Indiana Michigan Power Company

2018 - 2019 Integrated Resource Plan
Stakeholder Workshop #3

February 21, 2019
9:30 a.m. - 2:45 p.m.
Fort Wayne, IN
Meeting Minutes

Meeting Objectives and Introductions (slides 1 – 3) - Toby Thomas, *I&M President & Chief Operating Officer;* **John Torpey,** *Managing Director, Resource Planning*

Toby began the meeting at 9:44 am. Toby welcomed everyone to the meeting. I&M appreciates all the input to this point and welcomes continued stakeholder participation.

John indicated more modeling is to be done between now and the next stake holder meeting.

John went over the ground rules and reminded everyone to be respectful of all views and opinions. There will be time for stakeholder comments throughout the meeting. AEP/I&M representatives will be available during lunch as well.

Meeting Access Information: Those on the phone can access via Adobecconnect and call into the conference.

I&M's Key Priorities for the 2019 IRP (slide 4)

John emphasized that I&M is looking for everyone's input. The final report may not reflect all ideas given, but all input will be considered. In the end, the plan will meet the rules/requirements.

Meeting Goals (slide 5)

John stated that today's goals are to discuss the Integrated Resource Plan (IRP) portfolios, scenarios, sensitivities and initial model results. We will also review stakeholder feedback and discuss current modeling inputs. I&M is still looking at various ways to identify additional Distributed Generation (DG) opportunities. Final plans for Rockport plant have not been determined.

John re-iterated that the overall goal for this effort is to produce long term reliable energy at a reasonable cost.

The Michigan IRP will be filed soon after the Indiana filing. Today's feedback will be a consideration when running more modeling. Final modeling is to take place soon.

Updated Stakeholder Process (slide 6)

Four meetings will be held. The first meeting to kick off the IRP process was held on February 15, 2018 in Fort Wayne. The second meeting was held on April 11, 2018 in Indianapolis. The next meeting will be in Muncie on March 22, 2019. At that meeting we will review modeling results, have a discussion around the preferred portfolio and final inputs.

Stakeholder comments (slide 7)

A link is set up link on the web page for the IRP. Comments can be submitted there. Previous meeting minutes were posted on the I&M website.

Today's Agenda (slide 8)

John briefly reviewed the agenda for the day.

Opening Remarks & Welcome (slide 9) - Toby Thomas, *I&M President & Chief Operating Officer*

Toby welcomed everyone to the meeting and thanked all for their participation.

1. **Stakeholder Feedback Summary (slides 10 & 11) – John Torpey,** *Managing Director, Resource Planning*

John indicated that I&M has responded to a number of comments posted to the IRP website.

John specified that the modeling results are based upon many inputs. We are looking at low-carbon and DSM scenarios. Feedback was received on renewable pricing. Recently, we added a short term capacity purchase into the model. This buys time for building a facility in the future, if needed.

John reviewed several Rockport Plant options.

There were some individuals who did sign up to get modeling access to inputs/outputs.

2. **IRP Portfolios, Scenarios, Sensitivities & Initial Model Results (slide 12) - John Torpey,** *Managing Director, Resource Planning*

Portfolio Assumptions – I&M Going in Capacity and Energy Position (slides 13 – 14)

John reviewed the capacity position for I&M by discussing the chart. The dark line on the graph is the capacity obligation which is capacity needed to meet PJM Interconnect obligations in order to meet load. The bars represent the going in I&M capacity position of I&M (with no new resources). The two units at Cook and the two units at Rockport make up the major units for the bulk of capacity.
John reviewed the lease/ownership arrangements for Rockport. Rockport 2 is leased and the lease expires in December, 2022. The base case assumes a lease to not be renewed. Rockport 1 is 50% owned by I&M and 50% owned by AEG (American Electric Power Generating Company). In Dec. 2022, 190 MW's of AEG's output will transfer from Kentucky Power to I&M.
It is anticipated that Rockport 1 will retire at the end of 2028 per the current consent decree. That will cause I&M to be short capacity. At 2038, this IRP's assumption is that all major units retired so generation portfolio will be transformed.

Q. What is the dip in near term capacity?
A. Reflects the loss of wholesale contracts. Specifically, IMMDA accounts for 300MW loss in 2020.

Q. P Boerger - Are PJM market conditions impacting dispatch?
A. Both Rockport units are profitable. But at times SO2 limits and Transmission congestion issues can impact dispatch of the units.

