Northern Indiana Public Service Company LLC
Integrated Resource Planning
Public Advisory Meeting #2
SUMMARY

October 20, 2026

Welcome & Introduction
Jessica Cantarelli, Communications Manager
Amanda Lopez, Sr. Communications Specialist

Jessica Cantarelli and Amanda Lopez provided introductory comments including the Meet Safe instructions, a safety moment, stakeholder advisory meeting protocols, and a review of the agenda.

Kick-Off
Erin Whitehead, VP Regulatory & Major Accounts

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

Stakeholder Meeting #1 Recap & Action Items
Abe Lang, Manager Strategy and Risk

Abe Lang provided a recap of the first IRP stakeholder meeting, which was held on September 23, and reviewed action items resulting from that meeting.

Portfolio Modeling Approach
Abe Lang, Manager Strategy and Risk

Abe Lang presented the portfolio modeling approach, including the resource planning approach and the analytical framework for evaluating future uncertainty.

MISO Capacity Accreditation & Reserve Margin
Abe Lang, Manager Strategy and Risk

Abe Lang provided information regarding MISO resource adequacy and accreditation under Direct Loss of Load (DLOL), reviewed MISO's recently released accreditation outlooks and discussed risk.

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

- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked for clarification slide 17, for the different future years, which study year is NIPSCO planning

to use for the IRP?
    - Abe Lang responded that we are planning to use Futures 2 for the IRP baseline accreditation, which is what MISO said was their current state case when we had conversations with them. We will look at some scenarios that consider some other things, but Futures 2 is our baseline.
- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked a follow-up question regarding the other scenarios, and if those are represented in the scenarios that will be outlined today, or are those other sensitivities that NIPSCO will be running?
    - Abe Lang responded that we are going to be running sensitivities, particularly on the storage accreditation. That is the one thing that we are going to flex because it is probably the most uncertain. We do not think we are going to flex the other resources as a part of this, but if you have suggestions, we can. We are potentially looking at some of the other future scenarios, but Futures 2 is our baseline. We are going to run a sensitivity then on storage that looks at either some of the other futures or an acceleration of what is happening in 2045 in Futures 2.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, asked about the use of the Futures 2 case. In the workbook that was provided to several of the stakeholders, NIPSCO was using accreditation values from the September release of the Futures 2 study. But one of the things they have noticed about that study is that there are no accompanying PRM values, seasonal PRM values. NIPSCO used PRM values from the direct loss of load, indicative values that were published for the 2025-26 planning year. Did NIPSCO talk to MISO about which PRM values to use, to go with the future study?
    - Abe Lang responded yes, and that we would get into that when we talk about our supply and demand balance. MISO put out some indicative numbers, or output numbers (not really indicative), but output numbers in the September release for PRM percentages that were extremely high. NIPSCO discussed with MISO because our understanding is with the DLOL construct the PRMR requirements would go down as a percentage of the peak. MISO provided general guidance with fit roughly with their 2025-26 indicative values, so that is why we reference that as our starting point for our planning reserve margin requirement.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, followed up stating it's clearly very important that MISO puts out long-term accreditation values because having those values and having some sense of stability in terms of knowing where they might go is a big gap in resource planning in the MISO footprint. What concerns them about the Futures 2 study is that the accreditation values are significantly lower, especially for thermal generators, compared to the indicative values that MISO has published. If you use a PRM from a different modeling effort, there can be some mismatches that are not transparent and may end up having a much bigger deficit of capacity. Is there an upcoming meeting that MISO is planning to talk about how to use those futures values? And are you thinking that you might be able to update the values in the conversation at the RASC meeting, or is this what you need to go with because you have a relatively limited time frame in which to produce this IRP?
    - Abe Lang responded that this is what we are going to go with for now. We provided the data set that has all of our IRP modeling inputs. At the conclusion of this meeting, we are going to start the modeling process and begin sharing results. MISO has not put out clear guidance around their planning reserve margin requirement, particularly around the futures scenarios that we looked at. We wanted to use some published document to reference, and the closest thing to what MISO told us, was their 2025-26 indicative value for planning reserve margin requirements. We understand we are picking an old vintage for the planning reserve margin requirements and a newer one for the resource accreditation, but

right now there is no new planning reserve margin requirement that MISO has put out. If MISO has something that is dramatically different at their next meeting from what they have told us, we may take that into consideration. But right now, we are going to start our modeling based on the guidance they gave us.

- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, are you talking to MISO resource adequacy contacts, Neil Shah and Davey Lopez?
    - Abe Lang responded: Yes, for resource adequacy.
- Tyler Comings, Synapse Energy representing Sierra Club, asked: What is the default assumption for battery accreditation right now using event loss or early dispatch?
    - Abe Lang responded: We're looking at even loss. That's the assumption that might support out in terms of the guidance. And so that's what we're going with.
    - Pat Augustine also responded: That's right. That methodology is what was embedded in the futures projections that were just being referenced. In the slide we were showing is really an illustration of the type of uncertainty and the variance that MISO has put out over the last couple of years as they've studied this. But the even loss methodology is what is in there.
- Patrick Kelley, OUCC, asked: On slide 20, could you elaborate more on why the uncertainty in winter is growing beyond that winter is getting colder? I'm not understanding what was in the model that you ran to get that kind of distribution for uncertainty--the risk hours--in your simulation?
    - Abe Lang responded: There are a few variables: 1) The load shape – a lot of the load growth that we expect over the next 20 years is likely to be more 24/7 type loads, like large data center loads, as opposed to the traditional residential commercial shape that gets more concentrated in the summer. If you look at the relative load profile of summer versus winter, over time, 20 years from now, if you assume a lot of that load growth is more 24/7 base load, you are going to have higher growth rates in the winter versus the summer. Everything is going up, but the relative position of winter to summer is going to become a little bit more concentrated in winter as well. 2) The system is likely to get more intermittent in nature, so you're having a swap out of fossil resources of thermal resources for renewables, both wind and solar. Solar does worse in the winter than in the summer, so that is going to be a contributor. And although wind has potential to be relatively strong in the winter, there are periods of wind droughts that occur during the winter season that could be for several hours, and that is driving it. It's really the combination of those factors, load becoming a bit higher overall in the winter season relative to the growth rates in summer, and the more intermittent resources that opens up more risk.
- Patrick Kelley, OUCC, followed up with: In the simulation, have you also considered, for instance, you said it will switch to intermittent, solar and wind. Is there a situation simulation when you would switch it to nuclear? Nuclear may be an option by 2045. It is going to be more of a 24/7 demand. It will raise everything up. If you have a baseload that will match that, such as nuclear, that will basically balance it out.
    - Abe Lang responded: This is based on the reference case that we shared at the last meeting.
- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: Regarding the Schahfer gas peaker on slide 9, you have it listed as in pre-construction. Could you talk a little bit more about getting that unit online in 2028 as it's referenced here, both in terms of construction agreements and interconnection agreements?
    - Abe Lang responded: We are assuming the gas peaker is having the same in-service data that was previously assumed, which is the end of 2027. There is some risk to that, which we can take offline. But right now, we are assuming that as a part of our baseline. If that date changes, we will update this group. We do not have any of our major projects folks here today to talk through the risks, but

we acknowledge there are some risks to that in-service date.

- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: Would it be feasible to have those major projects folks on a technical stakeholder meeting, but also the next public stakeholder meeting as well, to the extent that risk is relatively large?
    - Abe Lang responded: Yes, to the extent that it is large, we will have somebody available to speak to it potentially at the next stakeholder meeting. We can talk about it at one of the private technical stakeholder meetings if you are interested in that. But we do not have a new date to communicate right now, but we will provide additional details as needed as anything comes up.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, asked: Can you clarify whether the Schahfer CTs are indeed under construction right now?
    - Abe Lang responded: The Schahfer CT is under construction right now. The site is being prepared. I cannot comment on the specific details of what progress there is at the site right now, but we can take that as a follow-up action to provide.

