Indianapolis Power & Light Company
2019 IRP Public Advisory Meeting #5
December 9, 2019

Meeting Summary

Introductions & Safety Message
Shelby Houston, Regulatory Analyst
(Slide 3)

Ms. Shelby Houston thanked attendees for joining today's IPL IRP Meeting. First, the group viewed a safety video prior to all attendees introducing themselves and what organization they are with/representing.

Meeting Objectives & Agenda
Stewart Ramsay, Meeting Facilitator
(Slide 4 – 5)

Mr. Stewart Ramsey noted that the topics for today's meeting are noted on the agenda slide. After introductions, IPL's President and CEO Vince Parisi provided an Executive Summary overview of IPL's 2019 IRP Preferred Portfolio and talked about how the Company came to the result and decision for this IRP. From there, Mr. Ramsey indicated that rather than spend half a day going through each specific result, Mr. Patrick Maguire from IPL would cover the insights from the modeling results. Mr. Ramsey noted that IPL had done a nice job at identifying insights that may not be directly intuitive. He noted that taking the time to go through this review personally helped him understand the results. Mr. Ramsey stated that after the insights review from Mr. Maguire, the group would spend more time going into the in-depth results. Mr. Ramsey noted this meeting set up and timing is intentional to allow plenty of time to answer any questions meeting attendees have on results and sensitivities. Lastly, Mr. Ramsey stated that Mr. Maguire would wrap up the meeting with a presentation and recap of the IPL 2019 IRP Short Term Action Plan. That plan includes the set of actions that need to take place in the near term to execute the plan.

Executive Summary of Preferred Resource Plan
Vince Parisi, IPL President and CEO
(Slide 6 – 16)

Mr. Vince Parisi welcomed and thanked the group for their time and input. He noted that IPL is better at what it does because of stakeholder involvement and input. Mr. Parisi shared with the group that the IPL 2019 IRP is based on information available today. The IRP is a 20-year plan and 20-year forecast, but the Company comes back every three years and takes another look. The frequent revisiting of this plan allows the Company to change the plan in accordance with the changing market. Many factors were taken into account when making this resource plan. Some of those factors include; safety, reliability, cost to customer (which is a critical component), as well as risk and uncertainty. IPL also considered the sustainability and environmental attributes for each Portfolio as well as future flexibility as new information becomes available in the future.

Slides 8 and 9 showed the outline of the 2019 meetings IPL hosted and how the Company had diversified our portfolio over time. Mr. Parisi reminded the audience that it was important to keep in mind that IPL has added 400 MW of renewables and retired 260 MW of coal at Eagle Valley and refueled 630 MW to gas from coal at Harding Street.

Mr. Parisi noted that IPL's Preferred Resource Portfolio was selected based on lots of input and review. The Preferred Plan includes the retirement of Petersburg (Pete) Unit 1 in 2021 and Unit 2 in 2023. IPL did not come to this conclusion and decision lightly. Although this is the right mix for IPL's customers, it will have an impact on the people in Petersburg. This is something IPL took very seriously. IPL plans to replace the capacity of Pete 1 and 2 with replacement generation that will be selected via an all-source request for proposals (RFP). Specifically, by 2023, IPL will need 200 MW of additional capacity. Right now, the IRP modeling suggests that the most cost-effective mix of replacement resources would be a combination of solar, wind and DSM, but the actual mix will be determined by the RFP responses. The modeling targets approximately 130,000 MWh per year of DSM as part of the 2021-2023 DSM Plan for IPL. This is consistent with what IPL is doing now. Lastly, this Plan gives IPL the ability to monitor any changes that may come in the near future. Note: The Short-Term Action Plan in Portfolios 3, 4 & 5 are all the same.

Mr. Parisi shared that he would also talk about the other benefits of the IPL 2019 Preferred Plan. Specifically, the Plan helps support the following areas of focus: customer centricity, least cost, flexibility & balance and a greener energy future. Mr. Parisi stated that IPL often hears from its customers about cost, reliability and green. This Plan seeks to balance these customers' requests. IPL looked at fifteen (15) portfolios across five (5) different scenarios. The Preferred Portfolio is the lowest cost solution across virtually all the scenarios. As far as Pete Units 3 & 4 go, it makes sense for IPL to continue to operate these units at this time. This Short-Term Action Plan gives IPL built-in flexibility and considers cost to customers. Both of which are important items that we need to consider and take a look at. The chart on Slide 15 shows how IPL's past and present decisions show movement towards driving down IPL's carbon intensity over time. Mr. Parisi introduced Mr. Maguire to discuss the efforts that went into the modeling process.

2019 IRP: Modeling Insights
Patrick Maguire, Director of Resource Planning
(Slide 17 – 29)

Prior to Mr. Patrick Maguire beginning this agenda item, Ms. Shelby Houston read questions that came in via the Microsoft Teams meeting chat during Mr. Parisi's presentation.

