



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

September 23, 2026

Welcome & Introduction

Jessica Cantarelli, Communications Manager
Joshua Nash, Communications Manager

Communications Managers Jessica Cantarelli and Joshua Nash provided introductory comments including the Meet Safe instructions, a safety moment on eye wellness, stakeholder advisory meeting protocols, and a review of the agenda.

Kick-Off

Vince Parisi, President & COO, NIPSCO
Erin Whitehead, VP Regulatory & Major Accounts

Vince Parisi kicked off the meeting with an overview of NIPSCO, the generation portfolio, and how NIPSCO plans for the future.

Federal & State Policy Update

Abe Lang, Manager Strategy and Risk
Matt Croucher, VP System Planning

Abe Lang presented Federal and State policy changes since NIPSCO's 2024 Integrated Resource Plan (IRP), the purpose of the 2027 IRP acceleration, Indiana IRP rule updates since 2024, and an overview of the NIPSCO-GenCo relationship.

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

- Jennifer Washburn, CAC, asked: Given the recent federal order overturning the Campbell 202c that is kind of the precedent case for the 202c orders that are out, is NIPSCO going to stop working on bringing back the coal plant, given that it's uncertain where that money is going to come from to pay for all of that, the millions of dollars for repairs going on now?
 - Abe Lang responded: We just received our latest order a couple of days ago, so we are going to move forward as is. Obviously, this is going to go through quite a bit of legal challenges and appeals before it is settled, so since we just received the other order, we're going to continue operating or continue to try to bring the units into operation as is. We're going to monitor that, but right now, we just got another order, and we expect everything to be appealed.

- Jennifer Washburn, CAC, asked: I thought I saw another utility in another state go ahead and use their legal teams to start challenging the orders. And we've seen another utility write the DOE saying this is not a good idea. So, is NIPSCO still just going to keep going?
 - Abe Lang responded: Yes, we just got our latest order and we are going to comply with that. We are not going to challenge it.
- Megan Anderson, Sierra Club, asked: In this IRP I'm hearing that we're not getting into the details about costs for large load customers and primarily bad service through GenCo. I think it's a little confusing how the energy demand is parceled out, how the assets are paid for, especially existing assets and who they are serving. Are you going to give information on that so that people are not paying for these coal plants to serve data centers?
 - Abe Lang responded: There will be the generation assets and the portfolios associated with them will be completely segmented from a cost perspective. So nothing that will be supporting NIPSCO right now. There are some affiliate rules where the two entities can transact. But right now, the portfolios are separate. The assets that are being built are separate. The costs associated with those assets are separate. We will get into that more in meeting #2. We're not going to get into the existing resource review today, but during meeting #2, we will.
- Marc Blanchard, BP, asked: Regarding the reference on the slide to ongoing negotiations, does that mean that some of those ongoing negotiations are going to influence what their capacity plans are? What was the process and hierarchy for such decisions, and you're referring to ongoing negotiations with data center customers, as well as the contacts on doing negotiations.
 - Abe Lang responded: We are going to model everything in our reference case, and we will get to this later in the presentation, with whatever contracts are signed as of today are going to be in this case for GenCo. Anything that we have announced publicly, which we will get into what that total load looks like. That is what is going to be in our reference case. We are going to handle what we call the strategic negotiation amounts that we have communicated in our investor relations material, as well as pipeline opportunities beyond that. We will handle that through some additional scenarios in the IRP process. But the reference case will just be based on what is signed as of today.
- Anna Sommer, Energy Futures Group asked: When you were talking about the drivers of this IRP, you didn't mention load growth. And you said in response to one of the questions in the room that the reference caseload includes the contracted load, which I assume essentially means the GenCo load, the Google and Amazon load. Is there other load that you are going to be looking at that would be additional to that in this IRP?
 - Abe Lang responded: Yes, our reference case is going to be focused just on what's signed. But in our investor relations material, we've highlighted that there are potentially three more gigawatts of opportunities that are in strategic negotiations with large load customers, an additional two gigawatts that are potentially in the pipeline beyond that. We've highlighted each quarter over the last year about what potential exists. We will handle those as potential upside scenarios for additional load growth beyond that. So the reference case is not going to include the additional three gigawatts or two gigawatts that we've called out in our investor relations materials. But we will analyze those in some scenarios that we run off of this IRP.
- Anna Sommer, Energy Futures Group asked: One thing that we are deeply concerned about for this IRP is the mismatch between load and generation in NIPSCO system. And this has several facets. One is the resource adequacy implications, as you demonstrated in a 2024 IRP. You had some big gaps to meet, especially when you add new load. And those gaps are not easy to meet. We have not just the challenge of actually getting

generators online, sourcing turbines, finding EPC firms actually constructing those generators. You also have the challenge getting transmission for those generators. So your Schahfer CCGT it seems like it may be limited in terms of its availability as accredited capacity because it's connected to an LRTP project that won't be online until the 2030s. So we are very, very concerned about whether you can even meet the load that you have signed, let alone additional load. The other concern is from a transmission planning, perspective. Have you done the analysis that looks at what the operation of those data centers would be; is there a stability concern? What is the loading on those lines, because you have so much more load on your system than you have in the past. So I just want to express a strong concern about that, because I think those are the fundamental issues that will impact your ability to meet your demand and to actually do so reliably.