Q. P. Boerger - Could nuclear licenses at Cook be renewed again?

A. It has not been decided. For purposes of the IRP it is assumed they retire at end of current license. The LCM project will add value so I&M can be ready, if it decides to pursue another license renewal. Planning for license renewal occurs about 15 years in advance.

Q. J .Washburn – What is the 15 years about?
A. That's not a rule. 15 years is just a planning horizon.

Q. Between 2025 – 2028 will Rockport be making money?
A. When looking at an asset in rate base, decisions are made based upon costs to operate Rockport vs a replacement source. That could be a trigger point to retire a unit. An example would be adding a scrubber in 2028 per the consent decree. That's the financial driver.

Q. S. Francis – Not seeing increase in demand response on graph. Does this show existing DSM programs?
A. This is the going in position and does not have incremental DSM included.

Q. D. Thomas – Is the amount of coal after 2028 related to OVEC?
A. Yes.

Q. J. Washburn – Any insight into OVEC? Contract length?
A. Contract goes to 2050. OVEC is a consortium that owns two coal plants (Kyger Creek, Clifty Creek). I&M gets a small portion of OVEC generation.

Q. If those plants cannot operate during contract, what happens?
A. If I&M can't rely on generation from OVEC, would use PJM for energy.

Q. What is the size of those plants?
A. I&M's portion is between 150 and 200 MW's combined from both plants. Model assumes those plants retire in 2045. They do have scrubbers.

Q. Can you get out of those contracts?
A. No.

John reviewed the going in energy position. We have excess energy and sell into PJM market. We have adequate energy until both Rockport units retire.

Q. In some years, energy available decreases. Why?
A. Cook Nuclear refueling outages reduces available energy.

Q. D. Thomas – What do we dispatch against?
A. PJM hourly prices. But also have to consider transmission congestion issues.

Initial Scenarios & Portfolios Considered (slide 15)

John stated that I&M analyzed 21 combinations of commodity prices and resources.

There are four scenarios in Group 1: Base/High/Low/Status Quo.
Base/High/Low – these assume by 2028 that a carbon tax is in effect and includes a 5% escalation.
Status Quo – assumes no carbon tax burden

Optimized portfolio selected resource mix to be lowest cost.

Group 1 presents different commodity pricing scenarios.

Group 2 & 2A – looked at various Rockport scenarios.

Group 3 – IRP scenarios that defer addition of a (Natural Gas Combined Cycle (NGCC) plant.

Q. S. Francis – What is the IRP basis for where you set the annual renewables amount? PJM data?
A. We let the model determine amount. Basis for annual amount is what we believe we can acquire.

Q. Is it reasonable to have a no carbon price scenario for 20 years? Why included? Are you willing to model different carbon prices?
A. We try to meet various group's requests. Some feel carbon prices should be in or out and at various prices. Different advocates feel the carbon tax should be later vs sooner. In other states, we receive pushback on including carbon tax.

Q. K. Krohn – What are the assumptions for storage?
A. Had one in model, but it was not selected. I&M is investigating storage, but the model did not pick it for economic reasons.

Q. J. Washburn – please discuss the MW constraint on renewables for renewable selection.
A. Constraints are follows: 150 MW per year. Total 2,100 MW total limit for Wind; (Solar – 150MW/tranche and can be selected in 50 mw blocks. 1,700 MW total solar limit)

Q. A. Sommer – The limitations on renewables causes concern. Different opinion on how MISO is setting maximum amount of renewables. It's based upon acceptance of resource. What matters is whether model can add significant amount of renewables to portfolio when coal plants retire. The model is not allowed to select them and it should be allowed to. IPL is modeling differently to remove individual constraints on renewable resources.
A. We can put a reserve margin on the model. It has to be constrained one way or another. This led into a discussion on modeling reserve margins and constraints on resource selection.

Group 4 indicates various load scenarios and Group 5 identifies various EE scenarios.

Summary of Analyses (slides 16 - 19)

John explained there are three scenarios that cost essentially the same amount in 2048:

1. Base case
2. Transitional portfolio to limit or defer the selection of NGCC
3. High renewables portfolio

He reviewed the three portfolios in more depth along with pros/cons.

The high renewable scenario has higher cost in near term. But has potential future high marginal profits that offset the early high cost.

