Final Director's Report

For AES Indiana's 2022 Integrated Resource Plan

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Draft Director’s Report Applicable to AES Indiana’s 2022 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Indianapolis Power and Light Company (IPL), doing business as AES Indiana, submitted its 2022 Integrated Resource Plan (IRP) on Dec. 1, 2022. By statute 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 Research, Policy, and Planning (RPP) Director in the report does not endorse the IRP nor comment on the desirability of the utility’s “preferred resource portfolio” or any proposed resource action.

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 integrated resource planning, 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. 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.

Every Indiana utility and stakeholder anticipates substantial changes in the state’s resource mix due to several factors and, increasingly, Indiana’s electric utilities are using IRPs 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 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 & BACKGROUND

AES Indiana's Preferred Portfolio in its 2022 IRP calls for the addition of 500 to 1,065 MW of wind and solar resources by 2027. The Preferred Portfolio has Petersburg Units 3 and 4 (1,052 MW) converting from coal to natural gas in 2025. The IRP results also show that AES Indiana has a 240 MW winter capacity need starting in 2025 because of MISO's new seasonal resource adequacy structure. According to AES Indiana, battery energy storage is the most cost-effective capacity resource to meet this need.

From the Director's perspective, AES Indiana, like most utilities across the United States, is addressing resource changes in an environment of extreme uncertainty regarding government policy, commodity prices, and technology. To better address these uncertainties, the 2022 IRP included a couple of significant changes compared to the 2019 IRP:

- AES Indiana used the EnCompass Power Planning Software for portfolio capacity expansion and production cost modeling.
- AES Indiana expanded the IRP scorecard evaluation metrics for portfolio evaluation, including the addition of the portfolio reliability analysis and scoring criteria performed by Quanta.

Consistent with the issues discussed above, the Director's report will focus on four broad areas: (1) load forecasting; (2) assessment of demand-side resources broadly defined to include energy efficiency, demand response resources, electric vehicles, and other distributed energy resources (DERs); (3) portfolio analysis and the consideration of risk and uncertainty on different resource portfolios; and (4) the five pillars of reliability, affordability, resiliency, stability, , and environmental sustainability.

III. LOAD FORECASTING

Load Forecast Methodology

AES Indiana's 2022 IRP load forecast methodology is unchanged since the 2019 IRP load forecast but has been refreshed by Itron in 2022. The 2019 IPL IRP appeared to still be using the models Itron developed for the 2016 IRP with AES Indiana having updated all Statistically Adjusted End-use (SAE) data included in the 2019 load forecast. Itron's update for 2022 is in Attachment 5-2 in Volume III of the IRP.

Historically, gross domestic product (GDP) and other economic indicators exhibited strong correlation with electricity sales. However, since 2008, this linkage is less pronounced. Itron's SAE methodology uses end-use saturations and efficiency trends to address the break down in the historical relationship between electricity sales and economic factors and GDP as sales have flattened due to increasing efficiencies and increased DSM while GDP continues to grow.

The SAE model is populated using AES Indiana's historical sales, customer counts, and prices; economic forecasts from Moody Analytics; heating degree days (HDD) and cooling degree days (CDD) measured at the Indianapolis International Airport (IND); and end-use saturation and efficiency trends from the U.S. Energy Information Administration (EIA).

The output of this is a monthly sales and customer forecast by rate code. The rate code forecasts are then aggregated into a system forecast and losses are added based on historical loss percentages. That system forecast is used along with historical hourly loads, peak-day weather, and end use intensity data to create AES Indiana's peak load forecast.

The Industrial sector does not use an SAE model due to the lack of data for developing industrial intensity estimates and therefore uses a more traditional econometric approach.

Data sources

Historical sales, customers, and prices are from internal AES Indiana data.

End-use saturation and efficiency trends come from EIA's 2021 Annual Energy Outlook for the East North Central Census region. DSM Market Potential Studies are also used to calibrate the Residential sector.

