# NS Power IRP

# Comments received from Participants in response to Draft Findings, Action Plan and Roadmap

## September 2020

Alternative
RESOURCE ENERGY AUTHORITY

Nicole Godbout
Director of Regulatory Affairs
Nova Scotia Power Inc
Delivered via email to nicole.godbout@nspower.ca

25 September 2020

Re: Letter of Comment Regarding IRP's Draft Findings, Action Plan and Roadmap

Dear Ms. Godbout,

The Alternative Resource Energy Authority (AREA) has reviewed the Draft Findings, Action Plan, and Roadmap circulated to stakeholders by Nova Scotia Power Inc. (NS Power) on September 2, 2020. Due to other commitments, AREA was not able to meet the September 18, 2020 deadline for written comments on these materials. AREA has now had the benefit of reviewing the comments filed by Natural Forces Services Inc. (Natural Forces) on September 18, 2020, including the report of its technical advisor, Cooke Energy & Utility Consulting (Cooke), and requests that NS Power also consider the following brief comments filed on AREA's behalf.

AREA is in general agreement with the comments and technical report submitted by Natural Forces. In particular, AREA fully supports the key point emphasized by Natural Forces regarding the cost of wind that has been modeled in the IRP. AREA also agrees with the comments at page 2 of Cooke's report that NS Power's modeling analysis of intermittent wind should allow wind to be installed on an economic level, and accepting that on rare occasions it may be necessary to curtail wind output to ensure the system remains stable.

As noted in AREA's February 14 comments on the Input Assumptions, AREA continues to believe that alternative, lower-cost, non-NS Power financing models need to be fully considered as part of the transformation of Nova Scotia's electricity system. NSPI previously indicated that such ownership structures are captured in the "low case" scenarios. AREA believes that too many realistic individual market conditions (lower wind installed costs, higher wind net capacity factors, lower costs of capital, etc) are blended into the "low case" making it difficult to separate and study their specific effects on the pace of cost-effective decarbonization.

AREA looks forward to receipt of NS Power's Draft IRP report on September 29, 2020, and hopes that it will address the specific points raised by Natural Forces and Cooke. AREA expects it will submit additional comments for NS Power's consideration following review of the Draft IRP Report.

Thank you for considering our input.

Regards,

Aaron Long

Aaron Long
Director of Business Services

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Resource Insight Inc.

# MEMORANDUM

*To:* Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

*From:* John D. Wilson and Paul Chernick

*Date:* September 18, 2020

*Subject:* Comments on latest IRP materials

Thank you for the opportunity to comment on the draft findings, action plan, and related materials. We also appreciate the stakeholder engagement which has contributed substantially to our understanding of the plans. NS Power has demonstrated significant responsiveness to input from stakeholders.

Our specific questions and recommendations are numbered throughout this memo.

## Clarifications and additional information

In the IRP plan, we anticipated that there would be cost sensitivities for selected portfolios, such as fuel cost sensitivities.

1. Will those cost sensitivities be performed?

The individual model run results refer to "average annual partial rate impact" but the summary slide "relative rate impact comparison" does not reference the word "partial."

2. Is there a difference between what is being shown on the relative comparison slide and the individual model run result summaries?

## Resource Questions and Comments

The wind, battery, inertia, and transmission related sensitivities address some, but not all, of the issues that need resolution to reach clear findings and have a well supported action plan. Below, we discuss some of the resource-specific questions that NS Power should address.

Two technical issues that we would raise at a general level. First, it is not clear whether Plexos makes unit commitment decisions to satisfy operating reserve requirements and meet inertia constraints sequentially or through co-optimization. Regardless of the answer, the interaction between these two requirements seems to be a significant driver of model output, and NS Power should verify that it has configured its model in a manner that handles all of the sensitivities in a reasonable manner.

Second, other more general model configuration decisions may affect sensitivity runs in ways that were not evident in the testing for the main cases. For example, the chronologies used in Plexos LT testing may have been optimal under the default assumptions around inertia but may not capture the different challenges of operating with lower inertia constraints, which are only tested for the 2.1C case.

3. Please provide discussion of the issues NS Power has evaluated in its model configuration decisions.

## *Wind resources*

The sensitivities indicate that the near-term benefit of wind procurement depends strongly on price. NS Power has also evaluated the capability of the system to operate reliably with a high level of near-term wind procurement (prior to completing the reliability tie), which NS Power believes may depend on either the cost-effectiveness of battery storage or on the development of operational practices that address the reliability. Either battery storage or operational practices would have some impact on the economics of the wind procurement.

Our review of the model results suggests that wind resource pricing is a more significant driver than considerations of reliability. Reducing the inertia requirement advances a small amount of early wind (2.1C v 2.1C.WIND-3), but also *delays* wind investment in the 2030–2033 period. Accordingly, in our discussion of the action plan below, RII recommends an aggressive near-term all-source request for proposals (RFP), including an opportunity for up to 700 MW of wind[1] by 2025, to be conditioned on price and performance thresholds.[2]

If the resources that bid into the RFP reflect NS Power's baseline assumptions regarding cost and performance, then the procurement would likely result in a more limited amount of resources, e.g., wind in the range of 100–300 MW by 2026.

4. RII recommends that NS Power adopt a finding that because the primary driver of wind resource procurement levels is price, the most important step NS Power can take to identify the appropriate level of wind investment is to conduct an all-source RFP.

[1] In addition to new wind, the RFP should also be open to repowered wind.

[2] The results may affect the timing of the reliability tie.

## *Battery resources*

In contrast to wind, price is not the main constraint for battery storage resources. While RII recommends that battery resources should be eligible for the all-source procurement, NS Power's primary focus for this technology should be to understand better the value that battery resources may have for the system in the near term. Case 2.1C suggests that the base case for battery resource acquisition at current price levels is relatively modest. The sensitivity results suggest there seems to be a tradeoff between imported power and battery resources.

Surprisingly, Case 2.0A.Import-2 indicates that both batteries and CTs are procured at relatively high levels, allowing additional retirements of steam units. This suggests some interesting interplay between battery resources and thermal unit operations that the modeling may not have explored fully. As was discussed on a call with NS Power, the model did not value synthetic inertia and other advanced applications of battery storage that could have a significant effect on advancing retirement decisions for steam units in favor of advancing new resource acquisitions.

We also noticed that in some scenarios, battery capacity drops in 2045.

5. Please explain why battery capacity drops in 2045, identify the resources the model substitutes for battery capacity, and discuss implications of late-model treatment of battery storage in the end effects calculation.

## *Transmission and system inertia*

The modeling raises more questions than it answers about the need for transmission projects and the role of system inertia constraints.

First, the results do not show the expected effects on the timing of the reliability intertie as its inertia benefits change. The reliability intertie is built earlier when the level of inertia it provides is reduced (2.1C.IMPORT-3) or the price of batteries, an alternative source of inertia, is reduced (2.1C.WIND-1 vs WIND-2).

On the other hand, some model results indicate that the timing of the reliability intertie reflects the demand for inertia. Reducing the need for inertia results in delaying the reliability tie (2.1C vs 2.1C.WIND-3 and WIND-4).

Second, we see extraordinary sensitivity to relatively modest drivers. For example, lowering the battery cost results in delaying regional integration by 10 years (2.1C.WIND-1 vs WIND-2), even though the additional battery capacity is negligible compared to the imports available through regional integration.

During our discussion with NS Power regarding wind pricing and inertia sensitivity results, NS Power staff indicated that the model might be seeking to optimize a transition to a more adaptive resource mix, and that some of these interactions might be enabling higher retirements of “slow inertia” units. This concept is consistent with the model output from 2.1C.IMPORT-3: with the reliability tie providing less inertia, more “slow inertia” steam units retire, to be replaced by additional imports, combustion turbines, and wind (presumably for the energy). It appears that the domestic CTs are being utilized more heavily for inertia and other services in this scenario.

6. Please discuss the tradeoffs of the benefits and indirect impacts of transmission and related reliability measures.
7. Please clarify how the concept of “slow inertia” modifies the inertia values by unit that NS Power provided previously. Does “slow inertia” refer to the long startup times of steam units before they can provide inertia? How does inertia vary with the operating level of a steam unit?
8. Are unit commitment costs for inertia and/or operating reserves a driver in determining the transition pace from existing to 2040 resources?

It was our understanding that the reliability intertie provided no operating or planning reserves, only inertia. However, the reliability intertie does seem to enable the system to rely more on imports.

9. Does the reliability tie provide any services other than inertia, such as reserves or load following?
10. Is the increase of imports with the reliability tie a result of the reduced need to commit domestic steam units?

Understanding this relationship will be critical prior to issuing an all-source RFP, since non-domestic resources may wish to bid into the RFP based on varying assumptions about the completion date for a reliability intertie.

11. Either NS Power should present more evidence and findings on this topic in its final report, or its action plan should set out a plan for investigating these issues further before investing in planning for the reliability intertie.

## Additional Findings Needed

### *Solar resource analysis*

In the workshop presentation, NS Power provided a brief summary explaining why there is “very limited solar generation in the resource plans.” This should be reflected in the findings, where solar is barely mentioned.

While we are unsurprised that wind outperforms solar, we wonder whether that is the only reason that the model does not select much solar for the portfolio. One other factor that NS Power should discuss in its findings is the role of firm and non-firm imports in meeting the carbon emission limits. It is our understanding that NS Power assumes that imports are exclusively or primarily low- or zero-carbon resources.

12. Are the import prices based on the costs of renewables in other provinces?
13. If imported power has some significant level of carbon emissions, would solar be more attractive?

### *Impact of COVID-19 recession on load*

This is a topic that will be of interest to many even if it is of modest importance in the action plan.

14. RII suggests that the findings include a discussion of the impacts of the current global economic recession on NS Power's load and the implications of that recession for the resource plan.

### *Optimal planning reserve margin*

It is our understanding that NS Power's findings regarding the optimal planning reserve margin are based on the E3 study from July 2019. During the course of the IRP process, numerous adjustments have been made to the key inputs to the RECAP model. Questions about the ELCC of hydro units and operating surpluses, discussed below, would be relevant to estimating the target planning reserve margin.

15. RII recommends that NS Power verify the findings of the July 2019 study using the updated modeling environment and include a clearer resolution of the planning reserve margin question in the final IRP report.[3]

### *Analysis of the combustion turbine fleet*

In the 2016-2017 FAM audit process, NS Power agreed to "include an evaluation of the costs and benefits of the combustion turbines in its fleet in the upcoming 2019 IRP."[4] In the draft action plan, NS Power indicates that it will "Develop a plan" to redevelop or replace its existing gas/oil-fueled steam units, but does not address the combustion turbine fleet. In the draft findings, NS Power suggests that its existing combustion turbine fleet is cost-effective.

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[3] NS Power has agreed to resolve this matter in response to an audit recommendation by Bates White. Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 225.

[4] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 229.

16. RII recommends that the findings include a specific discussion of the economics of replacing the current CT fleet with newer CTs or another type of fast ramping generation, including a summary of the modeling evidence in support of its findings and any constraints on the options that were evaluated that may suggest a need for further analysis.[5]

### *Operating surpluses and inefficient dispatch*

In the two most recent FAM audits, Bates White found "evidence that NSPI was carrying surpluses of operating reserves and that this may increase costs to FAM customers."[6] Bates White found that "the Day-Ahead and Real-Time schedules created by the marketing desk frequently differ substantially and persistently from the actual dispatch of the generating units." Bates White's audit discusses several findings that could be leading to inefficient dispatch, which are also related to the surpluses of operating reserves.

Bates White states that NS Power has agreed to document instances of high operating-reserve surpluses, to help inform the IRP process to resolve the apparent surpluses of operating reserves.[7]

17. RII recommends that NS Power verify that its IRP model assumptions and settings reflect good operating practice with respect to these topics, update the findings section to address this topic, and share relevant detailed supporting data with stakeholders.
18. If operating reserves were maintained at the target levels (rather than the higher levels reported by Bate White, would NS Power be able to dispatch additional hydro during periods with high operating costs?

### *Mersey hydro retirement evaluation and hydro system value*

The Board recognized the importance of evaluating the continued operation of NS Power's hydroelectric facilities in the IRP process in the recent Annual Capital Expenditure Plan review.[8] NS Power also committed to IRP review in support of

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[5] For example, model assumptions regarding the need to acquire additional gas pipeline capacity for new CT units and the opportunity to repurpose existing capacity rights to new units.

[6] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), pp. 185, 257.

[7] *Id.*, pp. 267-268.

[8] NSUARB, *Decision Approving Nova Scotia Power's Annual Capital Expenditure Plan for 2020*, Matter No. M09499 (June 25, 2020), p. 15.

the Mersey Redevelopment project, with an anticipated total budget of $161 million, anticipated to be submitted later this year.[9]

In the June 26, 2020 interim modeling results, NS Power shared initial analysis of system value provided by hydro assets as modeled by E3. It is our understanding that this modeling will be finalized by NS Power using Plexos and will provide key inputs into the replacement energy cost for hydro generation used in the Company's economic analysis model.

In the September 2, 2020 modeling results, NS Power shared the Mersey hydro retirement scenario. This sensitivity appears to indicate that customers would experience a slightly higher cost ($44 million) to retain Mersey through 2045, even with a $227 million cost to decommission Mersey.

Although redevelopment of Mersey hydro does not provide customer benefits during the planning period, NS Power staff highlighted that customers do benefit in the long run. The end effects calculation shows an economic advantage to retaining Mersey beyond 2045. NS Power staff have expressed the view that the redevelopment project could provide a very long-lived asset, on the order of a hundred years. If Mersey could last another 100 years with no unusual capital investments, then we would agree. But if Mersey might require another significant redevelopment investment, perhaps in 30-40 years, then that cost would not be considered by the end effects calculation and thus the analysis might not be reaching the correct conclusion.

Furthermore, the end effects calculation does not take into account the likelihood that Mersey would eventually be decommissioned.

We understand that the IRP is not the venue for making a decision on the potential redevelopment of Mersey hydro. Nonetheless, NS Power has committed to reviewing this issue in the IRP and using that as an input into its submission for capital investment at Mersey. It is appropriate that there be a thoughtful discussion of the findings so that it is clear what evidence may be drawn from the IRP study.

19. RII recommends that the findings include an explicit discussion of the hydro system value and the retirement analysis of Mersey in particular, including discussion of the treatment of post-2045 costs (including redevelopment and decommissioning) and the risk that either redevelopment or decommissioning could have significantly higher costs than currently estimated.

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[9] *Id.,* p. 10.

## Rate Impact Model

Thank you for sharing the rate impact model. We have reviewed the model, and believe that for two reasons the model may exaggerate the rate impacts overall, and the differences among the cases.

### *Incorrect removal of incremental fixed cost recovery*

While NS Power's estimate of incremental fixed cost revenues is a reasonable approximation, for purposes of determining approximate average rates, these incremental revenues should not be deducted from the rate estimate. The average rate should be total revenues divided by total sales. There is no reason to exclude a portion of revenues from the average rate calculation.

Our first case – "Correction" – presents just the impact of removing this portion of the model.

### *Treatment of existing non-fuel revenues*

NS Power's use of 1994 non-fuel revenues is an appropriate starting point for the adjustment to obtain a reasonable total revenue requirement. We interpret these non-fuel revenues as including sunk costs of existing generation, T&D capital investment, and utility operating costs.

