Northern Indiana Public Service Company LLC
2024 Integrated Resource Planning
Public Advisory Meeting #4
SUMMARY

October 8, 2024

Welcome & Introduction
Tara McElmurry, Communications Manager, NiSource

Kick Off
Vince Parisi, President & COO, NIPSCO

Recap of 2024 IRP Process
Abe Lang, Manager Strategy & Risk, NiSource

Abe Lang, Manager Strategy & Risk at NiSource, provided an overview of the revised stakeholder advisory process timeline, including the dates for rescheduled stakeholder meetings and the revised IRP submission date. He then summarized stakeholder questions and feedback received during and since Public Advisory Meeting #3.

Public Advisory Process and Responses to Third Stakeholder Meeting Comments
Abe Lang, Manager Strategy & Risk, NiSource

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

- We received Aurora files from you all on September 17th. As part of the last IRP's process there had been an agreement between CAC and NIPSCO to give the CAC an Aurora license to be able to look at those files because we hadn't been able to in the last IRP. We have a license agreement with Energy Exemplar but we cannot use Aurora right now, so it has been almost a month since NIPSCO has given us the files but we cannot look at them. Energy Exemplar's rep has now referred us to a different technical support person. So we have only been able to look at the summary files that NIPSCO sent over and I just wanted to be clear that there are a lot of things that we haven't been able to look at yet and comment on and I want to make sure that there is still time in the process to do all that and provide feedback to be incorporated into the IRP filing.
    - We can take this offline and talk through it today. We are going to be releasing additional data files today and NIPSCO can try to help facilitate things with Energy Exemplar to make sure that your license is usable. We have extended the IRP timeline for a variety of reasons but we can work with you guys at the conclusion of today's meeting to talk through what is needed to get that license working.

Portfolio Development Process and NIPSCO Portfolio Construction
Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA

Abe Lang kicked off the section with a review of NIPSCO's overall resource planning approach and modeling process. He then outlined the key considerations associated with portfolio construction, including major input assumptions and modeling constraints. Mr. Lang then provided a recap of NIPSCO's current capacity position, the new resource options under consideration, and the portfolio construction framework that defined six distinct themes based on MISO capacity accreditation rules and the emission intensity of NIPSCO's portfolio.

Pat Augustine, Vice President at CRA, then provided a detailed overview of the six portfolios (Portfolios A through F) that were developed through NIPSCO's portfolio optimization analysis. This included a summary of resource additions over time, portfolio supply-demand balances over time across all four MISO seasons, and projections of the portfolio's energy mix over time. Mr. Augustine then reviewed the energy efficiency and demand response selection for all six portfolios.

Mr. Lang then noted that after the development of NIPSCO's initial six portfolio, two additional "variants" on Portfolio D were developed to assess an emission trajectory between Portfolios D and F which would represent a more gradual trajectory towards Net Zero. Mr. Augustine then summarized the capacity additions and energy mix for the full set of eight portfolios, along with a set of key observations and conclusions.