Participants had the following questions/comments, with an answer provided after:

- Do you plan to run Pete 3 and 4 until 2042?
  - Mr. Maguire responded that the decision is based on information known to IPL at this time. IPL is not committing to any change to the retirement dates of those units at this time. As we continue to move forward, this could change.
  - Mr. Vince Parisi again shared that IPL looks at our plan and resource mix as part of the IRP every three years and it does not make sense for those two units to retire in the near term. This is the most flexible decision we can make today, and IPL will revisit this decision in 2022.
- Please identify the approximate proportion of retail sales that will be met with coal and natural gas in 2030 and 2039 under your preferred plan. (I don't see this info clearly

identified in your slides.) Thank you.
    - Mr. Maguire responded yes, it is not noted in the slides. For the preferred plan, in 2030, it is approximately 30% coal, 40% gas and 30% renewables.
- What are the actual CO_2 emissions decrease over time (not emissions intensity, the actual tons per year)?
    - Mr. Maguire noted this information is later in the deck. Over the 20 years of the study period, it is close to a 50% reduction in terms of annual tons.
- IPL raised rates to cover the costs of emissions controls equipment at Petersburg Station a few years ago. Since two of units will retire, will rates be lowered to reflect that the equipment is no longer needed?
    - Judi Sobecki, IPL General Counsel, responded that IPL anticipates that when we look at replacement capacity, we would need to go in for a filing in front of the IURC. It would be addressed at that time, but we have some time before we would be going before the Commission.

Mr. Maguire shared that he wanted to share with the group more about the high impact variables that impact IPL's current units and the technologies viewed in the IRP modeling. Mr. Maguire stated that the market has changed a lot in the past 10 years and a lot of these changes have impacted IPL's existing resources. Overall, the modeling shows that coal is being replaced with gas, wind, solar and storage. There is a focus in some of the upcoming insights slides in this presentation on utility scale wind and solar solutions. Mr. Maguire described the opportunities with these types of resources and the risks IPL was evaluating when reviewing modeling results. He noted that this insights discussion is helpful to have prior to the review and discussion of the present value revenue requirement (PVRR) numbers later in the presentation.

The first three slides of the insights section cover Coal Economics and how changes in the market have impacted the coal fleet. The market has shown that the low prices of gas from the shale gas revolution have had a number of impacts that play out in this market. The most substantial impact has been on coal. Mr. Maguire noted that this is not just IPL's take, but the DOE has analyzed that as well. The drop in wholesale prices is primarily due to the decrease in natural gas prices. Further context from history notes that the delivered coal prices at Petersburg were very stable over time (between approximately 1997 – 2005). Moving forward in time, that cost (heat rate times fuel cost) has doubled since 2005. Since 2005, at present, coal prices have come down some for various reasons. The variable fuel cost of a coal plant is the same or even higher than that of a new combined cycle plant. This is a direct impact on the economics. Another way to look at this impact is to look at the supply curve. Slide 20 displays the MISO Generation Supply Stack. IPL took all the capacity in MISO and sorted lowest cost resource to highest cost resource and stacked as the cumulative capacity. It is important to note that this presentation of information does not include fixed costs. Slide 20 showed the dispatch and energy value of the units presented. In the Day Ahead Market, resources bid in their price. There is a supply and demand for every day and every hour. This is an annual look. This is a tool to understand what is going on in the market. For 2014, you see that IPL Petersburg is sitting lower in the stack, in 2014 gas prices were higher (closer to $6). That decrease in the curve for 2018 shows Petersburg units at the same cost but pushed out further in the stack. One thing driving this is wind. By the end of 2018, there is 19,000 MW of wind in MISO. This shifts the supply curve out to the right. Zero cost marginal resources are pushing out other resources and wind causes a depression of off peak prices. The other thing you see is that low gas prices are affecting the curve in two ways. One way is it flattens the curve. It reduces the margin of the coal prices. You are paid the marginal cost price setting unit. A second way is that as more combined cycle units come online, more units get pushed out again. This helps tells the story of what has been happening over the past few years.

Looking forward in IPL's modeling, another way to visualize the high level economics of coal is the dark spread. The dark spread is commonly used as a way to assess the economic value of coal relative to other units. A higher dark spread means you can make more energy in the energy market compared to other units and your cost. Another caveat to this presentation (Slide 21) is no capacity value is included. A full evaluation would have to include capacity value. Also, fixed cost is not included. This is indictive of the manifestation of coal economics on a variable basis. IPL considered a wide range of futures or possible outcomes. On Slide 21, each line shows each one of IPL's 2019 IRP Scenarios. A Carbon Tax has a significant impact on the coal units and is the single largest driver in the changes in PVRR. This has huge implication on the future value of IPL coal units. The grey range on Slide 21 is the stochastic range of results. As IPL looks at the future, in the next five to eight years, there will continue to be risk around the price of natural gas. This is seen in the modeling results. The possibility of carbon tax or other environmental legislation is a longer lead time to have impact, but in the short term, as noted, natural gas prices are the main driver of risk on coal. In the longer term, the risk on coal would be impacted by future potential carbon legislation, downward pressure of renewable LMPs and natural gas prices. This type of analysis is illustrative. It is helpful to overlay the fixed cost of Petersburg relative to the presented dark spreads. If you are below the blue range, you are not making money in the energy market. Again, huge caveats, no capacity value is presented and does not reflect dispatch instructions when prices are low or high.

