# Indiana Michigan Power Company's 2024 Indiana Integrated Resource Plan

## Stakeholder Workshop #3A

## December 18, 2024

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# Welcome & Introductions

*Kayla Zellers covered Slide 1.*

Kayla Zellers, Director of Resource Planning at Indiana Michigan Power Company (I&M), called the meeting to order at 2:00 PM on December 18, 2024. Kayla welcomed participants to Stakeholder Meeting 3A for I&M's 2024 Indiana Integrated Resource Plan and introduced Andrew Williamson, I&M Director of Regulatory Services.

*Andrew Williamson covered Slide 2.*

Andrew welcomed stakeholders to Meeting 3A. Andrew reminded them that, as discussed at prior meetings, Meeting 3 (modeling results) has been split into two meetings to accommodate the high volume of scenarios being analyzed for the Indiana IRP. Meeting 3B will be held on January 27, 2025. Andrew also announced that I&M has recently filed an extension, requesting a submittal deadline of March 28, 2025 for the Indiana IRP.

Andrew reiterated that this IRP is a collaboration between I&M and its stakeholders and that feedback, questions and comments are encouraged during this meeting and at any time during the process.

Andrew then introduced the remainder of the I&M Leadership team present at the meeting before introducing Josh Burkholder, Managing Director of Resource Planning for I&M.

Josh introduced the remainder of the I&M Resource Planning Team, including Kayla, Mohamed Abukaram, Director of Resource Planning, and Mark Sklar-Chik, Staff Analyst. Josh also introduced the I&M Infrastructure Development Team that were in attendance to help field stakeholder questions regarding market conditions that informed analysis for this IRP. Finally, Josh introduced 1898 & Co., a consulting firm assisting I&M with coordinating stakeholder engagement and conducting technical portfolio analysis.

Josh presented an overview of this meeting's contents. Seven sets of scenario and sensitivity results are being presented at Meeting 3A to help stakeholders understand them and the analysis behind them. This represents approximately half of the results planned for this IRP. Furthermore, a comparison of these results will be presented. Josh reminded stakeholders that this is a preliminary presentation of results; I&M is forming no conclusions regarding a preferred portfolio until a full set of results has been presented for all analyzed scenarios and sensitivities. Josh thanked stakeholders for their participation.

*Kayla Zellers covered Slide 3.*

Kayla stepped through the agenda, presented in the order established within these posted minutes. Kayla reminded stakeholders that questions and comments are welcomed throughout the meeting and introduced Brian Despard, Senior Project Manager with 1898 & Co., to walk through guidelines for stakeholder participation.

*Brian Despard Covered Slides 4-5.*

Brian discussed stakeholder participation- questions would be allowed anytime during the presentation via Microsoft Teams' "Raise Hand" and "Q&A" functions. Any questions regarding the Indiana IRP can be submitted to I&MIRP@aep.com anytime. All questions and answers recorded during this meeting (or shortly after, via email) have been provided within these minutes.

Finally, Brian presented guidelines for constructive participation.

## Going-In Capacity Position Review

*Kayla Zellers covered Slide 6.*

Kayla presented the Capacity Needs Assessment ("Going-in Position"), noting the significant load growth I&M anticipates in Indiana as a primary driver of the IRP and thus important for review.

Kayla walked stakeholders through the going-in position chart, demonstrating the PJM obligation I&M is expected to meet and the surplus capacity I&M strives to meet for contingency. Annual accredited capacity is demonstrated, as is the additional capacity this IRP would need to identify to meet these goals.

Kayla called specific attention to a few individual years. 2028 is the first year in which the IRP model can select generation resources and is also the year in which Rockport Unit 1 Generating Station is planned to cease operations. In 2030-31 the model allows for the selection of additional resources and shows additional hyperscaler load growth. Finally, 2034 is marked by the expiration of roughly 870 megawatts of capacity-only purchases and 800 megawatts of accredited capacity from Cook Nuclear Plant Unit 1, which is available for relicensing selection in the model.