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

- There were two LDES options that submitted to the RFP, a battery with ten hours of duration and a battery with 100 hours of duration. Which LDES resource is being selected in these portfolios?
    - As we go through this presentation, we will have several different LDES selections that are shown. Most of the LDES selected in the various portfolios, including the post-2030 selections shown here in Portfolio A, is 100-hour in duration. This is due to very strong capacity accreditation with limited derating over time and an ability to shift energy over multiple hours. However, beyond the 2030 time period, NIPSCO is likely to continue to evaluate different storage technologies, so it's unlikely that this IRP will conclude that a specific technology is preferred. A bit later in this presentation we will see some of the portfolio concepts that restrict the amount of new resource available through the remainder of the decade, which contributes to earlier 100-hour LDES coming into the portfolio.
- Correct me if I am wrong but your RFP results seem to indicate that your thermal bids were maybe at a lesser capacity than what is in a lot of your portfolios here for 2029 and 2030. I thought there was under 2,000 MW of thermal bids and it looks like we are talking 2,600 MW maybe by the early 2030s here. Can you please explain the discrepancy here?
    - Yes, we had a limited amount of thermal capacity in the RFP. There was one combined cycle offer and several other peaking or existing units offered, but as a part of the modeling setup we did incorporate an assumption for additional generic thermal resource capacity which is included in what is shown here.
    - We had one bid for a CCGT which was just around 650 MW. What you will be seeing here in the modeling is that many of the CCGTs that come up are based on the self-build assumption. We have also included the RFP result in here but anything above that is based on a self-build assumption, which we are assuming that we can get into place within the timelines listed. I know there may be some constraints from a supply chain perspective but we are assuming based on what is modeled here that we can get those into place within the timeline shown.
- Are the CC options 1x1's and what technology are they?
    - From a modeling perspective, a 650 MW block size was evaluated, which is

generally considered a 2x1, but it depends on the turbine class. Given the size of the potential total CCGT additions, different configurations could be identified. However, from a modeling perspective, the general assumption is a 650 MW, 2x1 combined cycle. If NIPSCO were to pursue a specific project, there would likely be additional diligence on the specific turbine manufacturer and potential configuration. In stakeholder meeting #3 we laid out the relevant assumptions in more detail, and as we go forward in this presentation you will see that a lot of the additions are in block sizes of approximately 650 MW.

- I just wanted to note an overarching concern from CAC about data centers and that we do not have signed contracts. We do know that the data centers are shopping around talking to different service territories, so it kind of seems like the tail wagging the dog, when you're trying to meet load that you are not sure is even coming, especially with this portfolio showing an investment in a CC in a very short period of time.
    - Next meeting we will come back to look at some portfolios that will be constructed without the incremental data center load, so that feedback has been heard previously.
    - Yes, in response to similar previous feedback, we are working on views of the portfolio without any data center load included and what the resources would look like under that scenario, and we will share those publicly at the next stakeholder meeting.
- It looks like your portfolios are including a new CC by 2028, including Portfolio C. 2028 seems like an extremely ambitious timeline to build a new CC, especially when the gas peaker that is being built has already been pushed back to 2028. I am struggling to see how a new CC by 2028 is possible given that other utilities like Duke have told us that they cannot build one by 2030. So how is NIPSCO envisioning this as a realistic scenario?
    - We have been working with our Major Projects team as we built our self-build assumptions that went into this modeling. There is risk to anything when you are talking about 2028 and 2029, which is when you see the CC coming on here but that is what we have modeled because we believe it is possible. If we end up executing a project, there will obviously be other considerations that need to be taken into account.
- Can you build wind by 2028?
    - We did not receive any external bids for wind. As far as building wind ourselves, particularly given the land restrictions in Indiana, the places where wind could be sited are becoming more and more limited, which is why we did not build any wind into the model before 2028.
- Those local siting restrictions do not apply to NIPSCO as a public utility in the state of Indiana, correct?
    - Theoretically, a utility could use eminent domain in order to do a self-build, however we have restricted wind in the model to beyond 2030 based on the RFP results and likely challenges associated with development and land acquisition in the state. We appreciate the feedback though, and this is something that we can take into consideration.
    - Additionally, the difference in land use that we are talking about for a CC versus a wind farm is substantial, so that would add to the timing issue. We have land where a CC theoretically could be sited, but for a wind farm we would have to buy up a lot more land, so that is something to consider as we think about modeling and timing.
- For the gas that is coming online in the late 2020s and early 2030s in your model, do you already have specific sites in mind, like Michigan City or Schahfer?
    - We have not built specific locations in for anything that has been modeled, so nothing that you are seeing here assumes a location. This is only resource

selection based on economics. We do have bids in our RFP for specific locations, whether it is for storage or solar, but we did not assume any of those locations in the modeling.

