Indiana Michigan Power Company's 2024 Indiana Integrated Resource Plan

Stakeholder Workshop #2

September 24, 2024

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Welcome & Introductions

Dylan Drugan covered slides 1-3.

Dylan Drugan, Indiana Michigan Power (I&M) Manager, Resource Planning, called the meeting to order at 1:00 EDT on September 24, 2024.

Dylan welcomed stakeholders to the 2024 Indiana Integrated Resource Plan (IRP) Stakeholder Meeting #2. Dylan introduced I&M IRP, Infrastructure Development, and Load Forecast team members as well as Jeffrey Huber, Principal with GDS Associates, Inc. who is assisting I&M with market potential study inputs. Dylan also introduced I&M Leadership including Andrew Williamson, Director, Regulatory Services.

Andrew provided an overview of the meeting's purpose; this is a collaborative workshop to discuss modeling software, methodology, and assumptions that will drive I&M's decision-making process for the Indiana IRP. I&M values stakeholder collaboration, and Andrew encouraged stakeholders to ask questions and provide feedback throughout the meeting. Andrew announced the scheduling of Indiana IRP Stakeholder Meeting #3, which will be split into meetings 3A in December and 3B in February.

Dylan concluded introductions with Brian Despard, Senior Project Manager with 1898 & Co. (a part of Burns & McDonnell), who is assisting with the stakeholder process for the Indiana IRP.

Dylan presented the meeting agenda, briefly covering each topic of discussion that follows herein. Dylan reiterated that although there is a time set aside for open discussion as per the agenda, stakeholders are encouraged to provide input and ask questions at any time during the meeting.

Going-In Capacity Position Review

Dylan Drugan covered slides 4-5.

Dylan presented preliminary PJM Electric Load Carrying Capability (ELCC) and Forecast Pool Requirement (FPR) metrics.

Dylan described ELCC as a measure of accredited capacity by resource class that I&M must account for when analyzing resources for load obligation purposes. He noted that within PJM, renewable resource ELCCs decrease over time to account for increasing future penetration, lowering the accredited capacity on a percentage basis for these resources over time.

FPR denotes to what percentage of peak load PJM members, including I&M, must plan for to meet reserve margins. Like ELCC, FPR values decline over time, serving to offset the difficulties provided by declining accreditation figures for renewable resources.

Dylan then presented the capacity needs assessment, also known as the preliminary "going-in position." These values, adjusted from previous Indiana IRP meetings, reflect new preliminary PJM ELCC value forecasts. Overall, the decline in resource ELCC class values is partially offset by a lower forecasted FPR. Dylan also noted that FPR methodology, which was previously based on installed capacity, is now based on accredited capacity, resulting in PJM members, including I&M, being able to carry less than their peak load requirements.

Capacity totals in the capacity needs assessment assume no action on many decisions that the IRP process will be investigating, such as the relicensing of Cook Nuclear Plant and retirement of Rockport Generating Station. Shortfall values are not indicative of the goal I&M holds in acquiring year-over-year capacity that exceeds annual PJM obligation by roughly 5% to avoid overreliance on PJM under extreme conditions and other potential risks.

Q&A Related to Going-In Capacity Position

1. What is the ELCC assumption for years after 2034/2035?
    a. 2034/2035 ELCC values are held constant for all years past 2034/2035.

Dylan introduced Trenton Feasel, I&M Manager, Economic Planning.

Load Forecast Assumptions and Methodology

Trenton Feasel covered slides 6-11.

Trenton provided stakeholders with an overview of I&M's latest peak demand forecast assumptions. Significant forecasted changes in peak demand are demonstrated, accounting for a peak demand increase of roughly ~8.3% each year over the next decade within I&M. Trenton noted that hyperscale load (HSL) additions within Indiana are the primary driver for this sharp increase; commercial load is expected to grow much faster than industrial and residential load, from 31% of I&M's total load obligation in 2015 to 79% by 2030. This is largely due to the projected growth of data centers.

