**Director’s Comments – Load Forecasting**

**The Director understands the limitations IMPA faces when preparing load forecasts because of the wholesale nature of its business. The lack of access to uniform data on retail customer consumption imposes certain constraints on the modeling methodologies available to IMPA. Accepting this circumstance, however, there are several places where the load forecast documentation can be improved.**

1. **The use of the national unemployment rate is an unusual choice for a driver. As a rate statistic, it provides no indication of a change in the level of employment (e.g., if the workforce and employment both grow at the same rate, the unemployment rate is unchanged). Four of the five load zones use the unemployment rate as an explanatory variable, and three of the zones use the change in annual gross domestic product (GDP) as an explanatory variable.**

*These comments are always helpful to IMPA staff with thinking about the load forecasting process in ways that perhaps were not considered previously. We also appreciate the Director’s understanding of the challenges and limitations faced by IMPA when forecasting wholesale loads. In using national economic data, IMPA seeks to both find variables with explanatory power and have the ability to be independently forecasted. The Director’s points regarding potential pitfalls of using rate statistics are valid. Since filing the IRP, IMPA has essentially gone through two load forecast revisions, whereby the decision was made to shrink our sample size in order to mitigate the distortions of COVID related shocks, as well as to discover a better fitting economic variable. In our most recent load forecast update, IMPA has discontinued the use of the national unemployment rate and replaced it with the Labor Force Participation Rate. While this is still a rate statistic, IMPA believes this captures some of the potential demographic shifts that may be impacting our member communities more locally. In addition, we also recall that the Director has encouraged us in previous reports to find Indiana specific data and to this end IMPA had a meeting with the Kelley School of Business’ Indiana Business Research Center in late August to discuss some of their data offerings and forecasts. At the time of our response, IMPA is continuing to evaluate some of this data for inclusion in our load forecast.*

2. **The inclusion of the EV energy forecast is an improvement compared to previous IRPs.**

*With respect to the EV energy forecast we recognize this was an early attempt and IMPA believes this will be an area of continuous improvement.*

3. **The peak demand forecast description does not explain if and how the EV forecast impacts peak demand.**

*IMPA has no concrete data that would inform how and when consumers within IMPA communities would charge their EVs, nor the location of their charging. For example, are people living in Lebanon or Crawfordsville commuting to Indianapolis for work, where there are more prevalent charging options? If so, they may elect to charge using other utility systems as opposed to the IMPA member community system. If they are commuting, but charging at home, do commute times push this energy usage to later in the evening or to weekends? For these reasons and until IMPA can find supporting evidence to the contrary, the incremental energy was assumed to have no impact on peak load.*

4. **Comparing the energy model explanatory variables to the models in the 2020 IRP, there has been a change in the macroeconomic drivers. Real GDP growth rate and the national unemployment rate have replaced the 2020 explanatory variables Annual GDP and Energy Intensity (btu/$ of GDP). In the 2020 IRP, it was unclear how the energy intensity driver was forecasted. Perhaps that is the reason it is not used in the 2023 IRP.**

*IMPA's energy intensity variable was derived from the forecasted total energy demand for the US (supplied by Exxon Mobil in their Annual Outlook for Energy), converted to btu and divided by real GDP in dollars. This was an effort to capture the impacts of more efficient appliances, improved technology and various other energy efficiency gains made in the economy. However, it was ultimately decided that its inclusion was somewhat circular given the use of GDP in other areas of the forecast. In addition, IMPA wanted to reduce its reliance on derived variables, despite the intuitive nature of the variable. IMPA may reconsider the use of such variables in the future.*

5. **The energy models include a peak season dummy that is 1 for summer and 0 for all other seasons. The description of this variable in Table 5 in section 6 on page 36 has an asterisk as if it has a footnote, but there is no footnote.**

*This was a stray asterisk. No footnote intended.*

6. **The CenterPoint energy model includes a "Jasper" dummy to account for unexplained loss in the CenterPoint load zone. It is curious that IMPA has been unable to determine the source of the loss.**