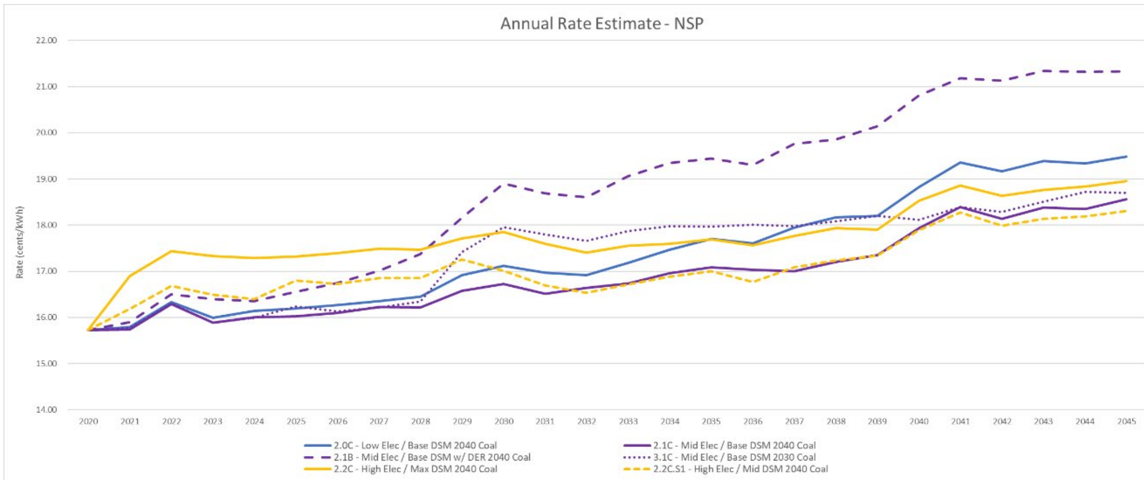
- Sunk costs of existing generation: These costs will depreciate, and are replaced by investments that are captured within the IRP revenue requirement. Accordingly there should be some downward adjustment.
- T&D capital investment: These costs will depreciate, but will be replaced by investments that are not captured within the IRP revenue requirement. Under higher load scenarios, a somewhat greater level of T&D capital investment may be required, but this would be hard to estimate.
- Utility operating costs: These costs should remain roughly stable in nominal terms.

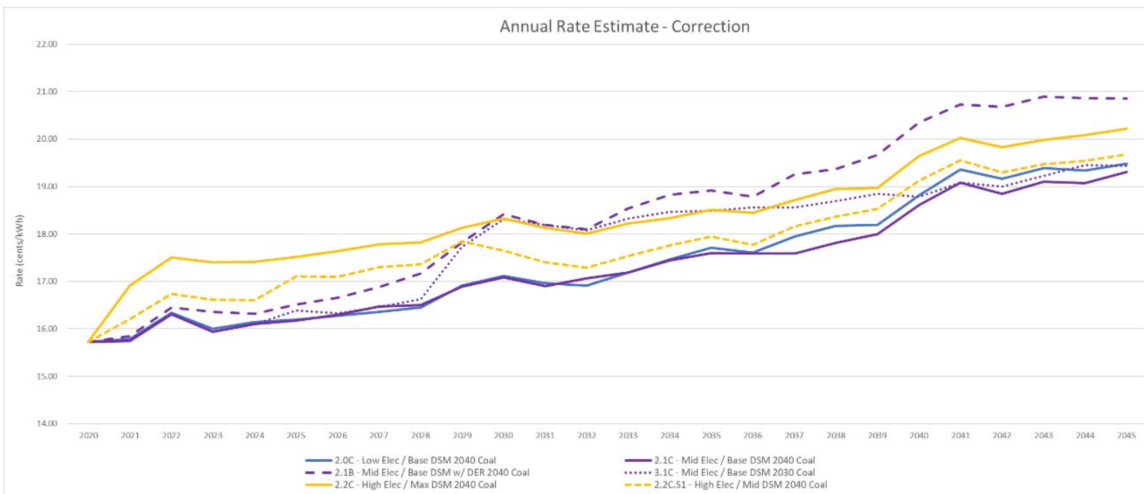
As a sensitivity, we suggest an annual reduction of 1.5% in these revenues. The net effect of this and the IRP revenues remains an increasing revenue requirement under every scenario.

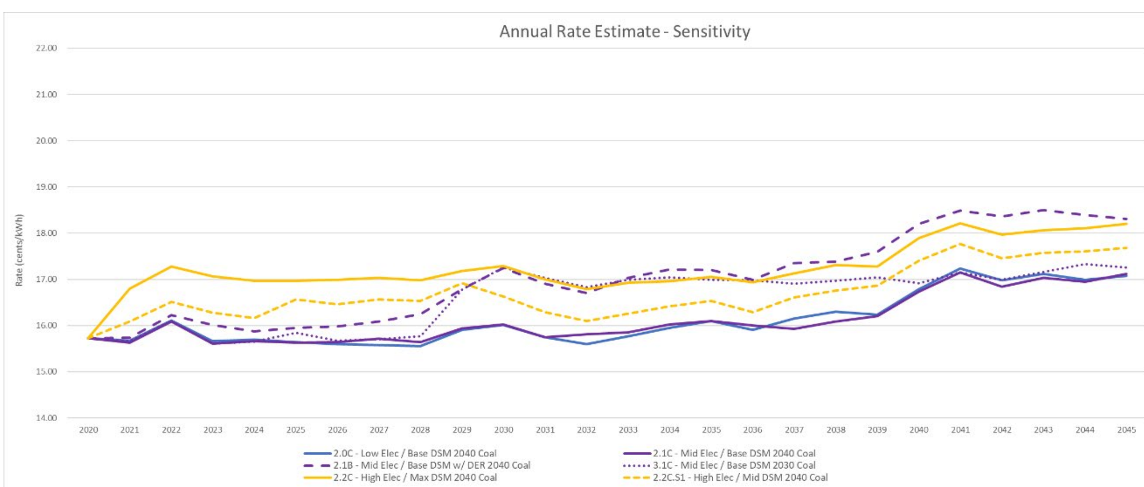
### *Findings*

Below, we provide all three charts – NSP, Correction, and Sensitivity. The Sensitivity includes both the correction and our 1.5% annual reduction in the existing non-fuel revenue requirement.

These charts demonstrate that NSP's rate impact model exaggerated the overall trend in rate increases and also exaggerated the differences among the different model scenarios.



## Action Plan

### *All-source request for proposals*

The draft action plan's resource procurement strategy should be significantly revised. NS Power suggests a wind procurement strategy and a plan for redevelopment or replacement of steam turbines with combustion turbines.

As discussed above, the most significant uncertainty in determining the timing and scale of new resources for NS Power is the cost of wind power and battery storage. Under the most favorable cost assumptions, NS Power could acquire as much as 300 MW of wind in 2023 and 676 MW of wind by 2026. The wind and battery price sensitivities also affect the timing and size of near-term CT procurements.

20. RII recommends that the draft action plan be revised to pursue an all-source RFP procurement process. NS Power should plan to conduct bid evaluation using its IRP models. Prior to issuing the RFP, relevant issues (e.g., load and DSM forecast, planning reserve margins, ELCCs, etc.) should be resolved in a transparent manner and the bid evaluation process should be clearly articulated in a submission to the Board.

The suitability of various levels of wind and other resources will depend on the schedule for construction of the reliability tie and regional integration. These decisions should be co-optimized. It should be recognized that if a high level of wind resources are procured, and those resources depend on the reliability tie, then any schedule delays affecting the reliability tie can be managed with temporary operating constraints on the wind projects.

21. RII recommends that planning for potential transmission projects proceed in parallel to an all-source RFP. Cost estimates for completion of the reliability tie for different in-service dates (several options, covering the range from the earliest feasible date to 2032) should be developed for use in bid evaluation. The regional interconnection should be handled similarly, except that there will be need for fewer in-service date options and accompanying cost estimates since the near-term resource acquisitions should be less sensitive to the exact date and cost estimate. Given some of the sensitivity results, the potential in-service dates for this project should be expanded to cover 2028-2040.

### *Electrification plan investment strategy*

The analysis of electrification presumes that NS Power would not bear any costs, such as program incentives to encourage transportation electrification, for example. It is our understanding that NS Power anticipates that it would need to operate electrification programs at some level of cost in order to achieve the higher levels of electrification studied in the IRP, but that such programs have not yet been studied or costs developed.

RII recommends that NS Power include in its action plan an "order of magnitude" estimate for the level of cost that might be appropriate for its customers to bear to promote electrification. As noted in the draft findings, "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors."

22. What level of program investment in electrification would result in no net change in electricity rates for a given level of electrification?

Given the diversity of the possible futures, RII recognizes that this question cannot be answered with certainty or exactitude. However, an order of magnitude estimate of the annual investment that might begin to cause upward pressure on rates would be informative to the Board and stakeholders.

While upward pressure on rates is an important consideration, we would also encourage the Board to consider that electrification may also have significant benefits to participants – such as cost savings for other fuels – and to Nova Scotia at large – by facilitating carbon reductions across all sectors. This may be viewed as a total resource cost perspective. While this is clearly beyond the scope of the IRP, we encourage NS Power to make note that these benefits exist to avoid creating the impression that rates should be a singular basis for deciding how much electrification may be considered affordable.

While many electric utilities in North America have already initiated significant electrification programs, it would still be prudent for NS Power to begin with pilot programs across the range of electrification opportunities. Some modest efforts have, in fact, already begun. Electrification should not be limited to residential, commercial, and on-road transportation. The industrial and maritime sectors also provide opportunities and should be involved early in the development of electrification programs.

23. Nova Scotia Power should propose a more intentional and comprehensive electrification pilot program strategy, with the intention of setting the stage for potentially launching larger programs in three to five years.

## *Evergreen IRP process*

RII recommends that NS Power engage with those stakeholders who have been most active in the IRP process to better define what an "evergreen IRP process" might look like. It is our understanding that in the past, NS Power has considered a two-year IRP cycle as potentially too frequent. The term "evergreen" suggests an even more frequent update process, with many small changes rather than a singular long process. This is an interesting idea, and we look forward to its further exploration.

## Remaining Concerns about Assumptions

### *ELCC for run-of-river hydro units*

In our memo of August 4, RII questioned the 95% ELCC for run-of-river hydro units. It is our understanding that this ELCC is based on DAFOR only, and that operational limitations were not factored into this finding. Our most recent analysis supports a lower ELCC for run-of-river hydro units.

As shown in **Table 1**, dispatch of hydro units increases from peak hours to the hours representing the highest 1.1% of net loads (i.e., load minus wind output), and then again to the top 0.1% of net peak hours. This supports a finding that system operators are increasing small-hydro dispatch in response to resource needs.

**Table 1: NS Power Generating Unit Capacity Factors**

| | **Peak Hours** | | **Net Peak Hours** | |
|---|---|---|---|---|
| | **Top 1.1%** | **Top 0.1%** | **Top 1.1%** | **Top 0.1%** |
| **Mersey** | 70.6 % | 66.2 % | 71.6 % | 77.3 % |
| **Hydro Group 1** | 69.2 % | 69.0 % | 71.3 % | 77.1 % |
| **Hydro Group 2** | 51.1 % | 52.5 % | 55.0 % | 63.2 % |

We are struck by how much the capacity factors in peak hours differ from the 95% ELCC that NS Power estimates. Perhaps low reservoir levels reduce the capacity of the plants in some years, or limited water flow limits the number of hours for which the dispatchable units can operate. Especially if water supply is limited, these units may be held for operating reserves.

24. Can NS Power explain the discrepancy between the claimed ELCC and the actual performance of the small hydro units?
25. If these units are being held for system reserve, why is this the most economic system dispatch? Wouldn't it make sense to fully dispatch these units at peak hours and reduce the use of gas/oil steam and diesel CT dispatch?
26. Does Plexos reflect NS Power's actual operating practice?

Resolving the dispatch and reliability contribution of the small hydro units may not result in substantial changes to the modeled resource plans. Nonetheless, these issues are relevant to the cost-effective operation of the NS Power system.

With respect to Wreck Cove, which is highly dispatchable and has very limited daily water availability in Surge Pond, we understand that its relatively low dispatch during peak hours is due to its use for operating reserve. Given NS

Power's long winter peaks, Wreck Cove may not be able to operate at full load for the entire peak period of a day, limiting its contribution to reliability. This limitation should be considered in combination with DAFOR in determining its ELCC and the overall system planning reserve margin.

### *Sustaining capital cost profiles*

According to the draft findings presentation, NS Power updated the Plexos model with new sustaining capital cost profiles for coal units.

27. Please share those updated assumptions with stakeholders.

Furthermore, RII has identified some inconsistencies between the original capital cost profile assumptions for Point Aconi and information provided in the recent FAM audit by Bates White. The audit states that Pt. Aconi personnel indicated that "major generator work (2022) and turbine overhaul (2024) will require substantial sustaining capital investment."[10] This language suggests above-average investment levels. The original capital cost profile assumptions for Point Aconi do not include above-average investment levels, and the higher investment years in that forecast do not match the information provided in the FAM audit. Furthermore, Point Aconi may require an expansion of its limestone mine in eight years, which could require significant additional investment that does not appear to be reflected in the IRP capital cost profile assumptions.

RII recommends that NS Power verify that its updated capital cost profile assumptions reflect the correct sustaining capital cost forecasts for all units, including Point Aconi.

28. Please provide the sustaining capital cost profiles and underlying assumptions in depth. The final report should include a comparison of the cost of continued operation (including fixed OM&A and sustaining capital) for each of the thermal plants.

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[10] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 222.

# CanREA Comments on September 2, 2020 Draft IRP

The Canadian Renewable Energy Association (CanREA) is pleased to present this submission in response to the Nova Scotia Power Inc. (NSPI) 2020 Integrated Resource Plan (IRP). CanREA is the voice for wind energy, solar energy and energy storage solutions that will power Canada's energy future. We work to create the conditions for a modern energy system through stakeholder advocacy and public engagement. Our diverse members are uniquely positioned to deliver clean, low-cost, reliable, flexible and scalable solutions for Canada's energy needs.

CanREA appreciates the efforts that NSPI has taken to provide stakeholders an opportunity to comment on its 2020 IRP, as well as the apparent refinements to the IRP draft assumptions and models to reflect comments from stakeholders regarding prior work elements of the IRP. Recognizing that the IRP is in draft form, CanREA offers the following comments on the September 2nd Updated Modeling Results Release, Draft Findings Release and September 10th Draft Findings Workshop presentation.

## Non-synchronous/Inverter-based Resource Integration

A major focus of our comments is the recent work that CanREA understands has been completed for the Offshore Energy Research Association (OERA) on behalf of the Nova Scotia Department of Energy and Mines on the ability of non-synchronous/inverter-based resources (i.e., wind, solar and battery storage projects) to provide various ancillary services and support the integration of additional volumes of such generation. CanREA commented on a draft of the report and various members participated in interviews with OERA's consultant, Power Advisory LLC.

In the Draft Findings Workshop presentation NSPI indicates that "Wind energy continues to increase in all IRP resource plans; new wind is assumed to contribute to grid essential services (e.g. ramping reserve, SCADA control) to enable additional renewable integration." (Slide 10) Furthermore, in the Draft Findings Workshop presentation NPSI notes

> "Wind is the lowest cost domestic source of renewable energy and is selected preferentially over solar in all resource plans. Incremental wind capacity of 500 -800MW is selected by the model over the period, with major installations paired with coal retirement dates to provide replacement emissions-free energy. Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system." (Slide 47)

CanREA observes that NSPI focuses on constraints to wind integration, questioning whether "additional dynamic system inertia constraints can enable this level of additional wind integration" rather than acknowledging that the ability of wind generation to provide various frequency response services including fast frequency response (FFR) and primary frequency response has not been fully considered. The provision of FFR by wind generation arrests the frequency decline after a system event and can reduce requirements for synchronous inertia. CanREA understands that additional work needs to be done to determine the impact of FFR provision by wind turbines on requirements for system inertia in Nova Scotia, but as the OERA work demonstrates there is a considerable body of work demonstrating this capability and its adoption by system operators in other jurisdictions. This is a critical issue because the IRP indicates that wind generation is the most economic type of domestic renewable generation and therefore can play an important role in assisting NSPI backout coal-fired generation.

