Northern Indiana Public Service Company LLC
2024 Integrated Resource Planning
Public Advisory Meeting #1
SUMMARY

April 23, 2024

Welcome, Safety Moment, and Kick Off
Tara McElmurry, Communications Manager, NiSource

Tara McElmurry opened the in-person and virtual meeting by discussing the meeting protocols and walking through the agenda. A safety moment was then provided by EJ White, Project Consultant, NiSource, related to fire safety. Ms. McElmurry then introduced Vince Parisi, President and COO of NIPSCO, to kick off the meeting. Mr. Parisi shared his personal background along with a general overview of NiSource, NIPSCO's profile and ownership structure, and the company's ongoing generation transition plan.

NIPSCO Integrated Resource Planning (IRP) Process Overview / Developments since the 2021 IRP / Environmental Policy Review
Fred Gomos, Director Strategy, NiSource; Pat Augustine, Vice President, Charles River Associates ("CRA"); Stephen Holcomb, Director Environmental Policy & Sustainability, NiSource

Fred Gomos began with an overview of NIPSCO's IRP process, which is conducted every three years and outlines the company's long-term plan to supply electricity to customers over the next 20 years. The objectives that NIPSCO focuses on during the IRP process include reliability, sustainability, flexibility, diversity, and affordability; while considering company employees, environmental regulations and market rules, and the local economy.

NIPSCO will follow the same five-step process that it used during its 2018 and 2021 IRPs. First, the company identifies planning objectives and key questions. Next, NIPSCO develops market perspectives (scenarios) to determine what could be happening in the markets within which we operate. Third and fourth, NIPSCO develops Integrated Resource Strategies (NIPSCO Portfolios) and then analyzes these portfolios with market, financial, and risk models. Finally, NIPSCO evaluates tradeoffs and then selects its preferred plan. Emerging issues for 2024 include MISO market evolution, environmental policy, and emerging load trends.

Mr. Gomos then presented a slide featuring Indiana's five pillars of electric generation long-term planning. These pillars came out of the Indiana 21st Century Energy Task Force, which was created as a result of the passing of House Enrolled Act 1278. The five pillars are Reliability, Resilience, Affordability, Stability, and Environmental Sustainability, which are consistent with the criteria NIPSCO uses for resource planning decisions. He then passed things over to Pat Augustine to present on ongoing MISO market developments and federal policy changes.

Mr. Augustine began by speaking about some of the significant changes happening at MISO, including how the resource mix is driving new resource adequacy challenges. He walked through MISO's Reliability Imperative, which describes the shared responsibility of MISO and its members to ensure reliability in the MISO region. In 2023, MISO implemented a four-season capacity construct, with obligations and resource accreditations varying by the four seasons across the MISO Planning Year. In 2025, MISO plans to implement a "downward sloping" reliability-based demand curve to value capacity across a range of reserve margin levels. Finally, MISO filed its Direct Loss of Load ("D-LOL") market design proposal with FERC in March 2024, which focuses on performance during tight margin hours, for implementation in 2028.

Next, Mr. Augustine provided a summary of how NIPSCO's 2024 IRP will evaluate the potential impacts associated with D-LOL implementation. He mentioned that accreditations will likely change and that NIPSCO's obligation is likely to decline, but the magnitude of the decline is still uncertain. He noted that this is not a wholesale change to MISO's planning process, but it does make tracking supply and demand more complicated and creates more uncertainty. MISO's D-LOL filing still needs approval from FERC and stakeholders have raised several questions and concerns. NIPSCO will discuss this topic further in future IRP stakeholder meetings.

Mr. Augustine then provided a summary of the Inflation Reduction Act (IRA), which was signed into law in August 2022, and some of the impacts it has had on NIPSCO's business thus far. Changes to the Production Tax Credit (PTC), Investment Tax Credit (ITC), and the new Hydrogen PTC (up to $3/kg) have all been items that NIPSCO has taken into consideration for business planning in recent years.

