Comments on 2014 IRP Technical Conference Analysis Results

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Many questions remain following the September 12, 2014 Technical Conference. These questions fall into three groups:

1. Information that NSPI must have developed in preparing the presentation but has not provided.
2. Important issues raised by the analysis, but not resolved.
3. Important issues that the IRP process does not appear to have addressed.

In the Technical Conference, NSPI indicated that not further analysis of plans or scenarios would be possible in this process. My impression is that the IRP analysis, as it currently stands, will not be particularly useful in providing guidance for future decisions. While NSPI plans to issue a Draft Final Report and Action Plan on September 30, it would be more appropriate that the work to date should be considered Phase I of the IRP, and the NSPI should be defining Phase II, to refine the inconclusive results of date.

In fairness, NSPI's description of the Action Plan (slides 19–21) acknowledges that it has some major analysis and collaboration before it, including DSM planning and evaluation and further study of

- intermittent generation,
- "the operational challenges associated with variable generation,"
- "the need for flexible resources to integrate additional variable generation,"
- "cost-effective market opportunities,"
- "industry best practices regarding sustaining capital,"
- the generation retirement forecast,
- the economics of an FGD at Lingan 3 and 4,

- optimization of solid fuel use,
- potential for savings in fossil-plant O&M and sustaining capital in the high DSM case, and
- appropriate planning reserve margin.

Some of these items are flagged for results as late as fourth quarter 2016, which seems like an excessively long delay. Other items are slated for reports in some future 10 Year System Outlook; NSPI should be aiming to produce results by the next 10 Year System Outlook, in June 2015.

Considering all the outstanding issues, NSPI has not completed the 2014 IRP. The analyses listed above, and some discussed below, should be considered to be part of a second phase of the 2014 IRP, with NSPI running far behind schedule in addressing important issues.

Normally, an Action Plan would consist of specific activities to implement the results of the IRP. NSPI is generally far from that point. Even if NSPI insists on calling its ongoing efforts an Action Plan, rather than a second phase of the IRP, all parties must recognize that no usable 2014 IRP exists and NSPI faces multiple decisions without the background of a tested IRP.

Information Embedded in Results but Not Provided

Underlying Data

Some of the figures are difficult to read, due to the large number of overlapping CRPs. Most of the tables present derived data (differences from a reference case, percentage changes, present values). NSPI should provide the underlying data.

Revenue Requirements

The slides for the technical conference provided summaries of the relative revenue requirement per kWh for a subset of revenue requirements. The results are provided as percentage differences in $/kWh across CRPs.[1] This information is of limited value, for three reasons:

- The percentage differences in partial revenue requirements per kWh can only be meaningfully interpreted if the reviewer knows what share of the revenue requirements are included in these results. The partial revenue requirements appear to exclude the return and depreciation on the existing generation system, all T&D costs (the treatment of the Maritime Link transmission is not clear); all retail costs administration, general and overhead costs; all taxes; and other costs listed on slide 15.[2] Hence, the significance of a 10% difference in this part of the rate is unclear: is it 8% of the average rate, or 4%, or 2%?
- The total revenue requirement is at least as important as the revenue requirement per kWh, but the presentation provides no information on the differences in total revenue requirement between plans.
- The percentage difference between the partial rates is less meaningful than the $/MWh difference, which NSPI does not provide.

NSPI should report both the rates and revenue requirements for the various CRPs, and report those values for full revenue requirements. As part of that computation, NSPI should reflect the reduction in T&D costs and line losses for the high-DSM CRPs and increase for the low-DSM CRPs.

Treatment of Port Hawkesbury Biomass as Firm Capacity

In the past, NSPI has assumed that retirement of one 150-MW coal unit on Cape Breton (e.g., Lingan 2) would free up more than enough transmission capacity off the island to allow the Port Hawkesbury biomass plant to be counted as firm NRIS capacity. For some reason, NSPI now assumes (slide 8) that at least two Cape Breton coal units would have to retire before Port Hawkesbury would

[1] Rather than admitting that it is comparing rates per kWh, NSPI refers vaguely to “adjusting the revenue requirements by load” (Slide 15) and refers to the rates as “revenue requirements.”

