Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #3
SUMMARY

July 13, 2021

Welcome and Introductions

Ms. Alison Becker, Manager, Regulatory Policy opened the virtual meeting by providing a safety moment on Parking Lot Safety and discussing the Webex meeting protocols. She then introduced Mike Hooper, President and Chief Operating Offcer of NIPSCO to kick off the meeting.

Mr. Hooper welcomed participants and thanked them for the level of participation, noting this was the third meeting with over 100 participants registered. Mr. Hooper thanked the numerous bidders and the robust response to NIPSCO's 2021 request for proposals ("RFP"). He then discussed NIPSCO's progressing generation transition plan, project construction, and progress on the renewables projects filed with the Indiana Utility Regulatory Commission. He discussed the next steps for the 2021 IRP – integrating the RFP results into the analysis, portfolio modeling to analyze all options, and directional results, which will be discussed at the next stakeholder meeting in September. Ms. Becker then reviewed the agenda for the day.

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 key planning considerations. He discussed the Stakeholder Advisory Meeting Roadmap and reminded participants of NIPSCO's Resource Planning Approach. He then outlined RFP and portfolio modeling progress since the last meeting and fielded participant questions.

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

- Does the reference to "portfolio optimization" mean that NIPSCO will use Aurora's portfolio optimization tool?
    - Yes, if you go back to slide 10, you see there are a number of models, but Aurora is the main dispatch and portfolio optimization tool used in the modeling. The portfolio optimization function will be used for portfolio development, but standard dispatch mode is also used during the scenario and stochastic analysis.
- As a follow up, is it correct that the Portfolio Optimization in Aurora relaxes the integer constraints on new resources? Just trying to understand why Portfolio Optimization would be used instead of long-term capacity expansion ("LTCE").

    - The primary reason for the use of the portfolio optimization functionality is run time and efficient integration with the portfolio calculation tool. It takes market prices as an input, so instead of solving against load like the LTCE does, the portfolio optimization functionality solves much faster.
- So NIPSCO cannot dispatch against price using LTCE?
    - It can by setting up the model in a different fashion, but the portfolio optimization tool performs the same functions as LTCE and is better integrated with the other portfolio analysis that will be performed. We would be open to discussing these details further in a one-on-one meeting.

Developing the Demand Side Management ("DSM") Study
Alison Becker, Manager, Regulatory Policy, NIPSCO
Jeffrey Huber, Managing Director—Energy Efficiency, GDS Associates, Inc. ("GDS")
Patrick Augustine, Vice President, Charles River Associates ("CRA")

Ms. Becker provided an initial overview of NIPSCO's history implementing energy efficiency and demand programs, and coordination with the NIPSCO Oversight Board ("OSB") on both the implementation and evaluation of these offerings.

Ms. Becker then discussed the role of a market potential study ("MPS") to assess the future of energy efficiency and demand response ("DR") savings and provide DSM inputs for NIPSCO's IRP. NISPSO worked with GDS to develop the MPS.

Mr. Jeffrey Huber, Managing Director – Energy Efficiency, GDS, reviewed the types of potential estimated in the MPS. GDS assessed potential at the following levels: technical potential, economic potential, and achievable potential. GDS assessed two types of achievable potential: maximum achievable potential ("MAP") and realistic achievable potential ("RAP").

Mr. Huber reviewed two key inputs into the MPS: the NIPSCO load forecast and market characteristics data. He also provided an overview of the primary market research conducted to better inform the MPS and allowed GDS to disaggregate the commercial and industrial sales forecast into building/industry type and by end-use. The market research also helped to inform expected technology adoption rates for assessing achievable potential.

Mr. Huber then reviewed the results of the MPS. Technical and economic potential for energy efficiency was estimated to be 34% and 33% of NIPSCO sales in 2043, respectively. Similar levels of technical and economic potential suggest that nearly all measures were found to be cost effective under the Utility Cost Test ("UCT"). Maximum achievable is 23% of NISPCO sales in 2043, and realistic achievable was estimated at 16% of NIPSCO sales in 2043. GDS reviewed the potential savings by end-use, overall MAP and RAP benefits and cost, as well as the levelized cost per kWh for each sector.