- Abe Lang responded: I'll address two of the things you said. The first is with both existing and prospective GenCo customer for any that may come on the system, there are transmission studies that are done as part of that process. So we are ensuring that we are not overwhelming the system that we have with each customer that we are evaluating. The impact of whether the NIPSCO customers and any transmission related items that will affect NIPSCO generation, if there is anything that comes up in this IRP, related to those, we will address it. But right now, the GenCo customers will pay for whatever upgrades are required for them to come online. One, we do studies for those. And if there's anything that affects NIPSCO customers as a part of that process, we will note it in this IRP, but right now, each GenCo customer has its own study as it applies to come onto our system.
- Anna Sommer, Energy Futures Group, asked: I'm not suggesting that you don't study those loads at all. I think there's a question about whether you're doing all the studies that need to be done and also what the criteria are for the studies they actually do now. We've asked questions about that elsewhere, and there's been no real transparency around those questions. If you're asserting that you have studied concerns coming out of NERC level 3 alerts for computational loads for what happens when you add not just the Amazon and the Google loads plus this potential load, show us the studies; please give us some transparency into how you've done that. Because I'm sure you've done some studies, but we don't know what they said and we don't know what exactly you actually studied. That's the way to help alleviate these current concerns is through transparency.
 - Abe Lang responded: We will take an action to document what we can and can't share. We're not committing that we can share everything related to those studies because some of it is confidential to a GenCo customer, but we will take an action item to see what can be shared from the transmission studies that have happened. As it regards to existing GenCo customers, we'll take an action to see what we can share, and we can perhaps cover that offline, maybe in a further discussion, but we'll take that as an action just to look at what we can't share. Can't commit to anything right now.
- Anna Sommer, Energy Futures Group, asked: You talked about the IRP looking at cost from a consumer perspective, and I think what you meant is a native customer perspective. Help me understand how you're going to do that if load associated with GenCo, for example, and generators associated with that are in the IRP. How would we know that all the costs associated with that are actually going to be passed on to GenCo customers if we don't have the details about what the GenCo customers are paying?
 - Abe Lang responded: There's a whole special contract process that the GenCo customers have that we work with through the IURC. So we can't share that due to confidentiality reasons, but what we will do in this IRP to be transparent with you, we can get into this more, perhaps offline. In our Plexos models that we're going to build, there's going to be a GenCo model and a NIPSCO model, where

the GenCo will have to be sufficient in and of itself without relying on anything from NIPSCO. We will share the details of that when that's ready, kind of like the guts of it with you as needed. And we can talk further about that then. But we cannot get into any of the specific special contracts and what the pricing is on.

- Anna Sommer, Energy Futures Group, asked: It would be very helpful to see what you're modeling. I think you're going to have to put all those costs into a spreadsheet anyway, because Plexos doesn't give you a total system cost. So it would also be really helpful to see how you're going to divide those things in your financial spreadsheet too.
 - Abe Lang responded: Yes, we will make sure to share at the appropriate time. We're not done, we're just beginning the running the modeling now, so we will, but we will share both the Plexos output as well as the financial model with you as needed.
- Jennifer Washburn, CAC, asked: I did just want to put on the radar a concern, though, related to the Schahfer gas peaking unit. I know retail native customers now are paying with the construction work in progress to construct that facility. But that was based on the premise that Schahfer unit 17 and 18 were going to be retiring. So since NIPSCO is continuing despite the Campbell order, I just want to put it out there that as a consumer advocate, we're concerned about us having to upfront the financing cost because the statutory language on that says you're displacing coal. And if the coal is not being displaced, then the cost is not eligible. So I just wanted to put that out there that that's going to become something that we're going to be raising this concern, especially if the retirement needs are pushed.
 - Abe Lang responded: Thank you for bringing that up. We're going to look at that as a part of the what if, if we were to extend it, what does that mean for customers from a cost? The fact that the peaker was contingent upon the coal units retiring in the way that the CWIP is being covered. We will make sure to include that in the financial model.

Short-Term Action Plan Update **Abe Lang, Manager Strategy and Risk**

Abe Lang provided an update of the 2024 IRP short-term action plan, project updates since the 2024 IRP for facilities previously in development.

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

- Ashley Williams, Just Transition, asked: I live in Michigan City, so I've lived with your pollution over the past decades. And we were really looking forward to that plant retiring and just the fact of seeing this new scenario and this play out really is quite unacceptable for us here in Michigan City. I wanted to ask specifically, and I think you kind of already answered it, but just to put it on the record, we're specifically looking at reevaluating the retirement for Schahfer and Michigan City for specifically GenCo. And then how are you navigating the compliance costs as well as the existing customer costs?
 - Abe Lang responded: If we were to evaluate the extension of Michigan City and Schahfer 17/18, we're not looking at it for GenCo. It would be for the NIPSCO native load customers, just to be clear. Right now, that's how we're thinking about it in terms of moving the things. It would only be for reliability purposes or cost benefit purposes to the NIPSCO native load customers. That's what we're doing right now. I can't say that something would change, but right now we are not considering it for the change.
- Ashley Williams, Just Transition, asked: So it could change over the course of this IRP?
 - Abe Lang responded: No, I'm not expecting that to.
- La'Tonya Troutman, Founder of HEART and a Northwest Indiana ratepayer advocate,

asked: Since NIPSCO and GenCo loads will be modeled together, what publicly reviewable cost allocations and true up safe guards will prove that existing NIPSCO customers are not paying for GenCo driven generation, transmission, backup capacity or stranded assets?

- Abe Lang responded: The financial model that we are running for this will not include any GenCo assets in its cost for NIPSCO customers. Any costs associated with it are not going to be included. It's going to be completely separate. We are including the total load to understand what it means for our system as a whole. But when it comes to the costs associated with that, they're going to be completely separate. We're not even putting any of the GenCo assets that are planned; any of those costs will not flow into the NIPSCO customer financial model.
- Marc Blanchard, BP, asked: If storage is scaled back for native load, does that create a capacity gap? And if so, what will fill that capacity gap? You've got something there as far as you're going to be transitioning out storage, does that create a capacity gap?
 - Abe Lang responded: It all depends. Right now, we have multiple things we can do, which we'll get into at the next meeting, but it doesn't inherently create a capacity gap. We're not saying that we're doing less storage. I just want to make that clear today. We're not saying we're doing less, we're just reevaluating, based on the latest MISO capacity degradations that we're getting, so it could be the same amount.
- Marc Blanchard, BP, asked: It could be more reevaluation?
 - Abe Lang responded: That's correct. We've just seen so much uncertainty over the past year and a half as to what storage accounts for in the MISO system that we're trying to balance that.

Continuous Improvement in the IRP

Abe Lang, Manager Strategy and Risk

Abe Lang presented the 2024 IRP feedback and continuous improvement plan for 2026 and provided the purpose and information on the 2026 Request for Information (RFI) that was issued. Modeling transparency was also discussed.