The IRP Draft Findings Presentation indicated that one of the “Key Plexos Model Updates” was to “Allow new wind generation to provide ramp down reserve service” (Slide 30) Chris Milligan confirmed that this was a refinement that flowed from the OERA work. CanREA notes that this is just one ancillary service that wind generation is capable of providing. By focusing on just this ancillary service NSPI failed to consider the range of ancillary services that are critical to enabling the integration of additional wind generation in Nova Scotia as demonstrated by the work performed for OERA. A ramp down service can assist with managing surplus wind generation during low load high wind output periods. However, as the OERA study indicates the critical ancillary services are frequency response services that allow NSPI to dispatch off thermal generating units and rely on the fast frequency response capability that wind generators offer. Chris Milligan noted that NSPI’s modeling has not considered this capability and also has not considered the ability of battery energy storage projects to provide a similar service.

CanREA encourages NSPI to continue to integrate the findings from the OERA report on how the ancillary service provision capabilities of wind, solar and battery resources (i.e., non-synchronous /inverter-based resources) can be utilized. Given the low energy costs offered by wind resources recognizing this capability is likely to reduce costs to customers, while enhancing system reliability. The low cost of wind relative to other resources also creates an opportunity to operate at a reduced capacity to provide head room to offer ancillary services (e.g., the provision of primary frequency response) under some operating conditions.

CanREA acknowledges that the September 2nd IRP Results includes a sensitivity that reflected a lower inertia constraint (2.1C.WIND-3 (LOW INERTIA CONSTRAINT)) and another that eliminated the inertia constraint all together (2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)). These sensitivities help advance the understanding regarding the impact of inertia requirements on the amount of wind generation that can be integrated. Additional background regarding insights from these sensitivities would be helpful.

The Draft IRP also notes that “significant wind penetrations (beyond what was modeled in the PSC study) will require additional study work to confirm system stability” (Draft IRP Findings Workshop, September 10, 2020, p. 26). Given the recent work by OERA, CanREA encourages NSPI to update the PSC study and when doing so to provide an opportunity for stakeholder input or alternatively to have committee of experts advise on modeling assumptions and protocols. This will help ensure that there is stakeholder support for the findings of this work.

## Regional Integration

The Draft IRP appropriately focuses on Regional Integration as a key strategy for decarbonizing Nova Scotia’s electricity supply: “Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the least-cost plans under each load scenario.” (Slide 47) The first element of the Draft Action Plan is to “Develop a Regional Integration Strategy to provide access to firm capacity and low carbon energy, increase the reliability of Nova Scotia’s interconnection with North America, and enable economic coal unit retirements.” CanREA agrees that this is an appropriate element of such an Action Plan. As NSPI’s IRP has indicated greater regional integration is critical to unlocking the potential of wind generation to provide the required renewable energy to enable coal unit retirements. CanREA encourages NSPI to accelerate this element of its Action Plan. Additionally, The inclusion of solar energy and energy storage applications will need to increasingly be factored in to planning scenarios. CanREA notes that Regional Integration investments are likely to offer multiple benefits including lower costs, enhanced reliability, and greater flexibility.

## Resource Procurement

One of sensitivities evaluated was a low wind price. This sensitivity advanced the "build of significant wind quantities from 2030 in base case to 2025." CanREA notes that the last major procurement of wind energy resources in Nova Scotia was over eight years ago and that the cost of wind generation has fallen by an estimated 42% on a levelized cost basis during this time, while wind turbine technologies have advanced significantly[1]. The majority of the IRP cases reflect modest near-term wind additions. With these wind additions likely to occur through competitive procurement processes, NSPI will then have a reliable estimate of the cost/price of wind in Nova Scotia that can be used to determine if the low wind price sensitivity is a better reflection of the actual cost of wind generation. One element of the Draft Roadmap is "to continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios)." CanREA agrees this is a best practice, such monitoring as well as evaluating the results of various renewable energy procurement efforts is appropriate.

Another element of the draft action plan was a wind procurement strategy, "targeting 50-100MW new installed capacity by 2025 and up to 350MW by 2030." CanREA believes that the 50 to 100 MW new installed capacity by 2025 is likely to be low given the various issues identified with NSPI's failure to fully consider in its modeling of the ability wind generation resources to provide frequency response services.

CanREA recommends that one element of this wind procurement strategy be an indicative schedule of future wind procurements based on the results of the IRP. We understand that such may need to be modified as additional information becomes available on load growth, technology costs, integration analyses. Nonetheless establishing such a procurement schedule will signal to the development community future procurement activity that will give them the confidence to invest in project development and the local supply chain, which can derisk future project development and reduce wind costs benefiting Nova Scotia consumers and its economy.

NSPI has indicated that it will be preparing its final report in the coming weeks. CanREA urges NSPI to acknowledge the potential for additional modeling and consideration of solar energy and energy storage for future iterations of integrated planning as two additional technologies that wil complement the projected wind energy contributions and provide NSPI with the tools to satisfy multiple objectives supported by Nova Scotia's electricity system. As costs continue to decline and the technology evolves, the next iteration of planning will ideally include consideration for the contributions that all renewable energy and energy storage technologies can provide, including hybrid projects.

Thank you for your consideration of this submission, we look forward to additional dialogue on this important file and we remain availbe to meet at any time to discuss further.

Sincerely,

Brandy Giannetta
Senior Director Ontario & Atlantic Canada
Canadian Renewable Energy Association

[1] See Lazard Levelized Cost of Energy and Levelized Cost of Storage 2019, https://www.lazard.com/perspective/lcoe2019

# Memorandum

To: Nicole Godbout

From: John Esaiw

Date: September 18, 2020

Re: 2020 IRP – September 2, 2020 – Release of "Final Modelling Results" and "Draft IRP Findings and Action Plan"

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EfficiencyOne is pleased to offer comments on NS Power's 2020 Integrated Resource Plan (IRP) Modeling Results, Draft Findings, and Action Plan, as released on September 2, 2020. These comments are summarized below, followed by a more detailed discussion of each.

1. The 2020 IRP Report must define a Preferred Resource Plan in line with quantitative results of the IRP modelling process, using the 25-year Revenue Requirement, adjusted for End Effects. Qualitative discussion should reflect these findings.
2. The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan.
3. Absent quantified impacts, it is important that the final report clearly indicate the qualitative effects on T&D investments from increased or decreased levels of DSM.
4. Provide more context on the results of the DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification.
5. Provide an assessment of the risks associated with large capital investments such as a regional intertie and the use of non-firm imports. The 2020 IRP Report should confirm that DSM mitigates the risks associated with NS Power's plan to reduce GHG emissions within the IRP Findings and Action Plan.
6. Provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan.

7. The rate effect metrics (10-year NPVRR and estimated rates) will not contribute to achieving the general purpose of the IRP process as set out by the UARB and should receive limited consideration.
8. Provide stakeholders with a proposed approach (technical and process-related) for calculating the avoided costs of capacity and energy associated with DSM. It is important that this approach quantifies avoided costs prior to the IRP Report being filed with the UARB.
9. Publish responses to all stakeholder comments and questions following the submission of comments on September 18th. Stakeholder comments and questions and NS Power's responses help inform all stakeholders.

A detailed description of the above recommendations and their rationale follows.

## 1. Identify the Preferred Resource Plan

Slide 48 of the "Draft Findings Release" presentation includes the following statement:

> *DSM energy efficiency programs consistent with a range of the "Low" to "Base" profiles, consistent with the E1 Potential Study, are shown to be most economic relative to other options evaluated.*

This statement does not appear to reflect the quantitative findings of the IRP scenarios as modelled.

Table 1 shows the Revenue Requirement with End Effects for each of the DSM sensitivities examined as part of case 2.0C, which is a key case for informing the findings and action plan (perhaps with contributions from case 2.1C, a similar case in the mid-electrification world). This information is taken from the "Updated Modelling Results Release".

Table 1 - DSM Sensitivity Results - 2.0C

| Case | RR w EE (NPV 2021) ($M) | % Difference relative to 2.0C |
|---|---|---|
| 2.0C (Original w/ Base) | $16,241 | N/A |
| 2.0C.Low DSM | $16,350 | 0.7% |
| 2.0C.Mid DSM | $16,561 | 2.0% |
| 2.0C.Max DSM | $17,153 | 5.6% |

Case 2.0C (Original – Base DSM) produces the lowest NPV revenue requirement (adjusted for end-effects).

The presentation of the final portfolio study metrics (i.e. the metrics used to evaluate each portfolio studied in the Final Modelling Results) is stated as "with and without End Effect adjustment" – this is distinct from the UARB-approved Terms of Reference, which state that End Effects are included.

End effects should be included when making these determinations, for the reasons summarized below:

1. The NPV of revenue requirements with energy efficiency is the primary metric in guiding IRP results, as stated in the following excerpt from the IRP Approved Terms of Reference (emphasis added):

   *Traditionally, the primary decision criterion used for IRP modeling has been the minimization of the cumulative present value of the annual revenue requirements over the* ***25 year planning horizon (adjusted for end-effects).***

   ***NS Power will continue to use this primary metric to guide resource planning****, and will also assess others of increasing importance, including:*

   - *Magnitude and timing of electricity rate effects;*
   - *Reliability requirements for supply adequacy;*
   - *Provision of essential grid services for system stability and reliability;*
   - *Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions);*
   - *Reduction of greenhouse gas and/or other emissions; and,*
   - *Flexibility (limitation of constraints on future decisions arising from the selection of a particular path).*[1]

2. It is a best practice, as suggested by the Regulatory Assistance Project and Synapse Energy Economics, on the basis that late resource additions are treated more equitably under this approach. DSM is both an example of a late resource addition (in that it occupies continuous investment trajectories), and subject to less-than-ideal competitive treatment associated with other late resource-additions.[2]

It is critical that the 2020 IRP provide clarity on the Preferred Resource Plan, for the purposes of making a determination regarding economically optimal DSM levels. The

[1] M08929, IRP Terms of Reference, Filed December 16, 2019, at Appendix A, Page 7.
[2] Synapse Energy Economics for Regulatory Assistance Project, Best Practices in Electric Utility Integrated Resource Planning, June 2013, at Page 31.

Preferred Resource Plan is used to provide avoided cost information which informs future determinations of appropriate DSM Resource Plan inclusions and levels, in part.

The 2020 IRP Report must define a Preferred Resource Plan in line with quantitative results of the IRP modelling process, using the 25-year Revenue Requirement, adjusted for End Effects. Qualitative discussion should reflect these findings.

## 2. Modify Revenue Requirement Calculations based on Carbon Pricing

As part of its feedback on the Assumptions and Analysis Plan, EfficiencyOne asked the following:

> *Does NSP expect to sell excess credits from lower emissions; if so, how will carbon cost be captured and will revenues from carbon credits be accounted for in revenue requirement for each scenario?*
>
> NS Power's responded with the following:
>
> *NS Power will incorporate cap and trade market revenue from sales of excess GHG allowances during the screening phase of the modeling work for some key scenarios. If market revenue is found to affect the preferred resource plan selection, then a determination will be made as to how to incorporate the cap and trade market in the full IRP modeling phase.*

NS Power's verbal update on this analysis at a Technical Session indicated that the initial modelling was conducted, and the results indicate that economic dispatch was not altered due to carbon pricing revenue, so no further analysis was required.

Several modelled cases produce emissions profiles below the requirements of regulations and below the "Net-Zero by 2050" profile (GHG Profile "2") requirements.

Table 2 shows the total cumulative carbon emissions for the DSM sensitivities examined by NS Power and the nominal (not NPV) impacts of certain pricing assumptions on revenue requirement. For clarity, the differences in carbon emissions (i.e. $CO_2e$ Cumulative Planning Period Emissions) are taken from the Final Modelling Results deliverable, while the estimation of monetary value has been performed by EfficiencyOne.

Table 2 - Nominal RR Impacts of Carbon Pricing

| Case | $CO_2e$ Cumulative Planning Period Emissions | Difference relative to 2.0C | Change in RR relative to Base – Nominal - $20 per Tonne | Change in RR relative to Base – Nominal - $50 per Tonne |
|---|---|---|---|---|
| 2.0C (Original w/ Base) | 65 MT | N/A | N/A | N/A |

| | | | | |
|---|---|---|---|---|
| 2.0C.Low DSM | 72 MT | 7 MT | $140M | $350M |
| 2.0C.Mid DSM | 59.4 MT | -5.6 MT | -$112M | -$280M |
| 2.0C.Max DSM | 62.1 MT | -2.9 MT | -$58M | -$145M |

Mid and Low DSM follow the trend that higher amounts of DSM produce incremental carbon reductions, and it is unclear why Max DSM results in higher cumulative emissions than Mid-DSM. Given a potential difference between Low DSM and Mid DSM of $630M (undiscounted) in potential carbon revenues (assuming $50 per tonne), carbon pricing merits full consideration in the IRP.

Absent forecasts of carbon prices, the Federal Government's "floor" for carbon pricing is $50 per tonne in 2022. Given that Nova Scotia's inaugural cap and trade auction resulted in a settlement price of $24 per tonne, assuming levels below $24 would not seem reasonable for projections extending out 25 years.

The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan.

## 3. Assess the Impacts of DSM on the Costs of T&D

NS Power has indicated that modelling of all T&D impacts is not feasible in an IRP process. Regardless, it is important to note that from an IRP methodological perspective, T&D is no longer an *"all-else equal"* item as it was in the past, and the varying levels of T&D investment across the modeled scenarios need to be recognized.

Energy efficiency and other forms of DSM are known to produce savings on the T&D system. The IRP needs to reflect this fact to clearly indicate the plan that provides most value to ratepayers.

The methodology for quantifying T&D avoided costs from DSM is now being developed by NS Power in consultation with stakeholders. Absent quantified impacts, it is important that the final report clearly indicate the qualitative effects on T&D investments from increased or decreased levels of DSM.

## 4. Provide Context on the Analyses of DSM Sensitivities

The full range of DSM sensitivities was explored only for the reference electrification scenario, which is the least aggressive of three electrification scenarios. Absent further analyses of sensitivities of DSM in other scenarios, it is unclear how DSM would compete in these worlds.

Higher amounts of electrification will likely require more generation on the system, given the average load and incremental peak load outputs of the Pathways studies, and hence could climb the cost curve of available supply-side resource options. It is expected that DSM would produce results that are in line with the reference electrification scenario, but with enhanced competitiveness.

Recognizing that further sensitivity analyses would be difficult to complete within the established IRP timelines, NS Power should provide more context on the results of its DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification.

## 5. Assess the Risks Inherent in Interties and Non-Firm Imports

The Updated Modelling Results include sensitivities related to reductions in intertie service (reliability interties) as well as reductions in the availability of non-firm imports. Those sensitivities and their end-effect adjusted NPV Revenue Requirements are shown in Table 3.

Table 3 - Import Sensitivities

| Case | Description | % Increase NPVRR (with end-effects) relative to original case |
|---|---|---|
| 2.1C.Import-1 | Reduces non-firm imports from all sources available to 0.8TWh | 2.3% |
| 2.0A.Import-2 | No reliability Tie | 2.1% |
| 2.1C.Import-3 | Limited reliability Tie Inertia | 0.4% |

The results demonstrate material sensitivity to the removal of some non-firm imports. Stakeholders do not have access to information relating to further constraint of non-firm imports (beyond 0.8 TWh of final availability); presumably, the costs would further escalate in such cases.

The mitigations selected by the model in these sensitivities for 2.1C. Import-1 are:

- Construction of one additional Natural Gas Combined Cycle unit (NGCC).
- More firm imports to replace non-firm imports.

These mitigation options do not appear to fully reduce the risk of reduced intertie capacity and in fact, could create new risks such as:

- The construction of an additional NGCC unit will place additional pressure to procure winter baseload natural gas. This mitigation option could add to the risks around existing natural gas assumptions, which are already heavily risked. In addition the Plexos ST runs indicate there is much more cycling of CTs, adding additional operational risk. These costs are not known and could be material with the additional wind that may come onto the system. If not already accounted for, in Plexos, there should be some factors added in the model that consider this type of operation.