*IMPA has worked with its Member Services group to engage with the community on possible local drivers but none have been found to date. Jasper as a percentage share of IMPA's Centerpoint load has declined noticeably since the Spring of 2020, which coincides with the COVID 19 Pandemic, yet this "market share" has not recovered. However, this share has also steadily declined since even before the pandemic. Noticeably, shares for the other 3 communities have stayed relatively stable (i.e., growth in other communities isn't displacing Jasper load). IMPA continues to investigate.*

7. **The peak modeling appears to have changed since the 2020 IRP although the near complete lack of details in the 2020 IRP makes it difficult to determine with any degree of certainty.**

*Apologies to the Director for the lack of detail in the 2020 IRP regarding peak forecasting. IMPA effectively made changes to the energy forecast model as discussed in the 2020 IRP, and then let those flow through the same peak demand model as used in the 2017 IRP. The table below shows the variables used in the 2017 IRP to forecast peak demand. For the 2020 IRP, IMPA was hesitant to make drastic planning requirement changes based on a load forecast with an unfolding pandemic. As a result, not much time was spent discussing it in the 2020 IRP. As IMPA gathered more data over the pandemic, new demand forecasts were developed. Peak modeling for the 2023 IRP, as discussed, moved away from some of the more granular variables shown in the table below (e.g. maximum wind speed) and towards variables common to the 2023 energy forecast, along with relevant daily weather variables.*

| Season/Area | DUK-IN | Vectren | NIPSCO | AEP | DUK-OH |
|---|---|---|---|---|---|
| Spring | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | Daily Peak MWh, High Temp | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | DUK-OH Load, HDD/CDD for Cincinnati |
| Summer | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | Daily Peak MWh, Difference between High and Low Temp, Average Wind Speed | Peak Dummy, Daily Peak MWh, High Temp | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | DUK-OH Load, HDD/CDD for Cincinnati |
| Fall | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | Daily Peak MWh, High Temp | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed | DUK-OH Load, HDD/CDD for Cincinnati |
| Winter | Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed | Daily Peak MWh, Average Barometric Pressure | Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed | Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed | DUK-OH Load, HDD/CDD for Cincinnati |

[1] *Indiana Municipal Power Agency 2017 Integrated Resource Plan, 5-34*

**8. IMPA does not cite the source for the assumptions of 44.6 kWh per 100 miles driven and an average annual mileage of 12,000 per EV.**

*As a proxy, IMPA utilized data from: www.fueleconomy.gov. As electric vehicle efficiency improves, as it has done, this metric will lower the implied energy impact to the IMPA load forecast.*

**9. In the peak load models, IMPA does not explain how the HDD equivalent and the CDD equivalent variables were constructed. It is curious that the CDD equivalent variable does not appear in the Duke Energy Ohio model.**

*The HDD equivalent variable is constructed by first calculating a "real feel" temperature based on the daily low temperature for the day. This is accomplished by using the following formulas:*

*https://meteor.geol.iastate.edu/~ckarsten/bufkit/apparent_temperature.html*

*This adjusted temperature is then converted to either an HDD or CDD equivalent with a base of 65 degrees in the same manner as one would calculate a HDD or CDD, but just using the "real feel" temperatures for the observed peak days.*

*Duke Ohio load is historically winter peaking and the CDD equivalent was a poor fit and was rejected for inclusion.*

10. **The “what-if” load forecast methodology is discussed in general terms, but there is no discussion of specific assumptions about how much the economic drivers changed and how the EV forecast was modified.**

*The changes in economic variables underlying the different scenarios were based on the upper and lower positive bounds in the Survey of Professional Forecasters at the time of forecast formulation. This resulted in a change of the average GDP growth over the forecast period from 1.7% in the base case to 3.2% in the high case, and 1.2% in the low case. Similarly, the average unemployment rate over the period changed from 4.2% to 3% in the high case, and 5.3% in the low case. IMPA's EV forecasts differ in the high/base/low cases in the timing of IMPA communities matching the national level of electric vehicle market penetration, with the base case reaching converging in 2030, the low converging in 2035, and the high case converging in 2027.*