- Are pipeline extensions a concern if you're going to build somewhere that needs a connection to an interstate gas pipeline?
  - That is all factored into our assumptions around the timing.
- In stakeholder meeting #5 could you share your seasonal target reserve margins used in this modeling, unless you have already shared those?
  - The assumptions were broadly laid out in one of the earlier stakeholder meetings, when we showed the supply versus demand balance. Under the current market rules, we are using:

Reserve Margin	Expected
Summer	8.97%
Winter	27.44%
Fall	14.21%
Spring	26.72%

  - In the DLOL construct we have received some guidance from MISO on how NIPSCO's obligation is likely to change, so you will note that each of these supply/demand balances reflect that, and there is expected to be a lower obligation in all of the seasons as a result of the fact that the MISO risky hours do not just happen the day of the peak but could happen at other times, The obligation discount for that is most significant in the winter and in the spring, so in the supply/demand balances you will see a kink in the line where it goes down when DLOL comes in.
- Following up on the load forecast portfolio that does not include the data center load, will we be able to see that portfolio with both the DLOL and the current market rules?
  - Yes. We are going to show it under both.
- Was the modeling used to select an optimal retirement date for existing coal? Is that the most economical date for coal to be retired? Or was the retirement date determined outside of the modeling process?
  - That was predetermined before we began with the modeling. We used the retirement dates that had previously been communicated and that is what is assumed in all of our modeling. So 2025 for Schahfer and 2028 for Michigan City are what has been assumed for our modeling.
- Do you have any thoughts on why the gas peaker is getting selected in Portfolio D, where it does not look like it is being selected in the other portfolios? To what extent could additional lithium-ion battery storage reduce the need for that peaker? Is it a close case?
  - To the first part of your question, I think it is close but there a lot of trade-offs in play. You potentially have more value from energy when your CCs are capped and you have MISO DLOL rules in place where we are modeling an expectation for a bigger hit on storage resources in certain seasons than natural gas resources. As a reminder, in the winter season those storage resources that are 4-hour duration go down to 56% accreditation while natural gas is in the 75-80% range. So, although these are low-capacity factor resources, they are operating 5-15% of the time and when you are capping your CCs you get into this position where in order to meet your energy constraints, a little bit of extra energy from natural gas peakers provides value.
  - To the second part of your question, the two technologies certainly offer similar attributes, but there are tradeoffs that would be considered in resource selection, as I just noted. Given that we see a lot of storage get picked up across the board, I do think storage and gas peaking remain a broadly comparable set of resources