[2] Slide 15 mentions the exclusion of interest payments, but does not discuss the treatment of return on equity.

become firm capacity, and in CRP 4-1 Port Hawkesbury does not become firm capacity even after 600 MW of retirements.

Retirement Rationale

Slide 8 shows Tufts Cove 1 and 2 being retired in every CRP. It is not clear why NSPI has forced the retirement of these units in all plans, considering the relatively low cost of keeping these units on line, the high cost of transmission to serve the Halifax load centre with less local generation, and the operational flexibility of the gas-fueled steam units (less so for Tufts Cove 1 than Tufts Cove 2) for integrating wind and providing reserve.

Similarly, in CRP4-1 and CRP4-1FGD (and only those two cases), NSPI assumes retirement of Tufts Cove 3. It is not clear how NSPI decided that it could and should retire this flexible unit, and why this retirement would be justified in CRP4-1, but not the lower-load CRP6-1.

NSPI should reconcile these apparent inconsistencies.

Fuel-Price Forecasts

Gas prices and market electric prices appear to be forecast from Henry Hub prices, with adjustments for basis to New England, tariff charges to Nova Scotia and implied heat rates. It would be helpful for NSPI to share the forecasts and adjustments, so that these projections can be compared to other sources, including the effect of carbon emission limits pending in the US.

The IRP should also provide information on the seasonal variation in gas and power prices.

Areas in which Analysis is Incomplete

The Treatment of the PHP Energy Load

Once again, NSPI has included PHP's economy energy under the load-retention tariff as it were firm energy for planning purposes, in violation of NSPI's clear promises in the LRT proceeding, Matter No. 4862, including the oral testimony of Mark Sidebottom, NSPI's Vice-President for Power Generation and Delivery, that NPSI would start with "a plan that has [the mill] not served, and then that we would provide them the incremental cost calculation that would then compare not serving them to serving them, and in that way we'll cover the incremental costs of them taking that decision to take that energy at the time" (Matter No. 4862, transcript at 400) and that "the obligation [to the mill] is limited to covering the incremental cost, not planning for the future" (ibid. at 459–460). NSPI followed up in writing with the following promises:

> To be clear, the agreement between NS Power and PWCC is that the mill will be served on a purely incremental basis only. As a result, NS Power will assume for all planning purposes, that the load required to be served is that excluding the mill's load. The Company will plan and optimize its fleet on this basis, independent of whether the mill operates. (Matter No. 4862, NS Power Reply Evidence at 9–10)

> Mill electricity consumption [is] treated as fully incremental throughout the term of the agreement. This means that the Company will not build generation capacity to serve this load, will not include this load in its planning work and will not manage its fuel portfolio to minimize cost associated with this load. (Matter No. 4862, NSPI closing submission at 14)

The Board accepted that representation as part of its approval of the LRT:

> NSPI will not include PWCC in its planning considerations, including future capacity additions or the restart of generation which has been seasonally shut down. (Matter No. 4862 Order of September 12, 2012, Appendix B)

This proceeding is exactly the type of "planning" from which the mill energy consumption must be excluded. Yet NSPI included the mill load, on the flimsy excuse that the load was needed "in order to calculate RES and emission compliance." (NSPI 2014 IRP – Draft Assumptions, March 14, 2014, slide 75). The RES is not binding in the CRPs during the LRT, so accounting for RES compliance is no excuse for this planning error. While the emission constraints must be accounted for, NSPI could have used a side computation to set aside enough emission allowances to meet the PHP load and optimize the system without PHP, rather than including the PHP load in computing energy costs.

As a result of this error, NSPI once again runs the risk of committing firm customers to pay for investments and other commitments to reduce the price charged PHP, even though PHP will not pay for those commitments.

The final IRP, or failing that, the Action Plan, must address this issue and determine whether any of the IRP results would change without the improper inclusion of PHP energy in NSPI's computation of plan costs.

Wind Capacity Value

In the Action Plan item list, NSPI proposes to "Pursue the study of further intermittent generation to determine appropriate capacity value…by Q4 2016." (slide 19). It is not clear why NSPI thinks it needs another two years to study the issue, or what further analysis is possible.