11. **There is no discussion of DERs in the load forecast section. The current state of DERs in the IMPA system is discussed in section 5 on pages 30-31.**

*IMPA ultimately forecasts projected billed energy and demand. To date, retail customer owned generation is very small and very difficult to predict timing and size. IMPA continues to monitor DERs in customer areas via their generation interconnection agreements. Going forward, IMPA is aware of some larger DER deployments and will have to adjust the load forecast accordingly. IMPA may also consider the use of customer generation applications as a variable.*

**Director's Comments – Energy Efficiency and Demand Response**

*Energy Efficiency and Demand response are areas where IMPA is continually improving and educating itself on how to best implement. In addition to this process, IMPA is also contending with ever evolving marketplace rules around how EE and DR resources are assigned capacity value in the marketplace.*

1. **The 2023 IRP report includes a brief explanation about modeling EE and DR programs, but it does not provide sufficient details to understand how the implementation costs and one-fourth load increments were determined. A more detailed explanation about the EE and DR modeling methodology would provide more resources and information to better analyze the whole DSM modeling process. Furthermore, in the current IRP's Action Plan, IMPA mentions that it will continue the EE programs. However, there are no quantifiable savings goals clearly stated as the potential future savings from these programs.**

*As IMPA spent time meeting with DR aggregators and learning how they work, DR and EE modeling in the 2023 IRP was largely an estimate of how these resources might work in the IMPA portfolio. EE programs in the model were set to small blocks priced based on our existing programs, but at 250kW tranches. These small sizes are due to IMPA experience of EE being a world of greatly diminishing return. For example, efficiency gains from incandescent lighting to CFLs were large (e.g., 75 watt to 20 watt), but the gain from moving from CFL to LED is much smaller (20 to 13 watt for 75 watt equivalent). Once those changes are made, the marginal increase in efficiency over replacement cycles is relatively low. Finally, EE as it pertains to IMPA is largely out of IMPA's direct control in terms of implementation. IMPA offers rebates, but beyond that it is ultimately the consumer who elects to implement. A slight correction is needed as the IMPA IRP stated "$700,000 in program costs per year" whereas this was set up as a program cost over a 5-year contract tranche wherein the model was able to select the resource for a $700,000 1-time cost and market potential, or capacity, was allowed to grow over time as aggregators found more enrollments to the program. These programs then expired after a 5-year term and were allowed to be renewed at a fixed 10 MW for the same $700,000 one-time cost across another 5-year term. Ultimately this was done to reflect some gain in learning as IMPA implements a DR program*

2. **Although IMPA provided specific implementation cost for the initial increment block of EE in this current report, it is unclear how the additional increments were "priced" (See IMPA IRP, sec. 12, p. 87). What factors were considered to determine the prices of the additional increments? How were prices assigned to reflect the difficulties of finding additional efficiencies? There are no details regarding the prices of the additional increment blocks of EE.**

*EE tranches were priced at roughly $237/kw for the initial tranche and $356/kw for the second tranche to reflect incrementally higher costs and ability to find efficiencies. These were MW limited due to IMPA's comments above that additional EE gains are very hard for IMPA to control.*

3. **What aspects were considered to assume that DR will grow at 2 MW per year?**

*At the time the IRP was written, early meetings with DR aggregators suggested IMPA would have an unknown level of market potential for DR until aggregators were effectively contracted to enroll potential members. Conversations around market potential included discussing what types of loads generally sought out DR programs and broadly speaking many of IMPA's industrial loads were not thought to be well suited for DR programs. IMPA estimated maximum DR capacity based on perceived eligible loads then broke the total number in to segments to reflect pacing of enrollment and learning. Ultimately, IMPA will not know market penetration until contracting with an aggregator.*

*4.* **What is the timing of the EE blocks and DR (e.g., does the model need to select a block for the entire 20-year planning period or are smaller time periods an option)? This could affect whether a block is selected. What was the total amount available for selection?**