Mr. Huber reviewed the results of the DR potential analysis. He noted that future potential appears less than prior assessments of DR potential because Rate 831 (large industrial customers) interruptible loads are no longer part of NIPSCO's load obligation and DR portfolio. The current DR analysis focused on residential smart thermostats, residential electric water heaters, residential and small commercial and industrial ("C&I) dynamic rates, and medium and large C&I load curtailment.

Like the Energy Efficiency Potential assessment, the DR Potential analysis screened for cost-effectiveness using the UCT and looked at both MAP and RAP. The 20-year RAP potential is roughly 57 MW of DR, and the 20-year MAP was 136 MW of DR Potential. In both RAP and MAP, large C&I load curtailment is the program with the highest DR Potential.

The DR Potential analysis performed a sensitivity analysis using an alternate avoided cost of generation assumption. The base avoided cost of generation capacity was based on a natural gas combined cycle unit. The alternate avoided cost scenario assumed a combustion turbine unit and a reduced avoided cost. The alternate avoided cost reduced RAP and MAP by 26% and 28% respectively. Mr. Huber noted that the energy efficiency analysis also considered the alternative avoided cost scenario, but that the overall impact on the future potential was negligible.

Following a review of the MPS results, Mr. Huber discussed how the results of the MPS were used to create the DSM inputs for the IRP. Based on coordination between GDS, CRA, NIPSCO, and the NIPSCO OSB, GDS provided DSM bundles for IRP modeling based on aggregate potential at the sector level. The IRP DSM inputs were informed directly by the MPS with a few minor adjustments.

Mr. Patrick Augustine, Vice President at CRA, then presented a summary of how the energy efficiency and demand response bundles would be modeled in the portfolio analysis phase. He explained that 12 total EE bundles were developed by GDS across three discrete time periods (2024-29, 2030-35, 2036-41) and across four different categories (two residential bundles, one C&I bundle, and one bundle for income qualified weatherization). He noted that the costs for the bundles would be assessed in the program years, with savings persisting over time. Mr. Augustine then displayed the three DR bundles, broken into residential, C&I, and rates categories.

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

- Thanks for a very great process at the Oversight Board ("OSB") level. The Citizens Action Coalition of Indiana, Inc. ("CAC") would be interested in talking to NIPSCO more about third party aggregators to get participation from the medium/small commercial and industrial customers in interruptible tariffs. The former interruptible tariff was a good example.
    - NIPSCO and the CAC agreed to schedule a one-on-one.
- What is the knowledge of installers regarding incentive rates and general awareness of programs?
    - As part of the process, GDS looked at additional market research, including JD Power, and there was not a consistent awareness factor across the board (different awareness types for small business vs non-small business). However, based on feedback, installers are aware of the programs.
- What drives the jump in residential costs from $0.075 in the realistic achievable potential ("RAP") scenario to $0.174 in the maximum achievable potential ("MAP")?
    - The incentive increases all the way to 100% of measure cost, driving the cost up.
- Please elaborate on the 2030 rate program?
    - That is a critical peak pricing program. Under such a rate program, a customer enrolled would face a lower rate during off-peak hours, but would face a much higher rate on certain peak days/hours based on a defined pricing structure.

Customers would be expected to shift usage out of peak times to save costs, which under this scenario would be the default tariff for residential customers. It is important to note that this is only a study at this point, and NIPSCO has not made any final decision on such a rate program. For RAP, the program is voluntary, but for MAP, the tariff would be default, with an ability to opt-out.

- If these bundles are going to be modeled with the integer constraints on them relaxed, would it not make more sense to condense the potential into all RAP (less Income Qualified Weatherization ("IQW") and all MAP (less IQW)? This is because the model could take a partial of amount of each bundle under linear optimization.
  - NIPSCO can consider this, although residential and commercial & industrial programs are generally considered somewhat separate. Note that the three time periods were designed to allow for the potential for different bundle selection amounts over time. We can also discuss this further during a one-on-one.
- Regarding slide 48, what is the optimization period? If it goes beyond 2041, will you not have an end-effects issue if the assumption is that no new energy efficiency occurs after 2041?
  - The optimization period will run out a full 30 years, including the end effects period. The DSM bundles will be modeled on a levelized cost basis to account for all costs and benefits and to keep all resource options on an equal footing.
- Did the market potential study consider possible opportunities for commercial and industrial customers to reduce electric usage with combined heat and power ("CHP") projects?
  - The MPS did not include CHP as a resource.
- The CAC would like to talk to you about extending EE through 2050. That is really important because the IRP will not capture the totality of the end effects issue otherwise.
  - The analysis only incorporates specific programs through 2041, but it does account for all savings for those programs through 2050 and beyond in the optimization. We can certainly discuss this further in a one-on-one.
- Will you model the avoided costs that cannot be explicitly represented in the IRP as reduction in costs to the DSM bundles, such as avoided transmission and distribution ("T&D")?
  - Avoided T&D costs are accounted for in the DSM screening and will be accounted for in the portfolio analysis phase. For example, on slide 38, the stacked bar of avoided costs associated with T&D (~$30 kW/year) will be included in the calculation of benefits. GDS will work with CRA to ensure that these savings are appropriately captured as offsets in the Aurora modeling, and we can review this further in a one-on-one setting.

