Northern Indiana Public Service Company LLC
2024 Integrated Resource Planning
Public Advisory Meeting #5
SUMMARY

October 28, 2024

Welcome & Introduction
Tara McElmurry, Communications Manager, NiSource

Kick Off
Vince Parisi, President & COO, NIPSCO

Recap of 2024 IRP Process and Responses to Fourth Stakeholder Meeting Comments
Abe Lang, Manager Strategy & Risk, NiSource

After introductory comments, Abe Lang, Manager Strategy & Risk at NiSource, provided a recap of the stakeholder process and timeline as well as a summary of stakeholder feedback since Meeting #4.

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

- Will NIPSCO address the impact of customer cost allocation in its IRP filing?
  - We will provide any legally required items related to customer costs and rates. Right now, we do not have anything to share about customer rate impacts. We will show total revenue requirement expectations, and we will show the total divided by megawatt hours of sales. We do not have any specific rate information to share about what data center customers are going to pay. We are still working through the process and cannot guarantee that we will have a specific call out as to what they are going to be charged until we have more information. When we have more information available on rate impacts, we can share that.
- When you model data centers, are you assuming they are going to be responsible for all the costs associated with their construction. Is any modeling considering whether they terminate early or operate shorter than the contract term?
  - In our current IRP modeling, we are looking at the system costs and everything as a whole. It is NIPSCO's strategy and position to have these large load customers carry the cost of their generation and transmission needs.

Portfolio Recap and Portfolio Scenario Analysis
Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

Abe Lang began the section with an overview of NIPSCO's overall resource planning approach and the portfolio concepts under evaluation. Mr. Patrick Augustine, Vice President at CRA, then provided additional detail regarding the resource additions and energy positions of the eight portfolios that were developed and presented in Stakeholder Meeting #4. Mr. Augustine then presented two new portfolios that were developed under a “Flat Load” condition with no incremental data center load. He reviewed annual capacity additions and the projected energy balance of these new portfolios and compared them with the original eight concepts.

Mr. Augustine then presented the results of NIPSCO’s portfolio analysis, starting with the net present value of revenue requirements (“NPVRR”) under Reference Case market conditions. He then reviewed NIPSCO’s alternative scenario constructs and presented the NPVRRs for each portfolio across each scenario. He closed the section with a comparison of the levelized generation costs per MWh for the various portfolios, including those developed under Flat Load conditions.

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

- What sensitivities did NIPSCO include about assumed carbon capture, utilization, and storage (“CCUS”) technology performance?
    - After the IRP filing and over the next 10 years, we are going to evaluate the feasibility and timing of CCUS. All portfolio analysis has made assumptions about performance as reviewed during Meeting #3, and we have also run Portfolios E and F, which assumed that you could have CCUS by 2030 vs. Portfolio D_CCUS, which assumed that we could get it by 2035. We have two different looks that we are showing today. We will continue to evaluate CCUS after the IRP filing.
- Is the only driver in the portfolio cost per MWh differences more megawatt hours with additional loads?
    - That is the primary driver of the cost per MWh relationship. The cost for the entire system is projected to go down with growing load. This conclusion is dependent on the starting point for NIPSCO’s system. NIPSCO currently has a portfolio that is relatively energy rich and potentially capacity short given evolving MISO rules, which means incremental resources that are coming into the system are needed to provide capacity and not energy, which will drive up the cost of the existing system per MWh. Adding high load factor loads into the system can allow the system to more efficiently absorb new resources that offer both energy and capacity.

Stochastic Risk Analysis
Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

Pat Augustine introduced the section with a recap of the stochastic analysis process and approach, including a review of the uncertainty variables that were evaluated. He then reviewed the expected forced market exposure of the different portfolio options by displaying market exposure risk profiles across the day and year, along with key quantitative metrics. Mr. Augustine then presented NIPSCO’s cost risk analysis and presented distributions of cost outcomes for the various portfolio options, particularly at the 5th and 95th percentiles.

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

- Is Portfolio D relying on CCUS?
    - No, not in 2030. This is a 2030 view and it is relying on new combined cycle capacity and gas peaking capacity. Portfolios E and F do have some CCUS additions, but Portfolio D does not have CCUS until the later 2030s. In this simulation, where we are focused on the year 2030, all requirements are met by conventional gas units.