- Market conditions may be such that challenges with obtaining non-firm imports may be interrelated with obtaining firm imports.
- Large capital projects have inherent risks. Investments such as strengthening the NB intertie, adding a new interconnection with other markets, or further delays to Muskrat Falls in-service date all pose material risks.

The added risks associated with NS Power's mitigation plans for interties and non-firm imports should be described qualitatively (if a quantitative analysis is not possible within the schedule) as part of the IRP Draft Findings and Action Plan.

DSM is known to have lower risk than large capital items such as those described above. This is recognized by the North American Electric Reliability Corporation (NERC):

> *DSM resources lead to reductions in supply-side and transmission requirements to meet total internal demand. They can be considered in long term planning exercises as a supplement to long-term planning reserves, and provide operational reliability through operating reserves and flexibility. DSM resources can also be used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with variable renewable resources.*[3]

The 2020 IRP Report should provide an assessment of the risks associated with large capital investments such as a regional intertie and the use of non-firm imports. The report should also confirm that DSM mitigates the risks associated with NS Power's plan to reduce GHG emissions within the IRP Findings and Action Plan.

## 6. Respond to Questions Regarding Natural Gas Assumptions

In its July 10th Letter of Comment, EfficiencyOne made the following recommendations related to natural gas assumptions in the IRP:

- A proxy for new gas supply should also include a sensitivity relating to the Algonquin City Gates Hub (AGT) as the commodity price for new winter (and summer) natural gas capacity, with the inclusion of energy cost and tolls reflecting transport from AGT to Tufts Cove, as it would address some of the uncertainties associated with the current approach of acquiring gas and transportation from Alberta (AECO), Dawn or LNG via Amsterdam (TTF).
- Sensitivity analyses that explore the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of

[3] NERC, Data Collection for Demand-Side Management for Quantifying its Influence on Reliability, December 2007, at Page 1.

20,000 MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply.

These requests, as far as we understand, have not been addressed, and IRP stakeholders do not have knowledge of other stakeholder positions relative to natural gas pricing assumptions. At minimum, NS Power should provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan.

## 7. Recognize the Cursory Nature of the Rate Effects Analysis

The Draft Findings and Action Plan describe qualitative and quantitative case assessments related to rate effects. The Final Portfolio Study section notes that the description for the "Magnitude and timing of electricity rate effects" is a 10-Year Revenue Requirement. The study then presents a high-level rate analysis. On September 17, 2020, an accompanying excel representation of the rate effects model was distributed to stakeholders.

The methodology described in the model is substantively different compared to the relatively more mature Rate and Bill Impact Assessment model, which has been reviewed by stakeholders and the UARB several times in Nova Scotia, and continuously improved.

Further, the IRP provides the only opportunity for analysis of the long-term revenue requirement associated with the NS electricity system. This long-term view is critical in determining the lowest cost electricity system into the future, which is a complex question to answer, given the degree of changes taking place in the electricity, and broader energy, system today. The UARB spoke to this important purpose of the IRP in the 2016-2018 DSM Resource Plan decision:

> The general purpose of the IRP process is to identify a plan which utilizes both supply-side and demand-side resources to reliably serve the electrical requirements within Nova Scotia at the lowest long-term cost to ratepayers.[4]

The outcome of the IRP should be primarily informed by the lowest long-term cost to ratepayers. Affordability should be examined as part of the lowest cost long-term trajectory, as short-term rate impacts have many influences such as fuel costs which are subject to the vagaries of the market. Many affordability considerations are affected by near-term cost pressures and the timing of investments, matters not examined in a detailed fashion as part of the IRP.

The rate effect metrics (10-year NPVRR and estimated rates) will not contribute to achieving the general purpose of the IRP process as set out by the UARB, and should receive limited consideration.

## 8. Propose a Methodology for Calculating Avoided Costs

[4] M06733, 2015 NSUARB 204, UARB Decision, Issued August 12, 2015. At para 93.

Beyond the remaining decisions relating to the selection of the Preferred Resource Plan, the generation of avoided costs remains an outstanding issue associated with the completion of the 2020 IRP. The determination of avoided costs must take place as part of the IRP process. While avoided costs are critical inputs to DSM planning, they are also meaningful and important to other stakeholders engaged in DSM proceedings.

The technical decisions and tasks associated with the calculation of avoided costs involve:

1. The designation of at least one comparator Plan for use in the Difference in Revenue Requirements method of avoided cost generation.
2. Decisions relating to what DSM elements will be included in a given avoided cost run (if more than one). For example, will Demand Response (DR) activities be aggregated with energy efficiency (EE) as a single avoided cost run.
3. The final form of avoided cost results.

These questions and decisions should be resolved as part of the IRP stakeholder engagement process. In each of the points above there are nuances and subtle changes in approach which stakeholders should generally understand.

NS Power should prepare the resource plan that is to be compared with the Preferred Resource Plan through removal of DSM load modification, and allow the model to re-run resource additions in Plexos LT. The comparator plan should then be checked for reliability and operability, such that stakeholders are assured that the comparison is performed on two viable IRP cases; each viable on their own merits, and only separated by DSM.

Furthermore, the 70MW of economically selected DR should be grouped with the End Effects case or cases being examined. EfficiencyOne is interested in NS Power's and other stakeholders views on this approach, but it seems that grouping these aspects of DR will avoid the requirement for the separate generation of avoided costs for DR and EE, and will provide inherently the interaction between EE and DR, which is consistent with how the 2019 DSM Potential Study was modelled (i.e. in that DR and EE were modelled as interacting in the DSM Potential Study).

Finally, the avoided cost data should be presented in the format used for the 2014 IRP. The key elements from the 2014 approach EfficiencyOne would like to see maintained on a public basis are:

1. The provision of annual avoided cost streams for both generation and energy.
2. The provision of levelized values over the planning period.
3. Key input assumptions (e.g. WACC).

In addition to the technical aspects discussed above, there does not seem to be a clear process for developing avoided costs as part of the this and future IRPs. The IRP Action Plan should propose a technical approach and process for quantifying avoided costs, taking into account the comments provided above. This proposed approach should be reviewed with all IRP stakeholders and updated according to their feedback. The process should allow for the initial draft production of avoided costs as part of the Draft Final Report deliverable. EfficiencyOne is strongly in favor of an approach that allows for resolving avoided costs prior to an IRP-associated regulatory process, on the basis of transparency and ensuring continued participation by the IRP stakeholder group.

## 9. General Responses to Comments

NS Power provided written responses to stakeholder comments on the Assumptions and Analysis Plan (December 27, 2019) and the Terms of Reference (March 12, 2020). NS Power has been readily available to discuss specific questions when requested by EfficiencyOne and has made every effort to meet and discuss results and issues, but it has not published responses to stakeholder comments since March 12. Responses to all stakeholder comments and questions should be published following the submission of comments on September 18$^{th}$. NS Power's views on these comments are important to all stakeholders.

EfficiencyOne appreciates NS Power's continued openness to formally and informally discussing technical issues and stakeholder concerns throughout this IRP process.

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# SUBMITTED COMMENTS REGARDING 2020 IRP DRAFT FINDINGS, ACTION PLAN AND ROADMAP

**September 18, 2020**

The Ecology Action Centre (EAC) welcomes the opportunity to participate as a stakeholder in the 2020 Integrated Resource Plan process. We submit the below comments and questions in response to the Draft Findings, Action Plan and Roadmap released for stakeholder comment on September 2, 2020 and discussed at the stakeholder session on September 10, 2020. Specifically, this submission is in response to the below document:

1) NS Power IRP 2020 Draft Findings, Action Plan and Roadmap

The EAC feels very strongly that this process should not be considered just another Integrated Resource Plan. Nova Scotia Power Incorporated (NSPI) is the third most polluting energy utility in Canada. This is an opportunity for us to make NSPI one of the least polluting energy utilities in Canada and there is limited time to make these decisions with significant long-term consequences for emission, especially for utility ratepayers.

The EAC appreciates the opportunity to participate and submit written comments in the IRP process, and help strengthen the energy system in Nova Scotia.

Thank you,

G. Gurprasad

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Comments on Draft Findings:

1. Nova Scotia's Sustainable Development Goals Act is a significant milestone in the province's climate plans, and actions adhering to these emission goals is a welcome scenario. The EAC supports the notion of a steep reduction in reducing carbon emissions in the province. While scenarios have comprehensively studied emissions reaching between 0.5 Mt and 1.4 Mt, the EAC expresses concern that no "zero" emissions scenario was studied. Zero emission cases will provide an assessment of the costs required to operate from imports, sequestered carbon emissions and renewable energy. Increased costs to the utility add value to efforts across the regional GHG reductions landscape by maximizing the impact of electrification. In addition, near-future regulatory benchmarks will dictate provincial emissions to align with net-zero carbon scenario. Therefore, it would be prudent to have a future-proof plan ready for deployment.
2. Access to firm capacity imports from the Maritime provinces and Quebec would be highly beneficial to the ratepayers, and draft findings statement 2 echo the same. At the same time, the Reliability Tie is a welcome move, which would strengthen the province's grid further. However, it is not shown if the study explored fully replacing coal generation with building interconnection infrastructure and investing in clean firm imports. Wind will play a key role in the region's renewable portfolio, and addition of an incremental 500-800 MW capacity is a welcome move.
3. Adding and relying on Gas turbine infrastructure and natural gas purchases run the risk of an upward carbon emission trend. The North American natural gas supply has additional emissions associated with upstream fugitive methane emissions. While not currently accounted for under this IRP process, there is a clear risk that at some point in time they will be included as regulators seek to achieve real emission reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion [Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain] & [Gas Exports Have a Dirty Secret: A Carbon Footprint Rivaling Coal's]. It would greatly benefit the study if complete replacement of planned natural gas/gas turbine infrastructure with regional transmission interconnection is analyzed fully.
4. The EAC appreciates that an accelerated coal phase-out scenario was considered in the analysis. It is encouraging to see that both 2030 and 2040 coal phase-out plans will have **similar rate implications for ratepayers by 2045**. While the findings indicate a higher initial cost for an accelerated 2030 coal phase-out, it is worthwhile to indicate here that the province would reap immense health and economic benefits from pursuing this target. As presented in the "Nova Scotia Environmental Goals and Sustainable Prosperity Act Economic Costs and Benefits for Proposed Goals" report, rapid decarbonization in Nova Scotia would result in the creation of around 15, 000 full-time jobs by 2030. In addition, the Federal Government's

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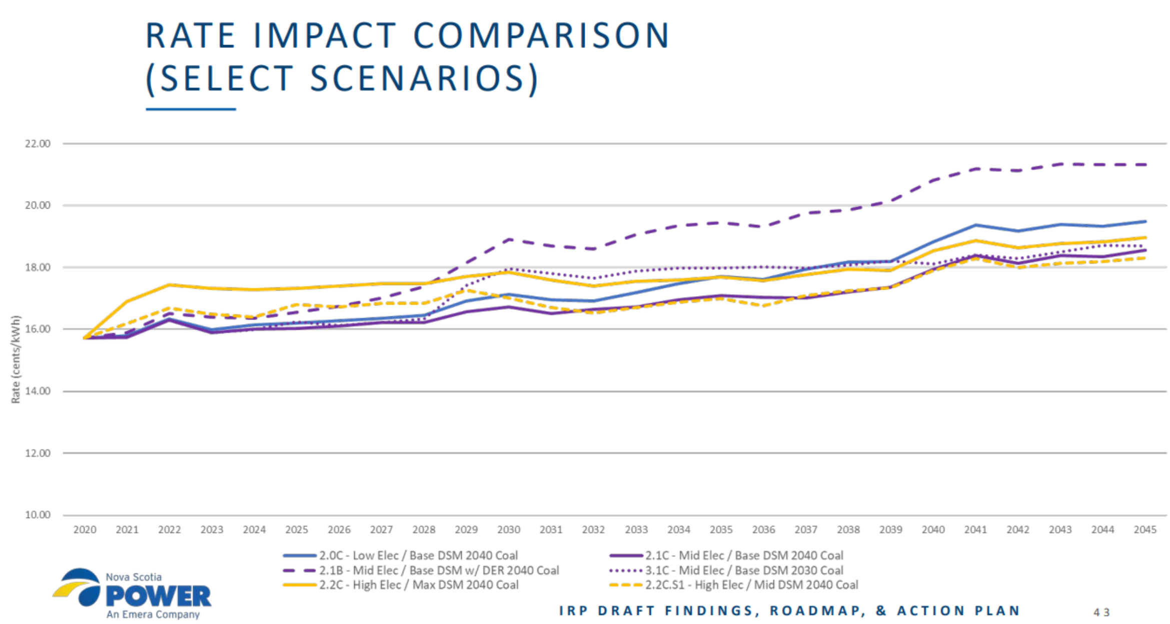
analysis indicates that an accelerated phase-out would avoid 89 premature deaths, 8,000 asthma episodes and 58,000 days of breathing difficulty for Nova Scotians, among other benefits [Ref]. Therefore, an accelerated phase-out of coal by 2030 would be a favorable long-term strategy for the province and its peoples.

Comments on Draft Action Plan:

1. Draft Action Plan statement 1 is highly desirable, and the EAC welcomes Nova Scotia Power's notion to develop a Regional Integration Strategy. This will be highly beneficial to the province and ensure a stable and reliable grid. Once again, it would be wise to link the addition of transmission infrastructure and phase-out of fossil fuel based (including natural gas turbines) infrastructure.
2. Electrification of the grid will have significant impacts overall and create opportunities for other sectors, such as transportation and small-to-medium-scale industries operating on carbon intensive fuels.

   Draft Action Plan statement 2 and Finding 1 b) are significant and would stand to benefit from stronger advocacy:

   "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors"



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According to the Rate impact Comparison (Select Scenarios), it is shown that High Electrification scenarios 2.2 C and 2.2 C S1 achieve lower rates as compared to select Low and Mid-Electrification scenarios. This indicates that electrifying the grid has key benefits. While, this comparison is comprehensive in terms of rate implications for ratepayers, it would be prudent to demonstrate economic benefit of switching to electric transport and electric heating through heat pump technology.

3. Decommissioning of the thermal unit at Trenton 5 is essential. As a significant number of units will reach end-of-life much earlier than 2040, earlier preparation for depreciation of these units is warranted. Accordingly, a comprehensive plan indicating the retirement scenario for all coal units is needed. Wind addition to the system is essential, but it would be necessary to consider a higher than stated "350 MW" of additional capacity. Consideration must be given to maximizing wind addition in combination with battery storage. It is clear in other jurisdictions (USA, UK, etc.) that this has worked successfully at a non-significant additional cost. Considering future examinations of upstream methane emissions from natural gas powered fast acting peakers would reveal that battery storage would be the right direction to proceed in terms of reaching carbon neutrality.

Comments on Draft Roadmap:

1. Statement 7: "Continuously refine these Findings and Action Plan items via an evergreen IRP process. This process should facilitate regular updating of the IRP model as conditions change and technology or market options develop."

   The capacity of EAC to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the Nova Scotia UARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines. This is true for other organizations who advocate on behalf of climate mitigation, environmental concerns and energy affordability concerns, who do not have staff regulatory or legal counsel capacity to engage in this important energy planning process.

   Although Nova Scotia Power has made every effort to make the 2020 IRP process accessible to stakeholders and is planning to adopt an "evergreen" IRP going forward, we regret the lack of financial and structural support for organizations to participate. The EAC feels that this problem is ongoing. NSPI and the Nova Scotia UARB processes will continue with ad hoc sustainability oversight until the Department of the Environment, Department of Energy and Mines, or Nova Scotia Power create an updated mandate to support climate change and environmental concerns in a way similar to the Consumer Advocate or the Small Business Advocate.