Finally, Mr. Augustine discussed bonus tax credit opportunities arising from the IRA. He summarized the Energy Community locations that exist in Indiana and discussed how NIPSCO is currently taking advantage Energy Community incentives for existing projects. He then presented the potential Low-Income Economic Benefit Projects (LIEBPs) opportunities that exist in Indiana and how NIPSCO may evaluate the potential of each. He then handed the presentation over to Stephen Holcomb to discuss environmental policies.

Mr. Holcomb began by covering EPA's proposed Clean Air Act Section 111(b) and 111(d) rules associated with greenhouse gas standards and guidelines for fossil fuel-fired power plants, which were published in the Federal Register on May 23, 2023. This rule is expected to be finalized by EPA this Spring and will be incorporated in NIPSCO's IRP analysis.

Mr. Holcomb then discussed how current environmental regulations are impacting NIPSCO's portfolio operations and planning. NIPSCO's coal fleet remains in compliance with several key environmental regulations, including Effluent Limitation Guidelines (ELG), the Coal Combustion Residuals (CCR) Rule, Mercury and Air Toxics Standards (MATS), and the Good Neighbor Rule. Retiring Schahfer Units 17 and 18 by 2025 will allow NIPSCO to avoid the significant capital costs needed to comply with some of these federal regulations.

Finally, Mr. Holcomb walked through a slide that shows NIPSCO's current progress in meeting environmental improvement targets, as well as progress toward 2030 environmental goals, mainly through the retirement of NIPSCO coal units by 2028. Also, in 2022, NIPSCO furthered its commitment to sustainability by announcing a 2040 Net Zero Goal for greenhouse gas emissions.

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

- Do I understand correctly, that the direct loss of load method, is going to be changing the accreditation on an annual basis? And so each year, MISO is looking to recalculate each resource and the capacity value that it is providing, and this is done after the fact? Do you know in advance when those tight hours are going to be for a year?

  - Yes, that is generally correct. The way it will work is that MISO is going to look at the capacity contribution of classes of resources during times of stress, and different resource classes will be awarded different accreditations. This will be done on a forward-looking basis, assessing the times of greatest risk through stochastic probabilistic modeling, drawing from historic weather years, load outcomes, wind availability, solar availability, and fuel thermal unit outages; based on the times of stress that are identified. MISO will then allocate a capacity accreditation to solar resources for the summer, fall, winter, and spring, then do the same thing for wind, gas, storage, etcetera. On top of that, once MISO has determined a class-level accreditation, MISO will go back and look at historical performance of actual units and then divvy up that class-level allocation to the specific units in each class. So although you will have advance information regarding class-level accreditation trends, you're not going to know well in advance how specific units performed to be able to plan with absolute certainty what capacity accreditation a specific unit will receive. Now, when you've got a new unit, that will get the class-level data until it's got actual historical operating characteristics.

    But as I talk through all that, the main message is that it is complicated and we are going to be evaluating the indicative forward-looking accreditations that MISO has published for what they plan to be the first year of implementation, which will be the 2028-2029 period. There's a transition period every year from now until then, and they will publish these indicative expectations to give market participants a sense of where things are going. And, like I said, this is still in front of FERC and we don't know if it'll be approved or if there'll be modifications, but there will be resource-specific accreditation changes that are going to happen year after year, based on MISO calculations, and based on actual historical performance of units that are within the fleet.

    Note that NIPSCO must operate similarly right now. For example, for the 2024-2025 capacity year, awards were published indicatively by MISO last fall and the actual awards are then made in the spring prior to the auction. Thus, we do have the same general process now, where resource performance over a historical period does dictate accreditation, but it's getting more complicated because of the forward-looking probabilistic assessment that MISO is going to run.

- (Regarding IRA new "bonus" credit opportunities) Do you know if you can get the total 40% bonus credit? Like, can you add them all up?
  - Yes, you can. Slide 21 shows how projects in different regions can get stacked credits for Energy Communities and other benefits, such as the LIEBP program.

- (Regarding EPA's Proposed Rule under Clean Air Act Section 111) Can you remind me of the distinction between an existing unit versus a new unit? Is that as of the date of the rule being published, or is there a different date?
  - The distinction actually occurs when the rule was proposed, which was in May 2023. So this is the date by which a gas unit is considered either existing or new, meaning that if the unit is constructed after May 2023, it will be considered a new unit. So, for example, the Schahfer peaker units that have been proposed will be considered new gas units.