Supply-Side Distributed Energy Resource ("DER") Considerations
Pat Augustine, CRA

Mr. Augustine introduced the section on supply-side DER options by providing an overview of how utility planning is evolving with regard to the interactions between generation planning and transmission and distribution planning. He summarized the interactions that NIPSCO accounts for in its planning work and noted that the 2021 IRP is including an explicit consideration of supply-side DER options due to declining technology costs and regulatory developments such as FERC Order 2222. He noted that NIPSCO would be evaluating DER options as supply-side options on equal footing with DSM and RFP resources, incorporating key considerations such as DER project costs and deferred T&D investments. Mr. Augustine then outlined NIPSCO's approach to identifying DER options and summarized the three supply-side DER bundles for use in the IRP. These bundles included solar and storage capacity and a net present value calculation of deferred distribution system investment that would be netted off of resource costs in the portfolio analysis.

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

- Thanks for putting the effort into thinking about how to better capture supply-side DERs. Can you share the analysis?
    - Yes, NIPSCO can share much of the analysis, which includes details on the distribution-level locations which were analyzed.
- What will the operating profile of the hybrid systems look like on the generation side of the resource offered?
    - There is unlikely to be a consistent ratio of solar and storage pairing across all DER sites. From a modeling perspective, the bundle summaries show that a certain amount of solar and a certain amount of battery storage will be analyzed together. The storage components will be allowed to dispatch optimally to meet peak requirements and take advantage of energy arbitrage opportunities.
- Is NIPSCO actively building out utility scale projects?
    - The short answer is yes. Slide 86 shows the projects that came out of the 2018 IRP and NIPSCO's two previous requests for proposals. These include wind, solar, and solar plus storage projects.

2021 RFP Results Overview
Andy Campbell, Director, Regulatory Support and Planning, NIPSCO
Bob Lee, Vice President, CRA

Mr. Andrew Campbell, Director of Regulatory Support & Planning for NIPSCO, opened the discussion on the results of the 2021 RFP. He summarized that NIPSCO's latest RFP solicitation garnered a robust response with more than 30 bidders submitting offerings for consideration by NIPSCO. Before turning it over to CRA to review the initial results, he noted that the information at this point is informative and preliminary and that there will be no conclusions until the conclusion of the IRP process

Mr. Bob Lee, Vice President at CRA, then summarized the responses to the 2021 RFP. He noted that the RFP responses generated 182 proposals spread throughout Indiana, Illinois, Kentucky, Missouri, and MISO with the overwhelming response centralized in MISO Zone 6, which encompasses Indiana and part of northern Kentucky. The RFP generated just over 15 GW (installed capacity, or "ICAP") of projects and proposals from those projects covering over 32 GW (ICAP). Mr. Lee also summarized preliminary average costs within the RFP bids. He concluded by informing the meeting attendees that the RFP asset tranches have been shared with the IRP team at CRA and that the bid evaluation phase is expected to be complete in late August followed by the possibility of definitive agreements thereafter dependent on the outcomes of the 2021 IRP preferred portfolio.