*EE blocks were set as .25 MW blocks up to 1.25 MW per tranche in each market area for a total of up to 5 MW. These were effectively permanent reductions in load. DR blocks as noted in question 1 were set as being able to be selected in 5-year intervals with the first 5-year block scaling from 2 MW to 10 MW. Subsequent blocks were a fixed 10 MW.*

5. **What kind of rework on DR tariff was performed to facilitate DR enrollments?**

*To date, most of our tariff revisions have been centered around ensuring compliance with any and all MISO and PJM requirements of demand response resources. IMPA is also moving to a fixed rate in lieu of a percentage of auction clearing price. This helps the customer with price certainty, and it acts as capacity hedge for IMPA.*

**Director's Comments – Resource Optimization and Risk Analysis**

**The use of only three optimized scenarios structured around differences in CO2 emissions restrictions and renewable energy, with each scenario also having three weather-based sensitivities seems limited.**

**Failure to perform a more traditional stochastic analysis limits the metrics that can be used to evaluate the performance of the portfolios under different circumstances. It is the Director's understanding that IMPA states in several places that the Aurora model requires Eastern Interconnection-wide modeling. This does not appear to be accurate as the State Utility Forecasting Group uses Aurora and only models Indiana.**

**In Table 18 titled "Generation Costs for New Generation Technology" in section 12 on page 85, IMPA uses a "Tech Optimism Factor" to increase the capital cost of small modular reactors but does not explain or justify the factor used.**

**In Figure 24 titled "New Generation – Overnight Costs ($/kW) – Unsubsidized" in section 12 on page 86, are these nominal or real dollars?**

*The Director's concern regarding IMPA's use of only three scenarios is a new concern. Traditionally, IMPA has only utilized three scenarios, albeit usually subjected to stochastic analysis. IMPA respects the Director's concern regarding running just the three scenarios while not running stochastics. As IMPA was developing stochastic parameters while using the Encompass software, IMPA quickly ran into computational and database constraints. In collaborating with the vendor, IMPA was informed that a client server solution was likely needed to run each scenario stochastically. At the time, a business decision was made to forgo the material spend required for implementing a client server solution and instead rethink the risk process, particularly as it pertained to the Five Pillars and IMPA's recent experience with extreme weather events. The Director's comments regarding Aurora seem to be a misunderstanding as IMPA no longer uses Aurora. However, when IMPA was using Aurora, more accurate pricing was achieved when running the entire interconnect as Indiana is not an electrical island and benefits from interconnectivity from bordering states/regions.*

*In Table 18 the Tech Optimism Factor is an EIA supplied factor and is updated annually. The most recent one can be found here:*

*https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf*

*The dollars in Figure 24 are in real terms.*

**The discussion of forward price development raises several questions.**

1. **It is unclear whether prices shown in this section are real or nominal.**

   *All prices are nominal.*

2. **The natural gas price forecast in Figure 29 seems unrealistically high. The Director understands the projected price through 2033 is based on Henry Hub forward prices through 2033 and then uses a price forecast provided by Horizons Energy. The very different price trend beyond 2033 deserves some explanation of the drivers for this trajectory.**

*IMPA respectfully contests the notion that the natural gas forecast seems "unrealistically high" when topping out just over $6/mmbtu (nominal), especially when average spot prices at Henry Hub averaged $6.45/mmbtu in 2022. IMPA is a firm believer in the phrase "the cure for high prices is high prices" and vice versa. Persistently low natural gas prices, as seen in 2023 and 2024 will most likely result in reduced investment, which in turn will lower output. Adding to this dynamic are increased investment in domestic LNG terminals, which will serve to absorb excess extant supply. [1] Globally this should tighten US natural gas supply while alleviating some of the supply constraints seen globally. Domestic demand outside 2033 could be further increased with much higher than historical utility demand as utilities continue to pivot away from coal and replace with natural gas fired assets.*

