Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs

Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: February 14, 2020

Subject: Input on Draft Assumptions Set

On behalf of the Consumer Advocate, Resource Insight would like to submit some initial suggestions related to scenarios and evaluation criteria. Also, we have no additional comments on the Draft Analysis Plan since the comments we sent you on February 5.

We appreciated the webinar on February 7, which clarified a number of points.

1. Load Assumptions

We appreciated Mr. Olsen's response to our question regarding EV load shapes. It is our understanding that the assumed EV load shape will represent customer behavior without influence from rate design. If that load shape seems significant enough to influence model results, then E3 would recommend an "ideal" load shape without any specific rate design or policy commitment to achieve that ideal in order to test the potential impact. We agree with this approach, so long as the effects of the "ideal" load shape (if needed) is reflected in the capacity expansion model and not just as a sensitivity in production cost modeling.

The load assumptions section doesn't provide any information on how NS Power views potential uncertainty in load (other than varying levels of DSM programs and EV loads). In addition to providing a sense of how much NS Power thinks load could vary from the baseline forecast (and why), we are also interested in whether NS Power thinks that the system load shape could change over time due to changes in load mix (industry shifts, changes in space- and water-heating technology, increased large-commercial air-conditioning load, etc.).

2. New Supply Side Options

Depending on the supply side resource, there can be a substantial difference between the costs of utility-built resource and a contract with an independent power producer to build and operate a generating unit. Ideally, once the IRP is completed, any recommendations for procurement would be tested in an all-source procurement that allows self-build options to compete with private developer offerings.

We were somewhat surprised to learn that decommissioning costs are not considered in the model, except for nuclear (which does not appear to be a serious option). Since the construction of a power plant creates a removal liability, it makes sense to include an allowance for decommissioning.[1]

While escalating and discounting the decommissioning costs for a reasonable life (like 30 years) may result in relatively small contributions to total fixed costs of the resource, NS Power should try to evaluate resources on an equivalent full-cost basis in the IRP. If an initial analysis indicates that the decommissioning cost for most resources are small enough to get lost in the round-off of other components, NS Power can make that showing.

Supply side capacity options should include flexible solar (which would give the utility dispatch control for ancillary services)[2] and hybrid (renewable + storage) resources.[3] The projected levelized cost of capacity is not included in the Assumptions Set, but was included in the resource options study. Flexible solar and hybrid resources are absent from the list of capacity resources in that presentation.[4]

Even if the entire reliability constraint occurs during the winter season, solar resources (particularly flexible solar and hybrid resources) can be relevant to the capacity need. These resources can provide relatively inexpensive regulating and operating reserves during many hours of the year. Adding these resources to the

---

[1] This may be inconsistent with NS Power accounting policies, which appear to require creation of a cost-of-removal liability upon putting a facility into service. NS Power, Response to NSUARB IR-5, *2020 Annual Capital Expenditure Plan*, Docket M09499 (January 30, 2020).

[2] Energy and Environmental Economics, Inc., *Investigating the Economic Value of Flexible Solar Power Plant Operation* (October 2018).

[3] Mark Ahlstrom, *Hybrid Storage Resources – Implications for Grid Services and Market Design*, presentation to US Federal Energy Regulatory Commission, Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency and Enhancing Resilience through Improved Software (June 25-27, 2019). The E3 Capacity Study discusses the benefits of combining solar and storage (e.g., Tables 28 and 29)

[4] Energy+Environmental Economics, *NS Power Resource Options Study* (July 2019). Note that NS Power intends to study the effectiveness and value of utility-managed curtailment. NS Power responses to CA IR-3 and IR-4, *Smart Grid Nova Scotia Project*, Docket M09519 (January 30, 2020).

capacity expansion model may affect the selection of the optimal capacity resources.

Regarding the supply-side cost assumptions, we would like to see more information about how those costs were developed and supported. NS Power's assumed renewable and storage project costs seem to be higher than those reported by Lazard. Benchmarking for gas-fired and nuclear generation tends to be lower, although a couple of the cost estimates seem to be on the high side. In the table below, costs that are high relative to Lazard are highlighted in orange, and lower costs are highlighted in blue.