The EAC believes that Nova Scotia still has an opportunity to set long-term ambition, and commit to phasing out coal-fired electricity in Nova Scotia. This IRP process will determine the future of our electricity grid in ways that will hinder or facilitate a just transition in Nova Scotia.

We need to ensure that low and middle-income Nova Scotians, coal workers and communities all benefit from this change in our electricity system, and the EAC believes that this transition is possible in an affordable, just and timely way. The EAC looks forward to continued participation in the 2020 IRP stakeholder process, and ongoing conversations regarding Nova Scotia's electricity future.

Ecology Action Centre is committed to continuing to ensure Nova Scotia sets a pathway to phasing out coal-fired electricity generation, and looks forward to working with all partners toward the just transition to a prosperous, green economy.

Thank you for your consideration,

G. Gurprasad

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Nicole Godbout
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And

Crystal Henwood
Administrative Assistant to
Doreen Friis, Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
3rd Floor, 1601 Lower Water Street
Halifax, Nova Scotia B3J 3S3
Via Email: Crystal.Henwood@novascotia.ca
September 17, 2020

Re: M08929 – Integrated Resource Planning

Dear Ms. Godbout and Ms. Fris:

Envigour Policy Consulting Inc. has been retained by QUEST and Marine Renewables Canada as their Consultant in this matter. We have reviewed the IRP Draft Findings, Action Plan and Roadmap. We have participated in the process for more than a year now. We wish to congratulate all those who have participated in this extensive and likely expensive process. We also believe the IRP has been comprehensive within the terms of the relevant legislation and regulatory practice.

However, as we begin to end this phase of the work, we suggest that we consider some context and acknowledge what the process did not include. First of all, the IRP is taking place within a rapidly changing public policy and technology environment.: one that will likely evolve in unexpected directions and produce technology breakthroughs for prices and solutions not anticipated in the IRP assumptions and modelling.

Secondly, the IRP of necessity had gaps when considering the broader energy and climate change agenda. It did not purport to be an energy IRP and thus did not evaluate the full benefits as customers shifted energy needs to the electricity system from other systems. It also did not assess the supply risks associated with dependence on imports of natural gas or environmental compliance implications of using back-up diesel. It also did not consider the opportunities for the grid from the customer purchase of batteries. And it, of course, did not assess the policy benefits of early action on decarbonization as that is the purview of the governments.

We would also note that the IRP attracted more interest and participation from stakeholders than usual with peak on-line call registration in the range of 170. In particular, Municipalities were interested in how the IRP conclusions and implementations align with their policy and program goals.

Finally, we observe that the measures under the actions and roadmap to ensure the plan is evergreen is not spelled out. It may be prudent to offer more clarity on that process using principles of inclusion, science-based conclusions, and a broad range of expert opinions and thinking tested for practicability in the Nova Scotia policy/regulatory environment.

On behalf of QUEST and Marine Renewables Canada, and after consultation with the Smart Grid Innovation Network, the following model is suggested for future engagement on matters associated with future adjustments to the electricity IRP.

**A Potential Pathway**

To enable a transparent and inclusive process, we suggest an annual or semi-annual extended workshop on climate change and clean technology policies and programs informed by expert views on trends for electricity technologies and costs. The declining costs for technologies such as wind, solar, offshore wind and storage should be a particular focus. The workshop could also include cross-over fuels such as RNG and hydrogen.

The first part of the workshop would be broad stakeholder-based and designed to inform participants and the utility's customers. Key national/global, as well as local/regional thinkers, could be invited. The workshop organization group might also commission papers. Following this event, there could be a more technical session to understand how all this impacts the IRP assumptions and advise on the impact to the 2020 IRP, and whether it is time to do a modelling update.

The first more public-facing workshop could be managed by a not-for-profit organization or a coalition of not for profits on a cost-recovery basis. Sponsors could also be sought with conference surpluses dedicated to research in matters associated with managing the energy transformation agenda.

From this, we suggest that the final Roadmap and Action Plan reference the need for a regular and inclusive informative process to examine changes in the technologies, business models and best practices, and the policies and program initiatives that could impact the IRP assumptions and scenarios. These regular workshop updates could provide useful context and information for broader public engagement needs and the more formal IRP stakeholder engagement process.

Bruce Cameron
Principal Consultant,
Envigour Policy Consulting Inc.

c.c. Tonja Leach, Executive Director QUEST
Via Email: tleach@questcanada.org

Elisa Obermann, Executive Director of Marine Renewables Canada
Via Email: elisa@marinerenewables.ca

Greg Robart, CEO Smart Grid Innovation Network
Via Email: greg@sgin.ca

September 18, 2020

Nicole Godbout
Director, Regulatory Affairs
Nova Scotia Power Inc.
PO Box 910
Halifax, NS B3J 2W5

**RE: M08929 – NSPI Integrated Resource Planning – Draft Findings, Action Plan & Roadmap**

Heritage Gas is the regulated provider of natural gas distribution service to Nova Scotia residents and businesses. Heritage Gas has been attending stakeholder meetings and workshops with Nova Scotia Power Inc. ("NSPI"), Energy+Environmental Economics ("E3") and other stakeholder groups. Heritage Gas has been fully engaged and interested in understanding NSPI's Integrated Resource Plan ("IRP") and its interplay with long-term overall energy planning for the province for the next 25 years.

The Draft Findings, Action Plan and Roadmap results distributed to interested stakeholders on September 2, 2020 and presented on September 10, 2020 further indicate a required need and reliance for natural gas in the province over the next 25-year period. The results presented show that natural gas will provide electrical grid reliability, critical ancillary services, an economic energy source, and a lower carbon energy source to meet the province's environmental goals.

**Reliability of Liquid-Fueled Combustion Turbines ("CTs")**

In Draft Finding 3(b), NSPI describes retaining these units for another 25 years, at which point they will have been in operation for nearly 70 years:

> *"NS Power's existing CT resources provide economic benefit to customers and are economically sustained through the planning horizon with appropriate reinvestment requirements."*[1]

[1] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 49.


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Dartmouth, NS B3B 1Y2

Throughout the IRP process, Heritage Gas has had several discussions with NSPI and the larger stakeholder group on the reliability of the CT units. Our concerns with keeping 1970's-era units to the end of the IRP planning horizon have been further underscored by the findings in the recent FAM Audit conducted by Bates White Economic Consulting ("Bates White"). Some of the issues identified within the report included:

> *"Second, the entries above also demonstrate a key point regarding NSPI's seven combustion turbines at Burnside, Victoria Junction, and Tusket. That is, during periods of high ambient temperatures, the units failed to sustain operations at a time when they were needed most. Worse, the tendency for these units to overheat, trip, and thus remain locked out from further operation was anticipated and expected by NSPI personnel. This suggests that the reliability of these units is limited and those limitations are understood by those who operate NSPI's system.*
>
> *NSPI's seven 33 MW combustion turbines' performance during the Audit Period saw, in some cases, elevated DAFOR rates and low Availability Factors […] NSPI also noted that DAFOR industry averages for gas turbines of this size are typically quite high (60.8% in 2018) and that over half of NSPI's combustion turbine fleet outperformed the average. We agree, but note that these resources are relied upon to provide power when it is most needed, when system conditions are tightest."*[2]

The concerns ultimately led to Bates White developing conclusions specifically related to the reliability of the units. The report also concluded that NSPI has significantly underestimated the frequency that these units would be called upon to provide critical grid services:

> "***Conclusion IX-16:*** *The seven LFO-fired combustion turbines are called upon to produce energy far more than forecasted by NSPI; actual output exceeded forecasted output by over 1,300%.*
>
> ***Conclusion IX-17****: The seven LFO-fired combustion turbines had elevated DAFORs in some cases and suffered reduced reliability during periods of high ambient temperatures. NSPI's recent investments in oil cooling systems are intended to address this latter concern; data on the impact of these investments is inconclusive at this point and should be monitored."*[3]

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[2] M09548 – (Exhibit N-1) Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018–2019, Page 205.
[3] M09548 – (Exhibit N-1) Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018–2019, page 231.

Heritage Gas also notes that in Draft Finding 3(a), NSPI discusses the requirement to add significant new CT capacity:

> *"New combustion turbines, operating at low capacity factors, are the lowest cost domestic source of firm capacity and replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. 50-150MW is required by 2025, while 600- 1000MW of new capacity is required by 2045 to support retirement of steam units."*[4]

As previously mentioned, Heritage Gas has natural gas distribution infrastructure in very close proximity to the four diesel-fueled Burnside CT's. The conversion or replacement of the now 45-year old CT's provides an opportunity to both address the reliability issues with the existing CT's and address the need for additional CT capacity. The replacement of the Burnside CT's should be strongly considered. Heritage Gas recommends that a specific Action Item be identified in the final report to address the reliability issues identified by Bates White and the cost-effective utilization of existing infrastructure to meet the needs for additional CT capacity.

**<u>Conversion of Coal-to-Gas</u>**

As previously mentioned in the Modelling Results, the long-term resource changes emphasize additional natural gas resources including coal-to-gas conversions.[5] The Draft Finding 3(c) shows natural gas as a key requirement of the developing electricity system in both the near and long term:

> *"Low-cost, low-emitting generating capacity may be provided economically through redevelopment of existing natural gas-powered steam turbines or coal unit conversions. Fuel flexibility, including low/zero carbon alternative fuels, may also be an option for new and redeveloped resources*."[6]

Draft Roadmap item 1 discusses the need for "advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations"[7]. The Action Plan should reflect a timeline of

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[4] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 49.
[5] IRP Modeling Results Workshop #4 – July 9, 2020, page 16.
[6] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 49.
[7] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 60.

completion of this study and scope of the work included in the coal-to-gas conversion scenario. Heritage Gas also notes that an increase of this size in natural gas consumption in the region requires long-term natural gas transportation commitment planning, which should also be reflected in the Action Plan.

**Electrification and Associated Transmission & Distribution ("T&D") Costs**

This IRP is unique in contrast to previous IRP's in that very significant investments will be required in NSPI's transmission and distribution assets. This investment is driven by potential increased electrification of end-use energy, such as transportation and building heat, and the need to meet the lower environmental targets specified in the Sustainable Development Goals Act ("SDGA"). Significant investment in T&D is also expected to arise from the large potential increases in peak energy demand[8].

Heritage Gas understands that there is an ongoing process through DSM Matter No. M09471, to agree on the avoided T&D costs of Demand Side Management ("DSM"). This matter considers only a fraction of total T&D costs and so, it would be prudent to discuss these findings with the larger stakeholder group and also include a continued study of T&D costs in the context of the increasing electrical load envisioned in the IRP.

**Natural Gas Supports the Transition to Low Carbon Fuels**

Heritage Gas acknowledges that electrification in certain sectors of the economy will assist in moving Nova Scotia toward a lower carbon economy. However, electrification alone will not substantially reduce the GHG emissions in the province in order to meet the SDGA net-zero 2050 target.

Heritage Gas notes that in the Roadmap, NSPI anticipates ongoing research in this area:

> "*Monitor the development of low/zero carbon fuels that could replace natural gas in powering generating units to provide firm, in-province capacity beyond 2050.*"[9]

Recently the Offshore Energy Research Association ("OERA"), Liberty Utilities, Heritage Gas, and the provincial Department of Energy & Mines engaged Zen Energy Solutions to determine the future potential

[8] 2020 IRP Assumptions Set (January 20, 2020), page 9.
[9] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 61.

uses of hydrogen in Nova Scotia[10]. Hydrogen is increasingly seen as imperative in meeting the net-zero goals established in the Sustainable SDGA and NSPI should specifically identify hydrogen within the action plan and roadmap.

**Recommendations for the Final Action Plan**

- The Action Plan should specially consider the replacement of the liquid-fueled CT's in Burnside with gas-fired CT's as a cost-effective means to reliably meet the incremental capacity requirements identified in the IRP.
- The Action Plan should identify the specific timeline and scope of the engineering study regarding coal-to-gas conversions. The assumptions on long-term natural gas transportation contracts should also be included within this action item.
- A timetable should be established for estimating the incremental T&D costs associated with the various electrification scenarios. The IRP stakeholders should be kept fully informed as these cost estimate are developed
- The Action Plan and Roadmap should specifically identify hydrogen as a means to assist the province in meeting the GHG reduction targets established in the SDGA.

**General Comments**

The assumptions and scenario modelling used in this IRP reflect the need for continued monitoring of the development of the electric and broader energy sectors in the Province. Unlike past IRP's this IRP suggests some possible fundamental differences in the future electric sector in Nova Scotia. These fundamental changes include for the first time a general future separation of capacity from energy, a potential focus on electricity growth versus general DSM (still dependent on full costing of such an approach) with a continued requirement for focused DSM and Demand Response on peak, the potential requirement for significant new regional transmission to allow both increased firm and non-firm energy imports, the requirement for more fast acting generation to support increased renewable development and provide peak response capability, and the need to significantly monitor over time the take up of new technologies such as electric vehicles, distributed generation, battery or other storage options, etc. Of these changes, one of the most significant is the availability of significant volumes of firm dispatchable imports that are

[10] https://oera.ca/news/news-release-feasibility-study-evaluate-hydrogen-production-storage-distribution-and-use

incremental to those available through the Maritime Link. To meet the lower carbon intensities for electrical generation in the low to high electrification scenarios highlighted in the Draft Findings[11], the study assumes that the Nova Scotia electrical grid will need to rely on between 435 and 615 MW's of firm dispatchable energy and the required investment in NS-NB tie-line to accommodate this energy. NSPI has not provided any of the key assumptions associated with these imports including costs or carbon intensity and they have indicated that there are no commercial agreements in place to underpin the incremental imports.

As such, it is important that all stakeholders are kept apprised over the next number of years of the data collection, study results and future opportunities that might present themselves, so that the electricity sector in Nova Scotia works in concert with other sources of energy and opportunities in the wider energy sector in the Province, to ensure a sustainable competitive energy sector which will benefit all stakeholders. In consideration of these potential fundamental changes all parties will need to closely monitor developments in the electric and broader energy sectors to ensure Nova Scotian residents and business have access to competitive alternative energy supplies and to cost effectively meet the goals of the Province.

Heritage Gas appreciates the opportunity to comment on the Draft Findings, Roadmap and Action Plan, and the continued collaboration with all stakeholders. We especially recognize the effort by NSPI to continue an open process, and look forward to the consideration of these comments being reflected in the final Action Plan and submission to the Board.

Regards,
**HERITAGE GAS LIMITED**

John Hawkins
Cc: M08929 Participants

[11] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 12.

HYDROSTOR

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**To:** Linda Lefler P.Eng, Senior Project Manager - Regulatory Affairs, Nova Scotia Power

**From:** Jon Sorenson, Executive Consultant, Hydrostor Inc.

**Date:** 17th of July 2020; REVISED 09/18/20

**Re:** A-CAES as a Solution for Nova Scotia

## Memorandum

Thank you for your consideration and review. As we have communicated to the Nova Scotia Power team, Hydrostor is a Canadian technology provider and global developer of energy storage facilities that uses commercially proven Advanced Compressed Air Energy Storage (A-CAES) technology. **Recently, a well-established energy consulting firm working for a large US utility, gave Hydrostor and it's A-CAES technology, a TRL (Technology Readiness Level) ranking of 9, the highest possible score. This means our process, compressing air and storing electricity is considered a proven technology and ready to deploy.** As you know, we have been following Nova Scotia Power's IRP process with great interest and continue to be frustrated or disappointed to learn that long duration energy storage technology is not and has note been given its due in the preferred portfolio solution into the future. We would like to continue to reiterate the following, that Hydrostor:

- Be a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects or pumped-hydro projects
- As a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal retirements and be located on or near the sites of former coal plants while retaining many of the plant's employee (this concept is now being considered in other areas of North America)
- Can be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset

We note that Nova Scotia Power has instead opted for a portfolio that calls for new transmission and fossil fuel assets to meet balancing and peaking requirements. We believe that long duration Energy Storage, and A-CAES in particular, is a credible market-ready solution that can address the issues solved by these assets in a cleaner and more cost-effective way.