A participant had the following question/comment, with an answer provided after:

- By fixed cost does that include fixed O&M or does that include the capital cost of the existing unit?
    - Mr. Maguire answered that this is just showing fixed O&M. It is difficult to show fixed cost on a $/MWh because you have to assume a capacity factor to the unit. IPL wanted to show this as an indication of where the market is compared to the cost range of other units.

Now, Mr. Maguire moved on in the presentation to discuss Wind Economics. A term used to help describe market impacts is captured energy revenue. This term is also sometimes called captured locational marginal price (LMP), realized price or realized revenue. All the terms mean the same thing. For wind and solar, it is a generation rated LMP at that location. Wind and solar are price-takers and will get the price when they are producing. The solid blue line on Slide 23 is generic new wind on a forward looking annual basis in the IRP model. Wind prices are generally closer to the off peak price because that is when wind produces more. But it is important to note that this varies a lot throughout the year.

Like discussed with Coal Economics, a Carbon Tax has an impact on the economics of renewables. It increases the revenues of renewables. IPL used Wood Mackenzie forward curves. When a Carbon Tax is implemented, the grid is not fully decarbonized, and gas tends to set the marginal price. The impact of the carbon tax is an adder to the variable cost. You see an overall shift to higher LMPs in a Carbon Tax Scenario. The solid black line is the levelized cost of new wind. The sharp increase is the expiration of the production tax credit (PTC). The PTC decreases 20% every year until 2024 when it is at 0%. As PTC is phased out, there are significant impacts on the levelized cost of wind. Also, as you add wind here, there is a shortfall in energy revenue as you move forward. The levelized cost is a cost specific to a point of time. Another way to look at is at a point a time draw a line of straight across is more reflective of what you build or contract wind for at that time. With an 80% PTC our levelized cost of wind is about $31/MWh. For every 20% decrease in PTC, it increases the cost to build or contract wind by $3-$5/MWh. One upside potential for wind would be additional new bulk transmission in the area where the new wind is being build. Also, co-located storage with the wind could increase the LMP at the wind + storage project location. On the policy side, the two things we see having an impact is carbon tax or a PTC extension.

Participants had the following questions/comments, with an answer provided after:

- When talking about the Pete units, you mentioned not including capacity revenue. It seems like for wind, you have the opposite problem. How does this all play out in PowerSimm? I understand that is it a market model on how to decide to what to build in comparison to market prices.
    - Mr. Maguire clarified that for the Coal Economics on Slide 22 the dark spread shows the revenue from the market. In the end, when IPL shows the full PowerSimm models for all resources we are selling all the energy into the market. That captures the fixed and capital costs and all of that is included in the PVRR results. The presentation of the Coal Economics slides is meant to be illustrative.
- To clarify, on Slide 22, there is no capital cost and no capacity value. But for wind, LCOE includes capacity cost but not capacity value. Is there capacity value assigned to all resources?
    - Mr. Maguire noted that to the extent that IPL shows net imbalance the capacity value is assessed at the bilateral capacity price. All this is shown in the PowerSimm model and the revenue requirement model. These slides again are meant to be illustrative to help explain context and further explain portfolio and scenarios results.
- Another stakeholder asked why is the capacity value noted from a bilateral price? Is this in contrast to the MISO capacity value? And if so, what is the difference?
    - Mr. Maguire explained that MISO is a residual auction for a prompt year, and it cannot be hedged forward; so the bilateral price is actually the MISO price/value.
- The stakeholder further noted I am not familiar with those prices; would you help me understand? How does it compare to levelized cost of energy (LCOE) of a new resource?
    - Mr. Maguire shared that $250 per MW-day is cost of new entry (CONE). In the short term, bilateral prices are much lower than CONE. IPL shows that is more like $50 MW-day.
- The stakeholder further asked and stated that it seems like in the long run you can't continue to assume that the capacity value is 25% of CONE. Is that accounted for at all in your modeling?
    - Mr. Maguire, yes this was considered in the range of modeling. This comes into play when the IPL position has an imbalance, either net long or net short. If IPL short, the model sees that and choose to build a resource at the actual cost of capacity for that new technology and that cost is reflected in the revenue requirement.
    - Mr. Maguire further noted that IPL also did a sensitivity analysis to stress capacity prices even more.
- A chat question came in that asked, how will retiring two units at Petersburg affect the overall efficiency at Petersburg? Will an economies of scale be lost and drive the cost of the remaining units higher?
    - Mr. Maguire shared that this was accounted for in the modeling. The plant worked

on a variety of scenarios. When two units are retired, not all fixed costs carry over to the other remaining units. Some fixed costs are used to cover operation of the whole plant and won't be saved.