    - that have different attributes that could be traded off across seasons and across the different values that they could offer the portfolio.
- Is there a carbon tax associated with energy from carbon resources that is included in the modeling?
    - The reference case, which we have shown for all of these portfolios, does not have a carbon price. As we get into the various scenarios next meeting, we have one particular scenario, the Aggressive Environmental Regulation scenario, which does have a carbon price coming in during the early 2030s and then scaling up to a fairly significant level.
- Will there be an estimate of what an annual bill impact would be under the different portfolios and maybe a compound annual growth rate for each one?
    - As we get to the customer cost results there will be an annual revenue requirement that comes out of this so you will be able to see the total cost of generation year-by-year, other various costs, and then ultimately for scorecard purposes the NPV, so that data will be coming and looked at as we run through all of the scenarios.
    - At stakeholder meeting #5 we will share the revenue requirement comparison between these various portfolios and what that looks like, as well as the costs on a $/MWh basis. But the revenue requirement is the main thing that we are including in our scorecard for each one of these and we show it on an NPV basis so that you can see 30 years discounted to today.
- Will we be able to see how much revenue is associated with each rate class and if the data centers fall under the commercial class?
    - For the purposes of the IRP presentation in the stakeholder meetings, we do not break things out by customer group, we just show the total revenue requirement.
- Can you explain again what “No New Uncontrolled Fossil” means?
    - From a portfolio construction perspective it means that we are not allowing new CCs or new gas peaking units to be selected or added to the portfolio unless they are controlled with carbon capture and storage technology or fully hydrogen enabled, meaning that they can blend up to 100% hydrogen.
    - In the modeling, what that assumption pragmatically means is that the cost of CCUS or hydrogen is included in the resource cost for a new gas build and we would not include it without that cost in Portfolios E and F.
- What is assumed about the GHG rulemaking underway for existing natural gas?
    - Given that there is no final rule for existing natural gas resources, there have been no constraints put on the Sugar Creek facility in general. In portfolios E and F, we have modeled the Sugar Creek resource converting to hydrogen blending capability, so you can see that the royal blue Sugar Creek slice would go away. But in the other portfolios, there is no explicit constraint associated with the operation of Sugar Creek beyond current finalized rules, because current rules do not apply to existing natural gas resources.
- Do you have a target minimum percentage for reliability; the percentage of NIPSCO’s system peak that must be dispatchable generation as a constraint for the long-term expansions?
    - Not specifically defined in that way, no. The long-term expansion was modeled under the two different accreditation regimes with associated seasonal obligations and accreditation assumptions. So that is attempting to proxy the reliability requirements that NIPSCO would have to meet across all four seasons, and that is essentially how the capacity expansion model was evaluated. One other point I will make is that one of the analysis steps is our stochastic reliability assessment, which will look at each of these portfolios in a 2030 sample year and flex the uncertainties associated with wind and solar output, thermal resource availability, and peak load and take a look at potential forced market exposure and rank the

portfolios across that type of metric. So that is the type of analysis that might get at what you are asking about. So, we are looking at it in a couple of different ways but there is not a specific mandate that we need a certain amount of dispatchable capacity as a fraction of peak load.

NIPSCO Portfolio Construction Continued and Next Steps
Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

Abe Lang kicked off the section with another recap of the overall modeling process and an overview of the remaining analysis components for NIPSCO's 2024 IRP. Pat Augustine then explained how the portfolios that were reviewed earlier would be evaluated across all five of NIPSCO's planning scenarios and across a distribution of stochastic uncertainty in renewable output, NIPSCO load, thermal resource availability, gas price, and power price. Mr. Lang then closed the section with a review of NIPSCO's integrated scorecard and the agenda for the final stakeholder meeting on October 28.

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

- Can you please confirm that you will be doing ratepayer cost analysis by customer class?
  - The IRP process is about the total portfolio and the revenue requirement on a total portfolio basis. We are not breaking it down by customer class. That would be a separate discussion while this is about resource selection from our generation side, so we will only be showing the all-in customer cost right now.
- Under the Five Pillars statute, the requirement is actually to do a rate analysis by customer class, so are you saying that you are not planning to do that?
  - In the final IRP report, we will include customer class considerations at a high level, but in the next stakeholder meeting we will not break it down by customer class.
- I want to make sure that the stakeholders who are engaged in the process will have an opportunity to comment on all of the Aurora files and have stakeholder feedback incorporated, to the extent necessary, into NIPSCO's modeling?
  - Yes, we will be following up today to find out what the issue is with Energy Exemplar and the license that the CAC is using. We have another data file release today that should go out shortly after the end of this meeting, where we will be releasing the output files that went into the slides that you see today from Aurora. We will make sure to answer any stakeholder questions and incorporate feedback before we finalize our IRP for the modeling. You can continue to use your license and comment after we submit our IRP in December as well.
- Could you talk more about the High Emerging Load Sensitivity Testing? Is that attempting to vary the amount of load associated with each of the data centers?
  - Yes, we discussed this briefly at stakeholder meeting #2 I believe, how we got to our reference case figure of 2,600 MW by 2035 of additional load on top of what we currently serve today. The high load sensitivity is 8,600 MW on top of our existing load, so it is three to four times more than what we are talking about in our reference case. The way we got to that is we looked at potential opportunities that were in the queue, where people had approached us with projects, and we built in somewhere between 2-3 projects that led to the 2,600 MW figure in our reference case and then around 6 projects that led to the 8,600 MW figure. This is just a snapshot in time as the situation with every potential data center is fluid, and we are not guaranteeing that we would see either of those amounts in our portfolio.
- When it comes to the 40% limitation on operating CCs under the EPA assumption