**Nova Scotia Power's A-CAES Cost Assumptions**

Based on our review of Nova Scotia Power's IRP assumptions, we believe that A-CAES's capital costs were inaccurately modelled. We believe that this played a decisive factor in it not being selected as a preferred resource. In particular, we found that in your cost analysis, the model used a $/kW cost of CAD $2,200. This was in effect, the mid point of our per KW cost estimates for a 200MW facility with a duration of 12 hours that we had previously provided to you. This was then compared to the cost of a lithium-ion system with 1 and 4 hours of duration. (See Figure 1 below).

| | | Capital Cost (2019 CAD $/kW) | | |
|---|---|---|---|---|
| Technology | Subtechnology | 2019 | 2030 | % Change |
| Wind | Onshore | $2,100 | $1,691 | -19% |
| | Offshore | $4,726 | $3,429 | -27% |
| Solar PV[a] | Tracking | $1,800 | $1,416 | -21% |
| Biomass | Grate | $5,300 | $5,146 | -3% |
| | Municipal Solid Waste | $8,470 | $8,470 | 0% |
| Tidal | n/a | $10,000 | $10,000 | 0% |
| Storage | Li-Ion Battery (1 hr) | $764 | $385 | -50% |
| | Li-Ion Battery (4 hr) | $2,125 | $1,071 | -50% |
| | Compressed air | $2,200 | $2,200 | 0% |
| | Pumped Storage | $2,700 | $2,700 | 0% |

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

*Figure 1*

Our concern is that this was not an apples-to-apples comparison as it accounts for the additional cost of a longer duration facility but ignores the additional value such a system provides. Additionally, by choosing to use the costs for a 200MW system, this did not account for the significant economies of scale that come with larger sized A-CAES facilities. **If you consider a 500MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW[1]. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market**.

However A-CAES's cost advantage is most apparent in the long-duration market where it can act as a non-wires alternative to traditional transmission for improving reliability or as a solution for integrating and time-shifting Nova Scotia's wind resources onto the grid. To illustrate this point, we compared the bid prices that we recently submitted for a 300MW 6 hour and 12 hour facility to a utility in California to what an equivalent lithium system would cost based on prices provided by Lazard's Levelized Cost of Storage Analysis 5.0. For the 6 hour system we found that lithium ion prices would have to drop 7%-50% from 2019 in order to achieve cost parity. Whereas, for the 12 hour facility we found that lithium ion would have to decrease their cost by a further 41%-70% in order to achieve cost parity.

### A-CAES is a Reliable Solution for Nova Scotia's Needs

Advanced Compressed Air Energy Storage, uses equipment, construction techniques

[1] [1] We also note there was a conversion error as our costs were presented to Nova Scotia power in US$ but were displayed here in $CA. We therefore question whether this conversion error applied to other technologies listed here.

and technology proven and optimized in the oil and gas sector to deliver a bankable and market-ready solution that can be delivered at scale. The technology benefits from large economies of scale which allow it to offer the lowest per kwh cost the energy storage market for system sizes larger than 250MW and at durations ranging from 4 to 12 hours or more. Because of our exclusive use of equipment produced by Tier 1 manufacturers such as Baker Hughes, Hydrostor can deliver facilities backed by global supply chains, comprehensive maintenance packages and performance guarantees. With no degradation or disposal liabilities, flexible expansion options, and a service life of 50+ years that give it unique advantages over batteries and makes it the ideal storage solution for integrating Nova Scotia's considerable wind resources into the grid.

It is also important to note that since A-CAES uses spinning turbines it can meet the grid's need for inertia and synchronous generation that is currently provided by Nova Scotia Power's coal fired generation facilities. Furthermore, unlike pumped hydro or fossil assets, A-CAES can be flexibly sited where the grid needs it. It is a benign technology that has minimal impact on its local environment while producing major economic benefits for local communities, reducing permitting risk and allowing it to be safely sited close to population centres. Furthermore, Hydrostor has studied the geology of Nova Scotia and New Brunswick and found the region to be highly suitable for A-CAES, making it even easier to site. For these reasons, we believe A-CAES is the right solution for accelerating the retirement of coal assets and avoiding further investment into fossil fuels.

We note that Nova Scotia Power intends to make considerable investment in transmission infrastructure to improve the reliability of the system. Again, we believe that A-CAES should be seriously considered by Nova Scotia Power as a lower-cost alternative that could save the utility 10's to 100's of millions of dollars. We have proposed this kind of solution to regulators and transmission companies in Chile, Australia, and California and would be happy to provide you with an indication of what the cost savings could look like for an A-CAES facility sited near the source or load instead of build a new transmission line. Please note that recently, Transgrid Utilities in Australia chose Hydrostor over competing technologies to provide its renewable energy storage technology now and into the future.

**https://bdtruth.com.au/main/news/article/11997-Air-power-proposal-to-back-up-supply.html#:~:text=Transgrid%20has%20chosen%20a%20150,the%20USA%20and%20South%20Australia.**

In short as communicated at the onset of this memorandum, we believe that a Canadian designed A-CAES facility built to a scale of 300 to 500MW with a long duration of 6, 8,10, 12 hours or beyond can assist Nova Scotia Power in its Integrated Resource Plan in the following areas:

- Be a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects
- As a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal

retirements and be located on or near the sites of former coal plants while retaining many of the plant's employees
- Can be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset

We would be very interested to better understand your thoughts on A-CAES and hope to address any questions or concerns. We would also invite Nova Scotia Power and its consultant, E3 to schedule a call to discuss A-CAES and in addition, take part in a virtual tour of our recently commissioned Goderich facility (Ontario) in the nearest future. We want to thank you for your consideration but do ask that you seriously evaluate and look at A-CAES instead of traditional means, as we and many others believe A-CAES can be a definitive resource option for Nova Scotia and its' energy future.

Please do not hesitate to contact me/us and again welcome the opportunity to provide a virtual tour of the now operating Goderich facility.

Thank you and Best Regards,

Jon Sorenson
Executive Consultant
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## Appendices

Appendix 1: A-CAES Technical Inputs Summary (Previously submitted to NS Power) natural forces

Natural Forces Services Inc. | 1801 Hollis Street | Suite 1205 | Halifax | NS | B3J 3N4 | T: (902) 422 9663 | F: (902) 422 9780

Doreen Friis, September 18, 2020
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

**-SENT VIA EMAIL-**

## RE: 2020 Integrated Resource Plan Initial Modelling Review

Dear Ms. Friis,

Natural Forces Services Inc. welcomes the opportunity to once again input comments on the IRP process. We note that again the time for comments to this process are extremely tight and it makes it very difficult for us to fully process the information that is being submitted by NSPI.

To simplify the process, we have attached our direct report from our technical advisor, Andrew Cooke directly.

The key point that Natural Forces wishes to emphasize is on the cost of wind that has been modeled by NSPI. As the board may know, Natural Forces is active across the country and is actively building out wind project currently and over the next few years, so the prices and energy numbers from today's and tomorrow's wind projects are well known to us. Two comments:

- the price per MW installed is much closer to the 1.5 million per MW; and
- the capacity factors are closer to mid 40% than the number stated by NSPI.

This does lead us to believe that more wind now is the answer, and that the way to unlock these saving for the rate payers and the utility is to look to other jurisdictions that have large wind resources in use and adopt some of their operating procedures in order to keep the system stable and allow for more wind on the system.

Thank

Sincerely,

Presented for, and on behalf of, Natural Forces Services Inc. Halifax, Nova Scotia.

**Cooke Energy and Utility Consulting Ltd.**

27 Willans Way
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# Review of IRP Modelling Results and Draft Findings

This Report is prepared by Cooke Energy & Utility Consulting on behalf of Natural Forces.

The report sets out a high-level review of the IRP Modelling Results and Draft Findings presented by Nova Scotia Power, principally in the following documents:

- NS Power 2020 IRP Updated Modeling Results Release (2nd September 2020)
- NS Power 2020 IRP Draft Findings Release (2nd September 2020)
- NS Power 2020 IRP Inertia and Constraint Modeling (15th September 2020)
- IRP Modeling Results Table (2020-09-02).

Key observations are summarised in the Executive Summary below. Issues are discussed in more detail in sections 1 through 5.

## Executive Summary

- **A major transformation of the existing generation resource base is required**. As Nova Scotia Power has remarked, significant efforts are required to achieve the level of carbon emissions reductions in line with Nova Scotia's Sustainable Development Goals Act. A major transformation of the existing generation resource base is required, including the integration of significantly higher volumes of intermittent, non-synchronous renewable energy resources. However similar transitions have been successfully achieved in other jurisdictions.

- **Higher electrification scenarios are beneficial to electricity consumers through lower rates, and will also support cost-effective achievement of broader emissions policy objectives.** NSP has identified that higher electrification is beneficial to reducing electricity rates. It is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals, as it supports decarbonisation of other sectors (transport, heat). It is recommended that this point is emphasised strongly in the findings and is considered in NSP's action plan.

- **Sensitivities with lower wind costs profoundly affect the resource plan and need significant further analysis**. The sensitivities with lower wind costs have a profound effect on the resource build-out plan. Much larger quantities of wind capacity (c. 600 MW) are being added by 2023 to 2025. These scenarios also have the benefit of lower CO2 emissions than comparative scenarios. As these scenarios are based on very credible wind cost projections (and disassociation of battery costs would also contribute to lowering the effective cost of wind) it is of critical importance that further analysis is undertaken in this area, including gaining an understanding of the price point(s) at which transition occurs. [Refer section 2]

- **The suggested build out rate for wind in NSP's initial draft action plan, is understated**. NSP's proposed/draft action plan item 3(c) states: *"Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030".* This is unduly limiting at this stage, particularly as regards the implied cap of 350 MW by 2030. Even before consideration of the "low wind cost" sensitivities, several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.

- **CO2 levels vary widely between scenarios.** There is a wide variation in the CO2 levels (both annual and cumulative) between the different scenarios. Even if not directly monetizable, there is a definite value in lower CO2 emissions:

  a) as a risk mitigation strategy against upward pressure on emissions levels from additional demand growth, or further downward revisions in emission targets; and,

  b) as can be observed from experience in other jurisdictions, lower carbon intensity of the electricity sector (lower CO2/MWh) promotes electrification of other sectors (heat, transport), which is identified as lowering electricity rates and will also contribute to achievement of broader emissions policy objectives.

  The differences in CO2 levels should be highlighted clearly in the results, to that individual stakeholders and stakeholder groups can consider the impacts. [Refer section 3]

- **Consideration of Risk.** There is merit in giving further consideration to risk assessment, as a tool for identifying scenarios and/or actions which show strong performance (in terms of low cost) across a range of future sensitivities. It is likely that scenarios with higher renewables and/or lower CO2 emissions would tend to be more favourable under such an examination, as they are "proofed", to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially resulting in breaches of emissions limits). It is recommended that this type of analysis is considered further. [Refer section 4]

- **NSP's continued adherence to allowing further wind capacity to be installed only in association with capital intensive batteries & synch comps, or the 2nd AC intertie**. This has been discussed at length before, and NSP's adherence to this position is quite frankly, rather baffling. The standard practice today in other systems integrating higher levels of intermittent, asynchronous renewable resources (such as wind) is to allow wind to install to an economic level, and accept that on rare occasions, it may be necessary to curtail (dispatch down) wind output to a level that ensures the system remains stable. The precise extent to which wind capacity is being "held back" due to the NSP approach is difficult to quantify (though it could be assessed through the modeling by disassociating the requirement for batteries/synch comps). However I believe it can be stated with certainty that the NSP approach will result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation). [Refer section 5]

  NSP has not (to date) provided justification for continuing with this approach, and should be requested to set out clearly, its reasons for not adopting what is best practice (and indeed increasingly standard practice) in other jurisdictions integrating higher levels of intermittent, non-synchronous renewables.

## 1. Overall results and Wind capacity levels

As Nova Scotia Power has remarked, significant efforts are required to achieve the level of carbon emissions reductions in line with Nova Scotia's Sustainable Development Goals Act. A major transformation of the existing generation resource base is required, including the integration of significantly higher volumes of intermittent, non-synchronous renewable energy resources. However similar transitions have been successfully achieved in other jurisdictions.

It is helpful that that there is a significant degree of commonality in the main "building blocks" selected in each of the scenarios, those being (for the main part): wind capacity; gas-fired CTs; the 2nd AC intertie, and regional integration. The scenarios differ in the order and rate at which the new resources are deployed, and the rate at which certain existing resources (principally the coal-fired units) are retired.

The build out rate of new wind capacity from the initial cases (i.e. not including the low wind cost sensitivities) is set out in the following graph:

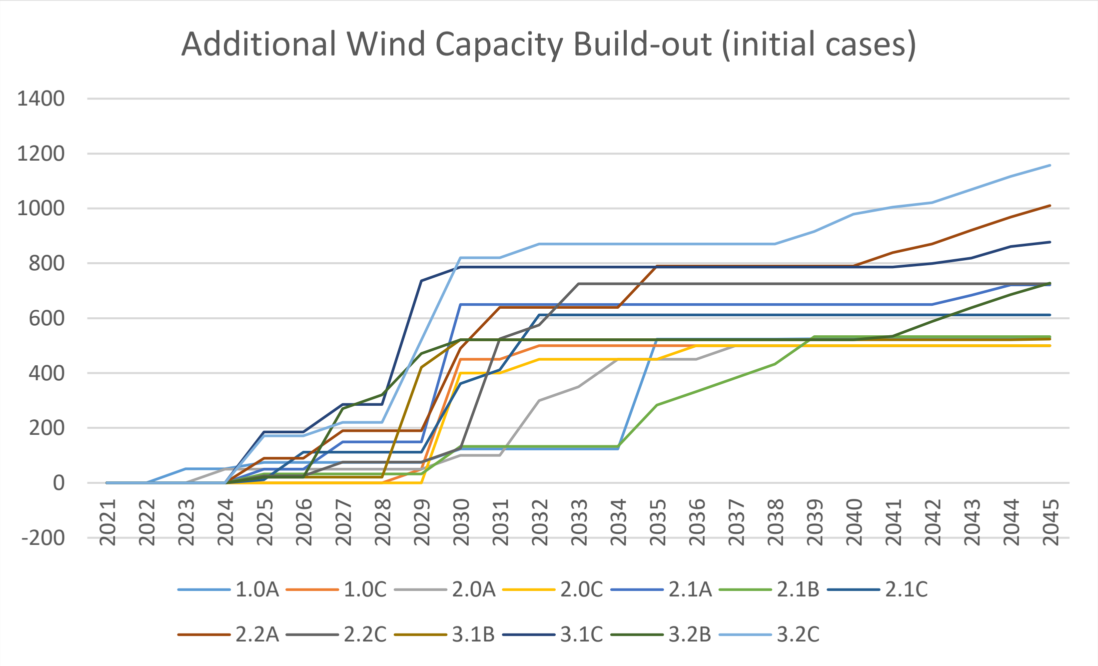


**Figure 1: Build-out of additional Wind Capacity in the initial Scenarios.**

As can be observed, several scenarios have approximately 200 MW of new wind capacity coming on by 2025 to 2027, and amounts ranging from 400 to 800 MW by 2029/2030. The higher wind capacities are generally arising in the cases based on higher electrification, as might be expected.

NSP has identified that higher electrification is beneficial to reducing electricity rates (and it is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals).

In light of the above, NSP's proposed/draft action plan item 3(c) viz:

> *"Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030"*

seems unduly limiting, particularly as regards the implied "upper limit" of 350 MW by 2030. Several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.