The difference between NSPI's current estimated value of wind capacity (12%) and the GE Consulting estimates (about 30%, excluding a case in which the COMFIT projects were assumed to be tightly clustered) is large enough to be the difference between the need to retain a fossil unit and being able to retire it. NSPI should provide a more complete explanation of why it believes that its 12% value is better than GE's estimates, or explain how it intends to improve its estimate.

Intermittent Generation Integration Costs

In March, NSPI reported that "A study to determine the costs to integrate additional intermittent generation is in progress." (2014 IRP – Draft Assumptions, p. 26)

In the June 25, 2014 Technical Conference, NSPI described the "use of Plexos in 2014 IRP… Plexos will be used to evaluate: 1. operability of a selection of Candidate Resource Plans developed by Strategist. 2. operability of Medium and High wind penetration cases and with various levels of DSM and to calculate operating portion of wind integration costs. 3. collateral benefit of system upgrades required to integrate further wind energy on the system." And "a limited number of Plexos runs will be conducted in the time allotted for the completion of the IRP." (Slide 85)

Six months after the draft assumptions, and three months after the June Technical Conference, the Analysis Results slides do not mention integration, but include the following in the Action Plan item list:

- Continue to develop an understanding of the operational challenges associated with variable generation and report to the UARB as part of the 10 Year System Outlook.

- Report to the UARB on the status of the need for flexible resources to integrate additional variable generation in the 10 Year System Outlook Report.

Assuming that NSPI means that it will report to the UARB in the June 2015 10 Year System Outlook Report (as opposed to some later report), NSPI is not promising any results for at least 15 months from the start of the study, and perhaps much longer. This delay is unacceptable. NSPI should have addressed renewable integration in this IRP; its failure to do so may increase costs to ratepayers. The final report on this phase of the IRP should describe NSPI's progress to date (including identifying the consultants who have been working on these issues), the plan for completing the analysis, and specific milestones leading to results that can be used to make resource decisions starting in 2015.

Effect of DSM on Total Costs and Revenue Requirements

In NSPI's revenue-requirements analysis for the CRPs with DSM differing from the base (CRPs 1, 5, 6, 7, 31 and 32), NSPI does not appear to have included the effect of avoided T&D investments, reduced losses, and increased steam plant layups and retirements. These DSM benefits should be explicitly included in the analyses conducted as part of the Action Plan and beyond.

Optimization of CRPs

Several of the CRPs, especially those with higher wind and/or DSM, have significant excess capacity, and will have even more, if and when NSPI recognizes the capacity value of ERIS resources. NSPI should be studying the feasibility and economics of additional retirements, to identify the least-cost plans for thermal generation in these CRPs.

Important Topics Not Yet Addressed

ERIS Capacity Value

Slide 19 proposes that NSPI should study the capacity value of Energy Resource Interconnection Service (ERIS) capacity until Q4 2016. That date is over two years in the future, and almost three years from NSPI's commitment (in the cost of service proceeding) to resolve this issue in the IRP. This issue appears to require only the examination of the nature of the constraints affecting each ERIS plant to determine whether it affects the deliverability of the plant's output at times of relatively high load and multiple outages of other capacity. This is a task for transmission engineers and does not conflict with the model runs for the IRP.

In addition to its role in the COSS, the capacity value of the ERIS capacity (wind and Port Hawkesbury biomass) may affect the ability of NSPI to retire or lay up additional generation, and should be resolved as quickly as possible.

The Value of Allowing Port Hawkesbury Biomass to Operate Economically

Following operation of the Maritime Link, NSPI will be able to meet its RES requirement while dispatching the Port Hawkesbury biomass plant only when it is economic. NSPI should be estimating the benefit of relaxing the current dispatch requirement, and seeking statutory and engineering solutions to allow that outcome.

Wind Plant Costs

NSPI's estimate of installed wind costs appears to be high, especially since the next wind additions are likely to be several years into the future, benefiting from significant technical progress. The South Canoe wind farm is budgeted at about $1,800/kW in 2013$, plus about $150/kW for transmission facilities and upgrades. NSPI should document the source of its wind-plant cost estimates.

