Draft Director's Report

For Indiana Municipal Power Agency's 2020 Integrated Resource Plan

April 29, 2021

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on behalf of the Indiana Utility Regulatory Commission

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Draft Director's Report Applicable to Indiana Municipal Power Agency's 2020 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Indiana Municipal Power Agency's (IMPA's) 2020 Integrated Resource Plan (IRP) was submitted on Nov. 2, 2020. By statute[1] and rule, integrated resource planning requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The Director's report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.[2]

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of IRP, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting.[3] By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

IMPA, like every Indiana utility and stakeholder, anticipates substantial changes in the state's resource mix due to several factors[4] and, increasingly, Indiana's electric utilities are using IRPs as a

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[1] Indiana Code § 8-1-8.5-3.

[2] 170 IAC 4-7-2.2(g)(3).

[3] In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

[4] A primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a

foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive long-term plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

II. INTRODUCTION AND BACKGROUND

IMPA is a wholesale electric utility providing long-term electricity requirements [5] for its 61 member communities under long-term power sales contracts. IMPA's member cities and towns own and operate an electric distribution utility. In 2019, IMPA's coincident peak demand for its communities was 1,198 MW and the annual member energy requirements during 2019 were 6,244,150 MWh. IMPA projects that its peak and energy will grow at approximately 0.5% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. *(IMPA IRP – page 2-13)*

IMPA operates in both the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM) regional transmission organizations (RTOs). IMPA has member load in five load zones and generation resources connected to six zones within the RTOs, plus two resources outside of the RTOs. IMPA's load is approximately two-thirds within MISO and one-third in PJM. Given that IMPA serves wholesale load in both the MISO and PJM, *(IMPA IRP page 5-23)* IMPA must comply with the resource adequacy requirements of each RTO for its load in that RTO. *(IMPA IRP page 4-19)*

III. FOUR PRIMARY AREAS OF FOCUS

Consistent with IMPA's comment about significant challenges, the primary areas of focus of the Director's comments include the interrelated topics of: load forecasting; demand side management (DSM), which includes energy efficiency (EE) and demand response (DR); and risk scenario analysis. Throughout, there will be a discussion of continual improvements to all aspects of IRP.

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result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

[5] IMPA's resources include: Joint ownership interests in Gibson Station #5, Trimble County Station #1 & #2 and Prairie State Energy Campus #1 and #2• Operation and maintenance responsibility of Whitewater Valley Station #1 & #2; Five dual fuel, natural gas or No.2 fuel oil, fired combustion turbines owned and operated by IMPA; Two natural gas fired combustion turbines owned by IMPA and operated by Indianapolis Power and Light ; 32 Solar Parks located in member communities; Long term power purchases from: Indiana Michigan Power Company, Duke Energy Indiana , Alta Farms II, Wind Farm LLC, Ratts Solar Park LLC; Short term contracts with market participants in MISO and/or PJM, and the IMPA Energy Efficiency Programs. *(IMP IRP page 5-24)*

The continual improvements include enhancements to load forecasting and risk analysis. IRP improvements should include an expansive definition of distributed energy resources (DERs) that subsume DSM as well as other resources such as rooftop solar, combined heat and power, microgrids, and storage which might be part of hybrid energy systems (HES). Because electric vehicles (EVs) have the potential for affecting resource requirements, it is imperative that IMPA understand the ramifications for IMPA and its 61 members. For both DERs and EVs it is also necessary for IMPA to develop full avoided costs to determine the benefits and costs of DERs and EVs and to integrate DERs and EVs.

A. Load Forecast

IMPA conducted a "back-cast" to try to understand the effect of the COVID-19 pandemic on IMPA's long-term load forecast. IMPA noted MISO and PJM conducted similar analyses comparing modeled load to actual load. While the emphasis of the IRP rule is on the long-term load forecast, a back cast may provide potential information on the impact of relatively short-term situations such as a recession, a polar vortex, or a pandemic to better assess risks. To improve the forecast in the face of COVID-19, IMPA staff attempted to incorporate macroeconomic variables in the forecast model that would be sensitive to COVID-19. This included but were not limited to Producer Price Index (PPI), Indiana ongoing jobless claims, ADP Construction Payrolls, ADP Manufacturing Payrolls, and average weekly jobless claims. It became rapidly apparent that regression models would not be able to sufficiently explain or capture movements seen in those variables as they became impacted by COVID-19. For example, initial jobless claims in the first weeks of the COVID-19 outbreak were unfathomable and were such an outlier that they caused the regression model to fail. *(IMPA IRP page 1-9 through 1-10*) IMPA engaged in an assessment of the load forecast process and concluded it was appropriate to maintain its model for load forecasting for this IRP, at least until more COVID-19 data is captured. *(IMPA IRP page 6-38)*

IMPA's longer-term forecast notes:

> IMPA transitioned to a unifying model for 4 of its 5 load zones after its last IRP was filed. This involved finding regression variables that satisfactorily explained movements in all of IMPA's major load zones (Duke-IN, NIPSCO, Vectren, AEP). With prior efforts laying the groundwork for a unifying regression, the variables chosen were: On and Off-Peak Days (as defined by NERC), Heating Degree and Cooling Degree Days for the respective area weather station, a dummy variable for winter/summer peak, energy intensity (btu per dollar of real GDP), and finally real U.S. GDP in average annual dollars. *(IMPA IRP page 6-38)*

The tables below illustrate the regression statistics for each of IMPA's largest load zones.