- What is the date for retirement for the Michigan City plant?

- We anticipate the Michigan City generating station to be retired by 2028.

2021 Short Term Action Plan Update / Continuous Improvements for 2024 IRP / 2024 IRP Analytical Framework
Fred Gomos, Director Strategy, NiSource and Pat Augustine, Vice President, CRA

Fred Gomos introduced the section by reviewing the progress made on the 2021 Short Term Action Plan and NIPSCO's Preferred Plan. Mr. Gomos noted Schahfer is on track to retire by 2025 and Michigan City is estimated to retire by 2028.

Mr. Gomos provided a summary of NIPSCO portfolio additions since the 2018 IRP, which showed ~1,000 MW of wind generation capacity and 465 MW of solar generation capacity placed into service. He then reviewed expected in-service dates for approved projects, which include Cavalry, Dunns Bridge II, Green River, Appleseed, Templeton and Carpenter.

Next, Patrick Augustine provided an overview of feedback received during the 2021 IRP and the continuous improvement plan for 2024. Feedback resulted in four major categories, which include load forecast, demand-side resources, portfolio analysis and stakeholder collaboration. Mr. Augustine provided additional detail on each category for improvement, including information about Aurora model licenses, which will allow interested stakeholders to use the modeling files to perform their own analysis.

Mr. Augustine closed the section by providing a preview of the IRP analytical framework, along with an introduction to the scenario constructs that are being worked on, including a Reference Case and Slower Transition, Domestic Resiliency, Aggressive Environmental Regulation, and Accelerated Innovation scenarios. NIPSCO's IRP analysis will use scenarios, special studies and stochastic analysis to perform a robust assessment of risk.

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

- Is it possible for Michigan City to retire sooner with a lot of cleaner energy coming online soon?
  - Michigan City is a large facility and would require sufficient replacement energy and capacity. We do not foresee those units retiring sooner.

- Are there any plans to convert Michigan City to gas?
  - No plans to Mr. Gomos' knowledge.

- Since the end of net metering, we have seen a significant decrease in the investment in distributed generation, what is NiSource or NIPSCO's position on potentially increasing incentives and increasing investment in distributed generation?
  - We have always been supportive of distributed generation, but net metering incentives are driven by state policy.
- Follow-up comment: It is within the company's prerogative to introduce and request approval for a new tariff when the current 15-year feed-in-tariff contracts expire.

- Related to the dispatch model, will the model select buying the energy from the wider MISO market or will it always dispatch NIPSCO resources first?
  - The portfolio model will be integrated with the MISO market so that purchases and sales are made economically. If the cost of an energy purchase is lower than the variable cost of operating a NIPSCO resource, an energy purchase will be made. If NIPSCO has more capacity than its native load operating at lower cost than the market price, energy sales will be made.
  - Note that in the portfolio construction phase, NIPSCO will likely set purchases and

sales constraints to avoid developing portfolio concepts that are overly reliant on market purchases and sales over the long-term.

- Are there some constraints around revenue requirement in the modeling or internally? What is NIPSCO's view of what is an appropriate increase in revenue requirement?
    - NIPSCO evaluates relative affordability across the spectrum of potential portfolio pathways that can be pursued. There is not a specific cost constraint per se, but we look at the need of the portfolio, need of megawatts or types of resources, and then assess the trade-offs across the different portfolios.

- Why was the 30-year NPV selected as opposed to what has historically been done in the 20-year IRP?
    - Although NIPSCO has historically run its dispatch models for 20 years, a 30-year NPV has been a key metric in past IRPs. 30 years is chosen because it reflects an average lifespan of new resources that could be added to the portfolio.

- Is it possible that NIPSCO could add a sixth pillar being equity or environmental justice as part of your scorecard and as part of your metric? Would like to see equity as a part of the scorecard.
    - We are contemplating the net present value of investment in Justice 40 communities this year within the Positive Social & Economic Impacts objective. We are proposing here that we would track investment in those communities in addition to some of the broader system wide economic investment metrics. We are available to talk further with you about other metric ideas if you have any.