Economic inputs are from Moody's Analytics 3rd Quarter 2021 projections.

Actual weather data comes from National Oceanic and Atmospheric Administration (NOAA) for the Indianapolis Airport. For Residential, the base temperature used for HDD is 60 degrees and for CDD 65 degrees. For Commercial, 55 degrees is used for HDD and 60 degrees for CDD. Historically, it was common for utilities to use a base temperature of 65 degrees for both heating and cooling degree days, but as weather trends got warmer this relationship started breaking down and it became common for utilities to use something less than 65 degrees especially for heating degree days. The base temperatures used here are the same as in the 2019 IRP, although it reads as if they changed the Commercial ones for 2022. The base temperatures in the 2019 IRP had changed from the 2016 IRP without a mention as to why, but in the 2022 IRP there is an acknowledgement of what analysis was done to determine the base numbers.

Normal weather is also based on data from National Oceanic and Atmospheric Administration (NOAA) for the Indianapolis Airport, but instead of using NOAA's own "normals", AES Indiana and Itron are doing a trend analysis of 1960-2021 temperatures and then increasing monthly degree days based on the historical trend instead of the traditional approach of using constant normal values throughout the forecast horizon. This is done to try to more accurately capture the effects of global warming. This method of calculating "normals" started with its 2019 IRP. The peak-day normal weather is not adjusted this way because it would double count the impact of increasing temperatures which has already been captured in the monthly values through use of the trend model.

Residential

AES Indiana's Residential sector has three main customer types - electric heat (RH), gas heat (RS), and gas heat with electric water heat (RC).

The forecast is the result of a residential customer forecast multiplied by a residential use per customer forecast from a monthly statistically adjusted end-use model for each customer type and then the three are aggregated to total Residential.

The customer model is a linear regression model driven by the population forecast for Marion County. The 2022 IRP uses population as the driver while the 2019 IRP used housing starts. Customer counts for all three residential customer classes are projected to increase. RH and RC customers are projected to increase 1.2% annually over the planning period 2022 – 2042. RS customers are forecasted to increase 0.3% annually.

The residential use per customer model for each customer type is a monthly statistically adjusted end-use model in which sales are a function of heating, cooling, and other end-use variables. The end-use variables capture the interaction of end-use intensity projections, household characteristics such as size and real income, electricity price, and heating and cooling degree days.

Residential average use has been declining since 2011. Over the forecast period, average use flattens out and begins to increase. The forecasted increase is primarily caused by two factors: economic growth offsetting improving end-use efficiency, and future utility-sponsored demand side management (DSM) program savings being excluded in the forecast period. Also, total rate class average use increases partly due to the increasing share of customers with electric heat.

Over the period 2022 – 2042, total residential energy sales are projected to grow annually at a rate of 1.0%, the number of residential customers at a rate of 0.9%, and average use per residential customer at 0.2%. It is important to note that these projections do not include adjustments for future DSM, distributed generation, and electric vehicles.

Commercial

Commercial, like Residential, is modeled and forecast with a statistically adjusted end-use model, except with a total sales model as opposed to an average use and customer model.

The model drivers are HDD, CDD, billing days, price, end-use intensity trends, historical DSM savings, and an economic activity variable.

The economic activity variable is weighted between non-manufacturing employment and non-manufacturing output for the Indianapolis MSA with a much higher weight on the employment piece, 65%, versus 35% on the output piece.

Commercial sales have been trending down having declined an average 0.9% per year since 2011. The primary factors driving commercial sales are economic activity, declining end-use intensities, electric prices, and historical DSM program savings. For the planning period, employment increases at an annual average rate of 0.6% and economic output at a 2.1% rate, and total commercial sector end-use intensity decreases 0.7% annually. The result is a 0.4% annual commercial sales growth through 2042 before DSM adjustments.