Table 5 Energy Forecast Variables & Regression Statistics

T-Stats & Selected Regression Statistics by Zone									
Area	Peak Days	Off-Peak Days	Relevant Weather Station HDD	Relevant Weather Station CDD	Peak Season Dummy	Energy Intensity (btu/$ of GDP)	Annual Real GDP (average annual $)	Model R^2	Observations
DUK-IN	10.5	9.7	14.6	20.9	5.8	8.1	7.4	0.94	168
NIPSCO	7.3	4.4	3.7	9.9	2.3	4.0	8.3	0.83	168
Vectren	9.0	6.6	4.7	17.1	4.2	9.6	4.4	0.94	168
AEP	8.1	7.1	13.7	13.4	5.7	2.9	3.8	0.87	168
DUK-OH	3.7	3.5	8.0	7.8	4.1	16.5	N/A	0.90	132

IMPA's smallest load zone in DUK-OH, is one zone where the data do not fit as well and so that load gets a similar model but excludes real GDP. Peak load forecasts are driven by hourly variables and are dependent on daily weather (i.e., wind speeds, temps), but are largely driven by the monthly energy forecast broken into a peak day shape for given peak day weather variables. (*IMPA IRP page 6-39* includes the table on the previous page)

IMPA is predicting low load growth over the forecast period. Electric vehicle penetration is a potential future source of load growth but IMPA does not anticipate this as a significant factor. Risks to the load forecast are skewed to the downside given the increased penetration of behind the meter generation, increased efficiency, and specific to IMPA, constrained service territory due to changes in state law. The following table illustrates the annual energy and peak demand requirements of IMPA over the next 20 years. *(IMPA IRP page 6-41)*

Table 6 IMPA Total Energy and Peak Demand Forecast

Year	*IMPA Total Energy (GWh)*	*IMPA Peak*
2021	6,338	1,178
2022	6,349	1,179
2023	6,370	1,180
2024	6,394	1,183
2025	6,436	1,189
2026	6,450	1,192
2027	6,474	1,194
2028	6,503	1,196
2029	6,543	1,197
2030	6,561	1,202
2031	6,594	1,207
2032	6,628	1,211
2033	6,680	1,213
2034	6,703	1,216
2035	6,742	1,220
2036	6,785	1,226
2037	6,843	1,232
2038	6,876	1,239
2039	6,923	1,244
2040	6,973	1,250

The following figures compare the IMPA peak demand and energy forecast used in the last five IRPs with actual results. As the below graphics demonstrate, IMPA's historic projected peak demand and energy shows very little load growth, which is similar to the types of trajectories that other Indiana utilities are projecting to experience over the next 20 years. *(IMPA IRP page 6-42)*

