over," 2024 The Energy Authority Energy Symposium, March 2024.

"Energy Transition Challenges & Opportunities," Panel Member, 2024 The Energy Authority Energy Symposium, March 2024.

"The Era of Flat Power Demand is Over: 2024 'Early Release'," NERC Large Loads Task Force, October 2024.

"Strategic Industries Surging," Midcontinent Power Sector Collaborative, February 2025; Institute for State Policy Leaders, August 2025, and others.

"Forecasting for Large Loads: Current Practices and Recommendations," with Sophie Meyer, Energy Systems Integration Group webinar, December 2025.

"Addressing Gaps in Load Forecasting," CERES Grid Mod 101, January 2026.

"Increasing the Certainty and Transparency of Load Forecasts," NASEO 2026 Energy Policy Outlook Conference, February 2026.

EXPERT TESTIMONY

2008 **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2009 **North Carolina NCUC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

Florida PSC Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

South Carolina PSC Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense

Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2010 **North Carolina NCUC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas' 2009 integrated resource plans.

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

Georgia PSC Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

2011 **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

South Carolina PSC Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

2013 **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

2014 **South Carolina PSC** Docket No. 2014-246-E, direct testimony in generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

2015 **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

2016 **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

2019 **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

2020 **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification, decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

Nova Scotia UARB Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

Nova Scotia UARB Matter No. M09579, direct testimony with Paul Chernick in Nova Scotia Power's application for the Gaspereau Dam Safety Remedial Works on behalf of the Nova Scotia Consumer Advocate. Alternatives to proposed project, project contingency factor, estimation of archaeological costs, and replacement energy cost calculation.

Nova Scotia UARB Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

California PUC Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

Georgia PSC Docket Nos. 4822, 16573 and 19279, direct, rebuttal and surrebuttal testimony in Georgia Power Company's PURPA avoided cost review on behalf of the Georgia Large Scale Solar Association. Reviewing compliance with prior Commission orders. Application of capacity need forecast in projection of avoided capacity cost. Calculation of cost of new capacity. Proposal of standard offer contract.

California PUC Docket A.19-11-019, direct, reply, responsive, and reply to responsive testimony with Paul Chernick in Pacific Gas & Electric's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate design, including customer charges, demand charges, real time pricing tariffs, TOU differentials and periods.

Nova Scotia UARB Matter No. M09548, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of fuel contract costs. Scope of study on dispatch practices. Impact of greenhouse gas shadow pricing. Compliance issues related to resource planning.

2021 **California PUC** Docket R.20-11-003, direct and reply testimony on rulemaking to ensure reliable electric service in the event of an extreme weather event on behalf of the Small Business Utility Advocates. Modifications to Critical Peak Pricing programs and Time of Use periods. Modifications to load management programs.

Nova Scotia UARB Matter No. M09898, direct testimony on Nova Scotia Power's Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Effect of delays in power contract. Unit modeling assumptions. Variable capital costs. Application of Time-Varying Pricing.

Nova Scotia UARB Matter No. M09920, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2021 on behalf of the Nova Scotia Consumer Advocate. Cost minimization. Project contingency. Economic analysis model. Analysis of specific projects.

Nova Scotia UARB Matter No. M09777, direct testimony with Paul Chernick on Nova Scotia Power's Time-Varying Pricing Tariff Application on behalf of the Nova Scotia Consumer Advocate. Effect of proposed TVP tariffs on load, capacity savings, and energy costs. Recommended CPP tariffs. Treatment of demand charges in TVP tariffs. Implementation and evaluation of TVP tariffs. Lost revenue adjustment mechanism.

South Carolina PSC Docket Nos. 2019-224-E and 2019-225-E, surrebuttal testimony on 2020 Integrated Resource Plans filed by Duke Energy Carolinas and Duke Energy Progress. All-source procurement process. Process for resolution of disputed issues in IRP proceedings.

California PUC Docket A.20-10-011, direct and reply testimony with Paul Chernick in Pacific Gas & Electric's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot on behalf of the Small Business Utility Advocates. Rate design for real time pricing tariff. Marketing to small businesses. Evaluation plan.

California PUC Docket R.20-08-020, direct and reply testimony with Paul Chernick in rulemaking to revisit net energy metering (NEM) tariffs on behalf of the Small Business Utility Advocates. Rate design for NEM tariff. Method for analyzing NEM tariff program.

California PUC Docket A.20-10-012, direct testimony with Paul Chernick in Southern California Edison's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate allocation and design, including customer charges and real time pricing tariffs.

Nova Scotia UARB Matter No. M10176, direct testimony on Nova Scotia Power's Smart Grid Nova Scotia Solar Garden Pilot Rate Rider on behalf of the Nova Scotia Consumer Advocate. Addressing risks associated with future cost changes.

Nova Scotia UARB Matter No. M10110, direct testimony on Nova Scotia Power's Wreck Cove hydroelectric project on behalf of the Nova Scotia Consumer Advocate. Reasonableness of project and unresolved issues.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 3) on behalf of the Small Business Utility Advocates. Reasonableness and prudence of remedial and replacement software costs to be included in authorized revenue requirement.