Another key point to note is that many scenarios are introducing some level of additional wind capacity, even with the imposed requirement that wind installed capacity of greater than 700 MW must be accompanied by either batteries/synch comps, or the second AC intertie. This has the effect of imposing an entirely unnecessary and inappropriate additional capital cost on wind (i.e. the associated capital cost of the batteries/synch comps), which is very likely reducing the level of wind being installed in many of these cases. It is difficult to be precise about the level of additional costs being imposed through this requirement as the batteries will bring some other benefits (such as energy arbitrage) which will act to off-set the added capital costs. However approximations suggest it may be adding in the region of 5 to 10% to the effective cost of additional wind capacity.

The continued insistence on the part of NSP to adhere to this position is rather baffling. The precise extent to which wind capacity is being "held back" due to this approach is difficult to quantify (though of course it could be assessed by disassociating the requirement for batteries/synch comps in the modeling). However I believe it can be stated with certainty that the NSP approach will inevitably result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation). This is discussed further in section 5.

## 2. Low wind cost sensitivity cases

The sensitivity cases undertaken with lower wind (and battery) costs[1] are or particular interest, and result in a fundamentally different build-out plan.

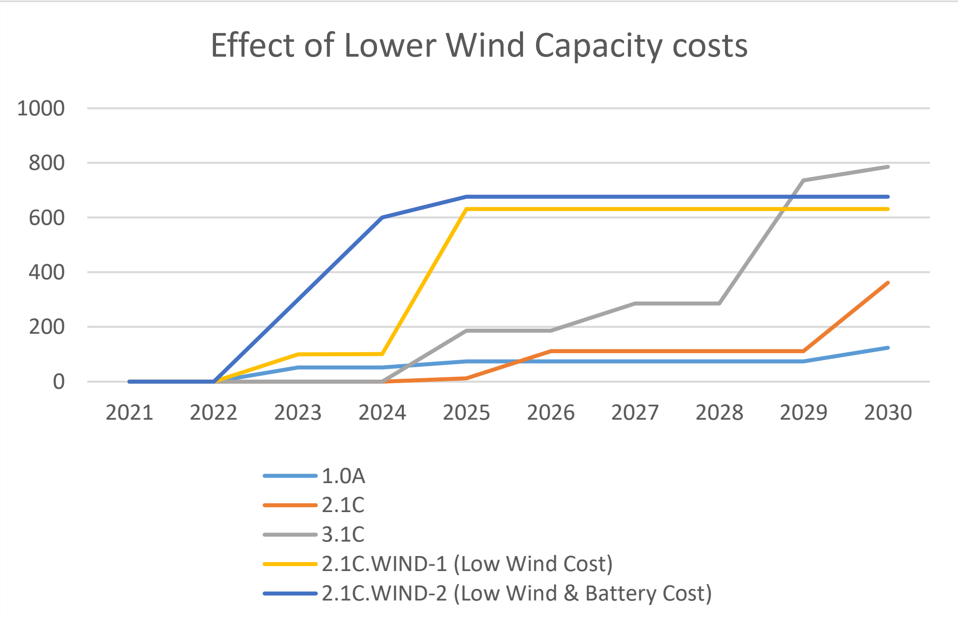


**Figure 2: Build-out of additional Wind Capacity in the initial Scenarios.**

As can be seen, the lower wind costs have a profound effect on the resource build out plan, even compared to the "original" scenarios with higher wind build-out (such as Case 3.1C). Much larger

[1] Cases "2.1C WIND 1 (Low Wind Cost)" and "2.1C WIND 2 (Low Wind and Battery Cost)"

quantities of wind capacity (c. 600 MW) are being added by 2025, and even earlier in Case "2.1C WIND-2" which also has lower battery costs[2].

Given that this has such a fundamental impact, coupled with the fact that lower wind costs are a highly credible scenario, further investigation of this scenario is critical. At present it tells us that changing the wind costs from the "Base Case Wind Cost" ($2,100/kW) to the "Low Wind Cost" ($1,500/kW) has a major impact on the timing of the deployment of additional wind capacity. However it does not tell us at what wind cost does this major change occur[3]. If it happens (in whole or in part) at a higher wind cost (somewhere between $2,100 and $1,500), it further increases the confidence level that the benefits of the "lower wind cost" cases are achievable.

Once more, the unnecessary association of the battery costs with increased wind (until the advent of the 2nd AC intertie) is also an important consideration. The reduction in wind costs required to create the change to a more rapid wind build-out plan, could be arrived at through a combination of lower wind capital costs and savings from disassociating the battery requirements.

There are also benefits (not currently monetised) from reduced CO2 submissions in the cases with higher wind build-out. This is discussed further in section 4.

In summary, the findings from the "low wind cost" scenarios are much too significant to ignore, and it is of critical importance that further analysis is undertaken to understand the price point(s) at which transition occurs. It is also strongly recommended that the association of battery and synch comp costs with additional wind capacity, is discontinued for these (as well as other) scenarios.

### 3. CO2 emissions variations

While all scenarios are intended to meet emissions limits, there is a wide variation in the CO2 levels (both annual and cumulative) between the different scenarios. As can be seen from the graphs included in the NSP presentation of Modelling Results, some scenarios track the CO2 allowed emissions limits quite closely, whereas others are significantly below it (at least for periods of time).

For example in the "low wind cost" cases, the CO2 emissions are (as might be expected) significantly lower than the comparative "base case (2.1C) in the period 2023 to 2030.

[2] Strongly suggesting that if the batteries were dissociated from the wind, then wind build out would be further increased/advanced.

[3] There may not be a single "threshold wind price" at which this change happens (though as the larger wind volumes are accompanied by the 2nd intertie, it is mostly likely to relate to a specific price point.

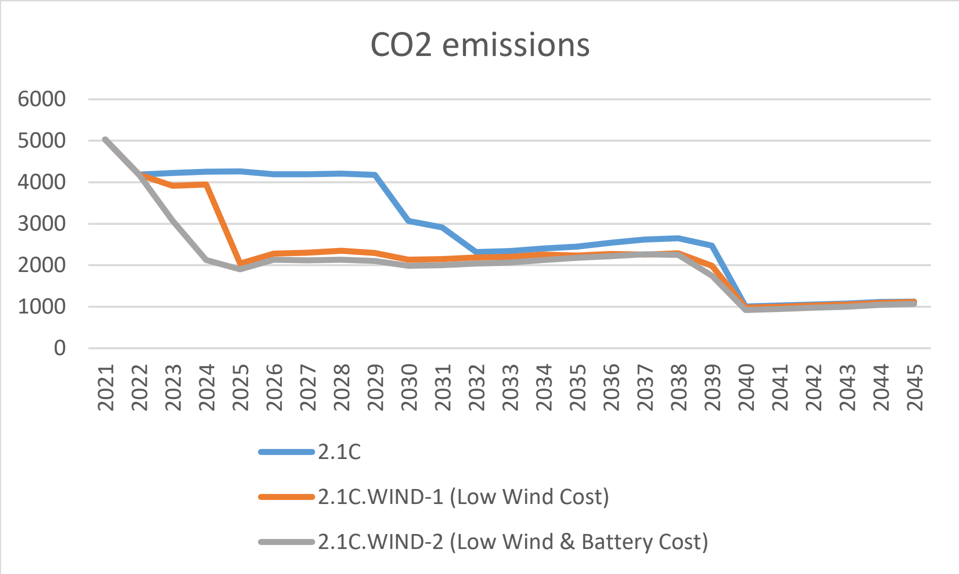


**Figure 3: Annual CO2 emissions for "low wind" cost cases and comparative "base case".**

## WIND & IMPORT SENSITIVITY COMPARISON

| | Description | Reliability Tie | Regional Integration | $CO_2$ Emissions 2021-2045 | 25-yr NPVRR ($MM) | 10-yr NPVRR ($MM) |
|---|---|---|---|---|---|---|
| 2.0A | Low Elec / Current Landscape | 2032 | n/a | 77.7 | $12,351 | $6,831 |
| 2.1C | Mid Elec / Regional Integration | 2030 | 2036 | 70.9 | $13,141 | $7,067 |
| 2.1C.WIND-1 | Low Wind Cost | 2025 | 2026 | 56.6 | $12,978 | $7,132 |
| 2.1C.WIND-2 | Low Wind & Battery Cost | 2023 | 2036 | 51.7 | $13,086 | $7,177 |
| 2.1C.WIND-3 | Low Inertia (2200 MW.sec) | 2031 | 2034 | 71.7 | $13,059 | $7,000 |
| 2.1C.WIND-4 | No Inertia / No Integration | 2040 | 2040 | 52.8 | $13,076 | $7,049 |
| 2.1C.IMPORT-1 | Limited Non-Firm Imports | 2024 | 2026 | 78.6 | $13,543 | $7,373 |
| 2.0A.IMPORT-2 | No Reliability Tie | n/a | n/a | 76.8 | $12,628 | $6,951 |
| 2.1C.IMPORT-3 | Limited Reliability Tie Inertia (50%) | 2028 | 2029 | 67.6 | $13,225 | $7,111 |

**Figure 4: Cumulative CO2 emissions (source "NS Power 2020 IRP Inertia Constraint Modelling" – slide 2)**

To the best of my knowledge, the benefits of a lower level of CO2 emissions is nor currently monetised in the IRP modelling approach. This is of course dependent on the emissions framework applicable to the jurisdiction. In Europe for example, the approach would be to directly monetise the benefit of a lower CO2 emission level[4].

[4] Every two years ENTSO-E (the European Network of Transmission System Operators in Electricity, an association which is vested with key statutory responsibilities under European and National Law) produces a "Scenario Report" including, among other things, forecast prices for CO2. The scenarios, which are widely consulted upon and ultimately approved by ACER (umbrella association for European national electricity regulators) and the EU, are used for the purpose of carrying out comparative analysis of "Projects of Common Interest", which mainly comprise proposed international interconnector projects and large-scale storage projects. The aim is that the projects are assessed on a common basis (so can be "ranked" for purposes such as European grant funding) , and to present a sufficiently diverse range of scenarios to test the robustness of the projects to a variety of futures. In the 2018 Scenario report, CO2 price projections varied across the scenarios between €27/tonne and €84.3/tonne.

Even if that is not appropriate within the current framework applicable in Nova Scotia, it is suggested that the differentiation between the scenarios in terms of CO2 levels is a significant factor which should be highlighted to a greater extent. Individual stakeholders or stakeholder groups may wish to take their own views on the value of lower CO2 levels, including in relation to overall emissions policy goals.

Also even if not directly monetizable, there is a definite value in lower CO2 scenarios as a risk mitigation strategy:

- In a scenario where CO2 is "only just" below the required limit, then there is a risk that in the event of, say, higher demand growth and/or greater levels of electrification, that the limits would then be breached (or that meeting them – if even possible – would involve suboptimal and expensive strategies).
- If emissions limits are revised downwards, the additional actions and costs required to achieve them (starting from a lower CO2 base), are likely to be much less significant.

It can also be observed from experience in other jurisdictions, that the lower the carbon intensity (CO2/MWh) of the electricity sector, the more it becomes a "strategy of choice" for other sectors (transport, heat) to achieve their emissions-reduction objectives. Aside from assisting in achievement of Nova Scotia's emissions policy objectives more generally, lower CO2 intensity is likely to promote higher electrification, which is identified by NSP as contributing to lower electricity rates.

Note that this point is applicable generally, and not only to the "low wind cost" scenarios used to illustrate the point here.

## 4. Consideration of Risk

NSP has aimed at identifying certain actions which are generally common to all or most scenarios, and has proposed these within its initial draft action plan.

A common approach is also to look for scenarios and/or actions which are "low regret" scenarios, i.e. a scenario which is not necessarily the "lowest cost" in a given set of circumstances, but shows strong performance (in terms of low cost) across a range of future sensitivities[5]. It could be likely that scenarios with higher renewables and/or low CO2 emissions would tend to be more favourable under such an examination, as they are "proofed", to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially causing breaches of emissions limits).

It is recommended that this type of analysis is considered further.

## 5. Continuation of association of battery and synch comp costs with additional wind capacity.

It is noted the NSP continues to insist on limiting the amount of installed wind capacity to 700 MW, allowing additional wind to be installed only if accompanied by capital-intensive batteries and synch

[5] There are various techniques which can be applied such as testing candidate capacity build-out scenarios across a range of future scenario projections (e.g. demand growth, fossil fuel costs, CO2 costs etc.). Results can be assessed on a more qualitative basis, or using techniques such as "least-worst-regrets" methodologies.

comps, or the 2nd AC intertie. This has been discussed at length before, and NSP's adherence to this position is quite frankly, rather baffling. The standard practice today in other systems integrating higher levels of intermittent, asynchronous renewable resources (such as wind) is to allow wind to install to an economic level, and accept that on rare occasions (such as the extreme system conditions modeled in the earlier "Power System Stability Study" [6]), it may be necessary to curtail (dispatch down) wind output to a level that ensures the system remains stable.

A compounding factor is that the "stressed system cases" used for the purpose of the technical analysis in the Power System Stability Study seem particularly unlikely to occur, and an initial analysis of 2019 data suggests that such conditions not only did not occur, but indeed were not even remotely approached. However as noted in our previous submissions and discussions on this point, this is a secondary issue. The key point is that if the conditions do occur, they can be managed by simply curtailing the wind output to an appropriate, safe, level.

The precise extent to which wind capacity is being "held back" due to this approach is difficult to quantify (though of course it could be done by disassociating the requirement for batteries/synch comps in the model). The effect may be less relevant in the cases with much larger volumes of wind integration, as these will tend to be associated with the 2nd AC intertie. The effect of the unnecessary association of the battery costs may in fact be more significant in scenarios/years with more modest levels of additional wind (c. 100 to 300 MW). However I believe it can be stated with certainty that the NSP approach will inevitably result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation).

**Approved:**

Andrew Cooke

**Andrew Cooke**
**Cooke Energy & Utility Consulting**
**17th September 2020**

[6] "Nova Scotia Power Stability Study for Renewable Integration Report", prepared by PSC North America on behalf of Nova Scotia Power Inc. (24th July 2019)

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Our File: 179164
September 18, 2020

Ms. Nicole Godbout
Director, Regulatory Affairs
Nova Scotia Power
1223 Lower Water Street
Halifax, NS B3J 3S8

Dear Ms. Godbout:

**Re: Integrated Resource Plan (IRP) 2020 – Draft Findings, Action Plan, and Roadmap**

Port Hawkesbury Paper LP ("PHP") has reviewed the Updated Modeling Results and the Draft Findings, Action Plan and Roadmap circulated to stakeholders as part of the 2020 IRP process. Representatives of PHP also participated in Nova Scotia Power Inc.'s ("NS Power") September 10th technical conference to discuss these materials in detail.

PHP does not have any specific comments with respect to NS Power's proposed Findings, Action Plan and Roadmap as currently drafted. Rather, PHP would like to take this opportunity to emphasize the importance of the following key principles that should continue to guide NS Power's long-term strategy going forward:

1. Ongoing Stakeholder Engagement
2. Flexibility
3. Rate Impacts

### *1. Ongoing Stakeholder Engagement*

PHP is appreciative of NS Power's efforts to actively and fully engage all stakeholders as part of its long-term planning processes. The IRP results clearly demonstrate the significant changes to the Nova Scotia electricity system that are expected to occur over the next 25 years. In this regard, the Draft Action Plan and Roadmap identify the need to initiate and develop several new strategies, plans, and programs in the near term. PHP supports this approach, as well as NS Power's plans to continuously refine the Findings and Action Plan items via an evergreen IRP process, on the basis that NS Power will continue to hold regular and transparent engagement sessions. Such sessions will ensure stakeholders have the opportunity to provide valuable feedback that can be incorporated in the transition of the electricity system, particularly as circumstances evolve and updated information becomes available.