Trenton presented stakeholders with the load forecast scenarios that inform the overall energy requirements I&M must meet, noting the drivers of high and low economic growth. These scenarios form the band in which the base energy forecast falls. Also noted is an "extreme weather" scenario using data from Purdue University that shows a subtle increase over base energy projections.

Trenton informed stakeholders that there has been a change in methodology as to how I&M accounts for control of Demand Side Management (DSM) and Energy Efficiency (EE) projects in its load forecasts. These have historically been studied and provided as a post-model adjustment to load. Following the Rockport Unit 2 declination of jurisdictional settlement, I&M committed to making EE and DSM assumptions an independent variable in econometric models. This has caused a sharp increase in the value of DSM/EE in load forecasts.

Finally, Trenton discussed electric vehicles and rooftop solar. Electric vehicle growth within I&M's Indiana territory tends to be less aggressive than USA-wide figures and does not contribute to load growth as much as may be seen in IRP filings from different entities. Similarly, a growing, albeit small portion of I&M's customer base is adopting the use of rooftop solar, leading to only a 0.4% decrease in I&M Indiana energy retail needs by 2040.

Q&A Related to Load Forecast Assumptions and Methodology

2. For the DSM slide 9, what is the unit of the y-axis?
    a. The units on the y-axis of slide 9 are megawatts (MW).
3. Do you model data centers separately or as part of the commercial model?
    a. Data center loads are forecasted separately from the traditional commercial load.

4. Any forecast on Community Solar installations or are they counted for in Rooftop Solar?
    a. No, we do not have a separate forecast for community solar installations. The current forecast for customer-owned solar is largely reflective of rooftop solar.

Jeffrey Huber, Principal Consultant with GDS Associates, Inc. was introduced.

DSM Modeling Inputs

Jeffrey Huber covered slides 12-15; and
Jon Walter, I&M Regulatory Manager covered slide 16.

Jeffrey briefly reviewed market potential study savings and the DSM inputs being used in the Indiana IRP. Modeling will utilize different EE and Demand Response (DR) bundles as shown on slide 12.

Jeffrey shared graphical overviews of energy savings being offered by these EE and DR bundles by sector.

Jeffrey discussed the potential opportunities for DER resources, including BTM solar and battery storage, with utility intervention at a 25 incentive for solar PV installs, with the saving potential for these resources as shown on slide 15.

Dylan introduced Jon Walter, I&M Regulatory Manager.

Jon discussed the Conservation Voltage Reduction (CVR) saving that will be forced into the model as shown on slide 16. He emphasized that this does not represent any new or incremental CVR beyond what was already planned.

Q&A Related to DSM Modeling Inputs

5. What are the cost assumptions for the EE bundles on slide 12? Full incremental cost of the measures? Additional program costs added?
    a. The cost assumptions for EE bundles are a bit of a mix and depend on what type of programs are being operated. For programs that are typically replaced at time of sale or market opportunity, generally an incremental cost is assumed. The full cost is assumed when programs are more of a retrofit basis. The assumptions about the measure cost we're putting in, the utility

cost, it's the utility incentive. It is the portion of that cost that the incentive is covering. Regarding income-qualified programs, the utility incentive generally covers 100% the income-qualified customer's cost. For other programs, the incentive is a percentage of that program's measure cost, whether it's incremental or full cost in the assumption. The bundle costs reflect only the utility's incentive costs and administration costs, not the full customer cost to implement the measure.

6. Do you assume data centers are energy-efficient?
    a. No explicit assumptions are made regarding energy efficiency around data centers.
7. Has I&M posted the methodology for T&D capacity avoided costs on the IRP webpage?
    a. This information has not been posted to the IRP webpage but is available and can be provided upon request via the I&M IRP email (I&MIRP@aep.com).
8. Is there potential for EE/DR savings associated with data centers?
    a. There are no assumptions made about EE/DR savings for data centers in the modeling. The expectation is that most of if not all the hyperscale large data center loads would be EE opt out customers, so they are not included in the energy efficiency potential analysis. Also, there are questions about demand response opportunities, whether data centers would participate via I&M or other markets. We are having conversations with data center customers about opportunities. For these hyperscale large data centers, there may be future opportunities to incorporate more efficient technology, but the current expectation is that those future opportunities would just allow data centers to expand their business beyond their current customer base which won't necessarily result in lower overall loads.
9. What assumptions are being made with the increased interest in I&M's territory by solar developers to install utility sized solar arrays at 200 MW and greater?
    a. This question will be addressed on an upcoming slide.