For Solar Economics and analysis, IPL shared solar insights. Like wind, the higher captured revenue depends on when solar is producing. Solar tends to produce more on-peak and in the summer. This aligns with MISO on peak forwards. The impact of adding a Carbon Tax shows a shift up in wholesale prices. Therefore, with the same level of production you see a higher revenue which is reflected in the PVRR results in the Carbon Tax scenario. In the levelized cost of solar you see the ITC at 100% until 2023. After that, it goes back to 10% for perpetuity. In nominal terms it goes up and in real terms you see the cost of solar go down overtime. Solar economics in the short term are better. As IPL continues to look forward and we review portfolio results that have a lot more solar installed, the impact of the back half of the curve on the captured energy revenue graph. This helps IPL understand what revenue may truly be received from solar. Next, in the second graph, the June 2019 graph on Slide 25, the hourly price shape impacts actual revenue for solar.

Meeting Facilitator, Mr. Stewart Ramsey, asked Patrick to help him understand the impact of carbon tax on prices. The prices of resources in MISO that emit carbon will be higher. This means the cost of marginal cost setting unit will be higher in the Carbon Tax scenario. This means solar, when paid, gets the higher marginal price.

Patrick Maguire of IPL continued with summarizing that a discussion around solar capacity credit was presented in multiple IPL IRP Public Advisory Meetings. As part of the IRP modeling work, IPL reviewed our solar data. Solar that is the tracking technology is currently on the IPL system. Looking at all IPL solar data, IPL calculated the solar capacity credit specific to our system. On Slide 26, the black line is the actual load. Hour ending 16, 17 & 18 there is the peak of the day. The small thin yellow lines are the actual production of the solar assets. As we add more solar to the system, how does that change the capacity accreditation for solar? To understand that, IPL took the load shape and added more solar in 50 MW increments. This is a presentation of the IPL duck curve (Slide 27). The net peak load is the load net solar production. You see the shift of the peak load into the evening when there is more solar.

With this analysis and data, you can calculate two things: (1) Average capacity credit and (2) Marginal capacity credit. The average capacity credit is the cumulative capacity contribution divided by the cumulative solar installed in this example. The marginal capacity credit reflects the capacity contribution of the next incremental 50 MW installed in this example.

Another important component to consider with solar is the winter peak. IPL is looking closely at this impact since in general solar produces less in the winter. The solar capacity credit in the winter is effectively 0. Back to Slide 28, there are mitigating measures to improve the solar capacity credit through time. The obvious one is storage. Adding storage at the solar site or as a standalone resource. Another mitigation would be demand response or other energy efficiency measures to shift the load in an electrified future. Also, picking geographically diverse locations will help mitigate the capacity credit issue.
Participants had the following questions/comments, with an answer provided after:

- A participant asked if the marginal capacity credit analysis made it into the PowerSimm modeling.
    - Mr. Maguire affirmed that it did not. The participant voiced that IPL has extracted

a lot of meaning from an ELCC study conducted by MISO which may differ from IPL's system and ultimately the ELCC for IPL resources will be through MISO. The participant further remarked that the diversity of resources can improve ELCC, according to some research such as NREL.

- The participant cautioned extracting too much value from this analysis for solar's ELCC, though they do agree that capacity credit will decrease with increasing penetration.
  - Mr. Maguire responded that overall, he agrees, and this analysis should not be considered a stake in the ground for a limit of solar on IPL's system. There are possibilities with co-location and diverse locations, but these solutions aren't free and involve congestion risk or transmission costs that aren't being done right now. Regarding MISO vs IPL's system, it's a huge risk to only consider MISO's capacity credit value and IPL needs to protect customers from that risk. It might not be a capacity risk but would be an energy risk for LMP and reliability.
- The same participant agreed that those risks exist, and they present a more meaningful metric to look at instead of the ELCC analysis. In addition, reserve margin might not be the only or the appropriate metric to consider.
  - Mr. Maguire responded that hourly dispatch results capture energy imbalance risk and are picked up in our model.

- Another participant commented that utilities frequently present load and solar shapes but don't spend enough time discussing diversification of resources such as wind and solar that complement each other.
  - Mr. Maguire said he doesn't disagree. It's not something that is explicitly called out, but it is reflected in the model results in that we see portfolios with different mixes of wind, solar, and storage. In the ultimate cost and risk that's assessed probabilistically across all iterations and scenarios it gets picked up and we see the diverse portfolios perform better overall.