Supply-Demand Balance / Resource Adequacy Needs
Abe Lang, Manager Strategy and Risk

Abe Lang explained the refined seasonal peak load forecast methodology and discussed the NIPSCO and GenCo IRP starting capacity position for summer and winter seasons.

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

- Nicole Chandler, Sierra Club, asked: Where will the Microsoft data center for LaPorte get their power?
    - Abe Lang responded: GenCo will be providing its capacity and that capacity is included in the charts. There is a large battery that is being built to support their capacity, as well as the GenCo pool of resources, which is there. GenCo provides capacity to these data center customers. The data center customers are responsible for buying their own power, and that will not affect the NIPSCO customer base.
    - Bryan Likins also noted that NiSource's upcoming Q3 earnings call will have more information, and we will make an IURC filing in late December.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, asked a clarification question on the slides: Does the capacity purchase shown represent an agreement that has already been executed?
    - Abe Lang responded: Yes, anything that's here represents something that has been executed.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, asked follow-up: So, there is a bilateral contract with some other generator to provide capacity?
    - Abe Lang responded yes.
- Patrick Kelley, OUCC, asked: On the previous slide, you showed summer and you were within your planning reserve margin requirement, but in winter, you are below it. Could you provide some clarity on that?
    - Abe Lang responded: Any shortfall will be solved for by GenCo and paid for by GenCo customers. The reason there is a difference is because the same resources that are supporting both the summer and winter have different accredited capacity in those respective seasons. So, it's the same pool, or it's not a different pool of resources, between summer and winter.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, asked: The accredited capacity values that you are showing for the native customers includes the Michigan City and Schahfer 16A & B units in 2027 and 2028. Those accredited values do not match up with the fleet-wide class average. They are a lot lower. Can you explain

why?
    - Abe Lang responded: Michigan City underperformed slightly over the past two capacity years. As a result, their accredited capacity was lowered in the near term, so it is not getting as high as the class average coal is across the season. For Schahfer 16A & B, those units have not run much in the past couple capacity seasons. They did not have as start of a drop as Michigan City, but it is the same story.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, asked: Are these values reflecting Schedule 53 or DLOL accreditation for those units, Michigan City and Schahfer 16?
    - Abe Lang responded: We are just assuming the latest PRA for Michigan City and Schahfer 16A & B. That would be the 2026-27 PRA. We are assuming those values going forward. We do not expect a material change once DLOL is in place. So right now, at least in this baseline, they are only going to be assumed online for a brief period of time. We can get into this more later in the meeting, particular around Michigan City, one of the things we would consider is if we were to continue running it, getting that capacity value higher and when that would happen.

DSM: IRP Input Overview
Abe Lang, Manager Strategy and Risk

Abe Lang presented the DSM process overview.

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

- Denise Abdul-Rahman, Black Sunlight Sustainability, asked: Why does GenCo show zero solar, wind, or geothermal as a resource?
    - Abe Lang responded: What GenCo is providing to these customers is capacity. The high value capacity resources are primarily focused on things like storage and thermal resources, so that is what is showing up in the GenCo portfolio. That does not mean that the GenCo customers or GenCo itself will not have those renewables going forward, like solar. That may be a part of the mix, and the GenCo customers may choose to purchase solar energy as a part of the mix. Our focus right now is on making sure they have adequate capacity on the GenCo side. So that is what is shown that has been secured as of today for their capacity need. That does not mean that those will not be a part of the mix.

Market Scenario Analysis Concepts
Pat Augustine, VP, Charles River Associates

Pat Augustine presented market scenario analysis concepts, including fundamental market modeling structure and an overview of scenarios and price drivers.