- Are you intending to actually produce the stochastic price forecasts based on simulations that you would run for each one of the different load and renewable permutations?
    - That's partially correct. We will be using fundamental market runs to assess the future correlations between load, renewable output, and market prices, and then we'll integrate that into historical analysis of weather correlations for all of the variables. Portfolios will then be evaluated against the distributions of outcomes.

- Are you truly performing an LOLE analysis for NIPSCO? I don't think that is the right term to use, since NIPSCO is in MISO and will not experience direct LOLE and EUE risk based solely on its own resources. It will be important to understand whether NIPSCO is facing market exposure risk during the same times as MISO as a whole.
    - Thank you, that's a fair comment. NIPSCO still believes that a probabilistic reliability assessment will help ensure that we're bringing our fair share of reliability attributes to the table as MISO undergoes significant market reforms. However, you're right that LOLE or EUE risk does not exist for NIPSCO on its own. The modeling techniques are still similar, but we can work on some terminology changes like "forced market exposure" and consider assessing NIPSCO exposure hours relative to MISO risk hours. We can discuss further.

Reference Case Load Forecast
Fred Gomos, Director Strategy, NiSource and Pat Augustine, Vice President, CRA

After a break for lunch, Mr. Augustine presented a major part of the IRP process, which is NIPSCO's Reference Case load forecast. He provided an overview of NIPSCO's forecasting methodology, which is similar to previous NIPSCO IRPs. NIPSCO begins with data gathering to create inputs that then go into the core forecast. Econometric modeling by customer class is then used to create baseline energy and peak load forecasts. Finally, NIPSCO develops various scenarios for the future.

For Distributed Energy Resource (DER) modeling, NIPSCO uses the PenDER model, which considers NIPSCO customer characteristics, economic decision-making, and social interactions to drive projections of the adoption of DER systems by various demographics. NIPSCO is also deploying an EV penetration model with local datasets, with an initial focus on light duty vehicles (LDVs) and medium duty vehicles (MDVs). Next, Mr. Augustine presented a slide about the main drivers of load uncertainty, mapping each of the drivers to the five planning scenarios.

He then went on to describe how NIPSCO determines its core electric sales forecast for Residential, Commercial and Industrial customer groups, saying that baseline customer counts and sales per customer energy forecasts by class are projected with the best-fitting variables. NIPSCO then projects the Reference Case energy sales and consumption by customer class. Mr. Augustine then presented peak load forecasts for the Reference Case, with NIPSCO expected to remain a summer-peaking utility. He then showed the fall and spring forecasts, where the fall load (September specifically) is projected to be much closer to the summer peak than the spring load.

Next, Mr. Augustine dove further into PenDER model key assumptions. These assumptions include avoided costs/revenues, PV costs, customer budget, and payback time. He also walked the group through a summary of other major assumptions that are used in the model. Among residential customers, a total of 80 MW of installed Solar DER capacity is projected by 2045. Among commercial customers, a total of 120 MW of installed Solar DER capacity is projected by 2045. Overall, for the Reference Case, a total of 166 MW of installed Solar DER capacity is projected by 2035, 180 MW by 2040, and 200 MW by 2045.

NIPSCO's next steps for DER analysis include evaluation of DER penetration levels across four alternative scenarios (Slower Transition, Domestic Resiliency, Aggressive Environmental Regulation, Accelerated Innovation) and integrating analysis with the DSM study to assess opportunities for incentives for customer-owned storage installations (i.e., to improve the capacity value of DER resources).

Next, NIPSCO discussed the Electric Vehicles Reference Case. NIPSCO blends a penetration forecast with hourly shapes to capture long-term trends in vehicle growth and charging behavior, while accounting for weather conditions. Mr. Augustine provided an overview of Light-Duty Vehicle (LDV) EV adoption projections, both for sales and registrations. NIPSCO then translates these results to show how adoption rates impact hourly load shapes in the future. NIPSCO utilizes NREL's EVI-Pro-Lite tool to develop hourly shapes, blending profiles to address long-term trends in vehicle type. As EV adoption becomes more widespread, model forecasts will align with changes in charging behavior and charger/vehicle efficiencies. Finally, Mr. Augustine presented a slide showing projected LDV load impacts over time, along with hourly load profile projections in 2030, both for a weekday and a weekend scenario.