- A participant asked if the LCOE prices of wind and solar include the effect of tax credits, to which Mr. Maguire affirmed they do. The participant further asked if IPL would be looking at PPAs considering it does not have a tax appetite.
  - Mr. Maguire responded that everything in the model was modeled as an IPL asset. Going forward the RFP will determine what's available. The ability to monetize tax credits can be worked out through different structures.

- The participant asked how IPL as handling the tax associated with accelerated depreciation.
  - Mr. Maguire responded that everything is modeled as utility owned. We did sensitivities isolating capital costs. The tax credits are reflected as reductions in the capital costs.
- The participant asked if IPL would also be looking at PPAs.
  - Mr. Maguire responded that the RFP will not specify the ownership structure.

BREAK (Slide 30)

Analysis of Alternatives: 2019 IRP Modeling
Patrick Maguire, Director of Resource Planning
(Slide 31 – 57)

This next section is focused on stepping through the results and the key metrics of the IRP. The modeling framework utilized for this IRP was based on, and in response to stakeholders' request, a holistic evaluation of the IPL coal assets. This evaluation is based on age, size, and starting capacity position of the coal units. This approach ensures that we are setting reasonable pathways that are based on what it would take to build and construct replacement capacity that would be needed if we did retire one or more coal units. This is combined with a scenario analysis that looked at the key drivers of carbon, gas, coal and load. These drivers were modeled stochastically to widen the range we are looking at. This even further combined with so we can stress all candidate portfolios. At the September meeting, IPL presented 5 candidate resource portfolios. In those results, DSM decrements 1 – 3 were selected. IPL further evaluated the change in PVRR by forcing in additional DSM until the company saw meaningful changes in PVRR. This arrives at 15 distinct portfolios with variations of coal retirements, level of DSM and supply mix. Each 15 portfolios run through 5 scenarios for 75 stochastic production cost runs.

For the 2019 IRP, IPL made many improvements (Slide 35).

Mr. Maguire then presented Portfolios 1 – 5 and noted that these Portfolios have variations in the DSM levels. These are denoted as ***a*** (DSM Decrements 1 – 3), ***b*** (Decrements 1 – 4) and ***c*** (DSM Decrements 1 – 5). Overall, you see the model selecting a lot of wind, solar and storage in all portfolios and scenarios.

Mr. Maguire shared that total installed capacity versus the retirements by Portfolio. There is a need for 3,000 MW of new capacity to replace 1,000MW in Portfolios 1 & More wind and solar needed for the firm capacity credit. In Portfolio 3 to 4GW of 2030 would be needed to retire Pete Units 3 & 4. The Cap Ex requirements for comparison is noted on Slide 37. For all portfolios, we are long today. Slide 38 reflects the reserve margin versus reserve margin target on a UCAP basis. The lines converge when the net capacity position is flat.

IPL presented the metrics summary in the September 30th meeting. Today we will step through each metric category by Portfolio. The 20 year PVRR for all portfolios is on Slide 40. This 15X5 matrix/table is color coded by specific scenario. For example, the blue in the Reference Case column shows how each portfolio performed in that scenario. The lighter shade is the lowest cost and then as the color gets darker the cost is higher relative to the others in that scenario. Portfolios that perform the best across multiple futures is more optimal. Portfolio 3b is the lowest cost across the scenarios.

Mr. Maguire noted that Slide 41 is the same data is Slide 40. The metric evaluation of PVRR color coded by the retirement. Identify what is causing the order of the portfolios in each scenario. Reference Case relative to Scenario A (Carbon Tax Case). In 2028, a Carbon Tax is implemented in Scenario A. The scale and timing of a Carbon price is unknown. It starts low at $2 or $3 a ton and increases overtime during the study. When a carbon tax is added, you see Portfolio 5 to move up to the top five portfolios. The chart on slide 42 shows the annual difference in revenue requirement for each portfolio shown compared to Portfolio 1. Looking at annual revenue requirement can highlight potential rate impacts with significant changes in the portfolio mix both in the short term and long term. IPL sees in the Reference Case that you see a decrease in Portfolio 3b than Portfolio 1b. Portfolio 5b is retirement of the full Petersburg plant by 2030. The dotted lines show the changes in the Carbon Tax scenario. A takeaway in this difference comparison, you see how the Carbon Tax increases the long-term value of renewables. Optionality to pivot to other Portfolios over time. Scenario B is the Carbon Tax and High Gas Scenario. Mr. Maguire described that in this Scenario you see Portfolio 4b moves up even slightly above Portfolio 5b. When you layer on the Carbon Tax, but you have a High Gas price, the high natural gas prices temporarily offset carbon tax impact on coal units.

Regardless of environmental changes and low-cost renewables, gas is still an economic indication of coal. Scenario C is a Carbon Tax, Low Gas and Low Load future. IPL sees in this Case that this Scenario is the worst case for Coal. Portfolio 5 is the lowest cost in the 20 year period in this Scenario, but others are very close. Scenario D has no Carbon Tax, High Gas and High Load. IPL sees in this Case that this Scenario is the best cast for Coal. Portfolios 1 & 2 move a little closer in the top 5 least-cost portfolios. Portfolio 3b is still lowest cost with the higher gas price in this Scenario.