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

- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, commented: The level of build that is in your model that you showed in the first stakeholder meeting represents a much higher completion rate for new generators in MISO that has occurred in the past. So, your model essentially implies that 75% of generators that are in the various MISO queues will reach their in-service date and will reach it by 2030 when historic completion rates are about 14%. That's just assuming that the in-service dates that are in the queue actually hold. We know that some of them have already missed

those dates and even if they get a GIA, they will get a three-year window to delay in-service before they lose their GIA. So, it seems that the main implication of that is that it is going to be really hard to put much stock in these energy market prices and in the capacity prices too. I don't know that it makes sense to resolve that through the modeling that you are doing. I think it probably makes sense to make sure that the expansion plan isn't relying to any great degree on energy sales or purchases or on capacity sales or purchases. The other thing I would say about the modeling that you're talking about is that historically, zonal modeling has been used to develop commodity pricing. That's very typical for industry, but we now live in a world in which congestion matters a lot. And you can't capture that through the zonal model that you are talking about here. And NIPSCO service territory happens to be located in a part of the state of Indiana where congestion is expected to be quite significant because it's sandwiched between the two regions of PJM, and it's the connector into Zone 7 into Michigan and MISO. And congestion itself can raise energy prices significantly, and that cannot be captured through a zone model.
    - Pat Augustine responded: I agree in general that the market is tightening in a lot of respects. The analysis that we've done here does take as a given the low forecast. It's possible that the pace of low growth responds or reacts to the ability of supply to come online. So, there's always that feedback. A lot of the capacity that we include in our analysis, both in the reference case and the SLG case, is approved capacity. You're right to say that it could e delayed, but especially the thermal capacity that we have for the most part has been approved via commission orders or is under construction. But I think you're raising a fair point that delays could result in more scarcity or a different supply demand balance than what we will show in a couple of slides. I will note that I think the SLG case is designed in part to simulate that type of outcome. And as you'll see, we've got higher energy prices, higher capacity prices, because this is a case that has low growth, outpacing the ability for supply to catch up. And as a result, we'll have higher market prices, and to the extent that NIPSCO is evaluating energy market purchases and sales and capacity market prices in the portfolio analysis, you'll have a much higher outcome in that scenario versus the reference case.
    - Abe Lang also responded: We do think that there will be an increase in the amount of items that are in the queue that actually make it to their COD, either on time, or don't drop out of the queue. The reason being there is a lot more of these resources that are going to come online in a sustained low growth environment, or just as we have data centers, even in our reference case. A lot of them have off takers or expected off takers. So, it's not what's happened in the past, which is putting stuff into the queue when they don't have an off-taker agreement. We think there's probably a lot more in the queue today, or that will be in the queue in the future, that will come to fruition because there is going to be demand; there is going to be off takers for those. So, some of the more speculative queue stuff in the MISO queue that has happened in the past, we do not expect that necessarily to stay the same in the future. Regarding congestion, we will take an action item to look at a congestion study after the IRP has concluded. That is something that we have done in previous IRPs, where we look at what congestion would mean for our customers. We have some baseline assumptions that we used from past IRPs that we have included in the data package that was sent out. But we agree a more formal congestion study will be needed. We will not have time between now and January to do that, but after the IRP, we will take an action to do a more formal congestion study.
- Patrick Kelley, OUCC, asked: For your aggressive environmental regulation (AER) scenario, you mentioned that you are going to have the base demand (that's referenced), but then you also state that the demand from thermal is going to decrease, which is also going to decrease the cost for natural gas. That's a natural consequence of it. In the

queue, or what you see in NIPSCO, I'm assuming then that renewable energy or renewable generation is going to meet that base demand in the AER scenario. Are there enough renewables that you see in the MISO grid or MISO queue that could actually meet that demand?

- Pat Augustine responded: In general, yes, in a couple slides, we'll see what the outlook looks like. And again, any modeling like this is based on the assumptions that you put in, and there are limits on how much wind and solar can come in by zone, by year, in these types of simulation models. But as you will see, there is a significant growth in wind, solar, battery storage, and nuclear to meet those demand requirements in that AER scenario when that straight carbon price comes in. We will get into some of the details in the next couple of slides. But I think the short answer is yes, with the caveat that there is a lot of local permitting, there is a lot of siting, there is a lot of transmission interconnection, and a lot of contracting uncertainty that exists on top of all these other policy and fuel price uncertainties. I think the main objective of this exercise is to give us a range of inputs to model with. So, we have a range of gas prices, power prices, environmental costs, and then an internally consistent engine that has correlated power prices and correlated hourly shapes in those power prices. So, when we take it to the NIPSCO level, we are doing it in an integrated fashion as opposed to just moving one lever and ignoring feedback.

- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: Has the congestion study from the previous IRP ever been formally considered in the subsequent IRP?
  - Pat Augustine responded: There were congestion studies that were done to look at the relative local price for that specific asset versus more of a zonal price that was used in the IRP.
- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: On the current graph, the AER scenario has a dip, or a change around 2034-35, and then for the sustained load growth, it has another spike or so in 2037. Can you elaborate on why those two time periods have a change in those scenarios?
  - For the AER scenario, the short answer is that is the year when we have the carbon price assumed to come in, so this is showing that introduction of a carbon price in 2035, which would have the impact of significantly changing the demand profile in the power sector for any fossil resource. It has a bigger impact on coal, but the idea here is that is the time when this policy would come into force and you would have some erosion of the amount of natural gas that is being demanded, not only in the MISO market, but potentially in other sectors of the economy and in other regions across the country. So that is the driver there. In terms of the SLG price trajectory, it is really just an acceleration of overall demand post 2036-37 and you re getting up the supply curve of natural gas and more and more demand for that product is pushing the price up.
- Anna Sommer, Energy Futures Group on behalf of Citizens Action Coalition, asked: I don't disagree that completion rates could rise, but the difference between 13% and 75% is pretty significant. And the other dynamic that matters for this analysis is that the volume of generators coming online means that those generators could well be limited by MISO's deliverability studies. New generators could have contingent facilities that mean that full service is delayed for many years after the generator has reached completion.
  - Pag Augustine responded: I agree. We see risk in there in certain seasons. We haven't fully commenced our modeling yet, but there are certain seasons where we may consider market capacity purchases in small amounts. But for the most part, we are going to assume that we are going to try to be resource adequate in all seasons. If there is an exception for some specific reason, we will note the risk around that.

- Anonymous attendee asked: Are these lifecycle emissions?
    - Pat Augustine responded: No, these are direct emissions from electric power generators across MISO (fossil generators at MISO.

Environmental: Costs & Considerations for Retirement Extension
Paul Heyborne, Manager Environmental Policy & Sustainability

Paul Heyborne discussed environmental investments required for continued operation of Michigan City Generation Station and Schahfer Generating Station Units 17 and 18.

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

- Cindy Armstrong, OUCC, asked: On slide 53, I'm curious about the $13M, the lower range of the Schahfer Operation into 2029. What does that assume:
    - Paul Heborne responded: That is for converting the submerged flight conveyor system from 14 to 15 was already there over the 17 and 18, and that is for bottom mass transport water treatment. We feel confident in these numbers; these are considered class 5 cost estimates, so they would not be super refined.
- Cindy Armstrong, OUCC, asked: If you do not operate beyond 2028, does that mean you plan on participating in the voluntary incentives program?
    - Paul Heborne responded: Yes, it would. We filed the 2028 NOPP, which allows us to extend operations through the end of 2028. But when the increase in TSS limits – it's incorporated into our permit right now – but the future program would require us transferring out of the NOPP through the formal process that EPA allows.
- Cindy Armstrong, OUCC, asked: Is this a possibility that you are seriously looking at in this IRP given the endangerment finding?
    - Yes, that's greenhouse gas emission related. These are the costs that are going to be incorporated under these different scenarios, and it really will inform the elements of the model. Again, it's not a decision to extend operations, it really is a decision to make sure that we have the best available cost information to include in it. Then when resource decisions are made, we can have full implications.

Incorporating New Resource Options
Abe Lang, Manager Strategy and Risk

Abe Lang presented the NIPSCO 2027 IRP new portfolio resource options.