Figure 14 Load Forecast Performance – Peak Demand

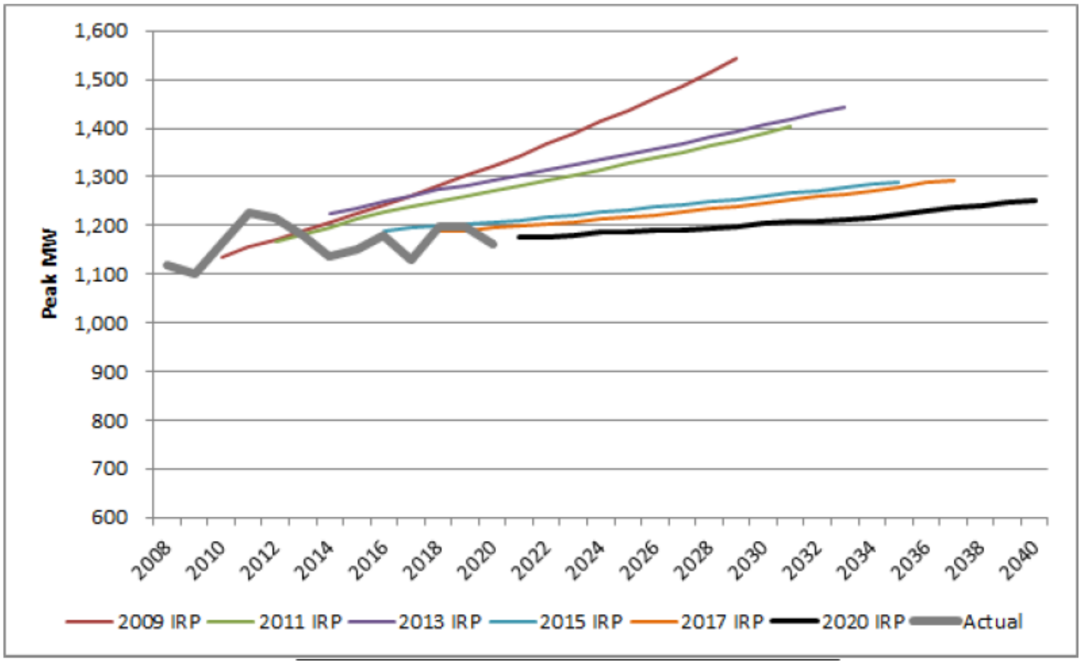
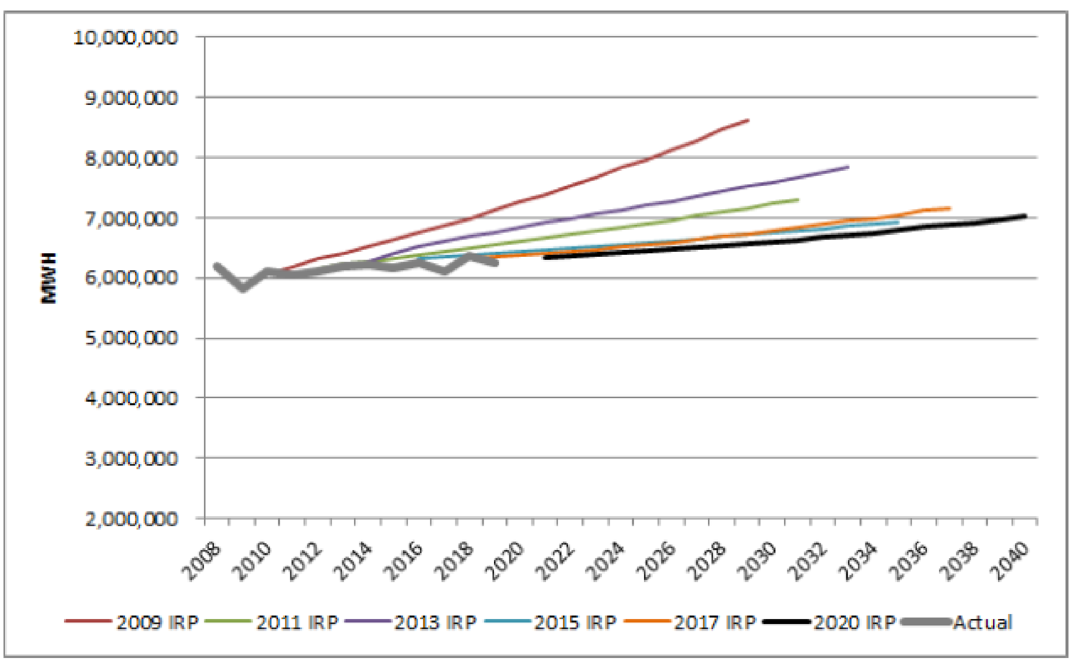


Figure 15 Load Forecast Performance – Energy Requirements



IMPA's load forecasting is characterized as a top/down approach. Since IMPA does not sell directly to retail customers, it does not have direct access to retail customer billing information. IMPA noted the criteria determining member rate classes can change and it would be nearly impossible to ensure consistent sector data back through the historical period. Finally, different members identify sectors (or classes) of customers differently which makes comparisons difficult, especially over time. *(IMPA IRP page 6-43)*

IMPA discussed an end-use (a bottom-up) forecast method, which would require detailed information on appliance saturations and usage patterns in the residential sector, data on building and business types in the commercial sector and detailed equipment inventories, lighting types, and square footage area in the industrial sector. However, IMPA contends the data requirements for an end-use model are too extensive given that IMPA's member communities are not uniform and would necessitate large sample sizes for surveys to develop the necessary information. All of which would be quite expensive. *(IMPA IRP page 6-43)*

The current status of customer-owned resources and the potential benefits are articulated in IMPA's IRP.