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

- Rebecca TeKolste, Hoosier Environmental Council, asked: Is there a concern that if coal plants are kept online to support native load that GenCo customers will be paying for cheaper gas while ratepayers are paying for more expensive coal? And what are the plans to avoid that discrepancy?
 - Abe Lang responded: If we were to consider an extension of any of our coal units, it would be for cost purposes and reliability purposes. And it would likely be because it is cheaper than other options that are available which GenCo is currently looking at. That GenCo will be paying less for another resource than if we end up selecting a portfolio that extends a coal unit, is not likely to happen. So other resources in the plan, if we choose to extend it, it's because everything else is more expensive and less reliable, and that would be our consideration. So GenCo is not looking at those fuel assets. It is considering new resources for those customers, as we've noted with the gas combined cycle plants that are being built.

2026 IRP Analytical Framework

Abe Lang, Manager Strategy and Risk

Abe Lang presented the IRP analytical framework, including the resource planning approach and

the framework for evaluating future uncertainty.

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

- Dotty Warrick, retired NIPSCO employee, asked: I was just wondering about carbon capture. Someone in Mississippi suffocated in her backyard because of the Mississippi CO2 pipeline explosion in February 2020. And I know Newton, Jasper, and Lake Counties will fight you on this. I'm sure going to be there too.
 - Abe Lang responded: We will cover this in more detail in stakeholder meeting #2, but the most viable solution today is ambient-based solution carbon capture, which is put in at the end of a unit to capture the CO2 and then underground storage after that.

**Natural Gas and MISO Market Reference Case
Pat Augustine, VP, Charles River Associates**

Pat Augustine presented the fundamental market modeling structure, key drivers of commodity price outlook, natural gas market forecasting, reference case natural gas demand outlook, reference case annual Henry Hub outlook, MISO market overview, load forecast, and market outlook, and discussed how data center load is driving most growth across the country.

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

- Attendee (did not introduce themselves) asked: Back on the other slide when you had a 48% growth in your assumptions around gas demand power generation, assuming that we move this forward with the IRP, we need some sensitivities built in there, if the load shows up at this model level, will that be factored in the IRP?
 - Pat Augustine responded: Yes, that will be a factor in the development of natural gas prices for this IRP. This is a national view. There are more localized demand growth scenarios that will be run for the NIPSCO portfolio in more detail. But this is a national view on power sector demand across the United States that is coming from natural gas resources.
- Marc Blanchard, BP, asked: Regarding your last slide, do you have any insights on heat rate expansion?
 - Pat Augustine responded: That's a data point that we could basically pull out by dividing the power price by the gas price. But yes, in the near to midterm, we do expect those market heat rates to go up a little bit, and the market heat rate is purely taking the power price divided by the gas price and proxy the heat rate or the efficiency of the natural gas unit that is setting that price. So in the near to midterm, yes, over the longer term, flattening and potentially even declining because we are seeing the potential for wind and solar and storage and nuclear to start to be a bigger contributor. So that means that less efficient natural gas plants maybe are not on the margin quite as much as we might expect them over the next five years. So that is embedded in here. We do not have a heat break graphic per se, but if you were to graph that, I think you would see the upward trend and then a stabilization.
- Sunil Maheshwari, Purdue State Utility Forecasting Group, asked: How does CRA factor in the community pushback against data centers in its load forecast? Do you consider this pushback a short-term phenomenon?
 - Pat Augustine responded: I think that's a fair question and something that will be addressed more in the scenario phase. What we are expecting in this reference case is what we outlined a few slides ago and what was in the center point of MISO's outlook. I think there is a low case that could materialize for any number

of reasons. One being difficulties in permitting and development that may come from community pushback. Another being just a less robust outlook for computing needs over time as the AI and other data center markets mature. Another might be more efficiency in computing resources that do not have this demand materialize. I think there is a lot of uncertainty in the forecast. And there is also a higher end case where more projects continue to come online in regions that are acceptable to siting and developing them. So, a fair point and a fair uncertainty, but I think what we have built up in this reference case is based on announcements, development pipelines, and the MISO forecast. And we are not explicitly haircutting that for local pushback or permitting challenges in this reference case, although it is something to think about in alternative scenarios.

- Dale Graeber, Graeber Family Farms, asked: At New Carlisle, the data center is up and starting, Wheatfield is in construction, Hobart is in construction, and the port is in construction. As of right now, do you say they are ready to go? Do you have the power for these?
 - Pat Augustine responded: I think that is probably a question for the NIPSCO specific GenCo portfolio. What we are doing at the MISO level here is taking a look at a projected ramp for data centers across the footprint, and then we are looking at a supply picture across MISO and trying to marry the two up. At a high level, really what goes into this model, is we are solving for sufficient energy to power those data centers, and then the market becomes more scarce and prices respond over time as a result of that. And then over the long term, we get some feedback. But maybe I will defer on the specific NIPSCO question, to a later point when Abe or others are talking about the specific NIPSCO resources.
- Dale Graeber, Graeber Family Farms, asked: You have to have more power, but you have to convince the average consumer that we are not going to pick up that tab. Our bidders are going to go higher. And I think that is why you are having so much pushback on these data centers. So that is something NIPSCO and you guys need to address.
 - Abe Lang responded: Yes, as we mentioned, the separate legal entity, GenCo, was set up to make sure that the generation costs that the data centers incur are paid for by the data centers and those do not impact NIPSCO customers. So, in the financial model that we're going to be running, none of those costs are going to fall on NIPSCO customers, none of the costs for building any of the new generation facilities. That is how we are running this IRP. That is how the legal entity of the GenCo is set up. In terms of specific ramp rates of customers, we cannot get into that right now. Due to confidentiality, we cannot share the exact amounts early on. However, we will talk more later about what the total load is going to look like as we move forward through the IRP.
- Drew Siebenaler, Energy Futures Group, asked: How much of the resource mix on slide 42 is reliant on MISO generation interconnection requests being reaching both Commercial Operation and full deliverability by 2035?
 - Pat Augustine responded: All of this generation is assumed to be interconnected, be servicing the grid, and being fully dispatchable with the appropriate interconnection rights by 2035. So, if you want to look at the additions that come into the market, it may be best to focus on slide 39, where you can see that roughly 30 gigawatts of incremental natural gas, 40 gigawatts of incremental solar, 20 to 30 gigawatts of incremental wind, and then another 15 to 20 gigawatts of storage are coming into service, so it is a significant amount of new resources. A lot of this is in the interconnection queue already. But over the next decade, in order to meet the demand that was outlined on a prior slide, there is the assumption that this amount of capacity can be interconnected, can be energized, and can serve data center and other loads without interruption.
- Attendee (did not introduce themselves) asked: How is MISO assessing what is actual

demand versus over speculative demand from data centers at this point?