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

- Cindy Armstrong, OUCC, asked: Are you able to provide maintenance costs for operating Schahfer?
    - Abe Lang responded: For those that have signed the NDA, including the OUCC, we did provide the full data input of what it would take to extend Schahfer. We are assuming the high end of all these ranges in our modeling because of the accelerated timeline. For Operations beyond 2029, if we take the $537M, then add an additional approximately $185M on top of that for repair costs, some of which are currently being done to the unit under the 202C order. They are not being recovered through base rate, so it's not being charged directly to NIPSCO customers. So that spend is in progress right now because we are being compelled to do that under the 202C order.
- Jennifer Washburn, Citizens Action Coalition, asked: What is the cost spent on Schahfer Units 17 and 18 this year given the 202C order?
    - Under the FERC MISO tariff, which is being filed, it's around $85 million to be

spent by year end. We can send the exact number. It was in the data we provided to the CAC so they should have it. It is not in base rates.

- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: Can you provide more color on how CODs were determined for both traditional and emerging technologies? Are these all reflective of actual bids or are there any additional assumptions made? If so, for which technologies?
    - Abe Lang responded: Yes, for solar all the way down to standalone storage, those are representative bids that we got. For CCGTs, that was representative of bids that we got with a little bit of verification from our internal projects team. But 2034 was the average date that we received for CCGTs. For CTs, that COD is what we have determined we could build something internally. For emerging technologies, for linear generation, we have treated the same as a CT resource; based on discussions with the vendor that provided a quote for linear generation, it would follow the same timeline as an internally built CT resource. For nuclear, that came directly from a single vendor quote for what they said that they could delivery by 2035. For sodium/iron air batteries, that was also based on a vendor quote.
- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, followed up: Were any of the CODs received for the other CTs as early as Q2 2030?
    - Abe Lang responded: Yes. We can send the detail, if we haven't already provided it in the data input package.

Portfolio Concept Review
Abe Lang, Manager Strategy and Risk

Abe Lang presented the portfolio analysis approach from portfolio concept development, to evaluation, to preferred portfolio selection, discussed stakeholder portfolio suggestions, and shared NIPSCO's proposed portfolio concepts to model.

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

- Ben Inskeep, Citizens Action Coalition, asked: You are saying GenCo had 4 GW of signed capacity prior to Microsoft. That is inconsistent with my understanding, which was closer to 3,000 MW prior to Microsoft. Could you help me understand that? And them help me understand if the 3 and the 5 GW additional load, or is that additional generation to meet potential speculative data center load in the future?
    - Abe Lang responded: The 4 GW that you see was in all of our investor relations materials, that is signed installed capacity on the GenCo side, not necessarily signed accredited capacity. The load on the GenCo side prior to the Microsoft announcement was just over 3000 MW at peak. That was what we had communicated in the last IRP stakeholder meeting. The 4 GW of signed capacity was installed capacity. Once you take the appropriate percentages off for accreditation, it was lower than 4 GW. So that 4 GW is installed capacity, not accredited capacity.
- Ben Inskeep, Citizens Action Coalition, followed up: It looks like this slide is mixing load and generation in an inconsistent manner. Can you elaborate on that?
    - Abe Lang responded: The chart shows signed generation, signed capacity, essentially. We have communicated our investor relations materials since we saw the opportunities for an additional 3 GW in strategic negotiations and an additional 2 GW in developing opportunities. For the purposes of this sensitivity, I'm translating that into potential mode opportunities.
- Ben Inskeep, Citizens Action Coalition, followed up: On the other sensitivity with storage, I'm curious why you're focused only on a sensitivity modeling a less favorable storage scenario that's not the current policy, but not for other resources like natural gas, for