> As of the date of this report, IMPA has contracted with 28 customers, totaling 2.4 MW of installed renewable energy systems. IMPA has a contract with one commercial/industrial customer of an IMPA member to purchase excess generation from its onsite generation facilities. Under the current contract, the customer has been selling small amounts of energy to IMPA under a negotiated rate. IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. While under the right circumstances CHP systems could be beneficial to both the customer and IMPA, the right mix of site-specific operating conditions and economics must be in place for both parties for a CHP project to go forward. Except for emergency back-up generators at some hospitals, factories and water treatment plants, IMPA knows of no other non-renewable retail customer generation in its members' service territories. *(IMPA IRP page 5-29)*

Director's Comments – Load Forecasting

IMPA's commentary on short-term, low probability, but highly consequential events is well-taken because projecting load over many years is fraught with uncertainty even without the existence of a pandemic. As IMPA notes, some events are very short in duration (e.g., the Polar Vortex) but the long-term effects of the COVID-19 pandemic may have significant ramifications for long term load, though it is too soon to know. IMPA's use of the Producer Price Index (PPI), Indiana ongoing jobless claims, ADP Construction Payrolls, ADP Manufacturing Payrolls, and average weekly jobless claims as explanatory variables to help identify the potential impact of the pandemic on long-term load is appreciated. However, IMPA is correct that regression models would not be able to sufficiently explain or capture the effects of such a significant event, especially something so recent that is continuing to develop. Kudos for IMPA raising this important forecasting issue and for highlighting short-term but significant risks.

The load forecast section of IMPA's 2020 IRP is somewhat confusing. The forecast starts out the same as its 2017 IRP, but includes far fewer details than in 2017. "IMPA decided to maintain its model for load forecasting for this IRP." However, the very next sentence states: "IMPA transitioned to a unifying model for 4 of its 5 load zones after its last IRP was filed." This is confusing. If IMPA is maintaining the model, that would seem to imply not changing the model. A unifying model suggests IMPA combined four of its five load zones into one model. Inexplicably, Table 5 presents the T-stats and R-squared results for five separate models suggesting IMPA did not combine zones. This adds to the confusion. The description of the chosen variables and revisiting IMPA's 2017 IRP seems to clarify "unifying" as using the same set of explanatory variables in four of the five load zones whereas, in prior IRPs, the four models had varying sets of drivers. The reader should not have to re-read a previous IRP to understand what was done. *(IMPA IRP page 6-38)*

Overestimation was noted for the NIPSCO zone and was thought due, in part, to the winding down of operation at St. Joseph's College in Rensselaer. IMPA said removing that load from the historical database or using a simple dummy variable should correct the forecast models. However, IMPA never states whether they actually used a dummy variable or adjusted the historical data. (*IMPA IRP page 6-38)*

IMPA states its smallest load zone DUK-OH [Duke -Ohio] data does not fit well so real GDP is excluded from the model. But the DUK-OH R-squared is actually higher than two of the other load zones and the T-stats are not lower across the board either. Perhaps IMPA meant the DUK-OH model, with GDP included, was universally worse. Detailing the results would be useful. *(IMPA IRP page 6-39)*

The model variables are on- and off-peak days as defined by the North American Electric Reliability Corporation (NERC), heating degree days, cooling degree days, dummy variable for winter/summer peak, energy intensity (Btu per dollar of real GDP), and annual real GDP (except, again, for DUK-OH model). There is no mention of the source for any of the driver data. IMPA did not clarify what was meant by "On/Off Peak Days" as a variable. IMPA did not articulate what temperature base was used for the heating and cooling degree days. The text says, "dummy variable for winter/summer peak" were used but Table 5 says "Peak Season Dummy." These do not sound like the same descriptor. What geographic region (state/census region/national) is used for the economic variables? *(IMPA IRP page 6-39)*

The following statement is the extent of the discussion of IMPA's peak forecasting and is far from clear or sufficient: "peak load forecast are driven by hourly variables and are dependent on daily weather (i.e. wind speeds, temps), but are largely driven by the monthly energy forecast broken into a peak day shape for given peak day weather variables." *(IMPA IRP page 6-39)*

While IMPA recognized the potential for DERs and EVs to have a significant effect on the load forecast, especially in the long run, there was discussion on the implications for DERs and EVs. It is not clear, however, that IMPA constructed any risk bands around its load forecasts. There was no discussion of explicit risk bands or development of alternative scenarios to test even modest changes and certainly nothing that would constitute a stress test.

IMPA states that one of the risks to the forecast is "constrained service territory due changes in state law". What change to state law does this refer to? (*IMPA IRP page 6-40)*

IMPA faces a longer-term dilemma should EVs and DERs increase in importance more quickly than it thinks likely. IMPA recognizes that it does not have the detailed information necessary to project the ramifications of DERs, EVs, and other infrastructure enhancements that may eventually result in dramatic changes for the operations and planning of IMPA and the distribution systems operated by member communities.

Even without developing a bottom-up forecast, it may be possible to develop detailed load research information from other Indiana utilities that would provide the detailed granularity that is essential to forecast the penetration and implications of DERs and EVs. IMPA could consider data from other Indiana utilities that is more specific to the five zones detailed by IMPA.