## Q&A Related to Going-In Capacity Position

1. An October 25, 2024 submission by AEP to PJM titled "2024 Load Forecast Adjustments" identifies 6,045 MW of load growth for I&M by 2030. This is much higher than what is depicted on slide 6 for 2030. Can you please explain the difference between these two forecasts, and which one is the current forecast for I&M?
    a. Since the October forecast, I&M pushed some of the forecasted load out into 2034. I&M previously provided load forecast details to technical stakeholders in technical conferences. If anyone would like additional details on the current load forecast, we would be more than willing to follow up on that after the session.

# Resource Modeling Parameters Update

*Kayla Zellers covered Slide 7.*

Kayla updated stakeholders on changes in resource modeling parameters since Stakeholder Meeting 2. These changes include pricing changes for existing natural gas Combustion Turbine (CT) and Combined Cycle (CC) plants. Stakeholders previously requested a review of prices for these resource types, and I&M's Infrastructure Development team provided the higher prices shown in the table on slide 7.

Wind modeling parameters were also updated; for 15-year wind resources, the first year available was shifted from 2029 to 2028, and annual and cumulative build limits through 2030 were decreased. However, the total cumulative build limit through the planning horizon (2024-2044) for all wind assets was increased from 3,200 MW to 4,000 MW. These changes were made based on the best available market information and stakeholder feedback.

## Q&A Related to Resource Modeling Parameters

2. I had a question about the slide you were just talking about (slide 7). As you know, we discussed last time whether the original cost estimates for those existing thermal units were in line with the market. Given the demand for capacity, not just in the PJM footprint but elsewhere, I'm curious how you arrived at these numbers. What was the process you went through to develop the increases shown here?

   a. We provided feedback on cost estimates as part of the technical Stakeholder Comments, which are available on the IRP website at the following link: Indiana Stakeholder Engagement Process. Also, we have an RFP out now and have ongoing contacts with the market that help drive our cost updates. We consider these estimates to be consistent with the current market.

3. How will you represent those units in terms of things like operating life and other characteristics? Are those going to be identical to the new resources, or will those be different for these? Can you speak to what those specific assumptions are? In terms of book life, do you have what your average assumptions are for these existing units?

   a. For existing gas plant options, we computed a 20-year average for asset life in the model, but also have 10 and 5-year options. We modeled multiple options for existing Combined Cycles and Combustion Turbines with 5-, 10- and 20-year remaining asset lives. The variable and fixed costs for these assets are consistent with their remaining lives (5, 10 or 20 years) according to the market data we have received. For heat rates, we took specifications from the market and used that intelligence to derive the model inputs. For example, a heat rate for an existing combined cycle would be higher than for a new combined cycle build. Other existing gas plant parameters such as variable O&M Costs and Forced Outage Rates are also differentiated from new build gas plant parameters based on market information.

# Key Modeling Inputs & Modeling Status Update

*Kayla Zellers Covered Slides 8-9.*

Kayla discussed key modeling points and constraints, including adding an energy import/export limit for each scenario. These limits are slightly higher for scenarios where thermal resources are imposed with capacity factor limitations, which were also presented to stakeholders as modeling constraints. Short-term capacity prices on slide 8 were discussed.

Kayla updated stakeholders on modeling progress, providing a list of which scenarios and sensitivity results would be discussed during Meeting 3A and which ones would be shared during Meeting 3B. Kayla noted that instead of reviewing the Base Scenario High and Low Load Growth sensitivities as planned for Meeting 3A, the High and Low Economic Growth scenarios would be discussed. The Base Scenario with High and Low Load Growth will be discussed at Meeting 3B. Finally, Kayla explained the renaming of the “Carbon Free” scenario to “Low Carbon” and its expansion to two scenarios for further analysis.