Industrial

The Industrial sector does not use an SAE model due to the lack of data for developing industrial intensity estimates and, therefore, uses a more traditional econometric approach based on manufacturing employment and industrial output.

The economic activity variable is weighted between manufacturing employment and manufacturing output with a higher weight on the output piece, 60%, versus 40% on the employment piece. This is an interesting change from the Industrial forecast in the 2019 IRP, which put a higher weight on the employment piece.

AES Indiana exogenously adjusts its Industrial forecast for anticipated customer load additions not represented in the historical data. For the period 2022 – 2042, industrial sales are forecast to remain flat. The sales projection excludes the impact of future DSM program activity.

Street Lighting

Street Lighting is modeled with a seasonal exponential smoothing model while Security Lighting is modeled with trend and monthly binaries model.

COVID-19
New to AES Indiana's modeling in the 2022 IRP is the inclusion of a COVID-19 variable in the residential average use and non-residential rate class models. The variable was constructed using Google Mobility Report data for Marion County.

Forecast Sensitivities
Economic inputs are from Moody's Analytics 3rd Quarter 2021 projections. For AES Indiana's high and low load forecasts, Moody's "Alternative Scenario 1 – Upside – 10th Percentile" and "Alternative Scenario 3 – Downside – 90th percentile" scenarios were used, respectively.

The scenarios apply the growth rates in alternatives above to the baseline economic variables starting in the first month of the forecast period (2022). Page 37 also states: "Scenarios are further adjusted to ensure the growth rates are less than or equal to the baseline growth rates in the low case and greater than or equal to the baseline growth rates in the high case."

Different economic projections are used in the load forecast to account for the risks and uncertainties caused by different economic futures. AES Indiana found, however, that the different economic forecasts caused only modest changes in the load forecast. AES found that the uncertainty in the future of electric vehicle (EV) and distributed generation (DG) markets was the greatest source of risk in the models.

To reflect the risk caused by the uncertainty of EV and DG markets, AES Indiana developed multiple scenarios with varying projections of EV and DG growth. The load scenarios are:

1. Low - low economic growth, low EV and DG
2. Base – base economic growth, base EV and DG
3. High – high economic growth, high EV and DG
4. Very High – high economics, very high EV and DG

Electric Vehicles and Distributed Solar
AES Indiana worked with GDS Associates, Inc. (GDS) and the Brightline Group in order to project the future impacts of electric vehicles and distributed solar. AES Indiana adjusts the baseline forecast for these behind-the-meter solar and electric vehicle charging loads.

Electric Vehicle Forecasting Methodology
AES Indiana recognizes that differentiating between residential and commercial vehicles is the first step in projecting the impact of new EVs. A bottom-up approach is required to forecast the number of each vehicle type before the energy impacts can be projected for the AES Indiana system. AES Indiana states that there is a wide variety of options for EV passenger cars. But the early state of EV adoption means that forecasting the adoption and associated energy use of each type has limitations.

Commercial EV Methodology
The forecasting methodology builds on the analysis by GDS as part of the MPS. The methodology is based on publicly available national and local historical data and trends including supplemental data specific to AES Indiana.

The commercial EV projection uses four linear trend scenarios of EV shares of total vehicle sales:

1. Low – starting at 1.7% in 2020 and increasing to 9.1% in 2042.
2. Medium – starting at 1.7% in 2020 and increasing to 18.2% in 2042.
3. High – starting at 1.7% in 2020 and increasing to 36.0% in 2042.
4. Very High – starting at 1.7% in 2020 and increasing to 85% in 2042.

AES Indiana used the linear trend approach was used because of its simplicity and the large uncertainty in the EV market. The linear methodology smooths out EV adoption to avoid incorrectly forecasting when EV adoption might spike in the future.