Nova Scotia UARB Matter No. M10197, direct testimony on Nova Scotia Power's Tusket Main Dam Refurbishment Authorization to Overspend application on behalf of the Nova Scotia Consumer Advocate. Whether the project should proceed and whether full cost recovery is justified.

Colorado PUC Proceeding No. 21AL-0317E, answer testimony in Public Service Company of Colorado's 2021 general rate case (phase 1) on behalf of

Energy Outreach Colorado. Reasonableness of capital project costs, choice of test year, adjustment to load to reflect effects of pandemic.

2022 **California PUC** Docket A.21-05-017, direct testimony with Paul Chernick in Liberty Utilities Calpeco 2022 general rate case on behalf of the Small Business Utility Advocates. Marginal cost study, revenue allocation, rate design.

Nova Scotia UARB Matter No. M10366, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2022 on behalf of the Nova Scotia Consumer Advocate. Alignment with IRP and new regulation. Cost minimization. Project contingency. Post-project review. Total cost of ownership. Economic analysis model. Decommissioning. Analysis of specific projects.

California PUC Docket A.21-10-010, direct testimony on Pacific Gas and Electric's proposed Electric Vehicle Charge 2 Program on behalf of the Small Business Utility Advocates. Program scale and unit costs. Cost controls. Cost Allocation.

Nova Scotia UARB Matter No. M10569, direct testimony on Nova Scotia Power's 2022 Load Forecast Report on behalf of the Nova Scotia Consumer Advocate. Impact of multi-hour average temperatures and wind speed on load. Use of multiple weather stations in load forecast. Electrification forecast. Load Research Sample model. DSM adjustment.

Nova Scotia UARB Matter No. M10400, direct testimony on Nova Scotia Power's Work Management and Scheduling & Dispatch Application on behalf of the Nova Scotia Consumer Advocate. Economic analysis. Additional applications for software. Contingency guidelines. Total cost of ownership.

Massachusetts DPU Docket No. 22-22, direct, surrebuttal and supplemental testimony on Eversource Energy's 2022 Base Distribution Rate Case on behalf of the Cape Light Compact. Allocation of distribution revenue requirement.

Nova Scotia UARB Matter No. M10431, direct testimony on Nova Scotia Power's 2022 General Rate Application on behalf of the Nova Scotia Consumer Advocate. Board directives. Fuel costs. Capital project revenue requirements. Deferral accounts and riders. Cost allocation. Residential customer charge.

2023 **Nova Scotia UARB** Matter No. M10959, direct testimony on Nova Scotia Power's 2023 Application for Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Seasonal and time-varying rates. Impact of Maritime Link power delivery. Cost of service study updates.

California PUC Docket R.22-07-005, direct testimony on Rulemaking to Advance Demand Flexibility Through Electric Rates. Income-graduated fixed charge: cost categories, rate design, and impacts on electrification, low-income ratepayers, and energy efficiency.

Nova Scotia UARB Matter No. M10960, direct testimony on Eastward Energy's 2023 General Rate Application on behalf of the Nova Scotia Consumer Advocate. System Expansion Investments. Customer connection incentive program. Impacts on electrification programs.

Nova Scotia UARB Matter No. M10416, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of biomass fuel costs. Shortfall in expected customer benefits from Maritime Link transmission project. Regional joint dispatch. Accounting issues related to coal supplies and wind farm tax credits. Impact of demand response and time-varying rates on fuel costs.

Nova Scotia UARB Matter No. M11009, direct testimony on the disposition of the Nova Scotia Power Maritime Link Inc's Holdback. Benefits of Maritime Link, including energy- and capacity-related benefits. Offset of replacement energy costs. Sufficiency of regulatory process to recover customer benefits.

Nova Scotia UARB Matter No. M11017, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2023 on behalf of the Nova Scotia Consumer Advocate. Capital projects with risk. Reliability investments. Cost minimization practices, including project contingency, total cost of ownership, project delivery model, and post-project reviews. Analysis of specific projects.

Kentucky PSC Case No. 2022-00402, direct testimony on Kentucky Utilities and Louisville Gas and Electric's application for the retirement of seven fossil-fired generation units on behalf of Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Demonstration that retirement of units meets statutory standard to overcome rebuttable presumption against retirement. Consideration of utility replacement portfolio and membership in PJM. Definition of dispatchable electric generating capacity. Use of dispatch practices including full flexibility operating mode for renewables. Updates to resource adequacy methods. Economic test for investment in small-frame CT units.

Nova Scotia UARB Matter No. M11108, direct testimony on Nova Scotia Power's 2023 Load Forecast Report on behalf of the Nova Scotia Consumer Advocate. Use of lagged temperatures and wind speed to forecast/normalize load. Use of multiple weather stations in load forecast. Electrification forecast, including backup to heat pumps and electric vehicle demand. Load research sample model. DSM adjustment.

Washington UTC Docket No. UE-230172, response and cross-answer testimony on PacifiCorp's 2024 General Rate Case on behalf of the WUTC Staff. Net power costs. Revision to power cost adjustment mechanism (PCAM).