## Q&A Related to Key Modeling Inputs & Modeling Status

4. If I recall correctly, you had to allow a higher level of purchases in the early years of the model because otherwise there just wouldn't be enough energy to serve the load and the load forecast. The conundrum that poses from my viewpoint is that relaxing those kinds of constraints within your model on the one hand might be a matter of necessity in order to actually reach a feasible solution, but on the other hand might not actually reflect the situation that is most economic for rate payers or the one that is feasible on the ground. And part of the reason that I say that is that we've also had a discussion about the market prices that you're modeling and I had indicated previously that the development of those commodity forecasts was not based on any modeling that actually assumed the large loads that are in your load forecast. And so, it feels like we're kind of avoiding the elephant in the room, so to speak, which is that the level of additional load within the load forecast is likely to have a material impact on market prices that's not part of the commodity price forecast. And we're also assuming that energy is basically freely available. But then sort of counter intuitively it ratchets down over time, which seems misaligned with where the market is. There's a lot of concern about whether there's enough capacity or energy right now. Whether these regions will be in shortfall right now and instead we're assuming the opposite as we go through the modeling period. So, I guess what I would like to recommend is that you actually try to model a scenario that gets at those dynamics, a scenario that has significantly higher commodity prices, for example. So even if that's just increasing those market prices by 25% in every hour of the simulation and then rationing down the level of purchases to 30%, I think that would be really informative in terms of whether that's a feasible solution, first of all and second of all, how much less load you'd have to serve in order for that to be feasible solution if it's not.
    a. The market import and export percentages that are displayed are upper limits, representing the maximum amount of market energy purchases or sales that can be made on an annual basis. Though based on the modeling

results, you will find that the market imports were on average far below these upper limits, particularly in the first 6 years of the modeling horizon. As far as the market prices are concerned, we did model a high load and high commodity price sensitivity, and in that case, you will also find that the percentage of market imports were also on average far below the upper limits, particularly in the earlier stages of the planning horizon.

5. Market purchases, we tend to look at that on an annual basis and if you sort of drill down into the specifics of your production cost modeling there and to be certain periods in which those purchases tend to accumulate in other periods in which they don't. And so, if you're doing an annual look that you are not reaching that 60% limit, for example, you might be reaching that limit and sort of key hours of the year. And I'm curious if that's part of the look you guys have done at the modeling so far.
    a. To address this, we will be performing a comprehensive stochastic risk analysis where load, market prices and commodities will be varied. With this analysis market risk will be assessed at a granular level.

Kayla reintroduced Mohamed Abukaram, Director of Resource Planning, who would present on expansion plan modeling results.

## Expansion Plan Modeling Results

*Mohamed Abukaram covered slides 10-26.*

Mohamed introduced stakeholders to the presentation layout that would be followed for all scenarios and sensitivities. Each set of results was displayed on two slides, one with a table showing cumulative nameplate capacity for resources throughout the forecast period.[1] The second slide contains two charts—a stacked bar chart of cumulative firm capacity and a stacked bar chart of annual energy supply, both over the forecast period. Both charts display resources included in the going-in position and incremental resource additions selected by the capacity expansion model. I&M observations regarding each table/graph are shared on their respective slides.

[1] Demand Response (DR), Energy Efficiency (EE), Distributed Energy Resources (DER), and Conservation Voltage Reduction Resources (CVR) were categorized together and displayed as Accredited Capacity. Short-term capacity was also displayed as Accredited Capacity and is shown as one-year purchases.

## *Base Reference Case*

Mohamed presented the results of the Base Reference Case. This scenario was designed to project the optimal mix of resources to meet capacity and energy requirements under base load and commodity prices. This case is a reference for all scenarios and sensitivities for this IRP.