example. I understand there's some uncertainty there, but it seems like that uncertainty would extend all resources 10 years out from now. Could you help me understand that?
    - Abe Lang responded: What we see is natural gas resources as holding their capacity value more stably over time. If you look at the MISO class averages for natural gas, there is some risk that's associated with that, but it's not as severe of a decline as you would see here with storage. There is no other resource within the MISO Futures 2 forecast that they put out that has as much volatility as storage. So natural gas does go up and down a little bit in what they projected, but it doesn't have the volatility storage does. I think the reason for that is this natural gas is both capacity and energy, gas-fired resources. They can provide capacity and they can provide energy. They are not reliant on other resources to provide their energy. Obviously, there's potential for natural gas to be constrained during certain times of year of high gas demand. We do feel that gas though as a whole, but CCGTs and CTs will generally hold their capacity value over time, assuming proper maintenance. The same cannot necessarily be said of storage. We can do all the investments we want to in storage, but if there isn't energy available to charge up the batteries, of the gith hour periods that MISO assigns are longer than the four-hour duration of these batteries, we could quickly run into trouble, So that's the thing that we need to consider is that there's a level of uncontrollability on the storage side.
- Tony Mendoza, Sierra Club, asked: I wanted to follow up on that accreditation issue for storage. In that Futures 2 that you were showing, the slide that you were just focusing on, how much storage is on the MISO system at those points that are revealed?
    - Abe Lang responded: I don't have that in front of me right now. They do have it in what they publish in their futures document, so we can take an action item to send that over to you.

Scorecard Update
Abe Lang, Manager Strategy and Risk

Abe Lang discussed proposed changes to the scorecard through which portfolios will be analyzed.

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

- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: Could you explain in a bit more detail why it was not feasible to take on a cumulative carbon emissions metric instead of a carbon intensity metric?
    - Abe Lang responded: Across the entire industry, because of the way regulations and policy are set up right now, and because of how much they've changed as a result of the current presidential administration, where there isn't support or pressure to move toward those goals, our focus as we are growing, and as a lot of other utilizes are growing, is on making sure that the megawatts that we produce have a lower and lower amount of CO2 emissions rather than just looking at what are the total emissions. Across the industry, emissions are going down. That's what's happening, so our focus right now is just on a CO2 per MW. We will share as part of our final data package the output of what the total emissions look like for each portfolio. But that's not going to be a metric when we compare portfolios to each other that we decide on this is going to be the better portfolio. It's going to be much more focused on this metric as well as the cost and the reliability metric. We will still have total emission, which we will share as part of our portfolio output. We want to focus on emissions per MW hour, given the growth that we're seeing across the industry.

- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: On the positive social and economic impact, which is not actually a pillar that you're expected to measure in terms of IRP, our comments requested that both of these metrics be removed. To your previous point, the bill credits passed back to customers, I agree, are a potential benefit, but without the context of what the overall bill is, there's no ability to understand whether that will actually mean a bill will go up or down for a customers. So, this bill credit passed back to customers in my view is not an indicative of a benefit and that's not a reasonable metric to be comparing the portfolios against. So, I'm wondering why it wouldn't be feasible or whether you've considered looking at these bill credits within the larger context of a total customer bill?
    - Abe Lang responded: That's an interesting point. The reason I think we're avoiding that, and it kind of coincides with what I mentioned around energy burden, is that there's a broader set of costs that customers face, which we're not looking at right now as part of this IRP process. For example, T&D cost, unless it's directly connected to a generation resource, that T&D cost is another portion of a customer's bill, so including these bill credits that are coming on as a part of the GenCo capacity being added, it's just a nominal kind of understanding of what it would do to a customer's bill. It doesn't necessarily give an exact impact.
    - Bryan Likins also added: I would note with the GenCo structure, the fact that additive data center load does not add cost to the NIPSCO bill but does add a corresponding reduction via the bill credit is really what we're trying to evaluate there. So, if the cost to serve the data centers was rolled into rate base in a traditional sense, then you would need to offset against it and evaluate both sides of that equation. But we're evaluating the NIPSCO side on its own without any GenCo costs being added there. Thus, it's purely a benefit as the data center load comes online.
- Rebecca TeKolste, Hoosier Environmental Council, asked: Are the comparative dollars per megawatt hour going to be available to the public as it relates to how you ultimately decide to support the GenCo needs?
    - Abe Lang responded: I have no idea what the GenCo customers are paying. That is confidential and it's not known to the NIPSCO folks who are working on this IRP. That's how steep the segmentation is even within our company. So, I cannot answer that directly.
    - Bryan Likins also responded: I think the difficulty is those costs are not known. The other piece of that is they may individually negotiate via the customer specific contracts or special contracts. The Commission or any stakeholders that have participated in each one of those underlying filings, such as OUCC, NIPSCO Industrial Group, or Citizens Action Coalition, would be able to see what those underlying costs are, with NCAs in those respective agreements. Those costs are typically total capex costs. They don't, for example, bring in the full cost of gas or energy purchases or things like that. It's more of the installed capacity cost on an estimated capex and then also different contract structures in terms of is the customer risk general risk, or is there shared risk, if there are possible overruns and things like that, which is a very different environment than how that works.
- Rebecca TeKolste, Hoosier Environmental Council, asked: I know we've done different scenarios to model different costs of gas inputs. Knowing we're increasingly relying on gas and the cost of gas is going to become increasingly volatile and will be passed on via the fuel tracker, is there a way to incorporate a metric in this scorecard that would say with more reliance on gas leads to greater risk to the customer?
    - Abe Lang responded: We are putting some scenarios where gas prices would go up. Those scenarios will be reflected in the scorecard output for when we do those runs. So yes, we are looking at if gas prices go up and you have a portfolio that's over reliant, what does that mean from a cost risk perspective. I also