Power Purchase Options

The IRP to date has not added anything to our information of the types and costs of power purchases that may be available in the future, including the cost and timing of required upgrades to the New Brunswick intertie.

Renewable Sales Options

NSPI has not addressed the long-standing issue of selling some of its excess renewable energy to New England at prices much higher than those available for fossil or large hydro. This option may have important effects in moderating the rate and bill increases from the Maritime Link.

Optimization of the Aging Fossil Fleet

In addition to determining the appropriate order of retirements, NSPI should consider whether it would be better to operate several units (Lingan 1–4, Trenton 5, Tufts Cove 1–3) in load-following service, accepting accelerated wear and retiring the units in the order that they wear out. This approach is explained at www.nrel.gov/docs/fy14osti/60575.pdf.

The IRP also does not address the local supply and reserve concerns that would arise with the retirement of one or more units at Tufts Cove (let alone all three, as assumed in some CRPs) and possibly at Trenton.

Inconsistencies and Questions

Additions and Retirements

The Preliminary Load and Resources tables in the Detailed CRP Results slides include additions that do not appear in slide 8 of the Analysis Results, including the 100 MW of small additions in 2015–2017.

The Preliminary Load and Resources tables, the addition and retirement in the "Preliminary Results" in the Detailed CRP Results slides, and slide 8 of the Analysis Results also show inconsistencies in later additions and retirements. For example,

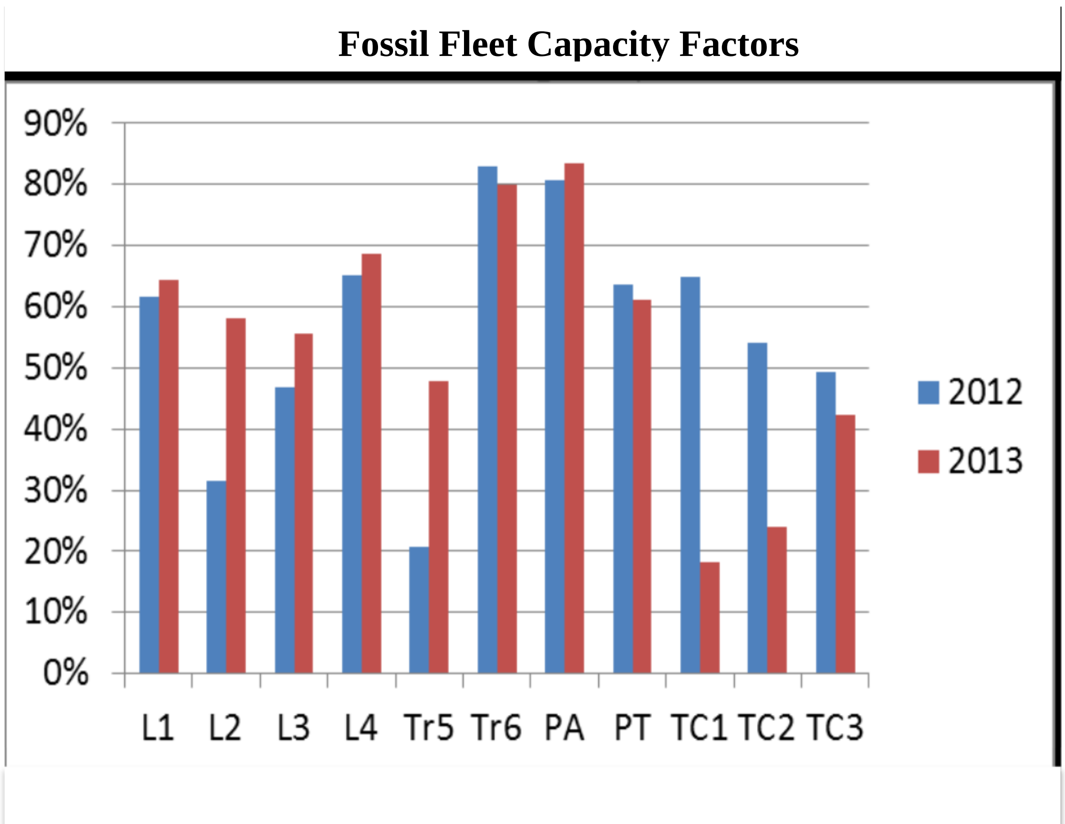
- For CRP 4-1, the Preliminary Results table shows the retirement of six 150-MW units, plus Tufts Cove 1 and 2; the Preliminary Load and Resources table shows 4 150-MW retirements and Tufts Cove 1; and Table 8 shows retirement of five coal units and Tufts Cove 1–3.
- For CRP 6-1, the Preliminary Load and Resources table shows the same coal retirements as slide 8, and Tufts Cove 1 and 3, but excludes the retirement of Tufts Cove 2 shown in slide 8.