*[1] https://www.eia.gov/todayinenergy/detail.php?id=62984*

3. **IMPA states that the forward power prices rely "on an internal market model constructed by IMPA utilizing the Encompass model and publicly available information regarding probable resources stacks for a given ISO. This model is used for the Indiana Hub price forecast only." (*See IMPA IRP, sec. 12, p. 88)***

   **IMPA briefly describes its use of the 2022 MISO Regional Resource Assessment to develop a long-term forecast of potential future resource mixes in the MISO footprint.**

   **The Director follows what IMPA did at a high level but thinks more detail would be helpful to more fully understand how the internal market model was developed and its reasonableness evaluated.**

*Our market model is under constant evolution but the initial process begins with pulling existing and planned MISO generation from sources such as S&P Global Capital IQ and Hitachi's Energy Velocity Suite. Those generators are set up with as much detail as possible and assigned relevant fuel delivery points and locational basis points based on their MISO Local Resource Zone. IMPA then utilizes MISO's PRA data to set import and export limits between each zone. Finally, to create an estimated resource plan, IMPA adds generic resources by fuel type as identified in the RRA. Loads are forecasted using combinations of RRA data and MISO OMS Survey Data*

4. **It is not clear if IMPA only projected energy prices or if it also projected capacity prices? If capacity prices were not projected, why? If capacity prices were projected, then how were the prices developed?**

*Capacity prices were not forecast for the purpose of the IRP modeling. Erroneous capacity price forecasting could lead to either underinvestment or overinvestment in generation resources. IMPA assumes unserved capacity is Cost of New Entry (CONE), while capacity prices when reserve margins are met are equal to $0. This helps Encompass build to meet load requirements and not be "enticed" by overbuilding just because of a high capacity price forecast.*

5. **The prices presented in Figure 28 "Price Forecast Comparison" in section 12 on page 91 is deserving of more discussion. The figure shows significant differences between the Blended Indiana Hub On-Peak and Off-Peak compared the Horizons Indiana Hub**

**On-Peak and Off-Peak forecasts. The differences are particularly obvious between 2025 and 2033.**

*The forward price forecast is a blend of 3 different data sources: forward markets, the Horizon's Energy long term price forecast, and the IMPA market model. With changes in market topology discussed in the MISO RRA, ever increasing renewable build out puts more and more resources on the grid with zero marginal cost. In particular, very high levels of solar penetration compress prices during the On-peak periods relative to Off-peak prices. Per the RRA, MISO Z6 sees renewable resources outstrip fossil resources starting in around 2033-2034.*

**Director's Comments – Risk Assessment**

**The risk assessment process discussed by IMPA *(See IMPA IRP, sec. 12, p. 111)* is both interesting and different. However, the lack of detail makes it difficult to understand fully what was done and why.**

1. **Were the weather event adjustments made on a percentage basis or on a difference in values? Given the relatively high base natural gas price projection, this could be significant.**

*Weather event adjustments to load and price were scaled to the load forecast and price forecast at the hourly level. Uri adjustments were made over 4 days while Elliot adjustments were made over 3 days. Effectively, these adjustments were just scaling the modeled hourly forecast and price up to actual observed loads and prices during these events.*

*Also of note, adjustments were made to IMPA's generation fleet to reflect actual unit availability over these days. For example, during the actual Elliot events, Trimble County 1 was offline, thus, during the modeling of these events in the IRP, Trimble County 1 was assumed to be out for each cycle of storm. Adjustments to loads were material but despite this, winter load during Elliot was still 200 MW lower than planned summer peaks. This exercise taught IMPA that volumetric risks on the load/price side are well managed by IMPA's portfolio diversity but where the real risks lie are on the generation side as they pertain to generator resilience to cold weather events or fuel availability.*

2. **The basis for calculating the adjustments is not explained. Were these calculated adjustments adjusted over the forecast horizon or set at one value?**

*These adjustments were calculated over the entire forecast horizon on a cyclical basis.*

3. **Was the 1.5 multiplier for gas prices applied year-round or only during the weather events? What was the basis for choosing to set the multiplier at 1.5?**