B. Energy Efficiency

IMPA's energy efficiency program offers incentives in the form of rebates for residential, Commercial. and industrial (C&I) customers. Since 2012, IMPA's energy efficiency programs [6] generated a cumulative savings of 120,214 MWh at the end of 2019 and a coincident peak reduction of 13.5 MW. In addition to energy efficiency programs, IMPA offers a demand response tariff, an excess renewable generation program, and education. Furthermore, many IMPA members utilize various rate structures aimed at assisting customers in lowering or controlling their energy consumption or bills. *(IMPA IRP page 2-14)*

IMPA's members have implemented programs and projects to reduce peak demand and encourage efficient energy use. Most of these programs are rate and customer service related (e.g., coincident peak rates, off-peak rates, power factor improvement assistance, etc.). As in the 2017 IRP and in this new IRP, no customers are reported to participate in the DR programs offered under the MISO and PJM tariffs. *(IMPA IRP page 5-32)*

Director's Comments – Energy Efficiency

The 2020 IRP has a better explanation of EE modeling in Aurora^{XMP} (Aurora is an electric utility modeling and forecasting software). As before, IMPA continues to use Aurora to determine the lowest cost resource mix for the various market areas modeled. The model develops various tranches of EE which are included as part of the resource options permitted to be selected by the portfolio optimizer. These tranches effectively act as decrements to IMPA load. That is, IMPA stated that the EE and DR programs were modeled as selectable resources. IMPA also said that EE and DR were treated as load decrements at incrementally higher costs. The initial block of EE was modeled in quarter MW increments, with the initial one-quarter being modeled at IMPA's current implementation cost. According to IMPA, this approximated the forward wholesale power price. Additional increments were priced on an increasing basis reflecting the "low hanging fruit" and it being increasingly difficult to find efficiencies as more end-users adopt energy efficiency measures (e.g., replace lightning and appliances).

The Director understands that IMPA's structure and relationship with its members imposes several complications, but IMPA's IRP discussion of the analysis of DSM suffers from an almost complete lack of information on the methodology and data used by IMPA. The failure in communication is such that IMPA does not even say if DSM was selected in the optimization.

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[6] Existing demand-side resources consist of programs coordinated by IMPA as well as those implemented by its members include: "In early 2011, IMPA launched the IMPA Energy Efficiency Program, designed to help retail customers in the Agency's member communities save money through incentives for implementing energy-saving measures in four different categories: energy efficient lighting; heating, ventilation and air conditioning (HVAC); motors, fans & drives; and refrigeration, food service and controls. IMPA worked with member utilities to market the program, educate customers and build relationships with local vendors to implement the energy saving measures. During 2011, the Agency as a whole saw approximately 90 companies participate in the program, representing 25 member communities throughout the state of Indiana. In 2012 and 2013, IMPA voluntarily participated in Energizing Indiana, a state-wide energy efficiency program in order to gain experience and evaluate the cost-effectiveness of a variety of residential, commercial, and industrial programs. The savings from these efficiency efforts was 32 million kWh (2012) and 52.7 million kWh (2013), annually*." (IMPA IRP 5-30 through 5-31)*

It is not clear what load research data was used by IMPA to construct the "blocks." Without information on how the blocks were constructed, it is difficult to assess how the blocks were optimized on a reasonably comparable basis to other resources, especially since the analysis and results did not explicitly appear in expansion plans.

IMPA's explanation of how it decremented existing and future DSM from the load forecast was unclear. There was no detail on how the current and projected cost of DSM implementation are determined. What is the "approximated to forward price of wholesale power"? How were the additional MW increments priced? (*IMPA's IRP pages 11-68)*. A more in-depth explanation about the EE modeling methodology used in this IRP and future IRPs will help the readers to have a better understanding of the integration of DSM into the modeling process.

Accurate assessment of relevant costs to establish the dynamic values of EE and DR by time and location is necessary for IMPA and its member communities to calculate the value of DSM. That is, IMPA needs to consider all avoided costs which include generation, transmission, and distribution systems. It is not apparent that IMPA and its members have attempted to calculate full avoided costs which is likely to understate the value of EE (and other DERs).

C. Resource Optimization and Risk Analysis

IMPA articulated its approach to risk analysis in developing its long-term resource plans as to "plan for the best expectation of future events based on information that is currently known..."

> The plan outlined in the following report may very well change depending on the outcomes of the pandemic and elections. IMPA believes the best way to combat this uncertainty is to rigorously plan for the best expectation of future events based on information that is currently known. More importantly, IMPA believes in the power of being adaptable and nimble as market conditions dictate. By doing this, IMPA can continue to supply wholesale power to our 61 communities. Power that is low cost, reliable and environmentally responsible. *(IMPA's IRP page 1-11)*

IMPA used Aurora for resource expansion modeling, market price studies and portfolio optimization. IMPA, then, utilized MCR-FRST by MCR Performance Solutions, LLC to develop the final revenue requirements for each portfolio.