Table 1: Comparison of NS Power Assumptions to Lazard Estimates (2019 CND$)

Technology	Subtech	Draft Assumptions Set[5]			Lazard[6]		
		Capital (2019) $/kW	Fixed O&M $/kw-yr	Variable O&M $/MWh	Capital (2019) $/kW	Fixed O&M $/kw-yr	Variable O&M $/MWh
Wind	Onshore	$2,100	$54	$0	$1,485-2,025	$38-49	$0
	Offshore	$4,726	$108	$0	$3,173-4,793	$108-149	$0
Solar PV	Tracking	$2,250	$20	$0	$1,485	$16	$0
Storage	Battery (1 hr)	$814	$8	$0	$378-693		$.3-5
	Battery (4 hr)	$2,325	$27	$0	$1,212-2,530		$.3-5
Natural Gas	Combined Cycle	$1,688	$14	$3	$945-1,755	$15-18	$4-5
	Frame Combustion Turbine	$1,080	$12	$7	$945-1,283	$7-28	$6-8
Nuclear	SMR	$8,073	$203	$0	$9,315-16,470	$146-180	$5-6

According to the US NREL Annual Technology Baseline for solar PV, the capital cost estimate of $2,250 / kW is inconsistent with all but a few very high recent estimates. [7] As shown below, those forecasts showing similar costs in 2019 were

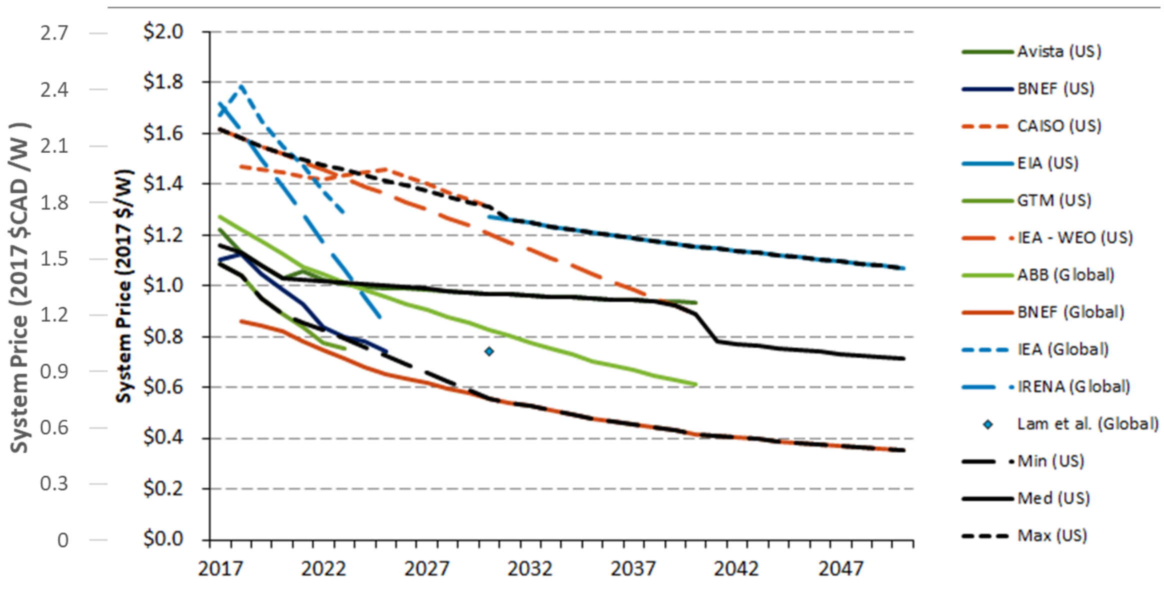
[5] NS Power, *Draft Assumptions Set* (January 20, 2020), Slides 35-37.

[6] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 13.0* (November 2019); Lazard, *Lazard's Levelized Cost of Storage Analysis – Version 5.0* (November 2019), restated to Canadian $.

[7] National Renewable Energy Laboratory, *Annual Technology Baseline: Electricity, Utility-Scale PV* (2019).

(a) generally created over two years ago and (b) associated with rapidly declining costs.

Figure 1: Solar PV Cost Projections



Utility-scale PV Overnight Capital Cost Projections, by Source, and "min," "median," and "max" U.S. projections

Literature sources: (ABB 2017), (Avista 2017), (BNEF 2017), (BNEF 2018), (E3 2017), (EIA 2019), (GTM Research 2018), (IEA 2018) (IEA 2018), (IEA 2018), (IRENA 2016), and (Lam, Branstetter, and Azevedo 2018).

Source: National Renewable Energy Laboratory, *Annual Technology Baseline: Electricity, Utility-Scale PV* (2019). Prices restated to Canadian $.

Similarly, for combined-cycle natural gas, the NREL ATB suggests costs at least 20% lower than NS Power's estimate. Of the sources reviewed by NREL, all but a few suggest CCNG costs lower than NS Power's estimate. The NREL ATB suggests that capital costs for combined-cycle and combustion-turbine plants are very similar.[8]

With respect to storage technologies, Lazard suggests that O&M should be treated as variable rather than fixed. Also, the assumptions should also include the charging cost and charging cost escalator, unless these values are calculated within the system planning models.

There may well be Nova Scotia specific cost data that justify these particular assumptions, we would like to better understand these assumptions or see them aligned with other sources.