Q. A. Sommer – Is the high renewable scenario more expensive if the model constrains renewable resources?
A. In short term, high renewable portfolio spikes due to build out, but comes down over time. Discussion ensued on how model calculates costs of renewables.

Q. South Bend Sierra Club – Slide 18 appears to make a case to penalize renewables due to high upfront cost while the gain is on the back side. What is point of this slide?
A. I&M recognizes that renewables are cost effective for customers. But need to recognize that adding these makes us energy long and assume market prices will increase over time. The Company believes we should

include renewables, and defer investment in NGCC. It's a question of scale. How much additional capacity do we want to be renewable?

Q. P. Boerger – What is the discount rate? What do you mean by cost? Fixed cost?
A. The Weighted Average Cost of Capital is the range of 7.5% to 8.0%. John reviewed the cost information for the scenarios on page 19. PJM pays I&M for MW's sold into the market.

Q. P. Boerger – on slide 18, what is driving the differences between the lines?
A. The line shows values incremental to the base case. John indicated that the incremental investment early on and benefit of PJM sales accumulate in later years. John reviewed the assumptions on the base model regarding carbon tax and natural gas prices.

Preliminary Preferred Plan Considerations (slide 20)

John discussed the base preferred plan which is Case 9 with certain modifications, including storage, micro grid deployment, and adding residential EE/demand response.

The transition plan (Case 9) includes solar, wind, and a NGCC plant in outer years.

Q. S. Francis – In high renewable cases, do you consider impact of not building NGCC in relation to increased storage?
A. No. Storage costs are still rather high. It's looked at mostly as a peaking solution.

Group 1 - Commodity Pricing Scenarios (slides 21 - 26)

John indicated that we are seeing a lot renewables added across the board for all scenarios as he discussed the Group 1 summary. Renewable storage is not included for 2023 and 2028. It would be modeled at a using 4 hours for storage capacity.

Q. S. Mullkoff – What are the assumptions for the ITC for solar
A. ITC expires in 2030.

Q. T. Dorau – Is there a regulatory or PJM restriction on how much purchased capacity can be included in a portfolio?
A. None that we are aware of.

Q. T. Dorau – What are the limitations in the model on market purchases?
A. 1,000 MW limit on purchases. This is an annual limit, not long term.

Q. S. Francis – Is there an analysis regarding installing solar before ITC phases out? Concern with cost assumptions compared to what NIPSCO included in their IRP. What are the differences that lead to different results from NIPSCO's plan?
A. S. Fisher pointed to page 84 which shows when ITC credit is available and what levels. In other models, solar gets moved forward when the model is not allowed to pick an NGCC. Marc opined that if solar projects come along that provide cost effective advantages, then those will be strongly looked at. Marc indicated that I&M is quite different from NIPSCO in terms of MISO vs PJM and generation facilities.

Q. J. Washburn – Appreciate efforts to work on model together. Want to continue work on understanding what limitations are in the model.
A. John indicated that we are developing a plan with management input that will show an increase in renewables.

John went over the EE results. The bundles are from AEG and are consistent with the 2016 market potential study. The model picks mostly commercial EE vs residential EE.

Q. A Sommer – Is the product due to an AEG study or EPRI for assumptions for market potential? She has a concern with residential lighting not being selected. Are end uses really reflective of cost? Concerns with pricing of some of the bundles.
A. D. Drugan mentioned the modeling assumptions were done by AEG for market potential study. Will discuss further later in the day. Residential EE will be included in final solution. There's no basis for changing bundles as reflected in results.

John reviewed the emissions impact from the Group 1 cases.

Group 2 – Rockport Scenarios (slides 27 - 33)

John reviewed the scenarios run for Rockport that support the Case 1 planning assumptions. In most cases, we are adding less NGCC due to Rockport capacity being available.

Group 2A – Rockport Scenarios – Status Quo (slides 34 - 40)

John indicated that the Group 2A slides are associated with running scenarios under the no carbon tax case.

Group 3 – IRP Scenarios (slides 41 - 47)

John reviewed the various scenarios. These plans show significant CO2 reductions. The longer the model waits to add an NGCC there is less time to realize the value/gain they bring. DSM scenarios are consistent across all of the cases.

Some of the cases add a NGCT peaking plant vs as much NGCC.

The high renewables portfolio selects a lot of renewables. If the model is allowed to select renewables, then as more renewables are made available then the model will select them.

Carbon intensity is reduced due to the amount of renewables.