- But doesn't the whole portfolio rely on a 20-year outlook?
    - Yes, cost metrics and some of the other metrics that we will talk about later are evaluated over the full 20-year outlook, but for this stochastic risk assessment we are doing an assessment of the year 2030, so the role of CCUS in Portfolio D is not showing up. Earlier CCUS is showing up in Portfolios E and F but this risk assessment is designed to be a snapshot in time.
- Do Portfolios E and F have any risk related to CCUS?
    - From a thermal outage perspective, yes, their thermal outage uncertainty is slightly higher, given the CCUS. They also have additional risk associated with some of the other resources that are in the mix due to limitations on with new gas build options. But for purposes of this analysis we are not measuring the risk of not being able to complete a project by that point in time.
    - This analysis is not looking at any feasibility or execution risk as related to the generation projects themselves, rather it is looking at what the year 2030 looks like, as far as if we have enough generation to support our load, if we implement these portfolios. In the times that we do not, that will show up in the yellow or reddish colors in these charts [on slides 56-58].
- I think relying on CCUS and not having any risks around costs or operations is a little bit short sighted.
    - That is something we will continue to evaluate beyond this IRP and you will see when we get to our preferred portfolio, we take all of these feasibility and execution-related concerns into consideration, between now and when we would actually be implementing CCUS. We will have to continue to study CCUS and what our best options are to continue to decarbonize after the IRP process is complete. Our preferred portfolio gives us some time to assess what the best decarbonization options are for natural gas units, and right now CCUS is probably the most feasible, although we will continue to also study and monitor the potential for a hydrogen economy to develop over the next couple of years.
- When you say 95th percentile, are you talking about with respect to load? Or peak net load? Or some other metric or driver that you looked at?
    - Net load is the correct way to think about it. These graphics are showing the 90th percentile of the net load – the capacity available minus the load in any given hour/month combination. For each little square on the graphic we are looking at the 90th percentile of that value. Across the distribution we have 1,000 runs for hour one in January, as an example, and for each of those iterations we can take the available capacity minus the NIPSCO load and then pull the 90th percentile from that distribution, so it is a net load view here.
- What size is the combined cycle resource that you modeled in Aurora?
    - Those are generally 650 MW blocks
- As you guys went through the stochastic analysis, was it possible for the model to have any correlated outages between units? And did you see any of those outages in your analysis? If you did, would it make sense to show a similar graphic for those events too?
    - Perhaps. We have correlations between thermal resource outages and weather and naturally there will then be some correlation between units, because if there is a particular weather event that is within an iteration that results in a unit being more likely than not to be in outage condition, that would likely be the case across the board. I do not have on hand what the correlation of combined cycle unit outages might look like so maybe we can follow up with some more data, but I will say that these types of instances are embedded within here so there might be some interesting data that we could look at.
- Can you generalize about which seasons of the year you are showing these iterations that are flying into the 90th percentile?
    - The graphic here has the twelve months on the Y axis so the 90th percentile is

being recorded at every block. We are showing the net load at the 90th percentile here within each block of time. We could potentially follow up with some additional data, but these graphics show that in certain seasons our exposure may be better or worse.

- You are trying to address the timing of potential risks through this set of graphics but I wonder if it also makes sense to think about the magnitude of the risks and is there a way to think about modeling today's portfolio and load to give a sense of where the exposure is currently in the system, compared to how that might change in 2030?
  - Yes, there is certainly a way to do that. This is a developing situation and for this IRP we tried to give some different potential views but I think your points are good and warrant additional review as the market changes.
- Is there an opportunity to put some of that, especially the comparison to today's portfolio, into the IRP?
  - Yes, we can follow up and potentially take this offline and try to include what you are asking for in our final report. We can set up a one off conversation to go over the exact details of what you are looking for.
- Does CCUS mean a CC with CCUS?
  - Yes, that is correct. That bullet indicates a CCGT, with CCUS being included.
- What is the parasitic load of CCUS in your modeling assumptions?
  - We have CCGT with CCUS blocks offering 585 MW of net load to the system, versus the 650 MW block of CCGT. So this would represent 65 MW of parasitic load, so essentially a ten percent de-rate of the net capacity to the grid.

Sensitivities – High Emerging Load and DSM
Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

Pat Augustine began the section with a review of the emerging high load sensitivity load growth parameters and then presented the resource additions and projected energy mix of the portfolio optimized under high load. He then summarized the assumptions associated with the DSM sensitivity (moving from RAP to Enhanced RAP/MAP) and presented the portfolio implications and cost results.