- Pat Augustine responded: I think MISO is conducting a similar screen as what the CRA team has done to come up with our demand forecast. They produced a report, in April I think, that you could look at for their detailed commentary. But essentially, they are looking at the pipeline and they are making some judgment calls about what is in advanced development and what they are going to haircut and what they are going to exclude from the forecast. And then they develop three different scenarios, one that's anchored on a base case or recurrence, and then one that is a low case that assumes only a fraction of that, even beyond the core haircut is accepted, and then a higher case where more of that development pipeline comes online. It is a combination of what they might consider project by project screening and then some judgment on how to discount the probability and likelihood of it advancing. It is definitely the case that there are a lot of speculative developments out there. There are developers that have projects in multiple jurisdictions that they are shopping around and I think MISO has not applied that. And what we've done is try to haircut things accordingly and capture projects that are clearly announced in utility filings, in data center and hyperscaler filings, and then take growth rates beyond that. But to the broader point, there is a lot of uncertainty here, and I think the scenario design will hopefully capture some of that.
- La'Tonya Troutman, Founder of HEART and a Northwest Indiana ratepayer advocate, asked: If NIPSCO customers will not pay to build the GenCo power plants, could the new data centers still cause electricity prices to go up for current customers? And if so, will NIPSCO measure and report that possible cost?
 - Age Lang responded: As we mentioned at the start, what we can say for sure is that the cost of building any of these generation assets will not burden any of the NIPSCO customer base. For the GenCo, none of the cost to build those assets will burden the NIPSCO customer base. There is a broader question that is raised with this around MISO market prices and market dynamics that may exist. We are going to look at the impact of that through scenarios in stakeholder meeting #2, like what the impact on the power market prices will be, not just from data centers, but from the broader MISO region what is happening with data centers and what is happening with new power plants. So, we cannot make a definitive statement on what MISO market prices are going to look like. We cannot specifically say that data centers are going to drive those up. We are going to analyze that through our scenarios, which we will talk more about during the second meeting.
- La'Tonya Troutman, Founder of HEART and a Northwest Indiana ratepayer advocate, asked: What public document will show that NIPSCO customers are not paying GenCo costs, and will the information be updated after the actual costs are known?
 - Abe Lang responded: We have communicated in our public investor relations materials that NIPSCO customers will not be paying the GenCo customers' costs. With the IURC, the special contracts that are filed with each GenCo customer are confidential to that customer, but those cover the cost of the new generation. In terms of what specific costs, we're not going to make public any costs around the GenCo special contracts. However, we will designate as part of this IRP process what the NIPSCO customer costs are, which will not include any of those GenCo customer costs. These documents that we are producing as a part of this IRP will live on. We also have our investor relations materials, which state our intent with GenCo.
- La'Tonya Troutman, Founder of HEART and a Northwest Indiana ratepayer advocate, asked: If a data center is delayed, uses less electricity, or is canceled, who will pay for any power plants or equipment that NIPSCO has already built?
 - Abe Lang responded: If the data center decides to walk, they are on the hook to

- pay. That is how these contracts are designed.
- Nicole Chandler, Sierra Club, asked: Are there concerns on reliability because of data centers?
 - Abe Lang responded: This is discussed in the presentation.

Environmental Considerations

Stephen Holcomb, Sr Director Environmental & Sustainability

Stephen Holcomb reviewed meaningful environmental improvements that have been driven by the IRP and investments in advanced pollution control technologies, and discussed environmental policy and regulations that impact operations and planning.

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

- Rebecca TeKolste, Hoosier Environmental Council, asked: We do a lot of siting advocacy, and one of the items of misinformation we hear a lot is the concept that agrivoltaics is a myth. Is there any material publicly available from NIPSCO to help us tell the story that agrivoltaics is real and working today?
 - Stephen Holcomb responded: Yes, we have sections in our last two sustainability reports on agrivoltaics. I thought I shared those with the Hoosier Environmental Council, but maybe not the most recent one that just came out. We will share that with you. We can also connect with you on what information would be helpful to tell that story better. For background, NIPSCO has 8,000 sheep between Calvary Solar in White County and Dunns Bridge in Jasper County. Those sheep are reducing mowing costs and supporting agriculture, so there is a really good story. I think it is a really successful program, and if we can provide whatever would be helpful to tell that story better, I will connect with you and we can discuss it.
- Ashley Williams, Just Transition, asked: Under the Trump administration, they proposed amendments in April this year that include rolling back the regulation for what we call legacy coal ash sites and historical ash sites. That is included in Michigan City as well as Schahfer. I am particularly concerned about Michigan City. We just took a million tons of legacy coal ash to the landfill. I want to ask the federal coal ash rule goes forward as such with all of these road maps. And we know the state program is basically a carbon copy or basically a rubber stamp of this. Are you going to be going along with it? Are you going to comply with that or are you going to go above and beyond? Because we know the coal ash sites are in contact with groundwater; they're unlined. And in Michigan City, we know that that ultimately it is going into Lake Michigan and Trail Creek. So, I wanted to ask, what is your plan for this? Are you going to go above and beyond for the people of our communities? Or are you going to go along with what EPA is saying through this proposed rule?
 - Stephen Holcomb responded: The honest answer is I don't know at this time. We will comply with all requirements. What I do know is that we have excavated hundreds of thousands of tons of coal ash from Michigan City Generating Station, transported it down to the line to permitted monitor landfill at Schahfer Generating Station. We are also assessing corrective action for the groundwater monitor, for the groundwater impacts that you mentioned. And we can follow up with you on the details there, including a planned permeable reactive barrier. Again, details of that are on our website. But to your direct question of, "Do we know what item CCR permit program will require us to do under the legacy CCR rules, which are changing," I honestly don't know at this time. It is out there right now. It is out there currently in review in draft form.
- Ashley Williams, Just Transition, asked: We are very concerned now because they are

trying to completely exempt these legacy sites, though you have removed that coal ash. This is a legacy historical ash site that has been untouched. And that is our big concern there with Michigan City as well as for other plants.