IMPA modeled the entire PJM and MISO in its expansion planning. A complete regional capacity expansion plan and the corresponding wholesale price for energy and capacity were determined for each scenario. The regional capacity expansion plan generated a list of eligible assets for selection for IMPA to create the optimized portfolio under each scenario. The market prices for capacity and energy from the regional capacity expansion plan were used as inputs in the IMPA's portfolio optimization as well.

IMPA modeled three different future paths and created an optimized portfolio for each path. The three future cases are the Base Case, Green Case and High Growth Case. The Base case optimal portfolio picked a combustion turbine (CT) and solar to replace Gibson 5 a coal-fired unit, while the optimal portfolios for the Green Case and High Growth Case included new combined cycle (CC and some renewables following the retirement of Gibson 5.

After the candidate portfolio being identified by the Aurora optimization, the risk of each portfolio was evaluated. Risk drivers including NG price, coal price, MISO system load, PJM system load, emission costs and IMPA load were included as stochastic parameters. The volatility and correlations of the risk drivers were first established based on historical data. These risks drivers were then modeled stochastically through simulation and were used to test the candidate portfolio for risk exposures and robustness to those exposures.

Director's Comments – Resource Optimization and Risk Analysis

Risk analysis was conducted with a variety of appropriate analytical tools including Aurora. IMPA developed risk profiles and tornado charts *(IMPA IRP page 11-97)* to good effect in this IRP and in prior IRPs. As a measure of robustness, IMPA opted to perform stochastic runs where the Green Case and High Growth Case portfolios were implemented in the Base Case scenario to make the performance of the three candidate portfolios more comparable. IMPA believes that installation of a CT covers IMPA's capacity position while still giving IMPA sufficient flexibility to meet changing load, regulatory and environmental conditions. Based on its analysis, IMPA recommended the Base Case portfolio to cover IMPA's capacity and energy needs when Gibson 5 is retired. It is not clear if IMPA performed an analysis of how the Base Case Portfolio performed under the two other scenarios. The short-term action plan is consistent with the preferred plan selected.

IMPA's statement that they plan for the best expectation of future events based on information that is currently known is concerning. That is, IMPA does not seem to consider highly consequential events that are not currently known as a risk that should be examined. IMPA does not enumerate or detail the future events they expect.

The IRP Report fails to include a well-developed discussion of how the potential retirement of generation resources was conducted. This consideration is highlighted where the optimized Green Scenario Portfolio lacked the inclusion of retirements. Was this caused by a lack of significant costs in the model associated with keeping the units available over a long period of time including high fixed operations and maintenance (O&M) and future capital expenditures? Is it accurate to say that Aurora will not retire generating units, even if they are frequently out of the money (i.e., not be dispatched due to market prices that are too low to warrant dispatch) if these types of costs are not considered? To be clear, the Director makes no finding about the reasonableness of the retirement analysis but, if the modeling did not include equipment replacement and other O&M, the costs of retaining these resources would be understated. IMPA's treatment of retaining generation or costs associated with retirement may alter the comparisons with other potential resources. These questions arise given the lack of discussion of how long-term generation unit O&M and ongoing capital costs are handled. The Director is interested in what was done, why, and how.

Also, of concern to the Director is IMPA's conclusion not to include battery storage. A more objective analysis might be to consider storage in conjunction with renewable resources and other DERs (HES). IMPA contends that "Storage assets were strongly considered. However, after an internal review of comparative economics and business use cases undertaken in the Fall/Winter of 2019/2020, IMPA opted not to consider storage assets for this IRP." (*IMPA IRP page 11*-68*)* The Director understands the difficulty of modeling battery storage because of the broad range of potential applications and limited incidence of batteries in IMPA's service territory but even an elementary analysis might have provided useful insights. Certainly, future IRPs should give more considered analysis of battery storage. As with other DERs and HES, IMPA would be well-served by obtaining more detailed operational data on battery storage to assess the potential implications for IMPA and its communities.

Despite IMPA's recognition that EV penetration is growing and the purpose of IRPs is to plan for a twenty-year planning horizon, IMPA seems to dismiss the potential ramifications of EVs.

> While there may be some pockets of load growth due to increased EV penetration in a carbon adverse world, IMPA believes those are likely to be drivers in urban areas. While it is too early to tell for certain, there also appeared to be some demographic shifts away from cities and into more rural areas during the COVID pandemic. Should these remain in place, that may mute any impacts from EV penetration. While EV penetration is undisputedly growing, it is notable that publicly accessible charging infrastructure is still relatively early in adoption in the United States. (*IMPA IRP page 12-06)*

Given that charging infrastructure will affect the distribution system's planning and operations and the additional EV energy and demand will affect the reliability of the IMPA system (including potential shifts in demand) the absence of greater interest in EVs seems inappropriate and IMPA has made no statement that they anticipate developing data to prepare for an increase in EVs and charging infrastructure. It also seems inappropriate to assume that COVID-19 mitigates any effects of EV penetration.