10. Is I&M considering modeling any CVR savings incremental to the savings presented in slide 16 based on costs?
    a. No. We did evaluate additional future incremental deployments beyond what is shown on slide 16, since those deployments did not turn out to be cost effective through cost effectiveness modeling. Only the CVR savings shown on slide 16 are forced into the model.
11. What do we mean by "forced" into the model?
    a. Forced into the model means the CVR savings will be included as part of our portfolio; it will not be an option to be selected or evaluated amongst other resources - it will be forced in.

Dylan introduced Tim Gaul, Director, Regulated Infrastructure Development for I&M.

Market Assessment of Existing and New Resources

Tim Gaul covered slide 17.

Tim presented availability in PJM's Interconnection Queue for resources eligible to serve load and contribute to capacity requirements in I&M's Indiana territory. Resources being considered are geographically and technologically diverse, with a variety of projects in Indiana, Michigan, Illinois, Ohio, and Kentucky being presented. Projects are sorted based on queue cluster and potential COD: "Fast Lane" projects, Transition Cycles #1 and #2, and Cycle #1 projects under PJM's new queue methodology are all being considered.

Tim walked stakeholders through the graph, talking through splits by both project number, megawatts available, and technology type. Solar projects constitute much of the available queue capacity and volume of projects through the presented queue cycles, especially within Indiana. Wind is in very limited supply, and most projects reflected are additional capacity for existing projects. Storage projects increase in both volume and capacity in later queue cycles, making them more viable in the future. Finally, very few new gas projects are in the queue. The primary source of resources eligible for consideration in our near-term RFPs will come from offers provided by owners of existing gas assets.

Q&A Related to Market Assessment of Existing & New Resources

12. Can't storage be added to existing assets to compensate for renewable accreditations going down as a result of declining ELCCs?

    a. Yes. Adding new storage to an existing asset would increase the ELCC value of the resource. However, the additional ELCC value gained is often limited relative to the cost of the storage addition.

Resource Modeling Parameters

Dylan Drugan covered slide 18-20.

Dylan presented an overview of key resource modeling parameters that will be shared with stakeholders. Examples of parameters include capacity, availability, lifespan, financial assumptions, energy production, and more.

Baseload resources include small modular reactors (SMRs) and combined cycles (CCs), and existing gas resources. These resources would help meet large load ramps in a short amount of time. Dylan explained that RFP results are used to inform these modeling parameters.

Peaking resources include combustion turbines (CTs) and reciprocating internal combustion engines (RICE). Dylan explained that these resources help add small amounts of capacity to meet reserve margin requirements and economically optimize resource additions.

Intermittent resources include wind, solar, and storage. Dylan emphasized that a subset of solar resources will be modeled as if they qualify for the Energy Community Tax Credit Bonus.

Q&A Resource Modeling Parameters

13. What is the basis for the annual build limits shown on slide 18 especially for existing resources given the resource summary you shared on slide 17?

    a. The annual build limits, which are specific to a particular resource, are based on work we did with our infrastructure development team. The limits are informed by what we're seeing in the market and what we think is feasible to be able to procure in one year. Specifically, the limits consider the timeline and availability of new resources at various stages of the PJM queue, as well as the availability and remaining life of existing, operational resources that potentially could be procured by I&M. The limits also consider the Company's experience in its 2022 and 2023 RFPs, including the number of bids/MWs received in the RFPs and the percentage of projects that experience development challenges that delay the commercial operation date or terminate the project. We also considered regulatory timelines associated with resources.

Limits on existing resources are based on our assessment of what is available in the market based on research of existing assets, responses to previous RFPs open to existing resources from a similar footprint, and outreach to potential sellers of existing resource assets gauging interest in contracting with I&M. In particular on slide 17, we are saying that through 2030, we think there is about 3,600 MW of existing resources available in the market and that the most we would be able to procure in a year is 1,800 MW of the 3,600 MW.