- Stephen Holcomb responded: I understand that. There is legacy ash on the site and there are groundwater impacts and we are complying with EPA's requirements for corrective action on those groundwater impacts.
- Marc Blanchard, BP, asked: Given that the phase two rules were recently repealed, going forward, will your IRP scenario still carry a carbon price?
 - Stephen Holcomb responded: Yes, we are planning to continue to include a carbon price in what we call the aggressive environmental regulation scenario, and tentatively planning to begin that carbon price in 2035, but certainly welcome input on that.

Reference Case Load Forecast
Abe Lang, Manager Strategy and Risk
Matt Croucher, VP System Planning

Abe Lang provided an overview of the forecasting methodology for the short-term and long-term load forecast, annual energy demand, electric vehicle and DER forecast, residential and commercial solar panel forecast, GenCo data center load forecast, seasonal peak demand, and total system energy demand.

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

- Marc Blanchard, BP, asked: Why are you assuming that the data center load renews that identical load while the industrial load is trending from history? You are basically saying that your data center load, contract load, total contracts, assumed contract renewal at the same load, right? But when you have average of historical peaks, when you go to the 631 customers, can you tell me why you are using average of historical peaks for industrials and assuming that it's renewing at the same load of the data centers?
 - Abe Lang / Matt Croucher responded: One of the critical things we model when we think about this is what is in those special contracts in terms of the applications. As we think about what our views are on the data centers, we have to be very mindful of essentially giving the GenCo environment what they are paying for those special contracts at the end of the day. It goes to the question earlier, as we get into what are they actually using, we have to be mindful of the load forecast, but is that load round or what are we required to serve? Because to be transparent at any given day, if they are at a lower amount, if they then pop back up, as long as they are meeting at their contractual obligations, then that is what we are going to be modeling as we go forward. It goes back to being consistent across our processes and our profile. This bottom section on the data center is very much guided by what has been agreed to in the GenCo world. In this world, we are also ring fencing assets. In terms of that bottom view, we are very focused on the agreements, in terms of that, and then matching it up on the other side with the generators, the assets. If there are errors there, you want to be very clear, like all errors, all actions don't materialize, then that is GenCo's solution to solve and there is no pass back to the customers, if they are not using as much of the generation that is being built. We have been very clear that we are not trying to model out and adjust from the future. We are being pretty clear of what we talked to the Commission about in terms the peak capacity that the special contract ties towards. Another difference between 631 customers and data centers is 631 customers pay for what they use from our system. If they don't use, they're going to still pay. So, there's certain capacity that is built for them. If they

don't use it, they're still going to pay for that capacity. So that is how we structured it differently, because we are looking at, what is the maximum that they could use rather than any type of historical feed?

- Sunil Maheshwari, Purdue State Utility Forecasting Group, asked: How are you creating the long-term forecast for data centers?
 - Abe Lang responded: We are going to get to the data center forecast in just a couple of slides, so we will cover that question then.
- Anna Sommer, Energy Futures Group, asked: I have a question about your residential forecast, in which you mentioned the model has an econometric variable for energy efficiency. My understanding is that metrics in the past utilized regional data that looks at projected increases in measured efficiency over time. Are you saying that what you are talking about in terms of energy efficiency is naturally occurring energy efficiency, or are you saying that your model is also accounting for some future looking to the sponsored utility savings as well?
 - Abe Lang responded: This is naturally occurring energy efficiency. We are going to layer in the DSM piece as a supply side resource. That will come later, so this is the naturally occurring energy efficiency that we just expect over time.
- Liwei Lu, Purdue University, asked: What drives the seasonality of data center load?
 - Matt Croucher responded: There is no true seasonality. The seasonality you are seeing is actually tied to the slight variation in reserve margins that we are applying. As we look at the peaks that we are getting, once we get to them, we are relatively stable, both from a high and low factor. There may be a slight bit of change in peaks as you go forward when you start thinking about the efficiency of the data centers, so that is measured in the calculation. It's just cooling, basically, what's the variation in cooling to their total load. But most of what you're seeing is minor in terms of the overall adjustments. And if it's anything, it could be tighter planning reserve requirements, but these are some of the things we are looking at. There is some potential where some might be slightly higher, but overall it's minor, especially when you look at the difference between that and native load peaks.
- Patrick Kelley, OUCC, asked: Will the NIPSCO native peak you anticipate have a slightly upward trend, but in the energy it was with a decrease?
 - Abe Lang responded: Yes, that is right. The overall energy volume we expect to be lower because EVs is one variable. There are probably three variables that are driving it, but we have lowered our customer count over the period for the most part. That is both on the commercial and the residential side, like between 6% and 11% over the period lower than we had in the 2024 IRP. So, less energy being used, less EV energy being used. But based on our analysis of historical peaks and historical kind of peak times of year, we are still expecting the peaks to stay pretty constant, even though energy is coming down. I would not say there is a major uptick in the peak.
- Patrick Kelley, OUCC, asked: Can I recommend that you have a separate case in the model based on history, and then in the EV and the DER and all of this other stuff afterward?
 - Abe Lang responded: If you mean just do a regression analysis solely based on historicals without pulling out the EV / DER, that is something we can consider. I don't want to commit to it right now, but we can take an action to look at what that would take.
- Patrick Kelley, OUCC, asked: It sounds like that is just a prior step in the modeling procession. First you have your historical basis, and then you add in the EV adoption later on.
 - Abe Lang responded: I think that is something we can provide, but we will talk as a team and get back to you on that.

