Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #4
SUMMARY

September 21, 2021

Welcome and Introductions
Alison Becker, Manager Regulatory Policy, NIPSCO

Ms. Alison Becker, Manager, Regulatory Policy, welcomed participants to the virtual meeting and provided a safety moment on Mental Health Awareness. She then discussed the Webex meeting protocols and walked through the agenda for the day. She then introduced Mike Hooper, President and Chief Operating Officer of NIPSCO, to kick off the meeting.

Welcome
Mike Hooper, President and COO, NIPSCO

Mr. Hooper welcomed participants and thanked them for the high level of participation. Mr. Hooper then highlighted the importance of the mental health safety topic, given the continued pandemic environment. He reminded participants of the generation path NIPSCO has been on and also highlighted the period of transition that NIPSCO, along with the rest of the state and country, is in. Mr. Hooper emphasized that the dynamic period makes it critical for NIPSCO to remain flexible and adaptable. Mr. Hooper also discussed that NIPSCO is focused on engaging with stakeholders to ensure continued considerations of all aspects and perspectives during this energy transition. He closed with an emphasis on the criticality of stakeholder feedback.

Participants had the following questions and comments, with answers provided after:

- What is the schedule for notifying participants as to whether or not their asset has been chosen for further negotiation?
    - NIPSCO is currently preparing a letter for those who are not moving to the next round.

Public Advisory Process and Updates from Last Meeting
Fred Gomos, Director, Strategy and Risk Integration, NiSource

Mr. Fred Gomos, Director Strategy and Risk Integration, NiSource, began the section with an overview of NIPSCO’s planning process and highlighted updates to the Stakeholder Advisory Meeting Roadmap. He announced that the October 12 Public Advisory Meeting has been converted to a Technical Webinar focused on the Reliability Assessment and that the final Public Advisory Meeting will take place on October 21, with the IRP being submitted to the

Indiana Utility Regulatory Commission by November 15. Mr. Gomos then walked through one-on-one stakeholder interactions with the Citizens Action Coalition of Indiana and the Indiana Office of Utility Consumer Counselor since the July public advisory meeting. He then provided a reminder of NIPSCO's resource planning approach.

Resource Planning Activity Review
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, Charles River Associates ("CRA")

Mr. Pat Augustine, Vice President at CRA, reminded participants of the five step planning process core to NIPSCO's resource planning approach. He started with an overview of the key planning questions and themes in the 2021 IRP and reviewed the major elements of the integrated scorecard framework. He then walked through NIPSCO's process of developing external market perspectives, including the use of both scenarios and stochastic analysis to perform a robust assessment of risk. He then reviewed the major scenarios and stochastic components shared in previous stakeholder meetings. Finally, Mr. Augustine discussed the development of integrated resource strategies or portfolios, sharing NIPSCO's current capacity and energy positions on both an annual and hourly basis.

Participants had the following questions and comments, with answers provided after:

- What basis did you use for the lower capacity credit (slide 17)?
    - NIPSCO relied heavily on published Midcontinent Independent System Operator, Inc. ("MISO") studies, including those summarized in the February report MISO published on its Renewable Integration Impact Assessment ("RIIA") study. NIPSCO mapped the solar additions included in the IRP's four market scenarios to numbers in MISO's RIIA report, along with accompanying capacity credit projections. It should be noted that the credits shown on slide 17 are for the summer, while solar credits for the winter were assumed to be below 10% across the modeling horizon.
- It does not seem to make sense for the federal government to offer long-term Investment Tax Credit for renewables when there is a mandate for decarbonization or aggressive regulation (slide 17).
    - That is a fair comment and part of the federal policy debate happening now. The current proposed bills being debated in Congress right now actually do both - 10 year extensions to tax credits, plus a clean electricity payment program that incentivizes significant year-to-year growth in renewables or other clean energy. Therefore, the Economy Wide Decarbonization scenario actually represents a plausible aggressive decarbonization scenario for planning purposes, although we will need to wait to see what makes its way into law.
- What summer and winter Planning Reserve Margins ("PRMs") are you using (Slide 20)?
    - We are using 9.4% for both summer and winter. Winter could be higher based on some indicative MISO evaluations, but for purposes of the IRP, 9.4% is used for both.
- Is that 9.4% adjusted for NIPSCO's coincidence factor?
    - Yes, it is adjusted to be coincident to the MISO peak, or in other words, NIPSCO's load when MISO has its peak. The coincident peak is approximately 95-97% of NIPSCO's internal peak.
- Can you talk a little about the capacity purchases on this slide in the front years? Meaning, are they forward bi-laterals or anticipated market purchases (slide 20)?