14. Do overnight costs for the NG resources include any cost for new gas pipeline extensions or firm transportation costs for natural gas?
    a. No. Generally, IRP modeling consists of modeling generic resources that are not location specific. Costs related to gas pipeline extensions and firm transportation tend to be location-specific costs. While these costs are not included in the overnight cost to build a NG resource, these costs can be considered when the Company receives bids through its RFP process and has a need to evaluate location-specific costs such as gas pipeline extensions and/or firm fuel.
15. How do tax credits inform model choices? Are these accounted for in 'overnight costs,' e.g., for NG with CCS?
    a. The overnight costs do not include PTCs or ITCs, however PTCs and ITCs are included in the IRP modeling.
16. Does NG assume Section 111d compliance?
    a. The Reference Case will not assume Fundamental and Operating conditions that reflect 111d impacts. We will run a scenario that will model a future with

111d compliance in place. 111d impacts are handled through the economic dispatch in the production cost modeling in the Enhanced Environmental Regulations scenario. Also, the capacity factor percentages on existing and new resources that are operating beyond 2032 will be capped based on 111d. So, we could see limited operation from NG resources which will result in less GHG output.

17. Is overnight cost based on RFP responses?
    a. Costs for new and existing resources consider some of the responses we've received through past RFPs. The Company continues to still fine-tune costs for existing resources and the costs shown are subject to change.
18. Does new NG assume dual fuel or onsite LNG to support operations?
    a. No, new NG resource overnight costs do not include dual-fuel capability or on-site LNG.
19. Does the discount on existing resource pricing compared to new resource pricing come with any downsides such as shorter lifetime or anything that would influence the selection of those resources compared to the new resources?
    a. We have not established final pricing for existing resources, but we anticipate the final pricing will reflect asset life and other factors specific to the resource when they are priced.
20. What is the rationale behind the first year available for combined-cycles being 2031? Is it mostly due to the challenges of buying turbines or is there more to it?
    a. The first year available for combined-cycle projects is based on several factors, including lead time and availability for new combustion turbine orders, timeline to build, regulatory approval, air and water permitting, and limited representation of combined cycle projects in the current interconnection queue.
21. Regarding the build limits given large load growth over the next six years - this would constrain the model from picking renewable energy and storage. Due to these limits, we are going to mostly see carbon based resources added. Also, it seems build limits overall are too constraining to be able to meet expected demand growth

with cost-effective resources. Do you think the build limits are too constraining to be able to meet expected load growth?

a. As noted in the answer to question 13, the annual build limits are based on work we did with our infrastructure development team, informed by what we're seeing in the market. We do not think the build limits are too constraining to be able to meet the load growth. We will evaluate the build limits as we model the different scenarios and sensitivities and adjust the build limits if they become a constraint to meet the load growth.

Dylan introduced Mohamed Abukaram, Director, Resource Planning.

Key Modeling Inputs

Mohamed Abukaram Covered Slides 21-25

Mohamed Abukaram, Director, Resource Planning & Operational Analysis, presented an overview of Inflation Reduction Act of 2022 (IRA) tax credit assumptions being applied to the Indiana IRP analysis. Investment Tax Credits (ITCs) will be applied to capital costs for solar, storage, and small modular nuclear reactor projects at 30% through 2036 before a "phase out" period through 2039.

Production Tax Credits (PTCs) will be applied to wind projects in place of ITCs. These $40/MWh-$58/MWh credits are applied through the first 10 years of asset life for projects completed in the 2025-2036 window. Like ITCs, these credits will decrease gradually for projects completed in 2037 and 2038, before being phased out entirely in 2039.

Finally, Carbon Capture Storage (CCS) credits are applied in the range of $29/MWh-$$44/MWh for the first 12 years of asset life for new combined cycle plants completed between 2025-2036.

Mohamed also discussed the Cook Subsequent License Renewal (SLR) analysis being conducted as part of this IRP. He shared model input assumptions such as current license expiration dates and assumed costs for relicensing the Cook Nuclear Plant. Similarly, Mohamed discussed relicensing cost assumptions for the Elkhart and Mottville Hydro Plants.