- Anna Sommer, Energy Futures Group, asked: You sent a spreadsheet to some of us this morning with load forecast information that was marked as confidential, but it contains some of the same information that you're showing here. Why is that spreadsheet confidential?
 - Abe Lang responded: Most of the data is the same, but there is some monthly detail in the spreadsheet that we were not ready to make public. We can send a new version of the spreadsheet that specifies what is public and what is not.
- Anna Sommer, Energy Futures Group, asked: There is additional information in that spreadsheet that you are not talking about here that I imagine influenced other cases and scenarios that you might run. Are you going to talk about that at some point?
 - Abe Lang responded: Yes, during the second stakeholder meeting, once we talk through more scenarios.
- Sunil Maheshwari, Purdue State Utility Forecasting Group, asked: Can you briefly discuss the forecasting error in your Industrial forecast (I understand you rely on your Major accounts to produce this forecast)?
 - Abe Lang responded: I can speak to how we did the industrial forecast. There may be differences between our latest industrial load forecast and what we did in 2024. There are large industrial customers that specifically have behind the meter generation. If that behind the meter generation is running at a steady capacity, they are going to use less from our system. If that behind the meter generation is down, they are going to use more from our system. And so at times there will be differences between IRPs and our load forecast based on what we get from our industrial partners in terms of what they're experiencing with their behind the meter generation.
- Sunil Maheshwari, Purdue State Utility Forecasting Group, asked: I understand your major accounts group creates the industrial forecast or at least contributes to it. It is not an econometric model, so I am trying to understand. The typical practice at any utility is either you are creating a backcast or you are doing some other measurement after the fact to say what kind of forecasting errors you have. That is what I am interested in knowing for your industrial sector.
 - Abe Lang responded: Our industrial customers make strategic decisions around their own production when it comes to what they expect to produce with their facilities, as well as how much energy they expect to use. If there are differences from IRP to IRP and how our load forecast looks for them, it is typically based on differences that they provide us with when it comes to either their expected production or the availability of their behind the meter generation. That information is what would drive differences between our 2024 IRP and today. I don't know if we call that error, it's that we don't know exactly how our industrials are going to produce. We take the information that they provide us with, recognizing it is not necessarily affected by the same seasonal and weather variables that our commercial and residential customers experience.
- Sunil Maheshwari, Purdue State Utility Forecasting Group, asked: I understand that part, but you must still be measuring it somehow, how well your major accounts working with your industrial customers are expecting the load to be, and after the fact, you are probably looking to say whether it panned out or not. That is what I am trying to understand.
 - Abe Lang responded: We do compare our forecasts to actuals, but the simplest reason is it often has less to do with any inputs that we have and more just to do with the internal strategic decisions that our large industrials make about their production. If you need to have a follow-up conversation on this in terms of that information, we can talk in a little bit more detail about what information we get, but obviously we can't talk about specific customers and what their expected load is.

- Anna Sommer, Energy Futures Group, asked: One thing that I think would help a lot in making clear what it is that this IRP is considering is to match up this energy demand forecast with your portfolio to do a going in loading capacity balance and provide that for stakeholders. And that would include both existing generators and also generators that you're expecting to come online so that we know what online dates you're assuming for them too. That would be very helpful.
 - Abe Lang responded: That is a great point, and we will do that. That is going to be covered fully at stakeholder meeting #2. We will show the net supply demand balance of NIPSCO, and we will show the position then also of the GenCo. The GenCo will be its own separate supply demand balance when it comes to our peaks and then obviously the solutions for that will have to be individualized to the GenCo. The GenCo will have its own resource solutions that will go toward the GenCo and be paid for only by the GenCo customers. And then same for NIPSCO. We will also do the same with energy. Any short or long positions that either the NIPSCO portfolio or the GenCo portfolio customers experience, we report that on a separate basis and on a combined basis. We will show a net position for both. That will come in stakeholder meeting #2.
- Anna Sommer, Energy Futures Group, asked: Since you already have that, can you send that out to stakeholders?
 - Abe Lang responded: To be transparent with you, we do not already have that. We just got data from MISO a week ago with new resource accreditation numbers., and we have had some discussions with them to make sure that we understand them before we finalize our supply demand balance. So, it is not final right now.
- Anna Sommer, Energy Futures Group, asked: Can you do that with your previous PRA values though? Because otherwise we have to wait a whole month to see those values and it would be really helpful to have them now.
 - Abe Lang responded: We can we can share our net position as of today, and if there are any adjustments, we will get something to you in the next week or two on that. We don't always have the timing of when MISO is going to drop a new resource accreditation number, and we were a little bit caught off guard by the latest one, but we are trying to adjust to make sure that we are still resource adequate given those numbers as well. So, we will get something to you in the next week or two in advance of our separate one-off call.
- Jennifer Washburn, CAC, asked: We had the slide about the NiSource 2025 sustainability report published this year. How is NiSource going to be reporting on the environmental and all the sustainability aspects between NIPSCO and GenCo? Will that be all under the NIPSCO umbrella or do you happen to know that?
 - Abe Lang responded: In terms of the public report, I will let Stephen Holcomb answer that. But in terms of this IRP, we have our scorecard where we are going to talk about like things like emissions, emission intensity of the portfolio, so we are going to put that there for NIPSCO. The GenCo piece, we may not have as much information about going forward, just depending on the resource mix that's going to be assumed. But we will definitely have it for NIPSCO in this IRP for the legacy customers, what the emissions are, what the overall strengths, not just CO2, but you know, everything. And obviously we can share that data once the portfolio modeling is done. In terms of how we're reporting the broader GenCo, we can defer that question and we will take an action to have Stephen respond to that.
- Jennifer Washburn, CAC, asked: It was brought to my attention that the request for the portfolios would be due September 28. I am concerned about that, just since we typically in a longer process would have the draft database before we have to make such a request. For example, we don't know what the capital costs are for the modeling or the

commodity pricing, so wanted to flag that as a concern. I am also really concerned about especially the near-term modeling from the market potential study, given that we have a litigated case on the energy efficiency figures where there are differences of opinion between NIPSCO and the consumer advocates on the 2027 to 2029 DSM plan on the savings level. So, I did want to just flag that. Typically, we have these conversations as part of the DSM oversight board and part of the market potential study process, so I would just flag that we are concerned about that and we want to still have further conversation about how all of that gets plugged into the model please.

- Abe Lang responded: We can continue the conversation about how we do DSM. GDS, Advanced Side Analytics will be here during our next stakeholder meetings to discuss that further, so we can talk more about that then. We recognize we are doing a bit of an abbreviated process for this IRP; we acknowledge that. We are trying to make a very near-term resource decision that affects the 2028, 2029 and 2030 planning years, and we are accelerating this IRP. We are trying to get the cheapest resources online the fastest. That is why we are doing it this way. I understand the concerns. I do want to acknowledge that, yes, we are doing this a little bit unconventionally fast when it comes to our DSM planning process.
- Jennifer Washburn, CAC, asked: When might we get the executable Plexos license for stakeholders involved in those tech meetings?
 - Abe Lang responded: We asked them to send them about a week ago, so we just sent an e-mail this morning to see if that had been mailed. I will get back to you by tomorrow as to their response. So, it's in the works. They're going to send an NDA or specific contract for a stakeholder license for it.