The capacity table shows market purchases to fill short-term (2025-2027) capacity needs before selecting natural gas and renewable resources in 2028 to meet capacity and energy requirements. Growing demand in the mid-2030s is met by adding a combined cycle in 2034 and renewing Cook Nuclear Units 1 and 2 in 2035 and 2038, respectively. Mohamed noted that the IRP model selected Cook renewal as the optimal decision in every set of results presented at Meeting 3A.

The capacity bar chart demonstrates capacity purchases through 2034 due to Montpelier and Kindle Lawrenceburg contract. The IRP model also selected license extensions for the Elkhart and Motteville hydro plants, set to expire within the next 10 years, for all scenarios and sensitivities. Mohamed noted that nuclear and gas resources with high accreditation rates represent most of the firm capacity. The capacity chart also shows increased capacity additions in 2034 due to increasing load and expiration of capacity purchases.

The energy bar chart shows Cook generation and market purchases through 2027, followed by significant gas and nuclear energy supplemented by portfolio renewables and market purchases throughout the study period.

## *Enhanced Environmental Regulations (EER) Scenario*

Mohamed presented the results of the EER Scenario, which shows the selected portfolio under Environmental Protection Agency (EPA) Section 111 rules, limiting annual capacity factors for existing CCs and CTs to 50%, new CCs to 40%, and new CTs to 20%. EER-reflected commodity prices are also inputs to this scenario.

This scenario shows a significant increase in renewables due to limited gas generation. Solar is the primary renewable selected in 2028, before high amounts of wind are selected to meet capacity and energy needs in the mid-2030s. Gas units are still selected as a cost-effective solution to energy and capacity needs. More existing CCs are selected due to tighter capacity factor limitations on new CCs, and fewer CTs are selected as wind already fills the needed capacity shortfall.

The bar charts show that the majority of capacity and energy contributions come from gas but also demonstrate increased renewable capacity and energy compared to the Base Reference Case. The capacity chart also shows an increase in supply-side resources to mitigate market import limits and prepare for mid-2030s load increases. The energy chart shows an increase in market imports to help serve load, as well as market sales from 2031 from a heavier thermal and renewable mix.

### *Base Under EPA 111(b)(d) Requirements Sensitivity*

Mohamed presented the results of the Base Under 111(b)(d) Requirements Sensitivity, which projects the optimal portfolio under EPA rules similar to what was shown in the EER Scenario. Mohamed noted that unlike the EER scenario runs, the Base Under EPA 111(b)(d) case was run with base case commodity prices.

The similarities between this portfolio and the EER Scenario show that EPA 111 restrictions drove portfolio selection more than commodity prices in each set of results. Similar to the EER case, more renewables are selected due to capacity factor limitations on gas generation. Natural gas remains essential in this portfolio to meet capacity and energy needs cost-effectively.

The bar charts also show firm capacity and energy mixes similar to the EER Scenario, with gas providing the majority of capacity and energy. Renewables, supply-side resources, and purchases, like in the EER Scenario, are more prominent in the Base Under EPA 111(b)(d) results than the Base Reference Case.

### *Low Carbon: Transition to Objective Sensitivity*

Mohamed began the discussion by explaining why “Carbon Free” was renamed “Low Carbon” and split into two sensitivities. The Low-Carbon sensitivities aim to produce enough annual energy from carbon-free resources to meet or exceed the energy requirements of I&M’s largest industrial customers. Production and Investment Tax Credits (PTCs and ITCs) were extended throughout the planning horizon, as previously requested by stakeholders.

Low Carbon was split into two sensitivities to represent different ways I&Ms low-carbon goals could be met. The first, Transition to Carbon Emissions Objective, assumed the base build limits assumed by all other scenarios, resulting in a transition period from 2028 to 2037 before the carbon emissions objective can be realized in 2038. The second Low

Carbon sensitivity, Expanded Build Limits, loosened these constraints, allowing the carbon emissions objective to be achieved earlier in the planning horizon. Mohamed shared a table comparing build limits, as well as a graph that showed carbon-free resource generation on an annual basis for each Low Carbon sensitivity.