Q. What percent of carbon reduction was used for NGCC?
A. John indicated that it's roughly 50% on an MWh basis.

Group 4 – Load Scenarios (slides 48 - 57)

John indicated that the group 4 slides compare the various Group 4 cases to the appropriate Group 1 cases.

The various impacts of considering low/high commodity pricing were reviewed.

EE Degraded (Value of Load Reduction) Model Results (slide 58)

This was an analysis requested by CAC. This scenario considered impacts of various load reductions for residential/industrial/commercial loads. I&M will discuss the results further with the CAC.

45 Minute Lunch Break

3. **Stakeholder Feedback on Initial Modeling Results (slide 59) - John Torpey,** *Managing Director, Resource Planning* and **Scott Fisher,** Manager of Resource Planning

John mentioned that the comments period is open for another week. Please send comments electronically if possible. What would stakeholders like I&M to consider between now and the next meeting?

Q. S. Francis – When running sensitivity analysis, is I&M open to more analysis on carbon and renewable cost /prices sensitivities? Suggest looking outside narrow bands used in the model. For example, IRP's in the past underestimated the decline of costs of renewables.
A. I&M is open for more discussion, but need to consider how it fits into the model.

Q. How is the cost of natural gas modeled?
A. It grows over time. Considering to adjust due to softness in gas market.

Q. Polly (customer) – Natural gas use is not acceptable for any plan. Methane is not any better. The plans don't consider cost of environmental damage, especially due to fracking. Climate change is not reasonable.
A. I&M's preferred plan pushes new NGCC out into future. This plan is based upon today's laws and costs.

Q. J. Washburn – What is the source of the EE capacity values?
A. They came from the Market Potential potential study.

Q. Sarah (MPSC) – What does the model consider make when making choices and what management inputs are there?
A. T. Thomas stated that we see long term advances in storage. We're watching a lot of things. In the preferred case, we're looking at projects to learn about these new technologies like micro grids. We're always evaluating ITC impacts on solar and wind. These are all inputs into how we best serve our customers.

Q. T. Dorau (South Bend) – What is the source of renewable energy pricing? Does the model hold it constant or does it change over time?
A. S. Fisher indicated that I&M relies on Bloomberg Energy and EPRI along with experts for assumptions. And it does decline over time.

Q. S. Francis - What impact is there of not having a Renewable Energy Standard (RES) in Indiana but you do in Michigan regarding roll out of renewables?
A. T. Thomas detailed that the State of Indiana has been supportive of renewables. The difference in mandates in Indiana and Michigan are not drivers. Economics are the driver. We expect that to not change. The State of Indiana has supported our solar and wind contracts.

Q. S. Francis – We can alter the preferred portfolio, but won't be opposed to do so due to no RES?
A. T. Thomas – Indiana has been supportive of our renewable plans. Based upon history and precedent, we don't expect any pushback.

Q. Customer – which model would you choose if your 9-year-old son has asthma?
A. It's hard to relate plans to health effects. I&M needs to meet environmental mandates established by the EPA and are proceeding on path to reduce use of fossil fuels and associated concerns from those effects.

4. **IRP Inputs Review – Load Forecasting (slides 60 - 66), Scott Fisher,** Manager of Resource Planning, **Chad Burnett,** Director of Economic Forecasting, **Connie Trecazzi**, Economic Forecast Analyst Staff & **Dylan Drugan**, Resource Planning Analyst Principal

Scott Fisher discussed that the load forecast is not planned to change, but commodity prices may. We received new info from Bloomberg on renewables pricing. Storage and EE pricing will not change.

Q. L. Thill (South Bend Economic Forecasting) – The Purdue University Climate Change Assessment provides evidence for 2% increase in cooling degrees days. She thought that was worth noting.
A. R. Holliday opined that we base our weather scenario forecasts on data from Purdue.

Q. L. Thill – Does the extreme weather assumptions hold with the base forecast?
A. R. Holliday - High and low forecasts change heating degree days/cooling degree days in the base forecast. The summer load is offset by weather effects. The scenarios fall between the high and low bands.

IRP Inputs Review – Fundamental Commodity Forecasting (slides 67 - 74), Karl Bletzacker, Director – Fundamental Analysis

Karl discussed the long term forecast of commodity markets/prices. The tool to analyze energy forecasts is done via the AURORA model. Karl suggested that cost forecasts of natural gas prices are rather flat. He further reviewed how prices for different commodity are interrelated.