Emerging Technology Considerations

EJ White, IRP Project Manager

EJ White presented emerging technology considerations, the screening and evaluation process for first of a kind resources, and pilot-ready resources which qualify for investment tax credits,

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

- Dotty Warrick, retired NIPSCO employee, asked: What does sodium storage actually mean?
 - EJ White responded: Sodium is a storage technology that uses sodium rather than lithium as the chemistry to store the power in the battery. The big benefit there for us is lithium is typically not found in the United States. Typically, it must be imported. And right now with the new one, big beautiful bill requirements, that would mean they are not able to receive tax credits. Sodium, however, we can access in the United States. We have supply chains already on shore. So, we think if that technology matures, we will still be able to pursue storage while still receiving ITC tax credit benefits.
- Dotty Warrick, retired NIPSCO employee, asked: Can you explain more about the iron air storage?
 - EJ White responded: Iron air storage is another storage chemistry. They use iron, literally rusting and unrusting the iron, to store energy over a longer duration than you might on a sodium or lithium battery, which is typically 4 hours. What we're doing here with the iron air storage is we're looking at storage options that give us longer durations than 4 hours, to 8 hours, and can withstand over 10 hours or more.
- Dotty Warrick, retired NIPSCO employee, asked: Some batteries catch on fire easily. Which one is better?
 - EJ White responded: There is a fire hazard with almost any generated resource,

but one thing that we are looking at is that these resources do not have as high a fire risk as lithium. They do not operate at as high of a temperature, and that is one of the things that is driving us to have interest in them as we look beyond lithium for storage technology options.

- Nina Peluso, Energy Futures Group, asked: Could you clarify exactly what this means for what will be put into the model? We have these four options. Are these the four that are qualified to submit the RFI? Are you expecting to model all four of these in the model? Could you expand on that, please?
 - EJ White responded: This is the non-exhaustive list of technologies we are exploring. We will model these in our portfolio model. We have data that we have received through protected confidential relationships with vendors, and we will use that information. I believe Energy Futures Group has an NDA in place as part of the stakeholder process, so that information would be available to you as well.
- Nina Peluso, Energy Futures Group, asked: Would we receive all of those resources as well as the first online dates, the operational parameters, as well as the cost assumptions?
 - EJ White responded: Yes, probably closer to the second stakeholder meeting, and of course, Energy Futures Group is part of a one-off stakeholder meeting for technical conversations.
- Shannon Anderson asked: Would you consider looking at virtual power plants or is that something you would consider under solar, storage or GSM?
 - EJ White responded: We are not explicitly looking at virtual power plants right now. But that is something that we will continue to monitor and track as that matures, especially in the MISO footprint and as we move toward FERC Order 2222 implementation.
 - Abe Lang also added: As FERC Order 2222 comes into play, that is something that we can continue to look at further. But right now, we do not have any specific offers when it comes to virtual power plants. Anything that we get now would just be under the helm of solar plus storage or something like that.

Request For Information (RFI) Results

Abe Lang, Manager Strategy and Risk

Abe Lang provided a summary of pricing from NIPSCO's 2026 RFI.

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

- Jennifer Washburn, CAC, asked: For those who signed NDAs, I wanted to make sure they would be able to see these. We like to see more detail to get an idea of the whole picture for the bid.
 - Abe Lang responded: We won't release counterparty names, but you'll be able to see pricing.
- Nina Peluso, Energy Futures Group, asked: Can you clarify when the RFI closed and what the expected online dates are for these resources?
 - Abe Lang responded: The RFI closed September 4th. We got this summary back just over the past week as we have been reviewing and analyzing everything. We will provide to counterparties under an NDA the list of the different resources and the expectation for when each one of these is to come online.
- Nina Peluso, Energy Futures Group, asked: Can you give a range of what the CODs would be?
 - Abe Lang responded: Near term, what I can tell you is that the primary things that can come online the soonest are the standalone storage assets. For those, late 2028, 2029, 2030 is what we are seeing for the standalone storage. For CCGTs,

we are talking about the early 2030s. We can get you back to you with the specific dates on those. Some of the linear generators can potentially come online sooner than those. We will send the dates for those as well. But the ones that are the earliest right now are just the standalone storage that we have, because many of those are either co-developed with an existing site, whether it's an existing NIPSCO site or other type of renewable resource, adding batteries to those. So that makes those the fastest right now, with the earliest being the end of 2028.

- Nina Peluso, Energy Futures Group, asked: Can you explain why the pricing on CTs is so much higher than the combined cycles? And also, there are a lot of factors we all know about regarding solar, but could you explain why the pricing is where it's at?
 - Abe Lang responded: CTs are usually cheaper, but this is just based on the offers we received. It's not really very competitive just based on this, so I'll acknowledge that. But so typically CCGTs would naturally be more expensive. Not sure why someone came in that high, but that's what we got in terms of requests. In terms of why solar has gone up, it's a similar reason to gas, but it's obviously not gone up anywhere near as much as gas. Gas has gone up by two or three times from what it was just two years ago. Solar's gone up, though, similarly, because a lot of large counterparties are interested in the energy value that solar provides. They want some of that energy as well, so that's part of what has driven up the cost. There's also the foreign entity restrictions on the tariffs and the trade issues that the United States is experiencing, which have played a role in that. It is a combination of both of those things.
- Selma Sharaf, Synapse Energy Economics, representing Sierra Club, asked: In the slides published online, there was a CT cost of \$4,406/kW. Can you please provide more information about that and why it is missing from this slide?
 - Abe Lang responded: Our initial deck had \$4000. I didn't realize the copy I had here was incorrect, but we can correct that. But a lot higher than we expected, I think, is the expectation.
- La'Tonya Troutman, founder of HEART & a Northwest Indiana ratepayer advocate, asked: After all costs are included, which option produces the lowest monthly residential bill, and do you know how much that would be?
 - Abe Lang responded: We are not going to get to a rate class level bill impact view as a part of this process. We are just going to show the broad-based customer cost and what it means for the system as a whole. We cannot provide a specific estimate of how residential bills would be impacted.