Finally, Mr. Augustine walked through slides representing Medium-Duty Vehicles (MDVs), which showed long-term growth projections, in a very similar manner to what was shown for Light-Duty Vehicles (LDVs). MDVs will have a much smaller peak impact over time, compared to LDVs. While overall EV adoption is expected to meet EPA targets in the reference case, EVs have a relatively modest, but growing impact on energy and peaks.

Mr. Augustine closed the section by noting that NIPSCO would next evaluate higher and lower EV penetration levels and perform an additional study on heavy duty vehicle charging in major transit corridors. The team will also be integrating the EV penetration analysis with the DSM study to assess opportunities for managed charging incentives in the LDV segment.

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

- (Regarding drivers of load uncertainty scenarios) So for the domestic resiliency scenario, will that at some point incorporate the increased interest in microgrids? There's a big push all over the country right now, especially for local units of government like police or water departments, in situations where they don't have any power but they have a power system themselves, to keep important, critical emergency services available through microgrids. Do you have any thoughts about including that as part of your discussion?
    - That's a good comment. The Accelerated Innovation scenario is where we've actually contemplated larger microgrid adoption. That's a scenario where we will be mapping larger distributed energy penetration, including around the microgrid theme.

- (Regarding Peak Load Forecast – Four MISO Planning Seasons) I'm just curious, where are you guys putting data centers? Are you considering them as potential Rate 531 customers, or not Rate 531 customers, or are you dropping them in those buckets?
    - Right now they're not in the Reference Case. As we get into the scenario analysis, we're going to have a separate category where we'll call out that data center load. It will likely be in the industrial class, but I think there's some uncertainty about which class and we'll get to that in some of the scenarios and subsequent meetings.
    - Rate 531 was a construct for customers at a certain point in time and there are certain requirements for those customers. Our sense is that as these data center loads show up on the system, that we may have to offer something a little bit different for them, versus steel mills that have their own backup generation and different levels of price sensitivity. I think that there could be potential for other constructs that make sense for those customers. Right now we're assuming that there is new industrial load potential coming onto the system in the scenario analysis, and we will do the analysis based on that.

- Is this projecting a certain amount of Rate 531 Tier 1 load reduction across time, as those customers are expected to step down their Tier 1 load requirements?
    - No, not in the Reference Case, but the step down will be incorporated in the Slower Transition scenario and possibly others. This is still somewhat speculative, as we don't have firm declarations on that yet. So, the Tier 1 load here in the Reference Case is essentially flat. There is some modest decline in all Rate 531 load as we've seen that in the econometric forecast, but we're not stepping down to their minimum takes in the Reference Case.
    - I believe last IRP we had a scenario where we moved Rate 531 off of the system, so we've looked at that as a scenario construct, but it's all speculative at this point because nobody has declared that they're moving off that rate.

- Are you projecting a change in the timing of those summer peaks? Are they shifting later into the evening or anything like that or are you still working on figuring that out?
    - That's a good question. We're in the middle of working on that. I think the biggest driver of that will be the electric vehicle charging. The core profile from just a base customer demand perspective is expected to be pretty constant, but electric vehicles and potential other electrification could shift the net peaks.

- Since NIPSCO is still a summer-peaking electric utility, what is the probability of looking at ways to induce customer-owned DERs to contribute power back into the grid when you need it the most. For example, your PURPA rates reflect seasonality, as well as on peak and off peak, however the normal NIPSCO rates do not address that.

  - We will have some of that specifically integrated into the DSM study. Under current constructs, there is the EDG rate that provides essentially an annual price but through this potential for rate redesign, you could incentivize energy to be offered, or at least avoid self-consumption, at different times of day. So, for example, storage could then be more attractive for a customer. In the DSM study, we will evaluate that further.