Residential EV Methodology

GDS developed a residential EV forecast for AES Indiana including low, base, and high scenarios for the number of residential EVs and the associated electricity consumption. The first input in the model is the number of AES Indiana residential customers. The number of residential customers is multiplied by the number of vehicles per household to estimate the total number of vehicles in the AES Indiana service territory. A second assumption is the number of EVs currently in the AES Indiana service territory. This information was developed from Indiana BMV registration data and the 2021 residential customer survey done for the 2021 MPS. The final assumption used in the residential EV model is the percentage of EVs that make up new vehicle sales. GDS used the publicly available data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2021. AES Indiana used the AEO EV trend data for the low scenario because the EIA estimate was at the low end of the current industry projections. GDS developed base and high projections based on various industry sources. A very high scenario was developed to capture potential risk associated with aggressive EV adoption.

Photovoltaic (PV) Forecasting Methodology

The GDS study analyzed the potential associated with roof-mounted PV systems installed on residential and non-residential sector buildings. The non-residential sector analysis also included the potential for ground mounted (or covered parking) systems for a few specific business types. Estimating technical potential required calculating the total square footage of suitable rooftop area in the AES service territory and calculating solar PV system generation based on building and regional characteristics.

GDS estimated total square footage using disaggregation analysis to characterize the residential and non-residential building stocks. Characterization was based on parameters such as number of facilities, average number of floors, average premise consumption, and premise end-use intensity. This information was used to estimate total rooftop square footage.

GDS relied on the research by National Renewable Energy Laboratory (NREL) to estimate the fraction of the total roof area suitable for solar photovoltaic (PV) in the AES Indiana service area.

GDS then developed standardized solar PV system configurations. System sizes for residential premises ranged from 3 to 20 kW (DC) and 10 to 2,000 kW (DC) for non-residential premises. GDS used NREL models to project system generation for both residential and non-residential sited systems. The PV system simulations used information specific to Indianapolis. Based on the resulting capacity factors for residential and non-residential buildings for Indianapolis, GDS applied the state-specific capacity factor to the system size to estimate annual electricity generation.

GDS also estimated the economic potential for solar PV. It was determined that no PV technologies pass cost effectiveness screening using the total resource cost (TRC) test. However, AES Indiana recognizes that customers still install solar PV systems. Consequently, a business-as-usual (BAU) forecast was prepared for inclusion in the IRP modeling. The BAU forecast was based on the following assumptions:

1. AES Indiana customer and rooftop characterization described above.
2. Number of existing systems.
3. Trend of existing system installation from 2015-2020.
4. Willingness to participate and market adoption data collected from AES Indiana customers.
5. Bass-diffusion curve and coefficients based on NREL dGen model and EIA DG/PV interconnection and census data.

Using this data, GDS prepared three adoption scenarios for PV installations for the residential sector:

1. Low – up to 6% market adoption
2. Medium – up to 15% market adoption
3. High – up to 29% market adoption

Three adoption scenarios were prepared for the non-residential sector:

1. Low – up to 7% market adoption
2. Medium – up to 19% market adoption
3. High – up to 35% market adoption

DIRECTOR'S COMMENTS – LOAD FORECASTING

General Thoughts

The electric utility industry is faced with extensive uncertainties that must be accounted for in the preparation of plans used to make resource acquisition decisions. Of these uncertainties, future load – both its magnitude and shape – is especially problematic. It is interesting that the impact of higher and lower economic growth projections had so little impact on the projections of energy and peak demand compared to the base economic forecast.

A major source of load forecast uncertainty is the extent and timing of both electrification and the adoption of distributed energy resources (DERs). AES Indiana recognizes this by preparing several different projections of EVs and distributed solar. The Director thinks it is too early in the projected adoption timelines to have any comfort in the various methodologies and data available to project electrification and DERs, but there will be evolution in this area over time, as in all areas of resource planning.