scenarios, can you talk about how that is going to be modeled and are there any sensitivities to that? For example, I am thinking about how you might not know when to operate the plant and when not to operate the plant with those limitations in place. How does NIPSCO think about that?
    - From a modeling perspective, the approach we have taken is to cap the total capacity factor at 38% and allow the model to optimize the top hours across the year when it would make economic sense, which is likely to be the most economic for NIPSCO's customers. These models have a fairly complex optimization algorithm that targets those periods of time under which it is most economic to operate, so it is not as if we are just running at 40% every hour of the year or hard coding in a set of dispatch patterns. But to your point, in real life, we will not have perfect foresight about future weather patterns so there is uncertainty associated with operating under this regime. The reason we left the 2% buffer is to reflect this risk and to leave open the possibility of unexpected events. Any given year will be different and so this will present some operational challenges if the rule comes into force.
- I was wondering about the stochastic variables associated with load and thermal resource availability. Could you please elaborate on these further?
    - On the load, it is really more short-term, weather-driven load uncertainty. In the stochastic analysis we are still within our reference case load forecast and we are not varying within this analysis the amount of data center or other economic development load that could come in. So, this is only focused on our base load forecast for this year but load is highly dependent on weather, and it is just random in certain hours and on certain days. Two meetings ago we showed some of our distributions and if you have further questions or want to see some backup data, we can certainly share that but it is really about weather-driven load uncertainty once you have your expected load assumption in place.
    - On thermal resource availability, it is also correlated to the weather to some extent. We have looked at NIPSCO's actual operating data for outages at the Sugar Creek facility, if they have or have not been correlated to weather, incorporating in forced outage rates and mean time to repair. There is some correlational to weather here but it is a bit weak based on NIPSCO's historical operational characteristics but what we want to pick up there is that thermal resources have uncertain operations as well.
- So, the thermal resource availability is for NIPSCO's thermal resources in particular?
    - Yes, this is a NIPSCO-portfolio specific evaluation, incorporating existing and potentially new thermal resources.
- How are you coming up with your purchased power prices?
    - The power prices are based on MISO-level market simulations.
- How do you come up with resource plans for each of the utilities that would be setting the MISO power price?
    - That would be done in the MISO-wide capacity expansion element of the work. Although we incorporate public announcements, the analysis over the long-term is done on a general MISO-zonal basis.
- My question really is, who sets those numbers? Where do those numbers come from? The resources in MISO, how do you know how much each utility is going to have of a specific resource?
    - We get these from a mix of public announcements for the near-term but the long-term is our independent, system-wide capacity expansion analysis. So we are actually solving for the long-term buildouts through that process and through this model.
- Is that information available so that we can see what your assumptions are?
    - Yes, that information was summarized in the second meeting. I think we also have

a set of spreadsheet details that went out in our first data release but we can certainly share that with you as well.

- Do you guys consider the data centers to be in the commercial customer class, instead of the industrial customer class?
  - That is something that we are still working through right now.
- We would appreciate if the load associated with the hyperscalers is broken out from the other rate classes.
  - Yes, we are not commenting on that right now, but more to come.
- Speaking about economic impacts to the community, I just wanted to note about the upcoming proposed rate hike in northwestern Indiana and the impacts it could have. There is a study that shows that the third largest stressor for northwest Indiana is their ability to pay their utility bill. Please take into account the community when you propose these rate hikes. I would urge to adjust your philosophy on this.
  - We appreciate your feedback.

Closing & Stakeholder Comments