- A stakeholder shared that IPL has moved leaped and bounds from the last IRP. As someone who reviews IRPs, I absolutely appreciate it. The stakeholder clarified that because of that, asked Patrick not to take these questions in the wrong context. My questions are around how these results seem odd. You characterize the portfolios as optimized portfolios selecting decrements 1-3 and forcing 4 and 5 to then see what is the lowest in cost. Another piece that seems odd is that there is very little difference in cost. More separation in a, b & c, not a product of energy efficiency, but what happens when that EE is added. Perhaps something inadvertent is happening based on the size of the supply side resources that might not be realistic.
    - When IPL set up the decrements/bundles, the hindrance of DSM comes from the position that IPL is long capacity through 2023. DSM is available 2021 and you had to have it for the full whole study period.
- How does the model decide it reaches convergence? What is the model using to test that?
    - Mr. Maguire shared yes, we can cover in the Tech Meeting tomorrow after this Public Meeting.

Mr. Maguire summarized key takeaways from the model runs. A carbon tax assumption is the single largest driver in portfolio PVRR as it has a significant impact on coal margins. Natural gas prices also have a high impact. Portfolio 3 moves IPL's portfolio to a 30/40/30 mix of coal, natural gas, and renewables.

Participants had the following questions/comments, with an answer provided after:

- A participant asked for clarification on how IPL will hit that 30/40/30 mix and commented that he doesn't see the 30% renewables in IPL's plan.
    - Mr. Maguire responded that the mix is based on what the model is selecting. To the extent that the RFP yields results drastically different from what was modeled, that could change the actual mix. Mr. Ramsey clarified that the 30% includes renewables that IPL already has.
- A participant asked if this mix is 20 years from now.
    - Mr. Maguire responded that it is over the next 20 years.

- A participant asked via chat if the retirement costs are accounted for in the portfolio.
    - Mr. Maguire responded that shutdown costs are not included in the PVRR results. Those costs are going to occur no matter what, so it's just a question of the time value of money which would be a relatively small change in comparing the portfolios.

Mr. Maguire continued with discussing the levelized rate impacts of each portfolio.

Participants had the following questions/comments, with an answer provided after:

- A participant asked if this rate impact (Slide 47) includes accelerated depreciation and if IPL is planning a rate case in the future to recover accelerated depreciation costs.
    - IPL's legal counsel responded that IPL is not planning a rate case imminently. We must also consider capacity replacement which is unknown at this time. The rate impact slide does not include accelerated depreciation.
- A participant asked when the RFP would be issued.
    - Mr. Maguire responded that we will get to that later in the presentation, after lunch.

Mr. Maguire continued with explaining the risk metric of risk premium. This accounts for the size of the tail of the PVRR distribution and is more meaningful than just looking at the mean PVRR. The risk premium is reflective of the hourly dispatch results. We do see a lower risk premium for Portfolios 1 and 2 because coal prices experience lower volatility than natural gas and coal units can also vary their dispatch to minimize loss during low prices and maximize revenue during high prices. Renewables have greater mismatches between load and generation resulting in more market purchases and sales, which increases the risk premium.

A participant had the following question/comment, with an answer provided after:

- A participant asked via chat if the portfolio includes a just transition for workers and the community.
    - Mr. Parisi responded that this was not specifically modeled in the portfolio, but that IPL is working to understand the impact. This transition will provide time to work through those considerations.
    - Mr. Maguire continued with the risk-adjusted PVRR, where the risk premium is added to the PVRR. From this we see that Portfolio 3 is the lowest cost on a risk-adjusted basis.

IPL also wanted to look at downside opportunities, the inverse of the risk premium metric. In the Reference Case, Portfolio 3b is the lowest cost by PVRR and has the lowest downside potential, which is good. In the Carbon Tax Case, Portfolio 3b is still the lowest and offers the lowest downside potential. This look allows IPL to incorporate risk into the decision-making process.

The other risk metric IPL looked at was market interaction. All portfolios have market purchases and sales, and it is important to look at both. IPL did not want to rely too heavily on purchases or sales, both create risk to the portfolio and customers. Portfolio 3b does increase market purchases a little, relative to portfolio 1b, but it also lowers market sales. Over a 20-year period, Portfolio 3b has less market interaction. Portfolio 5 does have an increase in market purchases which influences the risk premium.

IPL looked at a range of air emissions and compared average portfolio results to a baseline. The portfolios that retire the most coal provide the most benefit in terms of emissions. Evaluating non-air emissions is difficult. IPL made an estimate on the reduction of water usage for retiring portions or all of the Petersburg plant.