[8] National Renewable Energy Laboratory, *Annual Technology Baseline: Electricity, Natural Gas Plants* (2019).

3. Distributed Energy Resources

Distributed energy resources can offer low-cost resources for providing generating energy and capacity, avoiding line losses, avoiding T&D upgrades and providing backup service to host customers. They may result in positive or negative effects on revenue requirements. Any representation of DERs in the model should either

- include the full cost of the resources (not just the portion paid by NS Power incentives) and reduce those gross costs to reflect the T&D and non-energy benefits (including backup and other customer values), or
- if NS Power cannot estimate the non-energy benefits, just the costs paid by NS Power, reduced by T&D benefits (reduced line losses, avoided investments).

4. Planning Reserve Margin and Capacity Value Study - Generation

During the webinar, we asked about Port Hawkesbury's DAFOR and the lack of maintenance de-rate assumptions for several units. (E3 Capacity Value Study, p. 42)

Using the historical DAFORs from the Fuel Stability Plan filing (OP-9, Att 1), it appears that the DAFORs in the E3 study are the historical averages for 2016–2018. (E3 Capacity Value Study, p. 42) That seems reasonable in most cases. However, TC 1&2 performed much worse in 2018 than in recent years. Unless there is reason to believe that the units are permanently damaged and thus unreliable, perhaps a longer averaging period should be used. Using the 7 years from the FSP, the averages would be 19% and 11%, not 36% and 19%. Similarly, the TC3 DAFOR was over 8% in 2012-18, much higher than the 2% in the assumptions.

In Table 17, thermal units coal are reported to have an effective load-carrrying capacity of 100%, while wind is at 19%, as computed in the study. (E3 Capacity Value Study, pp. 55-56) We all agree that the thermal plants cannot carry load equal to their nameplate ratings. NS Power indicated that the capacity of the thermal units would be derated for capacity planning by the DAFORs used in the E3 study. Mr. Olsen agreed that nameplate capacity derated by DAFOR could be significantly higher than ELCC for the thermal units, especially the larger ones. Since ELCC is used for rating variable generation, the other types of generation should be de-rated using methods that are identical or produce essentially identical results.

The thermal plant contribution to reliability contributions appear to fall into a few buckets, based on the size and DAFOR data in Table 9:

- Large, low-DAFOR (TC 3, Lingan 1, PT 2)

- Large, mid-DAFOR (Lingan 3&4, Trenton 5&6)
- Smaller, very-high-DAFOR (TC 1 &2)
- Very small, high-DAFOR (CTs)
- The odd mix of TC 4-6

ELCC should vary among these units. Replacing a MW of TC 1 or 2 should require less capacity than a MW of Trenton 5, which should require less capacity than a MW of PT 2.

We also suggest revisiting assumptions around hydro ELCC. The E3 study says:

> For hydro resources that can be dispatched by the system operator without any substantial limits to maximum time limits (e.g. 1 week or more), E3 generally models these resources equivalently to firm dispatchable resources such as nuclear, coal, oil, and gas. (E3 Capacity Value Study, p. 30)
>
> All hydro resources except for Wreck Cove are modeled as dispatchable resources because they are deemed to have sufficient pondage such that they are equivalent to firm resources from a reliability perspective." (E3 Capacity Value Study, p. 43)

It is difficult to exactly match hydro plant capacity with energy output. Our best estimates for January projected capacity factors for 2020 are:

- 28% for Dickie Brook,
- 30-40% for Bear River and St. Margaret's, and
- 40-50% for Lequille and Sissiboo/Weymouth.

It is hard to believe that these plants can operate at full power for the entire period with non-zero LOLP in Figure 27 (6 AM to 2 AM on an average day). In addition to the storage issue, there are droughts. We understand that Nova Scotia experienced a drought in 2016.

We recommend that NS Power review its capacity value assumptions related to its hydro assumption, considering:

- Storage capacity by system, in terms of hours of full-load generation
- Time to recharge the storage from inflow in Nov-Mar
- Capacity factors for each of the hydro resources during winter peak hours (hours with any LOLP) in each of the last several years
- Effect of the 2016 drought (or other hydrological events) on effective hydro capacity over long winter peaks
- Historical frequency of droughts that have affected NS hydro capacity

Also, please make visible the numerical values behind Figure 27. (E3 Capacity Value Study, p. 55)

We also recommend that NS Power consider whether feeder circuit outages could significantly affect DAFOR for any generation units. According to one data response, the Wreck Cove Hydro feeder 85S-401 had a Circuit Average Interruption Frequency Index of 5.75, 17.45 and 7.64 in 2017, 2018 and 2019, respectively, placing it in the worst 5% of feeders in each year.[9]

During the webinar, Mr. Olsen explained that adding more EE would only change the ELCCs of various resources, especially DR over the long winter peak, if that EE changed the resulting load shape significantly. Mr. Olsen explained that one way to do reflect this possibility is to model EE programs individually, rather than as a block load modifier as planned for this IRP. We suggest that even as a block load modifier, if the program load shape is significantly different than the load shape assumed in the forecast, then the overall scale of EE resource investment could shift the load shape. This would be particularly true if EV resources are also affecting the load shape.