It is important to reiterate that, especially since the IRP is a long-term load and resource analysis, it would be appropriate for IMPA to consider battery storage and DERs as selectable resources. Battery storage and DERs should be included in the scenarios to ascertain whether the portfolios could be improved (e.g., resulted in a lower revenue requirement or improved resource adequacy) or result in diminished benefits. Moreover, according to the MISO, system reliability and the economic value can be at risk throughout the year, which should be considered in IMPA's scenarios and portfolios.

The reliable and economic integration of renewables has been a source of considerable interest by MISO and utilities generally. Given the increasing importance of renewable resources, IMPA's statement regarding the installed costs of solar panels seems to be little more than an assertion. IMPA said: *"…*as for renewable technology, any increases in demand for panels and inverters are likely to be met with increases in technological advancement and efficiency. Ultimately, this, in IMPA's view, leads to a net zero change in cost per installed watt for solar*.*" (*IMPA's IRP page 12-109)*

In the absence of empirical evidence, it may or may not be valid to assume demand for panels will keep capital cost of the panels to remain the same over time even with technological improvements. This assumption is too important to assume this outcome for future IRPs without empirical support. The analysis of possible implications of alternative cost assumptions could have provided insight into how sensitive resource selection is to changes in key parameters.

In summation, without analysis of the integration of all forms of DERs (including battery storage), EVs, and renewable resources, it seems likely that the potential effects of all forms of DERS and EVs are understated. As a result, the lack of information about DERs, EVs, and renewable resources prevents IMPA from fully assessing its current and future resource mix.

D. Future Enhancements to IMPA's IRP Processes

Director's Comments - Future Enhancements to IMPA's IRP Processes

IMPA did not advance any proposals for improving the interrelated elements of its future IRPs. This is inconsistent with the IRP rule which requires continual improvements. Considering the potential increases in DERs (including batteries) and EVs, it would be appropriate to obtain information about the ramifications of DERs and EVs.

The Director understands that IMPA is reliant on its member communities to undertake DSM programs. However, without higher quality and quantity of very discrete (sub-hourly) load data and detailed information about IMPA's and its member communities' ultimate customers, the credibility of load forecasts is diminished, and it limits the ability to develop more accurate rate design based on all avoided costs (generation, transmission, and distribution) of the resource.

Despite IMPA's use of state-of-the-art planning tools such as the Aurora model, the lack of high-quality data is a glaring deficiency that constrains the value of planning tools to develop improved load forecasting, assessing planning risks, enhanced rate design, and calculate the dynamic value of DERs.

IV. SUMMARY

The load forecast continues to be the foundation for the IRP. Based on recent history, the results of the forecast seem reasonable, especially in the short-term. The discussion of some of the possible implications of the pandemic were interesting. The longer-term forecast was less informative and concerning, largely due to there being no discussion of the development of bands around the energy and peak demand forecasts or alternative load scenarios. There was a lack of information and a failure to consider the potential forecast implications of all forms of DERs (including battery storage), EVs and the attendant charging requirements on IMPA's members' distribution systems, and potential loss (or gain) of customers (member communities or their customers). The Director understands that DERs – including batteries and EVs – are not currently significant. but IMPA needs to understand the potential ramifications for the IMPA system. It is just these types of considerations with a large degree of uncertainty that could have been addressed with alternative load scenarios.

The Director understands the organizational constraints that limit the quality and quantity of retail customer data available to IMPA. However, IMPA does not seem to acknowledge that changing economics and technology will make coordination between IMPA and its members more important. Just as MISO is looking at how it needs to change and enhance the exchange of information with its market participants, IMPA will eventually need to consider how to better coordinate various operational and planning activities with its members.

IMPA's narrative of DSM is not informative and not sufficiently detailed. Again, IMPA's ability to understand its customers' needs is constrained by a lack of detailed load research information. As a result, and not withstanding IMPA's comments, the information on how the DSM programs were valued, calculated, and treated on a reasonably comparable basis to other resources is not clear.

IMPA's discussion of the future of the existing resources (e.g., the analysis to retain or retire some facilities) was too limited to be of value in an IRP. The scenario and portfolio analysis were limited to a relatively tight risk bandwidth which suggests that IMPA did not give due regard to low probability events that were significantly impactful if they occur. The failure to include a reasonable analysis of all forms of DERs and EVs seem likely to affect long-term resource decisions that were not included in this IRP.

Finally, IMPA did not offer any improvements, which is inconsistent with the IRP rule.