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

- Does a peaker plant provide power when there is a parasitic load?
  - No, not necessarily. The parasitic load terminology is associated with a CCUS-facility, where there is a significant demand for energy to perform those CCUS activities on site, so a portion of the capacity associated with the resource is needed on site, leaving less energy for the grid. Peaker capacity refers to a separate facility that would be expected to operate economically but during periods when load is peaking throughout the system.
- What makes up the difference when there is a parasitic load? Where does that power come from?
  - It would come from other resources that would have to be added to the mix. So, when we look at a portfolio that has a CCUS facility that is operating at 585 MW rather than the 650 MW for a regular combined cycle, other resources would then be added to the mix. That could potentially be a peaking plant but it could also be additional solar, storage, or other. So, essentially, other resources in the portfolio are factored in to make up the difference.

Scorecard Summary, Preferred Portfolio, and Short-Term Action Plan
Abe Lang, Manager Strategy & Risk, NiSource

Abe Lang started the session with a review of NIPSCO's integrated scorecard objectives and metrics and then presented a fully populated scorecard for all portfolios. He then discussed the rationale for the selection of NIPSCO's preferred portfolio and presented NIPSCO's short-term action plan.

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

- Why did NIPSCO change the environmental sustainability metric to emission intensity? This is inconsistent with what NIPSCO has previously stated would be the metric in this IRP throughout this stakeholder process. It is also inconsistent with NIPSCO's 2021 IRP. We urge NIPSCO to use total emissions, not emission intensity.
    - We used this to show how emissions progressed relative to the amount of megawatt hours that are produced and we thought this was a more helpful metric when comparing the portfolios. However, in our December 9th final IRP report we will have all of the emissions numbers for all of these portfolios included, to be consistent with what we have provided in the past.
- In terms of due diligence regarding CCUS, what has NIPSCO done around seismic activity and community safety?
    - We are still in the process of evaluating the feasibility of CCUS, among other decarbonization options, and when we have more information that we can share publicly around associated risks from a cost or safety standpoint, we will make sure to share that. There are a variety of concerns that people have about CCUS and we acknowledge that.
- Is NIPSCO responsible for the seismic testing that is occurring around Sugar Creek, or is that someone else?
    - I am not familiar with this occurring but I do not believe that would be us.
- What is the true reality of carbon capture for coal or gas-fired power plants? It does not seem feasible in terms of costs right now.
    - It is more than double, or even up to triple the cost, to build a new CCGT with CCUS versus building a new CCGT without carbon capture included. There are also many unknown costs when it comes to things like preparing underground wells or piping the carbon, so we are still working through an understanding of what those costs would be. Our preferred plan does not include CCUS by 2030 because we do not think that is feasible by then, but we will have more time to evaluate whether or not it is feasible by 2035 and beyond. We currently see CCUS as being the more viable by then than hydrogen, as of today.
- How does carbon capture compare then to the new small nuclear units that are being developed?
    - A new small modular nuclear reactor has not been built in the United States to date, so it is difficult to say. But the costs of nuclear plants have notoriously run higher than whatever is initially estimated, so there is still a lot of uncertainty around this new technology and how costly it will be. The cost assumptions we used in this IRP for new nuclear were presented in Meeting #3.
- Where will the CCGT, CCUS and Gas Peaker plants be located?
    - We do not have locations at this time. The IRP only selects the resource types and MW amounts. Once we move towards trying to execute this preferred plan, we will have more information on where those locations would be.
- Which capacity addition amounts represent what will be needed for data centers?
    - [on slide 80] Any resources that are not italicized and do not have an asterisk next to them represent what would be needed for data center load. If we never end up signing a data center customer up, we might not end up needing these resources. Anything that is italicized and anything listed in the "Other Activities" will be needed no matter what.

- Then where is the gas peaker located? Is that the one that says “Thermal Contracts”?
    - The gas peaker that we are currently working on is listed in the first column, in the “Other Activities” row, where it says “~400 MW gas peaker”. Anything listed in the “Other Activities” row is already a part of NIPSCO’s existing plan. Everything that is in the “Preferred Plan – Capacity Additions” row is incremental to that plan, with resources that will definitely be needed italicized and resources that might be needed for data center load non-italicized.

Closing & Stakeholder Comments