Finally, Mohamed discussed storage modeling inputs and methodology for utility scale and distribution-sited resources. For utility scale resources, storage is dispatched against fundamental market prices within a production cost model with hourly generation and charge costs then used as inputs in expansion planning (PLEXOS). Storage options considered are lithium-ion batteries of durations from 4-8 hours, and iron-air storage.

Distribution-sited storage will be modeled under two cases: the Thermal Use Case, where storage is sited at stations nearing thermal overload conditions, and the Reliability Use Case. Where storage is placed at stations with historic reliability need. The intent with both cases is to improve capacity for existing resources.

Q&A Related to Key Modeling Inputs

22. How come you are crediting ITC/PTC to 2036 when the law says 2032?
    a. According to our internal tax group, there are some provisions in the IRA that enable us to go out an additional 4 years.
23. How did you determine the value for avoided customer minutes of interruption (CMI)?
    a. The interruption cost estimator (ICE) tool was used to estimate CMI costs. We looked at our different distribution stations and analyzed the CMI that was there historically and what can be improved by placing a distribution of storages of the sizes seen in the table on slide 25. We equated the CMI that can be saved and the associated dollar amount by placing storage at these stations. These savings were then deducted from the capital cost of putting the storage at that site.

Market Scenarios & Sensitivities

Dylan Drugan Covered Slides 26-29.

Dylan discussed a new carbon-free sensitivity that was developed with stakeholder feedback. This sensitivity meets the total system needs and serves hyperscaler energy requirements.

Dylan also reviewed the scenarios and sensitivities that will be evaluated in the IRP and forecasts being used for each. He explained that Meeting 3 will be divided into two sections (3A and 3B) to allow time to walk through each scenario and sensitivity.

Q&A Market Scenarios & Sensitivities

24. It is unclear why you are calling the new rule 111d. It is 111b that applies to new gas.
    a. While the presentation primarily refers to 111d, both 111b and 111d are considered in the IRP as both new and existing resources are being considered.
25. Is I&M also considering a low technology cost sensitivity?
    a. Not currently. The High Technology sensitivity will reflect the most up to date bids that we're seeing in the marketplace, which we expect to be higher than current prices. We are seeing upward pressure on market prices given the lack of resources and increasing demand and we expect that this trend will continue in the near term.
26. Does "Pre EPA 111d 2023 Proposed Rules" on slide 28 mean a situation where the EPA 111(d) rule was repealed or no longer exists?
    a. The "Pre EPA 111d 2023 Proposed Rules" scenario reflects fundamentals for our power prices and fuel prices developed prior to those rules. These are the set of fundamentals that we are using in our base high and low scenarios in this IRP. The proposed EPA 111d rules were incorporated into fundamentals that will be used in the Enhanced Environmental Regulations (EER) scenario.
27. For the Exit OVEC sensitivity, are you assuming the OVEC units are closed or that you will buy out of obligations?
    a. In such a scenario, I&M would no longer utilize OVEC as a generation resource but would continue to be responsible for the financial obligations that I&M would have under the contract and exit the contract early. I&M would replace OVEC with another generation resource to serve customers.
28. EPA deleted requirements on existing gas from Final Rule stating it planned to have a separate rulemaking. What are you assuming?
    a. We are currently assuming the 2023 proposed 111d rules under our Enhanced Environmental Regulations case.
29. Are the 111d assumptions applied to existing units PJM-wide in the analysis?

a. Only in the Enhanced Environmental Regulation scenario uses 111d assumptions. The assumptions are applied to all generating units in PJM in the Fundamentals forecast.

Open Discussion

Dylan asked stakeholders one final time for any unanswered questions. All questions and answers asked during the presentation are located under their appropriate segments.

Andrew made closing remarks, thanking stakeholders for their time and contributions to the Indiana IRP Technical Conference and overall process. Any unanswered questions, requests, or follow-up feedback is encouraged to be submitted to I&MIRP@aep.com.