Coal Plant Capacity Factors

For many of the CRPs (e.g., 1-1, 2-1, 3-1, 4-1, 5-1, 5-8, 10-1, 31-1), the Detailed CRP Results slides project that Trenton 5 will have capacity factors exceeding 65% in 2015–2019, and about 60% in 2020 through the unit's planned retirement in 2030 or 2035. With higher wind and/or DSM (CRPs 6-1, 7-1, 7-5, 8-

1, 21-1, 21-3, 32-1, and more modestly in 9-1, 9-3, and 9WC-2) , the Trenton 5 capacity factors gradually fall after 2020, to the 40% or 30% range. In all those cases, the Trenton 5 capacity factor is much higher than those of each of the Lingan units.[3]

Yet historically, Trenton 5 has run less than most or all of the Lingan units, as shown in this figure from the 2012–2013 FAM Audit. Since Trenton 5 was out of service for seven months in 2012 (March–September), its capacity factor was depressed. But since Trenton 5 operates primarily in the winter, it is not clear how much higher its capacity factor would have been without the outage.



The operating expense filings and the fuel updates from the last two GRAs and Figure 230 of the GE Nova Scotia Renewable Energy Integration Study support the conclusion that Trenton 5 generally runs less than the Lingan units.

[3] In the cases that add an FGD to Lingan 3 and 4, those units' capacity factors rise and the Trenton 5 capacity factor declines dramatically. That situation is not comparable to the historical data.

The IRP should explain why NSPI is projecting that future dispatch order would be so different from historical dispatch.

In addition, considering the operating problems Trenton 5 has experienced, and the limited dispatch of the unit in the real world, NSPI should reconsider its assumption that "Trenton 5 [is] expected to extend life beyond 60 years due to recent significant capital investment" (June 25 slide 23). NSPI should explain why it has consistently assumed that Lingan 2 (installed 1980) would be retired 12 to 17 years earlier than Trenton 5 (installed 1969), and that in the cases with higher DSM and/or wind (CRPs 6-1, 7-1, 8-1, 9-1), all four Lingan units (installed as late as 1984) would retire as much as a decade before Trenton 5.

NSPI should be selecting to retire schedules to minimize total system costs, rather than to maximize its recovery of plant investment through depreciation prior to retirement. If NSPI has concerns about stranded prudently-incurred costs, it should approach consumer representatives to find a solution to that problem. Customers are better off paying the sunk costs of a retired plant that is uneconomic to operate than both the sunk costs and continuing O&M and sustaining capital.

As Liberty observes "the largest [fossil unit] investments came at Trenton. Considering the longstanding and continuing trend of poor performance at Unit 5, the value of this large investment should be questioned. One cannot observe a correlation between spending at Trenton and improvements in performance." (2012–2013 FAM Audit, p. VIII-27)

Assessment of 2007 and 2009 IRPs

Slide 10 asserts that "The planning done through the 2007 IRP and refined in the 2009 IRP Update has proven robust." Given the magnitude of changes in NSPI's load and supply not anticipated in 2007 or 2009 (e.g., addition of the Port Hawkesbury biomass plant, another 170 MW of contract wind, COMFIT, and the Maritime Link; loss of large amounts of industrial load), it is not clear what planning in the 2007 IRP and the 2009 IRP Update has proven robust. That raises questions about the realism of NSPI's view of its planning efforts. Rather than broadly congratulating itself for its past planning, NSPI should clarify what part of that planning has proven to be valuable, and what parts problematic, to inform future planning.