The impact of this uncertainty is probably less on the timing and type of generation resources acquired or contracted for over the planning horizon than on the impact on distribution and transmission system investments and operations. This is not to minimize the problem of adding generation resources with the appropriate characteristics to provide reliable and efficient service. Rather, that increased attention must be paid to the impacts of load uncertainty (along with numerous other uncertainties) on the distribution and transmission facilities that enable and provide so many attributes necessary for the provision of safe, reliable, and economic electric service. No one knows the future, but it is important to try to understand the critical drivers of decisions and how these decisions can change, given changes in the behavior of drivers.

Question 1

- Itron's document in Attachment 5-2 states that the end-use saturation and efficiency trends come from EIA's 2021 Annual Energy Outlook for the East North Central Census region; however, Section 5, page 36, in the IRP states that it was the 2020 version. Which version was used?

Response of AES Indiana

The 2020 reference on page 36 was a misprint. The forecast used the 2021 Annual Energy Outlook.

Director's Reply

The Director appreciates the corrected citation and understands the difficulty at times of keeping the citations of sources accurate.

Question 2

- The way AES Indiana and Itron are calculating normal weather using trend models is something relatively new and started with the 2019 IRP. The limitation of trend models is that they assume the trend will continue in the future, which may not be the case. Alternative ways of capturing the effects of global warming without using trend models would be to use NOAA's most recent set of 30-year normal weather or using shorter periods such as 15 or 20 years instead of the traditional 30-year period.

Response of AES Indiana

The traditional approach for forecasting normal temperatures has been to use the average minimum and maximum temperature by month over a defined historical period and hold that temperature constant over the forecast period. However, analysis of Indianapolis historic weather data indicates a definite increasing temperature trend. Therefore, when applying the traditional approach, using a shorter normal period (e.g., 15 or 20 years) would provide a more accurate starting temperature than a longer 30- year period. However, assuming this temperature stays static does not account for trends identified in the recent weather history. Many in the energy forecasting industry, including other utilities as well as the Energy Information Administration ("EIA"), have transitioned to using trended normal weather.

The Company recognizes that these trends may change. Accordingly, AES Indiana will continue to monitor and reassess if a trend in increasing temperatures persists in its future IRPs and adjust the weather normal methodology based on observations.

Director's Reply

The Director understands the difficulties associated with modeling recent changes in climate and how these recent changes may evolve over an extended planning period. It is one more source of load uncertainty to be aware of and accounted for in the planning process.

Question 3

- Section 5, page 37, has a confusing labeling. There is a section called "Capturing Increasing Temperatures", however, only the first paragraph under it discusses weather data.

Response of AES Indiana

The paragraphs following the section labeled "Capturing Increasing Temperatures" are missing labels. The paragraph that follows the "Capturing Increasing Temperatures" section that starts with "AES Indiana-sponsored DSM was included as an endogenous variable…" should be labeled "Modeling AES Indiana-sponsored DSM." And the following paragraph that starts with "In addition to the base forecast, AES Indiana developed a high and low load forecast…" should be labeled "Low, Base and High Load Forecasts."

Including these labels should make the narrative less confusing.

Director's Reply

The Director appreciates the clarification.

Question 4

- The residential customer model driver in the 2022 IRP is Marion County population whereas in the 2019 IRP it was housing starts. It would be interesting to know why this change was made since it is not addressed in the report.

Response of AES Indiana

The 2019 IRP used the Moody's Marion County number of households projections. In the 2022 IRP, the change was made to use Moody's Marion County population projections as the driver in the residential customer model. While the Moody's Marion County number of households may provide a better estimate of the number of AES Indiana customers at a static moment in time, the growth trend in Moody's Marion County population data shows a stronger correlation to AES Indiana customer growth than the Moody's Marion County number of households. The correlation between population and customers is 0.982 while the correlation between households and customers is 0.975.

This change was made as an improvement in methodology.

Director's Reply

The additional explanation is helpful, and the Director appreciates the work for continued improvement.