V. STAKEHOLDER COMMENTS

The public input to IMPA's IRP is limited, as there is no public participation process comparable to that required for investor-owned utilities. Only one set of written comments was submitted, and it was provided by the Sierra Club.

As a preliminary matter, the Director will take this opportunity to remind all stakeholders of the limitations spelled out in IRP administrative rule on the appropriate content of the Director's report. According to 170 IAC 4-7-2.2(g), the Director's report can only address:

> (g) The draft report and the final report shall:
> (1) be limited to commenting on the IRP's compliance with the requirements of this rule;
> (2) list the areas where the director believes the IRP fails to comply with the requirements of this rule; and
> (3) not comment on:
> (A) the desirability of the utility's preferred resource portfolio; or
> (B) a proposed resource action in the IRP.

Given these guidelines, the Director will limit discussion of stakeholder comments that appear to target the resource portfolio developed by the IRP process or specific resource actions in the IRP. The Director will try to highlight stakeholder comments that address issues or questions about models, methodology, data, assumptions, and criteria used to evaluate the output of the IRP analyses.

Sierra Club

Sierra Club made three recommendations to improve IMPA's resource planning.

> First, IMPA has failed to study the economics of its most-expensive coal unit, Whitewater Valley, which is approximately double the cost of Gibson unit 5, a unit that is on track to retire within the next half decade. IMPA should produce an addendum to the IRP to properly evaluate the economics of maintaining Whitewater Valley versus retiring it. Second, IMPA should consider a clean energy portfolio that would provide the same services as its existing units for lower cost and less pollution. Third, IMPA should update its resource planning to consider energy storage as a resource option. *(Sierra Club Comments page 1)*

To estimate the long-run margin of Whitewater Valley, Sierra Club constructed a model to project future costs and revenues. All assumptions and projections are derived from publicly available information. *(Sierra Club Comments page 7)*

For the Clean Energy Portfolio analysis, Sierra Club used the Rocky Mountain Institute's Clean Energy Portfolio's algorithm from the 2019 report "The Growing Market for Clean Energy Portfolio's" to identify a suite of clean energy technologies (wind, solar, storage, energy efficiency, and demand response) that could replace the services of the coal plants IMPA receives energy and capacity from: Gibson 5, Prairie State, and Whitewater Valley.

> A clean energy portfolio, or CEP, is a combination of renewable energy, storage, and demand-side management (DSM) projects that meet the needs of the grid and a utility's customers. We use the term DSM to collectively refer to energy efficiency projects (which lead to a reduction in load) and demand response projects (which lead to the shifting or temporary reduction of load). The use of CEPs differs from traditional resource planning, which typically focuses on a specific technology. Instead, a CEP looks at how a range of available clean energy resources could contribute in each hour of the year, and finds the combination that meets the unique needs of customers at the lowest feasible cost. In this study, the CEPs are constructed to match the energy, peak capacity, and ramping characteristics of the JH Campbell coal plant unit 3. Portfolios are optimized to satisfy these needs at the lowest cost possible. *(Sierra Club Comments page 8)*

Regarding storage, Sierra Club also recommended IMPA consider using costs from the National Renewable Energy Laboratory's 2020 ATB Study.

Director's Response

The Director appreciates the comments submitted by Sierra Club and the focus on planning methodology and analysis improvements.

The Director agrees that IMPA could have done a better job documenting how the continued operation of specific generation facilities was evaluated, the data used, and the sensitivity of the analysis to variations in projected futures. The analysis might have been well developed, but the lack of discussion makes it impossible to know. Indiana utilities are increasingly including specific and detailed written discussions in their IRPs of how they evaluated the continued operation of generation units and the results. As the Director has stated many times, the purpose of the IRP is to help drive better analysis and, perhaps more importantly, to provide an opportunity to more fully document and explain what, how, and why something was done, and how the resulting information was used.

The Director understands Sierra Club has traditionally focused on EE. The IRP rule is more expansive, but the Director has no objection to Sierra Club's analysis. As part of a more expansive definition of DERs and HES (including battery storage), the Director urges IMPA to not only consider EE but also other forms of DERs and the potential effect on the resource selections. To facilitate cost-effective EE and other DERs, the Director has consistently encouraged IMPA (and all Indiana utilities) to calculate the relevant avoided costs that vary by time and location.

IMPA's analysis of DERs was lacking, not just regarding storage. The Director understands that DERs are currently a minor consideration and that IMPA's structural relationship with its members creates barriers to a sound analysis. However, the importance of DERs is likely to increase from its current very low rates, so the Director encourages IMPA and its members to use this time to better understand the potential implications should circumstances change more quickly than IMPA assumes to be the case. Also, IMPA is encouraged to use a range of projected cost data to evaluate the potential of DERs and the sensitivity of its analysis to variations in data and assumptions.