Our concern here is that the forecast marginal ELCC values may be missing diversity benefits associated with a mix of resources. This could result in the analysis selecting too much of the resources with high ELCC values in the E3 study and too little of other resources.

5. Planning Reserve Margin and Capacity Value Study - Load

The Capacity Value Study explains that hourly load profiles are a combination of actual hourly loads from the past 5-10 years, and weather data from the past 30-60 years. (E3 Capacity Value Study, pp. 25-26) We would like to review more details regarding the methods and key diagnostic outputs. Here are some examples of the questions we have:

- How are hourly loads related to weather data? What assumptions are made about weather conditions that did not occur during the past 5-10 years and load? Provide methods and data outputs (e.g., scatter plot of actual weather vs load compared to modeled weather vs load).
- What weather conditions are considered in the relationship between weather and load (e.g., temperature, wind, humidity, precipitation, etc.)?

[9] NS Power, Response to NSUARB IR-37, *2020 Annual Capital Expenditure (ACE) Plan*, Docket M09499 (January 30, 2020). Wreck Cove Hydro feeder 85S-402 and Ruth Falls Hydro feeders 96H-411 and 412 are also cited in these data, and have similar poor performance on Circuit Average Duration Index.

- What consideration, if any, is given to weather trends in the long-term weather dataset? For example, if there is a trend towards more wind (or less), is that reflected in the forecast? Similarly, are there any trends in rainfall, snowpack and hydro resources (p. 31)?
- Have weather conditions (mostly temperature) been correlated with generation outages (p. 42), efficiency (heat rate), or capacity?

6. Imports

We would like to see the following import-related issues addressed:

- How will the modeling reflect the correlation of temperature and load among Newfoundland, Nova Scotia and New Brunswick, and hence the availability and cost of imports (p. 48)?
- As discussed on the webinar, the assumptions set does not provide information on the potential cost of new transmission (slide 68), or how that would be dealt with in the analysis.
- How would the modeling reflect a new 800 MW tie line becoming the largest contingency, with associated reserve requirements?
- Discussion on the webinar highlighted concern that modeling all import energy options as clean energy options would either understate the emissions from New Brunswick coal or New England gas (and hence the cost of meeting emission limits), or ignore economic imports of fossil generation.

7. Fuel Pricing - Natural Gas

We previously asked about an additional fuel firming cost that might need to be assumed, if the gas-fired plants were assumed to be supplied by unreliable or constrained pipelines. We believe the question about new gas supply sources was clarified as follows:

> If the model selects new baseload (or intermediate) gas units, supply would be provided according to option 3. (Slide 78) The alternative gas supply options would be potential substitutes for option 3 that would be evaluated after the IRP. (Slide 84) The alternative gas supply options would not be necessary for the feasibility of any gas units evaluated in the IRP, since option 3 is considered feasible and sufficient.

Do we have that right?

8. Sustaining Capital for Existing Units

We have several questions about this forecast.

- Please confirm or correct our understanding of the discussion about the utilization factor. We understand that the base forecast assumes capital investments that would occur if each unit operated at what NS Power considers to be a high utilization factor for that unit. We think you are defining "high" utilization as the most demanding experience of the unit in some recent historical period, as opposed defining "high" by the same metric for all units (e.g., 80% capacity factor). Thus, if the IRP results forecast relatively low utilization factors for some units, compared to the historical base, NS Power would expect future capital investments to be lower than the base assumptions included in the IRP.
    - Do we have that right?
    - Did NS Power use a particular period to define the high utilization for each unit?
- NS Power has prepared forecasts of sustaining capital for the IRP and the 2020 ACE plan. (2020 ACE Plan, p. 17) Is the ACE plan sustaining capital forecast based on different utilization factors than the IRP? How does the approach to setting the utilization factors for the ACE plan forecast differ from that for the IRP forecast.
- Does projected sustaining capital for each unit simply reflect historical experience plus inflation, or is the projected capital cost increased to reflect the age of the plant?

9. Renewable Integration

The renewable integration section, including both the "assumptions about cost and operational constraints" and the "operability screening," leaves a lot unexplained. For example, what technology options will the model have to meet the minimum requirements for essential grid services, such as hybrid resources or flexible dispatch of solar?

We suggest that NS Power host a webinar to explain this topic and solicit feedback from stakeholders.