To summarize, Portfolio 3b is the lowest cost portfolio across a wide range of scenarios. It's also the lowest cost on a risk-adjusted basis and results in a near term reduction in CO2, NOx, SO2, and water usage.

A participant had the following question/comment:

- A participant commented via chat that they appreciate that IPL took into consideration the other environmental impacts such as water and not just CO_2.

There were no further questions and the group broke for lunch.

LUNCH (Slide 58)

Sensitivity Analysis
Patrick Maguire, Director of Resource Planning
(Slide 59 – 72)

A participant had the following question/comment, with an answer provided after:

- The participant (via chat) commented that on Slide 20, referencing the MISO supply stack, Petersburg Units appear not to be in line to be dispatched unless MISO is almost at peak load. Is there information regarding where the rest of the IPL fleet is in the supply stack?
    - Mr. Maguire responded that we do have that information but caveated its usefulness since this picture changes every hour. This chart shows all capacity in MISO at the installed capacity level and ignores outages. It is illustrative of the changes to the supply stack. For the past several years Petersburg has averaged about a 60% capacity factor.

Mr. Maguire introduced the deterministic sensitivity analyses that were conducted in addition to the stochastic studies. A sensitivity analysis isolates a single variable at a time while observing the impact to PVRR. The first sensitivity IPL looked at was capital costs for wind, solar, and storage resources because there is less certainty relative to natural gas technologies. Capital costs were adjusted up and down relative to the base forecasts, creating a wide range by the year 2039. Wind, solar, and storage costs were changed together in each sensitivity rather than one at a time. PVRR results were sorted from low to high based on the Reference Case results. A 30% reduction in capital costs by 2030 still leaves Portfolio 3b as the cheapest and Portfolio 5b among the most expensive. On the other hand, increasing capital costs by 30% by 2030 does not make Portfolio 1b cheaper than Portfolio 3b.

A similar capital cost sensitivity was also performed for the Carbon Case. Portfolio 5 becomes the cheapest portfolio given a federal price on carbon as well as a 15% reduction in capital costs by 2030. Conversely, an increase in capital costs makes Portfolio 3 the cheapest again.

A participant had the following question/comment, with an answer provided after:

- A participant asked how capital costs are represented in PowerSimm.
    - Mr. Maguire responded that capital costs are input in nominal dollars. Outside of

the model IPL has a starting capital cost of dollars per kW which is grossed up for AFUDC and a construction finance factor. This is on Kiteworks. IPL multiplied that by the size of a generic project. PowerSimm levelizes the cost so it's not all in a single year. Outside PowerSimm is where IPL built up the full revenue requirement model including capital costs. Dispatch needs to be rerun through production cost mainly for reporting and risk metrics.

Mr. Maguire introduced the sensitivity conducted on MISO's capacity price. PowerSimm modeled capacity prices as a triangular distribution, but this sensitivity looked at deterministic capacity prices. These capacity prices are only relevant to net portfolio imbalances. This only impacts Portfolio's 1 and 2 where IPL has a net long capacity position for a large part of the study period. In this sensitivity, the volume of capacity was fixed, and the price was varied from the bilateral floor price to CONE. Results to PVRR were sorted low to high based on the Reference Case. A higher capacity price would lower the PVRR of Portfolio's 1 or 2 because it increases the value of their capacity length, which increases the revenue that offsets costs. When the capacity price is CONE (as high as it can go) it is still not enough to make Portfolios 1 and 2 cheaper than Portfolio 3.

The next sensitivity IPL examined was for wind. IPL obtained an Indiana wind profile from NREL (link at bottom of slide 67). IPL picked a midpoint capacity factor in northwest Indiana of 42%. It's higher than what we've seen historically, and the DOE reports the Great Lakes Region having a weighted average of 35%. So, IPL wanted to test this sensitivity to understand the impact in case IPL can't get the capacity factor IPL modeled. IPL locked the captured revenue rate and varied the volume output to value higher and lower capacity factors. IPL changed the capacity factor up to 46% and down to 30%. Resulting PVRRs were sorted low too high for the Reference Case. Even a very low capacity factor (30%) does not change the answer of Portfolio 3 being the cheapest. Every 2% decrease in wind capacity factor increases the PVRR of Portfolio 5 by roughly 1%.

A similar evaluation of wind capacity factor was conducted for the Carbon Case. As capacity factors decreased, you begin to see Portfolio 5's PVRR become better than Portfolio 4's, but Portfolio 3 remains the cheapest.

The last sensitivity IPL looked at was the wind LMP basis or captured revenue. In PowerSimm, IPL modeled an LMP discount based on where IPL thinks wind will go in and the congestion at that point. IPL locked in the MWh and varied the captured revenue by 5% increments to remove the discount entirely. Wind was modeled at about a 20% discount to Indiana Hub but was tested down to a 0% discount. Removing the discount narrows the gap between Portfolio 3 and Portfolio 5 but Portfolio 3 remains the lowest cost.