    - The capacity purchases are forward bi-lateral deals and are already committed to by NIPSCO (short-term contracts). They are tied to capacity secured in advance of Schahfer Units 14/15 retiring. In addition, some of the renewable replacement projects for the remaining units at Schahfer have in-service dates that do not line up with MISO planning years, so secured capacity is also related to that gap.
- It was mentioned that capacity was purchased to replace Units 14 & 15. What is that replacement capacity resource?
    - These bi-lateral contracts are for zonal resource credits to meet capacity obligations within MISO. They are not tied to a discrete resource. Note that those capacity costs associated with the 2021/2022 and 2022/2023 planning years will NOT be recovered from customers.
- Can you explain why the capacity costs are not being recovered from customers? Is this for a particular time, and/or amount?
    - Given that Schahfer Units 14 and 15 are still in base rates even as they retire prior to 2023, the required replacement capacity purchases will not be charged to customers.

Existing Fleet Analysis
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, CRA

Mr. Gomos re-introduced the IRP's two-step analytical framework and the various reasons why the analysis is performed in two parts. Mr. Gomos walked through the composition of eight existing fleet portfolios that evaluate different retirement dates for NIPSCO's remaining fossil units. Mr. Gomos then transitioned to Mr. Augustine who walked through the existing fleet portfolio optimization results. Mr. Augustine also reviewed the deterministic cost to customer net present value of revenue requirement ("NPVRR") results and observations for all existing fleet portfolios. Next, Mr. Augustine walked through the NPVRR results and observations across the four scenarios. He then shared the existing fleet analysis scorecard framework and results. Mr. Augustine provided a detailed overview of portfolio level observations, and transitioned back to Mr. Gomos to discuss overarching existing fleet analysis observations.

Participants had the following questions and comments, with answers provided after:

- Totally get that it's iterative but I think one thing that would really help understand how you arrive at those portfolios is to also see the results of those minimally constrained runs (Slide 25).
    - The Aurora model is used to perform least cost optimization analysis within each of the eight existing fleet concepts, with the results illustrated on the next slide. We can provide additional material in spreadsheet format if stakeholders wish to review the annual capacity additions or other detail from the modeling.
- Was a carbon capture, utilization, and storage ("CCUS") retrofit assumed in 2030 in any case?
    - The eligible resources for the optimization modeling are based on projects offered through the request for proposal ("RFP") process. With respect to CCUS, no bids from that technology class were received in the RFP, so NIPSCO did not evaluate it as a replacement option in this phase of the analysis.
- The question is whether any of the environmental scenarios assumed CCUS would be required to keep a combined cycle gas turbine on line.

    - No, CCUS is not included in the NIPSCO portfolio analysis based on what was received from the RFP. However, as discussed in the May stakeholder meeting, it is possible that CCUS will be a viable long-term decarbonization option throughout the market. In addition, NIPSCO plans to document a potential CCUS option on the Sugar Creek plant in the IRP report section on emerging technology.
- What life is assumed for the capital related to the Sugar Creek update?
    - We assume a 30-year life, meaning that capital would be spread over 30 years for modeling purposes in accordance with revenue requirement accounting principles.
- What is the term of the capacity contracts?
    - Both thermal contracts are 10 years.
- I assume "SC Electrolyzer Pilot" is not a reference to a synchronous condenser, can you explain?
    - Yes, it is the Sugar Creek electrolyzer pilot. This was a 20 MW electrolyzer pilot bid into the RFP, with costs only associated with the electrolyzer. NIPSCO would have to acquire the electricity to electrolyze water into hydrogen, which would be burned at Sugar Creek. This option was effectively "forced into" Portfolio 7H. Note that the appendix includes details on assumptions for hydrogen-related costs over the long-term.
- A net present value ("NPV") analysis is not a proxy for rates. At least one other utility is now providing both an NPV and a rate impact analysis. Why not provide both?
    - Using planning-level analysis from an IRP to calculate specific customer rates by class is difficult. The NPV is a good metric, and it is based on annual revenue requirements. NIPSCO is willing to share annual revenue requirements and sales obligations, as a proxy for overall generation rates as was done in the last IRP.
- Why did you not consider retirement of Michigan City in 2025 instead of 2024? Would that be possible? Rather than consider a portfolio that is not viable?
    - The answer is the same whether it is 2024 or 2025. Transmission project completion is key, and the delta in costs between Portfolio 3 and 4 is very small anyway. 2024 was a good bookend (as soon as possible without transmission or replacement capacity considerations), and 2026 was the next window that was viable.
- Follow up on rates- customers pay bills not rates and comparing rates alone will make any activity that reduces sales look more expensive even if bills are cheaper.
    - That's a fair point, and once you layer in things like demand side management which change customer usage, the simple revenue requirement divided by sales metric may not be the best comparison.
- This discussion should be continued. Difficulty in calculation is not sufficient to not consider.
    - The difficulty is focused on translating planning-level financial modeling to specific rate structures by class. However, NIPSCO would be happy to have a one-on-one to facilitate continuing that conversation and is able to provide annual revenue requirement details so that stakeholders can assess costs over time in different ways.
- It seems like the difference between Portfolio 6 and 7 is largely driven by the "fossil free by 2032" constraint and not so much the difference in Michigan City 12's retirement date. Could you also run a variation on Portfolio 7 that retires Michigan City 12 in 2026 given that your other portfolios are showing a benefit to that earlier retirement date?