*The 1.5x multiplier was across the entire forward curve for natural gas prices. The application of that multiplier reflected approximate intraday movements in hub natural gas prices observed during winter storm events. Notably, IMPA uses a daily natural gas shape so moving the monthly hub price 1.5x will move the daily price in a parallel manner.*

4. **It is limiting when the risk assessment only discusses the impact on the annual NPVRR, 20-year NPVRR, 20-year levelized rate, 10-year NPVRR, and 10-year levelized rate. Should not other considerations be included in the discussion when evaluating the performance of the three portfolios across the weather and fuel shock sensitivities? The Director recognizes that some other performance characteristics are discussed in the chapter on the Five Pillars and the scorecard metrics, but there are limitations that will be addressed later.**

*Ultimately, IMPA chose to focus on financial metrics on the risk assessment because that is the metric IMPA members are probably most sensitive to. Some of the 5 Pillar metrics are possibly* *more of an abstraction since they happen rarely, if at all. Put another way, EUE for example, would be captured in a P99 metric of a stochastic process and, with traditional reporting thresholds of P5/P95, its impact may be lost. In addition, a loss of load event may ultimately be outside a utility's direct control whereas the rate making process can be controlled with prudent portfolio management. By stressing the financial aspects, it reveals potential gaps in the portfolio in a more concrete and actionable manner.*

**Director's Comments – The Five Pillars**

*To clarify the framework of the Five Pillars portion of the IRP, IMPA relied on a summary supplied by the Indiana Office of Energy Development. [1] The overlap between the selected metrics was largely driven by available output data and a relative lack of suitable, quantifiable variables. Thus, the use of single variables to capture multiple pillars. The Director's comments are well made, however, and IMPA envisions this area as one of continuous improvement.*

*[1] https://www.in.gov/oed/indianas-energy-policy/electricity/#:~:text=Since%20its%20founding%20in%202019,%2C%20affordability%2C%20and%20environmental%20sustainability.*

**Choosing not to use any stochastic analysis limits the choice of metrics to evaluate the Five Pillars because IMPA cannot identify risk probabilities.**

**The use of a weighted scoring system to rank each portfolio fails to capture the degree to which portfolio metrics may vary. For example, a very large difference for one portfolio compared to another portfolio for a given metric has the same impact as a small difference given the weighted scoring system. Also, there is no information provided as to what the actual values are for most of the metrics. Only the ranked scores are provided.**

**The substantial overlap between the different pillars and the metrics indicates a lack of clear definition of what the pillar represents. For example, the reliability and resiliency pillars seem completely redundant. While it is true that many metrics potentially reflect multiple pillars, it seems like greater clarity is possible. For instance, IMPA could have assigned the Market Energy and Market Capacity metrics to the Reliability Pillar, the Unserved Energy metric to the Resiliency Pillar, and the Ramp metrics to the Stability Pillar.**

**IMPA acknowledges that the Stability Pillar is difficult to quantify in resource planning as metrics like frequency response are not properly captured, but use of ramp capability seems like a reasonable proxy.**

**IMPA used market energy as a percent of load as a metric. IMPA assigned this metric a weight of only 5% because all the portfolios had constraints on how much reliance could be placed on the market for energy requirements. The result was that the three portfolios had very minor differences. This raises a couple of questions:**

1. **Where is the specific constraint on energy purchases stated in the IRP? How was the specific constraint determined?**

   *IMPA did not specifically address the market interaction constraint, however, when modeling portfolio expansions it is best practice to limit the ability of the model to rely on "market" as a resource. This was especially true for the 2023 IRP as most commodity curves were backward dated, increasing the likelihood of the model only leaning on the market as a best-case solution. In retrospect, IMPA could have run this as a scenario then scored that portfolio poorly on the "reliability" and "resiliency" metrics. The limit was set to be roughly 15% of annual load in each market. IMPA will state these assumptions more directly in the future.*

2. **If the differences in results for this metric across the three portfolios are very minor, then what is the value of this metric in evaluating portfolio performance?**