recognize those scenarios that are run are not one-to-one comparisons. You look at them and then see what's the best option based on all of these various scenarios.

- Nina Peluso, Energy Futures Group on behalf of Citizens Action Coalition, asked: If the bill credit is fully separate from this IRP, how will it differ from portfolio to portfolio?
    - Abe Lang responded: It will only show up in the GenCo sensitivities that we run. When we run a GenCo sensitivity that assumes a higher amount of load, technically it will be roughly the same from portfolio to portfolio, except when we look at those higher GenCo load sensitivities. But it will be the same across the NIPSCO portfolios.
- Selma Sharaf, Synapse Energy Economics, representing Sierra Club, asked: Has NIPSCO considered costs associated with future coal ash disposal from Michigan City, assuming its coal ash is currently transported to Schahfer?
    - Abe Lang responded: We have current costs that are built in as a part of our ongoing operations of Michigan City, and those will just continue going forward. We do have those costs built into our modeling that the costs we're experiencing today, we assume would continue as a part of transporting and disposing of the coal ash.
- Selma Sharaf, Synapse Energy Economics, representing Sierra Club, followed up: Do you have enough capacity there to continue operations for Michigan City beyond the 2028 timeframe? And if not, have you taken into account any kind of cost to permit and build a new cell?
    - Abe Lang responded: Yes, as of now, those are built into our costs to run beyond 2028. However, we have one portfolio where we're looking at an indefinite run of Michigan City. In that instance, there may be some additional costs that we need to consider. So, we will take that as a follow-up to look at.
- Dottie Warrick, retired NIPSCO employee, asked: Do the commissioners in Jasper County know that you are taking the coal ash from Michigan City to Schahfer?
    - Abe Lang responded: Yes, that is what is currently happening as part of Michigan City's operations.

Calendar & Next Steps
Abe Lang, Manager Strategy and Risk

Abe Lang reviewed the stakeholder advisory meeting roadmap and discussed content for the third stakeholder meeting, which will be held January 13, 2027. A virtual one-hour stakeholder meeting for DSM review will also be held on November 3, 2026.

Closing Comments / Stakeholder Questions
Erin Whitehead, VP Regulatory & Major Accounts

Erin Whitehead concluded the meeting with closing comments and a final opportunity for stakeholder questions.

Energy Futures Group Presentation
Drew Siebenaler, Energy Futures Group

Drew Siebenaler, Energy Futures Group, made a presentation on Transmission Considerations – Optimizing Portfolios and Avoiding Risk.