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

- Two questions related to Michigan City. Will the coal ash on the lake stay there indefinitely? Has NIPSCO read the recent report on the Great Lakes, and will the Company use it in making decisions related to the closure at Michigan City?
    - NIPSCO is coordinating with the Indiana Department of Environmental Management regarding the Michigan City plant's plan to close the ash pond and remove the coal ash after retirement. The ash will be extracted and taken down to the landfill at the Schafer location. This will be done in compliance with the United States Environmental Protection Agency ("EPA") rule that oversees all facilities. It was requested that the individual asking the question send a copy of the referenced report.
- For thermal, is the purchase power agreement ("PPA") $/MWh $0.36/MWh or $36/MWh?
    - It is $0.36/MWh for only the variable operations and maintenance ("VOM") cost components specified in the bids that are aggregated here. Note that fuel and emission costs are generally assumed to be separately passed through to NIPSCO and would be *additive* to this VOM when the portfolio modeling is performed.
- I understand now that a lot of operating costs are excluded from the $0.36/MWh for thermal. With that said, is there an apples-to-apples way to compare thermal to other sources? Can thermal be expressed as $/MWh as well?
    - It would be hard to do that for thermal bids. You would need to make a lot of assumptions around natural gas prices and future emission costs. In addition, a $/MWh price is sensitive to plant heat rate, market prices for energy, and other factors. Such analysis will be performed in the IRP modeling when it establishes the preferred portfolio.
- What kinds of technologies are in the "other" category? Are those the same as the emerging technologies you mentioned earlier?
    - No, they tend to be system power arrangements and are sometimes not tied to an individual facility. So it is a "catch all" category for bids like these.
- Is there a plan in place to reach out first to hosting coal plant communities with clean job opportunities as part of environmental reparations? Also The NAACP is requesting a carve-out for community owned solar. Is that a foreseeable possibility?
    - NIPSCO would be happy to have a one-on-one with the NAACP to discuss options for community solar. Please reach out to Alison Becker (abecker@nisource.com) to set up a meeting. Regarding the jobs created, that is considered both as part of reviewing the RFP responses as well as throughout NIPSCO's Your Energy, Your Future initiative. The Company is happy to continue conversations.
- Can NIPSCO elaborate on what you were referring to by "emerging technologies"?
    - This primarily includes hydrogen-enabled thermal resources. This is a new emerging area that NIPSCO wants to consider, and the Company also wants to cast a wider net around other developmental technologies, including storage options or small scale nuclear. While we did not get bids for all types of potential emerging technologies, the outreach is allowing NIPSCO to start discussions with developers for further consideration. While some bids in this area are not actionable, they may be considered for long-term portfolio modeling, particularly for managing carbon risks.

- Does the pricing provided by respondents include the cost of any required MISO network upgrades as a pass through cost to NIPSCO? Did NIPSCO require respondents to estimate their own network upgrade costs if the respondent didn't already have those reported by MISO?
    - The RFP did ask bidders who they are assuming is responsible for interconnection costs, and the bids fall into three categories: developers are on hook for all costs, which are included in their price; a cap on such costs is included in the bid, and higher costs might trigger adjustments to pricing; and the third assumes that NIPSCO will be responsible for all such costs.
- How will NIPSCO's assets/portfolio concept be impacted in terms of redevelopment opportunities if toxic coal ash is allowed to sit indefinitely on the lake front at the Michigan City Generating Station? How valuable will that property be for redevelopment if the coal ash remains in place?
    - The coal ash will not remain in place, as noted earlier. The other questions fall into the realm of how changes in the portfolio will impact property tax, employee base, etc. The Company is in compliance with all environmental issues at Michigan City, and there is no threat to human health from the facility as it stands. However, we have noted that NIPSCO has more actions to take, and no final decisions on the plant's future have been made.
- What is your plan for revitalizing the Michigan City Generating Station once it's closed?
    - No decisions have been made on that yet.

Incorporating RFP Results into the IRP
Fred Gomos, NiSource
Pat Augustine, CRA

Mr. Gomos began the section with an introduction of how the RFP results inform the IRP analysis. He outlined how NIPSCO will be performing both an existing fleet analysis and a replacement analysis using detailed information from the RFP. He then introduced Mr. Augustine, who provided the rationale for why individual RFP bids are organized into tranches for portfolio modeling. Mr. Augustine then outlined NIPSCO's three step process for analysis, which included (i) tranche development, (ii) portfolio optimization, and (iii) portfolio modeling.