    - Yes, that has actually been done in the replacement analysis phase. Since Portfolio 3 (2026 retirement was lowest cost), NIPSCO took that and built out several more concepts, including one very similar to Portfolio 7. That will be covered in next section of the presentation.
- Why are you continuing to use a 30 year NPV when the industry norm is 20 year NPV, not to mention the high uncertainty in years 21-30.
    - The industry norm is not necessarily 20years, as utilities often look at longer term NPVs. It is also important to note that the fundamental modeling period (with fundamental forecasts for fuel costs, carbon costs, power prices, and plant dispatch) is 20 years, with the last 10-year period being an end-effects extrapolation on variable costs, with all financial treatment of rate base accounting extended through the full 30 years.
- Why are carbon dioxide (“CO2”) emissions so much higher for 7H?
    - The CO2 emissions on the scorecard represent the average across all four scenarios. In two of the four scenarios, it will likely to be more economic for Sugar Creek to burn more natural gas than hydrogen, so Portfolio 7H is effectively the same as other portfolios that retain Sugar Creek in those cases. In addition, Portfolio 7H also retains Michigan City until 2028, so it has higher emissions associated with that plant than other portfolios that retire Michigan City earlier. There is an appendix slide with annual trajectories of CO2 emissions for all portfolios across all four scenarios that provides more detail.

Replacement Analysis
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, CRA

Mr. Gomos introduced the core questions and key decisions in the replacement analysis, the second part of the two-step IRP analysis. Mr. Gomos illustrated the expected supply-demand outlook following future resource retirements and shared the replacement concepts developed across frameworks assessing differing levels of emissions and dispatchability. He explained that this framework drove the development of nine replacement portfolios, noting that resource combinations were constructed based on RFP projects. Mr. Gomos then transitioned to Mr. Augustine who provided an overview of the specific installed capacity additions in each of the nine portfolios, along with summer and winter supply-demand balance summaries. Mr. Augustine then walked through cost to customer results and observations across each of the four scenarios. Mr. Augustine also discussed stochastic results across the nine portfolios and the changing risk profile of different resource options over time. He then shared the replacement analysis scorecard framework and results. Mr. Augustine provided a detailed review of portfolio level observations and transitioned back to Mr. Gomos to discuss overarching replacement analysis observations. Mr. Gomos then pivoted to NIPSCO’s approach to reliability in the IRP and shared that reliability will be discussed in more detail in the upcoming October 12 Technical Webinar. As part of that discussion, Mr. Augustine introduced the sub-hourly ancillary services analysis that was performed and that will be reviewed in more detail on October 12.

Participants had the following questions and comments, with answers provided after:

- Regarding slide 40, I'm not sure I totally follow how you went from optimized portfolios with overall similar NPVRRs (on slide 27) to now portfolios that are mostly more expensive than those optimized portfolios. Similarly, now the portfolio with the combined cycle (“CC”) is the lowest cost, but a CC was not picked at all in the optimized portfolio, I do not understand that either. And it may be that looking at the modeling files would be the easiest way to unpack that.