- (Regarding the PenDER Model: Summary of Major Assumptions) I've seen a lot of the breakout with respect to solar, but isn't there a lot of CoGen and CHP in your service territory? You've got some large CHP customers and customers on PURPA contracts that you serve. I'm not quite sure where all of that gets incorporated, or is it at all?
  - We pick that up from a load forecast standpoint and I think there is some in the supply/demand balance in the supply stack. We can follow-up on that for the next meeting.

- My understanding is that there's a 1 MW cap on many of the DER resources in the territory. Is there any consideration of making that larger or increasing the cap?
  - No. These are smaller scale residential and commercial customers. To the extent that some larger distributed projects either could participate directly in the RFP or apply for PURPA, I think that's a separate topic from the residential and the commercial DG being summarized here.

- (Regarding the Reference Case inputs) Is this model primarily based on existing market factors and historic adoption? Is it factoring in things like the Solar for All grant, which was just announced yesterday, and then some of the others like not specific tax credits, but specifically grants and financing products that are designed to broaden market adoption and will be implemented in the next several years, permanently from the IRA?
  - The short answer is that some of those are picked up within the scenarios. We are not attempting to model every incentive that might be out there, but the idea is that we want to develop an envelope of outcomes, associated with all-in economic considerations for customers.

- (Regarding Projected LDV Load Impacts Over Time) So, right now, there are 2,000 EVs in the NIPSCO area?
  - Yes, that is the approximate number based on registration data.

- Is NIPSCO going to get into how it plans to help ramp up EV sales? One of the other utilities shows on its website how they're getting into the EV market. So are you going to be doing things to ramp up EV sales?
  - Not directly within the IRP setting. This is a Reference Case that shows a projection for service area penetration, and we'll also be studying a range of potential outcomes. However, there is a state program for EVs and we've been studying how to do something in that space as well. We also did work in our last electric rate case around an EV tariff. We have also deployed eleven fast-charging stations across our territory, which was part of the VW settlement.

- Will you be employing Justice 40 as it relates to where you locate your charging stations? Will you be ensuring that 40% of them benefit disadvantaged communities?
  - The short answer is, yes. We're trying to understand where the demand is, in terms of the IRP. Within the context of EV pilot programs, we're studying how to site charging stations with respect to Justice 40.

- EV charging stations take a lot of energy and we only have a small amount of cushion right now during max periods. Will there be upgrades to the transmission system and upgrades to handle the EV stations that will need to be integrated? Will this topic be brought up in these IRP meetings?
    - The IRP process is more macro but meeting these new loads will require generation, demand-side management, and T&D resources. There is a distribution planning process that does get integrated into the overall IRP process. This IRP process will answer some of your questions, but there are separate implementation elements once the IRP is finished.

2024 Request for Proposal (RFP) / 2024 Public Advisory Process Next Steps
Patrick d'Entremont, Manager Planning Commercial Support, NIPSCO
Bob Lee, Vice President, CRA

Patrick d'Entremont noted that the purpose of the RFP is to bring in new resource parameters. He provided a high-level explanation of where the RFP fits into the IRP process. Bob Lee then outlined the four RFPs planned for this cycle, preliminary evaluation criteria, and the estimated timeline for each.

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

- Could you clarify the difference between the bridge resources and the intermittent dispatchable RFPs?
    - The bridge resource category aims to identify potential projects that may be available and capable of meeting rapid new customer growth. Customer timing delineates the RFP category.

- Is the company planning to share with us the names of the companies that have responded to the RFP?
    - We are anticipating sharing that with stakeholders at the June meeting.

- Will the stakeholders have time to review the RFP?
    - Yes, a draft will be provided for comment for those signing an NDA.

- If you sign an NDA, are you able to bid on the RFP?
    - Typically, the people reviewing and providing comments on the RFP itself are not bidders because we do not want to give a material advantage to any party over another.

Closing
Fred Gomos, Director Strategy, NiSource

Mr. Gomos closed the meeting by thanking stakeholders for their engagement as NIPSCO sets the stage for the 2024 IRP. He provided an overview of the stakeholder advisory meeting roadmap, with dates and expected meeting content, including a summary of the plan for the next meeting in June.