Q. What is the basis forecast for natural gas in our area?
A. Karl indicated the value of natural gas in our area is less than the Henry Hub. Shale reservoirs nearby lowers our local price and these do not show up at Henry Hub which is in Louisiana.

Q. D. Thomas – Noted the transition of commodity prices from first few years to outer years. Why is there a disconnect?
A. K. Bletzacker – The warm weather in prior winters has reduced demand from normal years and has impacted the forecast curve.

IRP Inputs Review – DSM/EE Inputs (slides 75 - 78)

Dylan discussed some inputs on the DSM market potential study. He reviewed various EE bundles, costs, and time periods.

Q. J. Washburn – Concern with AEG credibility in adoption rates, costs, etc. She raised similar concerns in prior plans. I&M has not committed to doing a new market potential study. Concerns with the costs being used in I&M's model. Why are costs going up while savings levels drop? She has major concerns with EE. Further, she indicated that on slide 76, the measures for residential EE is slim. I&M's values of potential savings are smaller than what NIPSCO had. She has several questions regarding data on slide 76. On slide 77, how does I&M prevent double counting of the HVAC thermostat program? The CAC will pose all of their comments in writing.
A. Dylan indicated that I&M would appreciate the opportunity to respond to the written comments. At a high level, there are a number of differences in the model from the last IRP to this one. Some of the differences are the changes that reflect input based upon working with the CAC since last time. Further, many assumptions have changed over that period of time.

Q. J. Washburn – On page 77, are the demand response levels based upon current response levels?
A. Jon indicated they're based upon commercial programs we had modeled. Different tranches out of the four can be selected.

Q. J. Washburn – Do you incorporate the interruptible forecast in the model?
A. Yes. We include current interruptible participation.

Q. J. Washburn – How is EE determined in the model? Are these in high potential and/or achievable potential?
A. Dylan indicated that these inputs begin to get selected in 2020. Technologies will continue to develop without EE and those non-EE program impacts are built into the load forecast as well. I&M also adds programs to add onto that. Dylan said that the highest achievable potential is included. Discussion followed on what is modeled for highest/achievable potentials.

Q. S. Francis – In the NIPSCO modeling they looked at risk analysis and determined the renewables with lower risk and cost. Have we used stochastic modeling? Have we looked at the NIPSCO modeling?
A. We do stochastic evaluation. We looked at the high renewable plan and no renewable plan. The high renewable plan is less risky.

IRP Inputs Review – Resource Options (slides 79 - 86)

Scott indicated that supply side resources will be updated. He mentioned that J class NGCC will be modeled vs H class NGCC due to better economics.

Scott also discussed wind resources for the IRP. We will maintain the capacity factors for tranches.
For solar – have two tranches as well. We will be updating solar prices. Investment Tax Credit phase out was reflected previously, but now it is maintained through 2023 and then phased out.

Q. S. Francis – Referring to slides 83 & 84, NIPSCO had a lower Levelized Cost of Energy (LCOE) for their solar. He is concerned with pricing for both solar and wind forecasts. Why is there such a difference between NIPSCO's renewable cost figures and I&M's?
A. Scott stated that prices in our model are in line with figure 4-15/4-16 in NIPSCO's IRP. He said we are open to an alternative pricing scheme. John opined that whether the costs are adjusted down or not does not affect the modeling. The model is already seeing them as economic.

Q. S. Francis - Would a lower forecast of solar cost impact our slide on the preferred plan? He would like to understand the differences between PJM and MISO.
A. Scott indicated that the overall cost of the plan would be lower. Not sure if the model would select an NGCC if the cost of solar changes. I&M's analysis is reflective of PJM rules. MISO appears to have allowed NIPSCO to claim a different nameplate value. Scott reviewed what our preferred option is (page 20, case 9) which includes 3,800 MW of renewables.

5. Nest Steps & Wrap-Up (slides 87 - 89) – Toby Thomas, *I&M President & Chief Operating Officer*

Toby closed the meeting at 2:45 pm and thanked everyone for their time so we can get a better IRP at the end of the process. The next stakeholder meeting will focus on modeling results, preferred portfolio, and final inputs and will be held on March 22 in Muncie.

Q. T. Dorau – Appreciates the approach used to conducting the meeting via a web conference.
A. I&M plans to continue to conduct future meetings in this manner.