2024 **Nova Scotia UARB** Matter No. M11017, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2023 on behalf of the Nova Scotia Consumer Advocate. Capital projects with risk. Reliability investments.

Distribution routine budgets. IT routine budgets. Cost minimization practices, including project contingency, project delivery model, post-project reviews, and quality control. Analysis of specific projects.

Nova Scotia UARB Matter No. M11621, direct testimony on Nova Scotia Power's Smart Grid Nova Scotia Final Report on behalf of the Nova Scotia Consumer Advocate. Classification of capital expenditures. Completion of business plan.

Washington UTC Docket No. UE-240006, response and cross-answer testimony on Avista's 2024 General Rate Case on behalf of the WUTC Staff. Net power expenses. Impact of carbon emissions policy. Revision to energy recovery mechanism (ERM).

Nova Scotia UARB Matter No. M11689, direct testimony on Nova Scotia Power's 2024 Load Forecast Report on behalf of the Nova Scotia Consumer Advocate. Consideration of weather trends. Hybrid scenario for electrification. Forecast for peak demand impact of time-varying pricing tariffs. Forecast peak demand for electric vehicle charging. Inconsistencies between load forecast and distribution planning.

Washington UTC Docket No. UE-240004, response and cross-answer testimony on Puget Sound Energy's 2024 General Rate Case on behalf of the WUTC Staff. Net power costs. Impact of carbon emissions policy. Prudency of power purchase agreement.

Nova Scotia UARB Matter No. M11533, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Regional joint dispatch. Net benefits of hedging. Recommended disallowances related to maintenance, human error, and uneconomic dispatch issues.

2025 **Nova Scotia UARB** Matter No. M11150, direct testimony on Nova Scotia Power's Appeal of Minister's Decision on behalf of the Nova Scotia Minister of Energy. Lack of independent assessment of project schedule. Due diligence in compliance with renewable energy standard.

Nova Scotia UARB Matter No. M11989, direct testimony on Nova Scotia Power's 2025 Application for Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Forecasts of power imports. Impact of scheduling uncertainty for new generation. Seasonal and time-varying rates. Stakeholder engagement on updating methods.

Nova Scotia UARB Matter No. M12012, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2024 on behalf of the Nova Scotia Consumer Advocate. Capital projects with insufficient support. Reliability investments. Cost minimization practices, including project contingency, project delivery model, post-project reviews, and Mersey Hydro. Progress on planned renewable resources.

Louisiana PSC Docket No. 37425, answer testimony on Entergy Louisiana's Application for Approval of Generation and Transmission Resources in Connection with Service to Single Customer on behalf of the Southern Renewable Energy Association. Compliance with Commission orders. Failure to evaluate renewable and storage resources. Corporate sustainability rider and expedited certification process.

Colorado PUC Proceeding No. 24A-0442E, answer and cross-answer testimony on Public Service Company of Colorado's 2024 Just Transition Solicitation on behalf of Interwest Energy Alliance. Just Transition incentives. Utility ownership target. Bid flexibility. Transmission planning. Procurement contingencies. Systemic risks to generation developers.

Georgia PSC Docket No. 44280, direct testimony on Georgia Power Company's stipulation on extending its alternate rate plan on behalf of Natural Resources Defense Council, Sierra Club, and the Southern Alliance for Clean Energy. Sufficiency of information and opportunity for review. Assurances regarding impact of large loads on existing customer rates. Need for an illustrative cost of service study.

Virginia SCC Case No. PUR-2025-00058, direct and surrebuttal testimony on Dominion Virginia's 2025 rate case on behalf of Appalachian Voices. Minimum system method and monthly customer charges. Review of proposed new large energy user rate class and related standard energy service agreement terms. Generation and transmission cost allocation methods.

South Carolina PSC Docket No. 2025-154-E, direct and surrebuttal testimony on Duke Energy Progress's 2025 rate case on behalf of South Carolina Coastal Conservation League and three other organizations. Large load tariffs and contract terms. Generation and transmission cost allocation methods. Treatment of interruptible load.

South Carolina PSC Docket No. 2025-172-E, direct and surrebuttal testimony on Duke Energy Carolinas' 2025 rate case on behalf of South Carolina Coastal Conservation League and three other organizations. Large load tariffs and contract terms. Generation and transmission cost allocation methods. Treatment of interruptible load.

North Carolina UC Docket Nos. E-2, Sub 1383 and E-7, Sub 1332, direct testimony on Duke Energy's proposal to combine its two operating companies on behalf of the Southern Alliance for Clean Energy and three other organizations. Rate consolidation, including jurisdictional cost allocation effects. Large load tariff. Cost minimization strategy.

2026 **South Carolina PSC** Docket No. 2025-230-E, direct and surrebuttal testimony on Duke Energy's proposal to combine its two operating companies on behalf of the South Carolina Coastal Conservation League and three other organizations. Rate consolidation, including jurisdictional cost allocation effects. Large load tariff. Class allocation of jurisdictional revenue sharing. Cost minimization strategy.