Mohamed then presented the results of the Low Carbon: Transition to Objective Scenario. Starting in 2028, a large amount of solar and wind are selected, with the energy of these assets resulting in fewer CCs being selected. CTs are selected more in this sensitivity than the Base Reference Case, as renewable capacity alone is insufficient to meet PJM obligations. In this scenario, Small Modular Reactors (SMRs) are added in 600 MW increments in 2037 and 2043 to provide high energy production essential to meeting the carbon-free resource objective. An additional metric is provided for the Low Carbon Sensitivities: “Objective Achievement Percentage”, which represents the percentage of load from I&M’s largest industrial customers served by carbon-free resources. This objective fluctuates as load advances faster or slower than build limits allow renewables to be built and serve load. 100% of the objective is met in 2038, which is maintained through the forecast.

Like the other scenarios, the capacity chart shows that thermal resources meet most of the PJM capacity obligation. Nuclear capacity increases due to SMR additions, as do capacity contributions from renewables and supply-side resources. The energy mix chart shows a decrease in thermal-generated energy contributions and a high amount of market sales and purchases as contributions from renewables increase over time.

### *Low Carbon: Expanded Build Limits Sensitivity*

Mohamed presented results from the Low Carbon: Expanded Build Limits Sensitivity. Due to the expanded build limits, starting in 2028 more solar and wind are added than in the Transition to Objective Sensitivity. Less CC capacity is added than in the Transition to Objective Sensitivity, as renewables provide enough energy to reduce the need for CC generation. More CTs are selected to offset the absence of CC capacity used in most scenarios to meet PJM obligations. 300 MW and 600 MW of SMR capacity were selected in 2037 and 2043, respectively.

The firm capacity chart shows CTs meeting the majority of the capacity obligation, with lower CC figures than the Transition to Objective Case. Wind also shows a more significant increase in capacity in this sensitivity. Due to the expanded build limits, the energy graph shows more contributions from solar and wind earlier in the study period. Due to high renewables, market sales and purchases increase compared to the Base Reference Case.

### *High Economic Growth Scenario*

Mohamed presented the drivers of the High and Low economic growth scenarios. “High” corresponds to high load growth and commodity prices compared to the Base, while “low” refers to lower figures than the Base for the same metrics. The high and low load assumptions deviate from the Base assumption over time, with trends ending 10,000 GWh higher or lower than the base by 2044.

Mohamed presented the results of the High Scenario. The capacity table shows an increased selection of solar and wind due to increases in fuel prices. With wind meeting higher energy needs, less CC capacity is selected than in the Base Reference Case. More CTs are selected in this scenario than in the Base Reference Case to fill in gaps in capacity obligation requirements.

The firm capacity chart shows a similar capacity mix to the Base Reference Case, with most accredited capacity coming from gas resources. The energy mix chart, however, shows heightened contributions from wind and solar resources as opposed to gas generation, due to the increased renewable builds to meet energy requirements. Through 2030, 35% of demand is met by market energy imports. This figure decreases to 17% from 2031 through the end of the study period.

### *Low Economic Growth Scenario*

Mohamed presented the results of the Low Economic Growth Scenario. In this scenario, similar amounts of CC and wind capacity are selected compared to the Base Reference Case. Due to the decrease in commodity prices, energy needs, and capacity obligations, these CC and wind resources are sufficient to meet demand, resulting in no solar or storage being selected. Similarly, about 500 MW less CT capacity was selected than in the Base Reference Case.

The firm capacity and energy supply charts show significantly less contribution from renewables, storage, and supply-side resources than in the Base Reference Case. Through 2030, 29% of demand is met by market energy imports. This figure decreases to 15% from 2031 through the end of the study period.

Mohamed concluded the presentation of portfolio results, and thanked stakeholders for their participation, pausing for questions.