***2. Flexibility***

In contrast to prior IRPs (which specifically sought to develop a long-term "Preferred Resource Plan" from among a set of candidate resource plans), the 2020 IRP results provide a comparison of various resource portfolios across a range of electrification scenarios. Maintaining maximum flexibility in the near term is needed to ensure that NS Power's long-term strategy best accommodates the current uncertainty regarding future electric load growth in the Province. Preserving such flexibility will also enable NS Power to consider any subsequent changes in technology and/or government policy, as well as the results of ongoing costing analysis of generation and transmission options. These items will impact the economics of important long-term decisions regarding the timing and extent of (i) coal retirements, (ii) new capacity additions, and (iii) new renewable energy generation. Further, the significant potential investments in regional integration will require careful and strategic consideration and coordination with other jurisdictions in the region to ensure Nova Scotia stakeholders receive the intended benefits.

***3. Rate Impacts***

In its Updated Modeling Results and Draft Findings, NS Power developed a rate impact calculation using IRP partial revenue requirements for each scenario to illustrate the long-term effects of various levels of electrification. PHP believes that consideration of the potential overall impacts on future rates should remain a central consideration of NS Power's long-term strategy and planning processes. The cost of electricity, as well as the stability and predictability of electricity rates, remain critical issues for all stakeholders, particularly industrial customers that compete globally and require ongoing capital investment.

As parties are aware, earlier this year, the Board approved NS Power's Application for approval of the Extra Large Industrial Active Demand Control Tariff. This innovative rate structure, developed following extensive collaboration with the utility, provides NS Power with a new demand response service that allows the utility to better operate its electricity system for the benefit of all customers. The 2020 IRP results indicate that firm capacity resources will continue to be a key requirement of the developing NS Power system in both the near and long term, demonstrating the inherent value in demand response-type approaches going forward. Continuing to pursue deeper levels of collaboration and innovative solutions, whether through rate design approaches or otherwise, will help ensure that the transition to Nova Scotia's electricity future can be achieved in an environmentally and economically sustainable manner for NS Power and its customers.

Thank you for the opportunity to submit these comments. PHP hopes the above points are helpful to NS Power in preparing the draft IRP report, and looks forward to reviewing it when available.

Yours truly,

James MacDuff

Blackburn Law

VIA EMAIL

September 17, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

**Re: M08929 – Draft Findings, Action Plan, and Roadmap – SBA Comments**

The Small Business Advocate (SBA) and its experts from Daymark Energy Advisors, John Athas and Jeff Bower have reviewed the IRP Draft Findings, Action Plan and Roadmap.. Please find a memo from Mr. Athas and Mr. Bower attached, setting out comments and questions regarding the modeling results that were presented.

Please let me know if you have any questions or require any clarification.

Yours truly,

**BLACKBURN LAW**

N Dunling. for

E.A. Nelson Blackburn, Q.C.
Small Business Advocate

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SUITE 231 BEDFORD HOUSE, SUNNYSIDE MALL, 1595 BEDFORD HIGHWAY, BEDFORD, NOVA SCOTIA B4A 3Y4

**TO: Nelson Blackburn and Melissa MacAdam, Nova Scotia Small Business Advocate**

**FROM: John Athas and Jeff Bower**

**DATE:** September 18, 2020

**SUBJECT:** Comments on NSP Findings, Action Plan, and Roadmap

This memo summarizes Daymark's comments regarding draft IRP Findings, Action Plan, and Roadmap, dated September 2, 2020 and presented by Nova Scotia Power (NSP) to stakeholders on September 10.

**Connect Findings with model results**

NSP has conducted extensive modeling and analysis in support of the IRP analysis. However, in the presentation of the draft findings, it was not always clear precisely how each finding was supported by the modeling analysis. In the full IRP, we encourage NSP to support the findings with specific references to model runs and related analyses.

**Specify the schedule for additional analyses on reliability**

A major topic of discussion throughout the stakeholder process has been the system inertia requirements and the capability of the system to integrate higher penetrations of inverter-based resources. The IRP analysis relied on conclusions of the 2019 PSC study, but NSP has acknowledged that additional analysis will be needed to more fully understand the inertia requirements in the future.

The draft Finding #2 acknowledges this, noting that "Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system" (Slide 47). The draft Roadmap item #2 also states that NSP will "Complete detailed system stability studies…while considering higher quantities of installed wind capacity…" (Slide 60).

The modeling of the inertia requirement has supported certain resource decisions, in particular the addition of the Reliability Tie which is assumed to provide all the system inertia needed by the NSP system. However, this conclusion requires some further investigation. Additionally, NSP has previously noted that it has not evaluated the possibility that wind projects could provide fast frequency response, which is a method of addressing system inertia concerns used in other regions.

We recommend that as part of the IRP, NSP should provide a concrete plan for conducting the additional analyses needed to assess the system needs, and the ability of different resources to address these needs (conventional generators, the Reliability Tie, Maritime Link, advanced wind turbines, and load resources). While the draft analysis indicates that the assumed system inertia requirement is not binding for several years, it is possible that cost declines for wind capacity or other factors could advance the timeline for wind development, hastening the need for a solution to the reliability need.

**Address potential coordination with New Brunswick**

Most IRP scenarios include the selection of the Reliability Tie and Regional Integration as part of the optimal portfolio. Implementing this strategy will require significant coordination with New Brunswick and availability of supply. Given the primary role of the transmission solutions in NSP's plan for a reliable and economic supply portfolio, the Company should prepare a specific timeline and plan for the steps required in Action Plan Item #1 to ensure that this is a feasible solution to deliver the benefits assumed in the IRP.

**Provide clear interpretation of rate impact analysis**

We appreciate NSP developing the rate impact model to help assess the implications of various portfolios for customers (Slide 31). We believe this provides important information in the consideration of various strategies. The summary of results provided in the draft Findings presentation (Slide 43) contain interesting conclusions, particularly related to the rate impact under high electrification scenarios. This slide was accompanied with important discussion during the stakeholder session which provided context on rate trends.

We recommend that NSP provide sufficient context in the IRP to communicate the implications of the rate impact analysis on customers, specifically as it relates to Finding 1b ("Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors.")

**Electrification data strategy**

Increased electrification and advanced technology can provide enhanced capabilities to NSP to manage some of the challenges introduced by higher penetrations of non-dispatchable resources. Action Plan Item #2c calls for a data collection program related to electrification. We support this program, and encourage NSP to pursue it rapidly so that any insights can be incorporated into the next IRP.

**Provide additional details on Demand Response Strategy**

Demand Response resources can provide cost effective capacity or grid services. NSP's Action Plan calls for the creation of a Demand Response Strategy with a target capacity of 75 MW (Slide 57). We caution on the limitation placed by identifying Demand Response potential of only 75MW. This resource needs more examination to understand its true size potential and cost for different levels of DR.

| | |
|---|---|
| **From:** | Omar Bhimji |
| **To:** | Lefler, Linda |
| **Cc:** | Devin Lake |
| **Subject:** | RE: NS Power IRP Workshop |
| **Date:** | Monday, September 21, 2020 10:41:18 AM |
| **Attachments:** | image001.png<br>wolfville comments on 2020 IRP Draft Findings Action Plan and Roadmap.pdf |

**This is an external email from: obhimji@wolfville.ca - exercise caution**

Hi Linda,

Please find attached our comments on the IRP Draft Findings, Action Plan and Road Map.

(I apologize that it arrives late. I finished it as my last task on Friday afternoon, hit send, and apparently closed down my computer before it actually left my inbox)

We appreciate the rigour of the process, and the opportunity to participate and provide comment. However, I want to echo something I noticed was included in the letter of comment provided by EAC that doesn't directly pertain to the Draft Findings, Action Plan and Road Map: small communities like Wolfville lack both the resources and expertise to meaningfully engage in a necessarily complex and lengthy process like the IRP. We've been very fortunate to receive patient and expert guidance from a number of helpful individuals and groups, but still don't feel terribly confident that we've fully understood and engaged with the process. You and your colleagues have made every effort to make the IRP process accessible to us, but we believe that our efforts, and those of communities throughout Nova Scotia endeavouring to address climate change, would be well served by an updated mandate to support climate change and environmental concerns within the IRP process in a way similar to the Consumer Advocate or the Small Business Advocate.

Regards,

Omar Bhimji
**Climate Change Mitigation Coordinator**
c 902-599-4988 | e obhimji@wolfville.ca
200 Dykeland St., Wolfville, NS B4P 1A2
wolfville.ca

Submitted comments re. the 2020 IRP Draft Findings, Action Plan and Roadmap

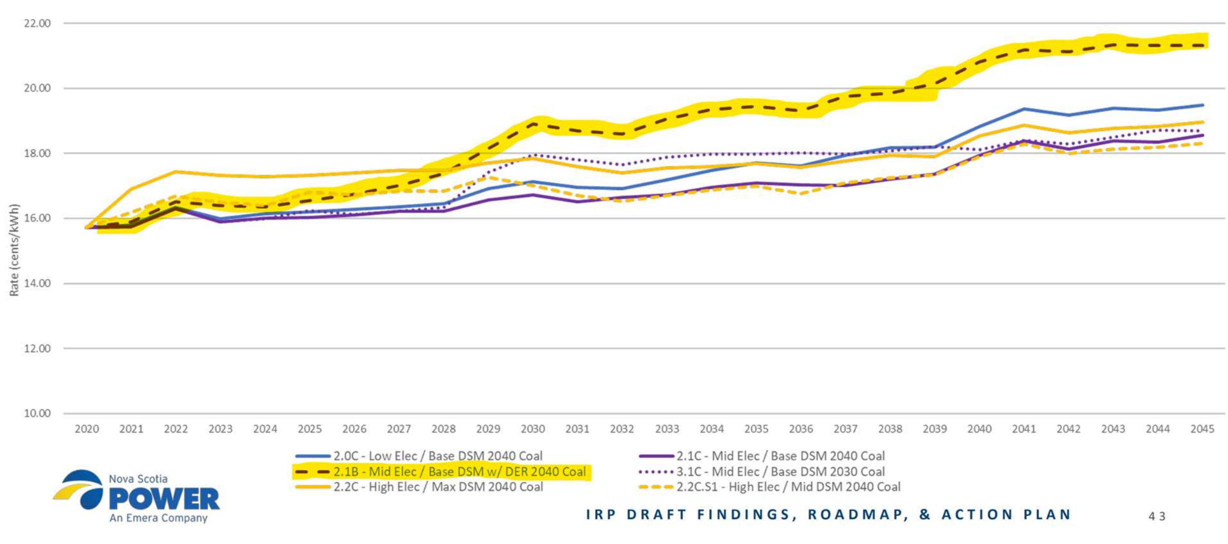
The Town of Wolfville appreciates the opportunity to patriciate in the 2020 Integrated Resource Planning process. We submit the below comments in response to the Draft Findings, Action Plan and Roadmap released for comment on September 2, 2020 and discussed at the stakeholder session on September 10, 2020.

Comments on Draft Findings.

1. It was encouraging to learn that all scenarios under consideration in the IRP process satisfy NS Power's reliability target. Reliable and predictable access to electricity is vitally important to Nova Scotians and will be become increasingly so as efforts to electrify transportation and heating systems in communities proceed.

2. The Town of Wolfville appreciates that an accelerated coal phase out scenario was considered as part of the IRP process. We note that, in the rate impact comparison, substantially similar scenarios that included coal phase-out by 2030 and 2040 were projected to have similar rate implications by 2040. There are both short- and long-term benefits to an accelerated phase out of coal and other fossil fuels: it has recently been confirmed that we have drastically underestimated the health impacts of air pollution on human health; the latest air quality research suggests that in the US, the health benefits alone are enough to justify an immediate transition away from fossil fuels.

3. The rate impact comparison also illustrates the inequitable economic implications associated with high levels of Distributed Energy Resource (DER) adoption. By 2040, the models suggest that high DER uptake could increase electricity costs by 10%, or 2 cents/kWh:





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While this increase would be experienced by all rate payers, under the current regulatory regime governing Distributed Energy Resources – which limits the scope and scale of electricity-producing resources that can be connected to local distribution system –its impact would not be equitably distributed. For example, Nova Scotians with the financial capacity to both own their own homes and invest in solar PV systems would experience significantly less impact that those not in a financial position to do so. The possibility that public policy not only enables this, but is in fact subsidizing such investments, facilitating access to reduced energy costs by the wealthiest members of our society with the modelled implication of increasing the burden on the less affluent, is in urgent need of re-examination and consideration.

4. The Town of Wolfville appreciates the clarity and directness of the 1st Draft Finding, which states that "[s]teeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role."

   Wolfville is currently working with the Sustainability Solutions Group (SSG) to develop its Climate Change Mitigation Plan. As part of this work, staff developed a set of working targets relating to activities and conditions in Wolfville both responsible for our GHG emissions and within the Town's regulatory and policy ambit to address or influence. These include targets such as:

   - increasing active transportation mode share from 23% (current) to 40% in 2030 and 50% in 2050 through programming and infrastructure investment;
   - increasing residential density through upzoning to decrease the average dwelling size in Town by 36% by 2050; and
   - reducing thermal and electric energy use to achieve 50% thermal savings and 50% electrical savings in 100% of all existing dwellings by 2040 by facilitating energy efficiency retrofits for current buildings through the implementation of a Property Assessed Clean Energy program.

   Wolfville's targets are ambitious, reflecting the climate change emergency declared by the Town's Mayor and Council in May 2019 and the urgency of the crisis posed to its citizens and the world by global climate change.

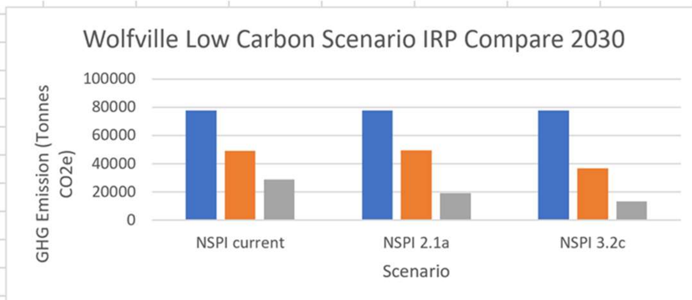
   SSG used the CityInSight modelling tool to project the emission-reductions that Wolfville could realize should it achieve its targets for both 2030 and 2050 under 2 of the scenarios currently being considered as part of the IRP process, along with the scenario included in the most recent National Inventory Report based on the National Energy Board's (NEB) 2018 Energy Supply and Demand Projections.

   1. NEB 2018
   2. Net Zero 2050 / Mid Electrification / Current Landscape (2.1a)

3. Accelerated Net Zero 2045 / High Electrification / Regional Integration (3.2c)

SSG's modelling projects that, under scenario 3.2c, should the Town of Wolfville achieve the working targets in its draft climate change mitigation plan, it would achieve a 53% reduction in GHG emissions by 2030, in-line with the emissions reductions goal legislated by the Province in the Sustainable Development Goals Act (2019):

| | GHG Emissions (Tonnes CO2e) | | |
|---|---|---|---|
| **Scenario** | **2020** | **2030** | **2050** |
| **NSPI current** | 77678 | 49252 | 28897 |
| **NSPI 2.1a** | 77678 | 49352 | 19291 |
| **NSPI 3.2c** | 77678 | 36610 | 13513 |
| | % Reduction from Peak Emissions | | |
| **Scenario** | **2020** | **2030** | **2050** |
| **NSPI current** | 100% | 37% | 63% |
| **NSPI 2.1a** | 100% | 36% | 75% |
| **NSPI 3.2c** | 100% | 53% | 83% |




It also projected that the Town's climate change mitigation efforts would realize essentially identical emissions reductions under both the NEB 2018 and Net Zero 2050 / Mid Electrification / Current Landscape scenarios – both of which would fall far short of the provincial emissions reductions goal mandated by the Sustainable Development Goals Act (2019).

Thank you for this opportunity to comment and for your consideration,

*Omar Bhimji*

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