Mr. Gomos then transitioned to a review of NIPSCO's assessment of reliability in the 2021 IRP, including the focus on resource adequacy, energy adequacy, and operating reliability. He described the way that NIPSCO evaluates each of these elements in the IRP portfolio analysis, and Mr. Augustine then provided a detailed overview for how NIPSCO will quantitatively assess real-time energy and ancillary services value at a five-minute level of granularity in CRA's Energy Storage Operations (ESOP) model. Mr. Augustine then noted that not all reliability metrics can be captured in economic analysis, and Mr. Gomos closed the section with a review of how NIPSCO is planning to perform additional reliability analysis on six specific criteria. He noted that NIPSCO is open to stakeholder feedback on the topic and will be engaging a qualified consultant to develop scoring methodology utilizing the metrics identified for individual technologies and in aggregate on a portfolio level and score and rank various generation resource technologies bid into the RFP across these metrics.

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

- Can you talk more about how the analysis will measure energy market risk exposure?

    - Risk metrics will come out of the scenario and stochastic analysis, and when NIPSCO eventually gets to the scorecard, it will include measures of uncertainty and tail risk. Energy market risk exposure will not be a standalone metric, but the uncertainty analysis, particularly the stochastic component, will evaluate hourly portfolio costs, including exposure to the energy market. Different portfolio constructs will have different exposure.
- Will the metric be annual sales/purchases or will it look at particular seasons or conditions?
    - The risk metrics will be summarized on an annual basis, although more granular portfolio analysis data will be available and will ultimately be driving the annual summaries. There is no defined metric at the scorecard level for seasonal sales and purchases, since such risk exposure is captured in the broader uncertainty metrics.
- Will the Real Time ("RT") and ancillary services ("A/S") value of flexible resources from ESOP then be a reduction in their cost for purposes of use in Portfolio Optimization or just to reduce the present value of revenue requirements ("PVRR")?
    - The RT and A/S values will be incorporated as a reduction in the cost of relevant resources (such as storage or flexible thermal resources) in the portfolio optimization and full portfolio analysis phases of the IRP. This will then be rolled into the full PVRR analysis.
- Do you have a list of resources to meet these criteria?
    - No, we haven't established a full list of resources that meet these criteria. However, we will be looking at specific resource types that participated in the RFP and we will be engaging a third party reviewer to support this task.
- For Ancillary services, can they provide the list for them to provide feedback?
    - Yes, spinning reserve and regulation (both up and down, which is a combined product in MISO) will be evaluated in this exercise.
- Is NIPSCO planning to stratify resources by service provided?
    - It is not binary, as some resources have the ability to provide multiple attributes for energy and ancillary services, as well as other reliability values. The analysis will look to incorporate that, so in some sense there is some level of stratification to ensure all value attributes are accounted for.
- It is possible that some of the reliability services you've outlined may not be needed at all or under certain conditions, meaning that they may not actually provide value to ratepayers. For example, grid-forming inverters are coming quicker than realized and they may provide some of these services. In addition, it's not clear why Automatic Generation Control ("AGC") is necessary when NIPSCO is in MISO. Finally, the need for some of these ancillary services can get saturated very quickly. One concern is that you're ranking portfolio options against criteria that may not be always needed.
    - We certainly agree that the space is moving fast, and this is why we want to get someone who is familiar with the details to review our metrics and scoring. The Company also wants to be sure that it is not assessing things that are not applicable. MISO is dynamic and will continue to evolve, but what NIPSCO is trying to do here is recognize that there are MISO products, NERC standards, and required compliance plans to ensure reliability under a variety of system conditions. For example, there are normal market mechanisms that will likely not be available during a blackout condition, so NIPSCO needs to ensure resources would be in place to maintain grid stability. These factors are critical considerations as we retire Schafer and Michigan City, so while looking at

    - resource replacements, we want to make sure we have resources that provide needed services under normal conditions and during emergency conditions.
- What voltage are Schahfer Units 16AB connected to?
    - Units A & B are connected to the 138 kV system.
- Could you please discuss assumptions for Largest Single Hazzard ("LSH") evaluations? Are there any special considerations in selection criteria for this future heavily intermittent weighted portfolio?
    - The Company does not have an answer at this time, but we will consider this question when reviewing reliability criteria further.
- Are these assessment criteria going to be used to evaluate whether or not a resource should be included or will it be used to assess a portfolio of resources after the fact to see whether these criteria are met given the overall mix of resources in the portfolio that was modeled?
    - This is evolving, but the Company wants to perform this review on a portfolio basis. Individual resources will be scored and the impact on a full portfolio will be assessed. We don't intend to eliminate any resources from consideration as part of this process, but use it to score a range of candidate portfolios.

Wrap Up and 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.