## Q&A Related to Expansion Plan Modeling Results

6. Could you please go over the concepts of "Existing CC" and "Existing CT"? These are facilities that have already been constructed and are operating, but not currently owned/operated by AEP or I&M? If so, where is I&M planning to find 5,000+ MW of existing gas CCs? Does this available capacity exist within PJM today?

    a. The cumulative build limit through 2030 for existing gas CCs is based on market availability and intelligence from our review. In our most recent RFP, we received over 45 bids from gas combined cycles and combustion turbines, totaling approximately 15 GW. The vast majority of bids were for existing generation.

7. Would it be reasonable to consider existing combined cycles and combustion turbines as being I&M internalizing resources that already exist in PJM? Meaning this internalization of existing resources is likely to drive a need for replacement resources by other market participants in the PJM.

    a. Yes, it is possible that I&M acquiring existing resources could create a need for replacement resources by other market participants in PJM.

8. Just to confirm, is it correct that the base scenario does not assume the recent changes to EPA Section 111(b)(d) are implemented? That is what the Base Under EPA Section 111(b)(d) Sensitivity is for?

    a. Yes, that is correct. The recent changes, or capacity factor limitations noted on slide 8 are implemented in the Base Under EPA Section 111(b)(d) Sensitivity and the Enhanced Environmental Regulations Scenario.

9. Why are residential and commercial customers not part of the low-carbon objective? Do you have a sensitivity that incorporates these customers into the low-carbon objective?

    a. The objective is to target an overall amount of I&M's load, not necessarily to assign carbon-free generation to specific customer types or specific customer load. The carbon-free generation percentage represents the full diversity of I&M's load, not just larger industrial customers. This helps inform the difference in the resource mix and the cost associated with achieving a certain amount of carbon-free generation.

10. What are the ramifications of adding significant new load without new generation in the AEP zone? Who would have to wrestle with those ramifications?
    a. I&M observed that most resources in our RFP are within the AEP zone or immediately adjacent to it. If the load continues to grow without new generation development, our assumption is that the market will respond by developing new generation over time.
11. I know we have put this request out there a couple of times now, but I want to reiterate and beg for it. We have been able to see RFP results from other utilities that were open to figuring out an arrangement that will make heightened confidentiality measures. Given how central these bids are to I&M's modeling, again, we would ask for that for transparency's sake. We really feel blind and given the public stakeholder nature of our IRP planning, would again just request that I&M facilitate our ability to see the RFP results as soon as possible. Even with the March due date, a lot of these plans and whatnot can be hard to move once they are baked, so again, just would ask for transparency's sake and the public stakeholder involvement, that we can use our existing non-disclosure agreement or anything additional to get some insight and transparency into the RFP bits. Thank you.
    a. The challenge providing recent RFP information is that we have a very competitive market and a significant near-term resource need. The confidentiality of this information is very important to maintaining I&M's competitiveness as it seeks to acquire new generation in the near future. We will discuss further the type of information we may be able to provide and follow up with you.
12. What is the certainty in implementing SMRs in the Low Carbon Portfolio? So far there are no implemented SMRs in the USA, and the ones that were planned on were plagued by cost & time extensions, namely NuScale Power ended its Utah project.
    a. We have received feedback on the SMR assumptions and provided additional feedback, which you can find on the IRP website at the following link: Indiana Stakeholder Engagement Process. To briefly answer, we have

build limits reviewed in stakeholder meeting two, vetted by our generation engineering team. We base the limits on discussions with peer utilities and reviews of their Integrated Resource Plans; industry groups such as the Electric Power Research Institute and Nuclear Energy Institute; discussions with leading SMR suppliers; and our internal SMR feasibility and siting studies conducted for Indiana Michigan Power and Appalachian Power Company. See this link for additional information (Appalachian Power - SMR | Appalachian Power - SMR).