Portfolio Development & Scorecard

Abe Lang, Manager Strategy and Risk

Abe Lang presented the portfolio analysis approach and how portfolios will be analyzed through the scorecard, and reviewed the IRP stakeholder advisory meeting roadmap.

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

- Nina Peluso, Energy Futures Group, asked: Can you explain the addition of the social and economic impact pillar, though it's not one of the five Indiana pillars, and the combination of reliability and resilience rather than staying with the five standard Indiana pillars.
 - Abe Lang responded: The five are incorporated here as you mentioned. We have added the last one there, the positive social and economic impacts to our community, because that is something we believe, by signing up these data center customers, they can provide value back to the NIPSCO native load customers. We've highlighted that in our public materials in terms of the expected

value that is going to come back to customers in the form of bill credits from GenCo to NIPSCO, so we want to continue to reiterate that. We also want to mention that there is a significant amount of property tax value that both our generation facilities and any associated assets that come with those are going to provide to the local communities. That is an important thing to call out because we understand that having a new generation resource in a particular community can raise a lot of questions, but we want to highlight some of the economic benefits so that the public is aware of what those are.

- Nina Peluso, Energy Futures Group, asked: I think unfortunately, without a full estimation of rate or bill impacts, the NPV of a property tax or a bill credit back to a customer doesn't itself confer a rate change or a bill change. So I would actually say that this isn't terribly indicative of any progress on any of those five pillars. I do think they're useful metrics, but I don't know that they necessarily have a place in the scorecard, within Indiana's construct. One of my other questions is on affordability. Here you've got revenue requirement, which I think is a good start, I would really like to see a customer or household specific affordability metric. So that NPV is great. It tells us about system cost, but to my previous point, we don't have anything on here that tells us anything about what an individual residential or small commercial customer might be paying. Would it be possible to consider implementing such a metric?
 - Abe Lang responded: We can consider it, but we'll have to discuss it internally. If there's a specific metric you'd like to propose, we can discuss it. We are not going to commit to it though. We want to stay consistent with what we've done in prior IRPs and how we compare customer costs using net present value of revenue requirement. There is a lot of complexity to creating the type of metric that you're looking at, and I'm not talking about in terms of the formula. I understand what you're getting at, but there's a lot more complexity in determining that. And then we want to make sure that we put out a customer billing impact when we do rate cases. We want that to continue to be the process where we show that. Whereas as rates change, that is more clear because it's inclusive of more cost than just generation. The IRP is primarily focused on generation. And so if we were to highlight something very specific, it might get muddled in what we show in our next rate case, for example, because we're including a lot more cost when we're talking about bill impact in a particular rate case. So that's traditionally what we've done and that's most likely where we're going to do this IRP. But if there's a metric you'd like to propose, we will consider it and discuss it in turn.
- La'Tonya Troutman, founder of HEART & a Northwest Indiana ratepayer advocate, asked: How will NIPSCO weigh affordability, environmental effects, and local economic benefits when those results point in different directions? Is there a household bill increase or affordability level that would make a portfolio unacceptable, even if it scores well in other categories?
 - Abe Lang responded: I know this came up in a meeting that the IURC put on just a couple weeks ago relating to IRPs. And there's a question around weighting. How do we weight the various factors in the scorecard? And although we don't have a specific weighting formula between these variables, there obviously are some that are more important than others. And I'll highlight right now in terms of cost and reliability, those are probably going to be the two highest weightings when we make a decision on our preferred plan. Customer cost and reliability. And when I say customer cost, I'm not just talking about whatever our reference case shows, it's really customer cost risk. We want to make sure we're doing things for the long term that consider different policy environments, that consider different load environments, and what is the best plan, not just in terms of where the policy environment sits today or where load sits today, but over the long term. So I would say customer cost, customer cost risk, and reliability are the heaviest

weights that we apply when we look at this. We still do consider things like flexibility, carbon emissions and local economic benefits in the portfolio.

- Marc Blanchard, BP, asked: On the slide, you have Cost Certainty, Cost Risk, and Lower Cost Opportunity as NIPSCO. But for Carbon Emissions, you show NIPSCO plus GenCo. Can you elaborate any more on that, what is driving that?
 - Abe Lang responded: We are not showing GenCo costs as a part of this. We are trying to just focus on what is the NIPSCO customer cost for this. The GenCo costs are handled in the special contracts based on the rate that is charged to that customer. We don't want to confuse this metric with any of the GenCo costs.
- Nina Peluso, Energy Futures Group, asked: Replying to your response to my first question, I would say that if you don't want to have those sort of unindicative metrics, then the NPV of property taxes and the bill credits pass back to customers, are similarly metrics that aren't indicative of affordability. I want to have a conversation about the consideration of those metrics. The recommendation for an affordability metric to add would be an energy burden metric. I'm happy to provide past examples of that. On resiliency, I would say that megawatts of black start and fast start capability is not a standard metric for resiliency. We tend to look at those using other metrics, and I am happy to recommend others.
 - Abe Lang responded: If you have metrics you would like to suggest when it comes to resilient supply and flexibility, please do send them for consideration.

Calendar & Next Steps

Abe Lang, Manager Strategy and Risk

Abe Lang reviewed the calendar and next steps. NIPSCO is planning to submit the IRP on February 1, 2027. The second stakeholder meeting is scheduled for October 20, 2026, and the third stakeholder meeting is planned for January 13, 2027.

Closing Comments / Stakeholder Questions

Robert Sears, Director, Regulatory Policy

Robert Sears concluded the meeting with closing comments and a final opportunity for stakeholder questions.

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

- Selma Sharaf, Synapse Energy Economics representing Sierra Club, asked: Can you please confirm that NIPSCO is assuming no EPA GHG regulations in the base case? Also, can you please confirm that NIPSCO is assuming lithium ion battery availability because of foreign content requirements?
 - Abe Lang responded: We are not assuming any EPA greenhouse gas rules in our reference case. In our scenarios, which we will cover during stakeholder meeting #2, we will talk about a scenario where those rules or similar rules come back into place, but in our base case, we are not considering any EPA greenhouse gas rules. We did get lithium ion battery submissions as is listed here in our RFI, so we are assuming that at least a good portion of the 16 that were shown are lithium ion batteries. So, there will be lithium ion batteries that we will be considering in our modeling. However, as we go forward, that availability may continue to be constrained as projects get taken up and supply becomes less.