This was also done for the Carbon Case where removing the basis discount does begin to position Portfolio 5 ahead of Portfolio 3.

Preferred Resource Portfolio & Short Term Action Plan
Patrick Maguire, Director of Resource Planning
(Slide 73 – 77)

The Preferred Resource Portfolio is Portfolio 3b which includes the retirement of Pete 1 by 2021 and the retirement of Pete 2 by 2023, the addition of four Decrements of DSM, and additions of wind, solar, and storage through time. It is the lowest cost portfolio on a risk-adjusted basis across virtually every scenario that IPL modeled. Stressing many values such as capacity price still shows Portfolio 3 being the lowest cost. Committing to only retire Pete 1 and 2 preserves optionality in the face of uncertainty in the future. The short-term action plan for Portfolios 3, 4, and 5 is the same. Going into Portfolio 3 allows IPL to move into other portfolios.

Today we're about 400 MW long in terms of capacity. IPL's first capacity shortfall comes with the retirement of Pete 2 in 2023 where IPL will be about 200 MW short of firm capacity. Based on IPL's costs, the model selected the lowest cost portfolio which is about 500 to 600 MW of wind, solar, and storage by 2023. Variations in the model produced slightly different mixes of those technologies and the actual replacement capacity will depend on what is bid in through the all-source RFP.

IPL contracted with Sargent & Lundy to run the competitively bid all-source RFP. More detail will be coming out in the upcoming weeks. IPL will be looking primarily at Indiana projects. All information will be at iplpower.com/RFP, but this is not live yet. 2020 projects in the MISO queue are already spoken for so IPL will look more at those projects for 2021, 2022, and 2023. IPL will look for projects that are already started. The MISO queue is dominated by solar. There's a huge drop off in wind after 2020 coincident with the phaseout out of the PTC.

Participants had the following questions/comments, with an answer provided after:

- A participant asked if they would be able to see the RFP prior to it being issued if the proper NDA is executed.
  - o Mr. Maguire said IPL can discuss and consider that. It is moving very quickly though.
- A participant asked, when will the RFP be issued?
  - o Mr. Maguire said it is still being decided and more information would come in the following weeks.
- Another participant also expressed interest in reviewing the RFP prior to its issue, via chat.
  - o Mr. Maguire said IPL can talk and consider that. Timing may be an issue.

Mr. Erik Miller (IPL) stepped to the front of the room to discuss the IRP DSM plan. Mr. Miller recapped that IPL started with 8 decrements (or bundles) in the model, each representing 0.25% of sales for a total of 2%. The lowest PVRR in the Reference case was Decrement 4 which is about 145,000 gross MWh per year. That will be IPL's target for the 2021-2023 action plan. IPL will target for somewhere between Decrement 3 and Decrement 4. Lighting programs have been a challenge and a source of contention. Baselines have changed, savings are going away, and IPL has decided not to include residential lighting in the plan. IPL is currently working with vendors to determine what IPL can actually get in the market. Actual results could differ from what was initially determined for the model. IPL plans to file the DSM 2021-2023 plan around April next year (2020).

Participants had the following questions/comments, with an answer provided after:

- A participant asked, what about the potential for specialty bulb?
  - o Mr. Miller responded that IPL will do what is possible with specialty lighting to try to keep programs going. Additionally, IPL will continue to offer general service specialty bulbs to the income qualified sector because we do still tend to see

savings there.

- The participant further asked, how will a stretch goal of 168,000 MWh be reconciled? Also, is this on a net or gross basis?
    - o Mr. Miller clarified that the stretch goals pertained to the 2018-2020 plan. IPL is currently wrapping up the IPL 2020 plan for next year and this presented 2021-2023 plan will be based on a new DSM filing.

Mr. Maguire resumed speaking, noting that the IRP process will continue to evolve going forward. This includes looking at the capacity value of renewables and the introduction of renewables, storage, and other variable resources that introduce complexity in the market and change the type of modeling required.

Concluding Remarks
Patrick Maguire, Director of Resource Planning
(Slide 78 – 79)

The last IRP cycle used an annual reserve margin, a "typical week" capacity expansion model, a deterministic view, static renewable prices, and a cursory but limited view of electric vehicles and distributed solar. This IRP used a new model that used hourly chronological dispatch in capacity expansion, modeling weather, load, and renewables together, changing solar capacity credit through time, and a more detailed look at electric vehicles and distributed solar. Future IRPs might require sub-hourly modeling and will probably continue to look at DSM using the bundled approach. The future of DSM will rely on determining the peak contribution towards reducing load and shifting the peak. IRPs will continue to get more complex.

Mr. Maguire thanked everyone for coming and participating in the year long stakeholder engagement process. The IPL 2019 IRP will be submitted a week from today on December 16, 2019.

Meeting attendees, in-person and remote, had no further questions.

Meeting adjourned.