13. I see very little storage in any of the cases, which is surprising. Can you describe how you modeled storage? Can you also explain why so little storage is picked up in any of the scenarios?

    a. For the low carbon sensitivities, storage or any proportion of energy from storage was not considered a carbon-free resource to hit the objective, so there was no extra incentive for additional storage in these cases. For the other cases, we had 300 MW to 500 MW of storage selected as early as 2028. We model storage by simulating it in the energy market through energy arbitrage opportunities, also considering the value from ancillary service and real-time markets.

## Results Comparison and Draft Portfolio Performance Indicators

*Kayla Zellers covered Slides 28-34.*

Kayla reminded stakeholders that the individual case results represented only approximately half of the scenarios and sensitivities covered in this IRP. As a complete set of results becomes available, full comparisons of the results will be shared. A brief comparison of the covered results was shared to highlight early differences in results presented during Meeting 3A.

Kayla first shared a graph of accredited capacity for each case in 2025, 2034, and 2044. This information compares the results shared on the capacity charts for each scenario and sensitivity. Kayla noted that each scenario shows an approximate doubling of capacity from 2025 to 2044, necessitated by load growth in I&M’s Indiana territory. Kayla also called attention to the similarities of each case in 2025, with short-term capacity supplementing existing nuclear and coal resources. Similarities continue in 2034 and 2044, with all portfolios relying on some combination of CCs and CTs supplementing Cook Nuclear, renewed in each case. Differences are also observed: in 2034 and 2044, Low Carbon and EPA 111 cases show an increase in renewables, and in 2044, Low Carbon cases show expanded nuclear capacity due to SMRs.

Kayla then shared a graph of the energy generation mix, again showing 2025, 2034, and 2044 data. Like capacity, energy increases significantly, nearly tripling over the study period. Similarities include nuclear, wind, and market purchases in 2025, gas providing significant generation in 2034 and 2044, and market purchases filling in gaps in energy needs. Differences shown include increased generation from renewables in the Low Carbon cases compared to other portfolios, indicating greater portfolio diversity.

Kayla also shared a table demonstrating the build plan for each case, shown as incremental additions through 2034 and 2044. Kayla called attention to the differing total capacity figures; EPA cases require more capacity than the Base Reference Case. Low Carbon cases show even higher capacity figures due to increased renewable resources with low accreditation percentages.

Kayla presented portfolio performance indicators designed to meet the "Five Pillars" established by the Indiana Utility Regulatory Commission (IURC). Kayla covered the five pillars of Reliability, Affordability, Resiliency, Grid Stability, and Environmental Sustainability. Kayla presented the metrics that I&M, with stakeholder feedback in Meetings 1 and 2, agreed would lead to a strong portfolio aligning with the five pillars. Kayla finally shared how these metrics would be evaluated and how a preferred score on these evaluation metrics would look. For the full table of these criteria, refer to Slide 31 of the posted Meeting 3A IRP Presentation.

Kayla walked through the draft portfolio performance indicator matrix, noting that EER results are not shown due to their similarity with Base with 111(b)(d) results. Kayla presented the Affordability and Environmental Sustainability results first.

For Affordability, Base Reference and Low Growth show the lowest values for Compound Annual Growth Rate (CAGR) and Net Present Value of Revenue Requirement (NPVRR). Low Carbon: Expanded Build Limits show the highest costs for both of these metrics. Kayla noted that high NPVRRs across all scenarios is due to the high load growth projected in I&M. NPVRR shows particularly high results for Base With 111(b)(d) and Low Carbon sensitivities, displaying the cost impact of compliance with stricter environmental regulations. Due to the importance of Affordability to I&M's customers, additional analysis of costs will be provided at future meetings.

Under the Environmental Sustainability pillar, it is noted that natural gas is the most economic option in all scenarios, impacting the percent change in carbon dioxide (CO2) emissions in each. Differences in CO2 emission reductions across scenarios can be attributed to the amount of renewable generation selected in each, as well as the kind of gas generation being chosen. All portfolios perform well in reducing NOX and SO2.