*The minor differences across categories are largely down to the fact that each portfolio had to meet the modeled constraint and because this was a constraint IMPA enforced, it is also why it received a low portfolio weight. In other words, because all of the portfolios were held to the same standard, IMPA did not feel like material differences would arise on this metric alone. However, in the future, the Director has given us some ideas on how to better differentiate these metrics in order to derive more value from them. For example, portfolios could be optimized with and without market constraints then scored independently with a higher weight given to the relevant metrics.*

*As Encompass changes its service offerings, IMPA foresees going back to stochastic analysis. Encompass has been planning for a web-based version of its software which would eliminate the database constraints IMPA encountered during the IRP process.*

**Another metric was market capacity as a percentage of IMPA's overall obligation. It is unclear if there was a limit imposed by IMPA on how much the market could be relied on for capacity, and, if there was a limit, how the appropriate limit was determined. The Director notes the conversation in section 4 on page 19, but no detail was provided.**

1. **Did IMPA optimize its portfolios using a planning criterion based on MISO and PJM planning reserve margins?**

*Yes*

2. **If the portfolio optimization was based on reserve margins, how can EUE be zero?**

*Expected Unserved Energy should be zero in a portfolio that is optimized to expected load plus reserves unless that optimized portfolio is then shocked above and beyond expected conditions, such as was done in the weather shocks, where loads exceeded the planned supply when the constraint on market interaction was also considered. Also, portfolio robustness was evaluated under the cross-scenario analysis where each portfolio was tested in a world in which it was not optimized.*

3. **Explain how EUE is an artifact of limits on how much portfolios can interact with the market, resource adequacy, and unforeseen shocks.**

*We can think of EUE as a condition that exists when portfolio load is greater than the sum of available portfolio resources plus market purchase ability. The base case, under base case assumptions, should never have EUE as the optimization has known reserves, forced outages, loads, and known, if fixed ability to procure energy from the market. When these assumptions are challenged, through higher forced outages (as was done in the weather shocks), or higher loads (as done in the weather shocks or cross portfolio work), EUE then reveals itself.*

4. **If EUE under the resource evaluation process utilized by IMPA has little information value, then why is this metric used to evaluate portfolio performance?**

*We disagree that there was little informational value to the EUE metrics, but agree that it was not a significant driver of scoring due to the weighting. Informationally, it did suggest that IMPA can endure weather-related shocks with good planning and robust portfolio management. During winter events, the two most material risks were unit availability and fuel availability. Deviations to load did not exceed annual peak forecast demand. Unit availability or fuel constraints were handled via resources not being available during the events (i.e., they were forced out or derated according to their historical performance), however, going forward, IMPA envisions perhaps being able to model fuel constraints more dynamically which will enhance the usability of the EUE metric.*

**Summary**

*IMPA appreciates the Director's comments and they have given us several paths forward in the spirit of continuous improvement. Overall, we believe key takeaways are that IMPA should spend more time in discussing methodology, resuming stochastic modeling, and scorecard development. With respect to in depth discussion of methodology, IMPA was guilty of trying to "get to the point" of the analysis and was trying to perhaps distill the document into a single, highly readable document for both knowledgeable readers and perhaps new readers alike. In short, we attempted to write an IRP that was a blend of a technical document and a more readable "executive summary" document. In the end, we did not spend enough time on the technical details that went into the modeling efforts. Future IRPs will involve separate documents, one being highly technical, and one more distilled for broader consumption.*

*With respect to stochastics, we feel that Encompass' plan to release a cloud-based edition will help alleviate the database constraints at a more effective price point than their client server offering. As more developments become known on that product, IMPA will make a detailed evaluation of that offering.*

*With respect to the Five Pillars, we wholeheartedly agree with the Director on this being an area of improvement. This was the first year in which IMPA needed to evaluate our portfolio within the context of these metrics. Power supply models frequently come with sets of pre-determined outputs and it was a challenge to find pre-determined outputs that fit the spirit of the Five Pillars. IMPA believes some of the Director's comments regarding these metrics and how they were assigned, in addition to the use of stochastics, will greatly enhance the value of the scorecard process.*