    - NIPSCO is happy to share portfolio construction details and outputs so that you can review further. Regarding the first part of the question, these replacement portfolios are based on the same mix of resources optimized from the existing fleet analysis, but as was done in 2018, the long-term generic build-outs are specifically set to a split of purchased power agreements ("PPAs") and owned resource options, while the existing fleet analysis was based solely on extrapolated costs for PPAs. NIPSCO has typically found that on a pure cost to customer perspective, PPAs are slightly lower cost than owned assets, so this is why the long-term mix of owned and PPA resources results in slightly higher NPVRRs than the existing fleet analysis with only PPAs. With regard to the second part of the question, the CC portfolio violates the net sales energy constraint that was enforced in the existing fleet analysis. In the replacement analysis, we have allowed that constraint to be violated to specifically test a CC theme. As you will see, this portfolio is net long in the energy market and thus subject to significant scenario-based cost risk.

- Why does utility ownership raise the costs? Is this based on bids from developers or other factors like tax credit normalization?
    - In this RFP and in the past, NIPSCO has found that ownership has a slight cost premium to PPAs based on RFP bids, although there are other considerations that NIPSCO also looks at when evaluating owned vs. PPA resources. With regard to normalization, tax credits are assumed to be monetized through tax equity partnerships, which avoid utility normalization issues.
- Portfolio A meets reserve margin. Why is it cited as non-viable?
    - Portfolio A meets the summer PRM and just barely meets the winter reserve margin in the graphic shown on the slide for 2027 (slide 39). However, over time, the portfolio continues to add more solar than storage and thus does not meet the winter reserve margin, given winter load growth expectations and other portfolio changes. There is an appendix slide for 2040 that illustrates this.
- Repeating the comment "The importance of flexibility cannot be understated." Is the value of flexibility explicitly considered in these portfolios? Any consideration of small nuclear reactors ("SMRs")?
    - Flexibility is important, which is why NIPSCO considers multiple options for evaluation and assesses different scorecard metrics including one around commitment duration of the portfolio. With regard to SMRs, because the Company is constrained to the universe of RFP bids and because no SMR bids were received, they have not been explicitly evaluated. However, that does not preclude them from being long-term options as NIPSCO performs additional IRPs in the future.
- Why are you constrained on resource options to the RFP?
    - NIPSCO wants bids that can be transacted against as part of the Action Plan that comes out of the IRP. Although additional diligence needs to be performed, and although NIPSCO may run additional RFPs in the future, RFP data provides a level of commitment with somewhat binding prices and collapses uncertainty. When you introduce concepts like SMR, there is not real-world pricing that can be relied upon. However, as noted, it could be a resource in the future, and the 2021 IRP will not lock-in all future resource decisions for the next 20 years.
- Since we're talking about dispatch of resources 19 years down the road, can you also perform this analysis with flow batteries and multi-day storage?

    - We did not get a lot of bids in the RFP for such technologies, although a few conceptual offers were introduced for long-duration storage. In some sense, Portfolio I with hydrogen picks up the value of long-duration, highly dispatchable clean energy technology. In addition, storage technology is likely to evolve and inherent in that question is the theme of flexibility, so that as new technologies come forward, NIPSCO can take advantage of them. This means that the Optimized Portfolio concepts over the long-term that are developed now in 2021 do not imply that NIPSCO's preferred portfolio will be locking in such additions. Instead, as technology evolves, the Company can continue to assess it.
- Well said, that's exactly what I wanted to say. I wouldn't expect these technologies to show up now for an online date 19 years down the road.
- Why is Portfolio A considered higher carbon compared to D and E mid-carbon when all 3 have the same average carbon emissions?
    - Portfolio A has thermal PPAs, so within its dispatchability category, it was considered more carbon-intensive than the others. However it is a fair question, since these thermal PPAs are not energy resources, but simply provide capacity from thermal plants might have higher carbon emissions in the wider MISO market.

Analysis Next Steps
Erin Whitehead, Vice President, Regulatory and Major Accounts, NIPSCO

Ms. Whitehead, Vice President, Regulatory and Major Accounts for NIPSCO, closed the session by thanking attendees for their participation and feedback. She then outlined key next steps in the IRP process and invited participants to reach out for one-on-one discussions.