Kayla shared results for the Reliability, Resiliency, and Grad Stability Pillars. Reliability was evaluated from an energy market risk perspective, in which portfolios differ noticeably. Base Reference Case is among the portfolios that rely the least on market sales, while Low Carbon and Base with 111(b)(d) results show a greater dependence on market sales, due to the level of renewables selected. Energy purchases are mostly consistent, with Base With 111(b)(d) seeing higher energy market purchase risks.

Kayla stated that reliability was also evaluated under planning reserves as a percentage of the planning reserve margin, with average target values being -3.0% and -5.5% over 10 and 20 years, respectively. The target values represent the average PJM forecast pool requirement. The goal of this metric is to get modeled reserve margins values for the cases as close as possible to the target values without providing less reserve margin. The Base Reference Case shows the lowest 10 year average of planning reserves compared to the other cases. In the remainder of the cases, there are wide variations in the 10 year average ranging from -0.3% to 5.5%. Looking at the 20-year average reserve margins, there is a similar relationship amongst the cases where the Base Reference Case is the lowest while the remainder of the cases have closer or fairly consistent values.

Kayla described the diversity metrics, pointing out that the metric represents a 10 and 20 year percent change from the 2005 level. All cases, excluding High Growth and Low Growth, see improvement in capacity and energy diversity as compared to the Base Reference Case. One thing that was identified was that the relative diversity across the portfolios is really impacted by the different renewables that the model is selecting. In addition to the increased amount of renewables added in the Low Carbon cases, SMRs were selected, which adds another resource into the mix and further improves the Diversity Index for those cases.

Kayla moved on to discuss the grid stability and resiliency pillars focusing on dispatchable nameplate capacity. It was noted that significant dispatchable resources exist in each case due to the relicensing of Cook and the economic selection of natural gas resources. In the 10-year period, the Base Under EPA Section 111(b)(d) has the highest dispatchable percentage value due to the incremental amount of natural gas reserves resources economically selected compared to the other cases. In the 20 year period, the Base Reference Case,  High Growth, and Low Growth scenarios provide the highest values for dispatchable capacity, however, all cases provide significant dispatchable resources compared to the company peak demand.

### Q&A Related to Results Comparison and Draft Portfolio Performance Indicators

14. Could you provide some insight into how your $CO_2$ emissions have changed between 2005 and today so we can understand how your emissions have changed over time?
    a. As of January 2025, I&M has the following information. $CO_2$ values are rounded to the nearest 0.01 million US tons.
        - I&M 2005 base year $CO_2$ emissions = 22.47M US tons
        - I&M 2024 $CO_2$ emissions = 5.63M US tons

15. Do any of the sensitivities include modeling replacement resources at Rockport site or uprate at Cook?
    a. No, none of the sensitivities include either of those options. However, we have an early retirement scenario related to Rockport that will be presented in the next stakeholder meeting. For this scenario, much of generation resource acquisition focuses on acquiring resources needed to replace capacity and energy needs once Rockport retires at the end of 2028. Regarding the uprate at Cook, we have looked at this in the past. We will continue to evaluate and consider it in the future.

## Remaining Modeling and Next Steps

*Kayla Zellers covered Slide 34.*

Kayla shared the tentative schedule for the remainder of the IRP process. Stakeholder Meeting 3B is scheduled for January 27, 2025, and will include a results presentation for the remaining sensitivities. Stakeholder Meeting 4 is scheduled for March 5, 2025, and will cover risk analysis and the preferred portfolio identified in this IRP. Finally, I&M will submit its Indiana IRP on March 28, 2025.

## Open Discussion

I&M staff thanked stakeholders for their participation and reminded them that any additional questions or feedback can be submitted to the IRP Email address at I&MIRP@aep.com. Staff fielded all remaining stakeholder questions and adjourned the meeting at 3:44 PM.