Question 5

- The commercial model economic activity variable is weighted between non-manufacturing employment and non-manufacturing output at 65% and 35%, respectively. These weights are significantly different than in the 2019 IRP when they were 80% and 20%, respectively. What is the reason for this change?

Response of AES Indiana

Increasing the weight on non-manufacturing output improved the out-of-sample statistics resulting in a lower Mean Absolute Percent Error ("MAPE"). MAPE measures the accuracy of a forecast compared to actual results as a percentage with lower MAPE values representing more accurate forecasts. Using a 20% weight resulted in a 3.95% MAPE, while using 35% weight resulted in a 3.78% MAPE. Accordingly, AES Indiana used the 35% weight as this improved the accuracy of the forecast.

Director's Reply

The additional explanation of what was done and why is helpful.

Question 6

- The Industrial economic activity variable is weighted between manufacturing employment and manufacturing output with a higher weight on output than employment. This is an interesting change from the Industrial forecast in the 2019 IRP which put a higher weight on the employment piece. Why was this change made? Manufacturing employment can be a problematic driver for sales because as manufacturing processes become automated manufacturing employment and sales move in opposite directions. Is this why the change was made or was it for some other reason?

Response of AES Indiana

AES Indiana and Itron recognize the potential lack of correlation between manufacturing employment and sales due to automation. However, the reason for the change in the 2022 IRP was because the manufacturing employment data series from Moody's included a significant downturn due to COVID impacts in the historical data, whereas the Moody's output data series was less erratic. Weighting the industrial economic activity variable more heavily to output helped to smooth the impact of the COVID downturn in the final combined economic activity variable used in the model. AES Indiana considers the weighting used to provide a more stable application of this driver.

Director's Reply

The additional discussion of the thought process behind the change is helpful.

Question 7

- Figure 5-3 lacks a legend to indicate whether the bars represent energy and the line is peak demand or vice versa.

Response of AES Indiana

In Figure 5-3 from AES Indiana's 2022 IRP (p. 34), the blue bars represent the energy in megawatt hours ("MWh") and the green line represents the peaks in megawatts ("MW").

Director's Reply

The clarification is appreciated.

Question 8

- On page 36, AES Indiana says how the historical prices used in the load forecast were derived but does not indicate the source for future prices. The Itron report shows the prices graphically but does not show how future prices were projected. It also appears the price forecast did not vary by scenario.

Response of AES Indiana

Future prices are based on AES Financial Services projections. The price forecast used to develop the load forecast does not vary by scenario. The estimation is based [on] estimated operating expenses and return on rate base with approximate adjustments for future rate cases.

Capturing the impacts to rates is somewhat circuitous in IRP modeling because a utility's rates are largely determined by the portfolio that results from the capacity expansion analysis using the base price forecast. Therefore, you won't understand the impacts to rates by scenario until you have the results. Ultimately, the price elasticity included in the load forecast modeling is low ~0.05%. Thus, changing the price forecast has an immaterial impact on the resulting forecast and load obligation. These are reasons why the price forecast was held constant across portfolios.

Director's Reply

The Director understands the "circuitous" nature within IRP modeling of utility rates and the resource portfolio. As you will recall, the State Utility Forecasting Group (SUFG) explicitly accounts for the circuitous, or dynamic, interactions between customer demand, the utility's operating and investment decisions, and customer rates by cycling through the SUFG's various models until an equilibrium is attained.

The Director is aware that the price elasticities used in modeling vary across the utilities and the industry. For example, the price elasticities in the SUFG models are significantly larger than those in the AES Indiana models. The SUFG methodology clearly thinks the interaction of resource choices and retail prices has important effects that need to be considered.

Question 9

- Pages 44-45 indicate the street lighting model is a trended time series model. Are there concerns that this may result in a forecast that shows future efficiency gains that are not achievable, since the recent history includes the conversion to LED lights? That is, since the history shows a trend of significantly improving efficiency, will the future be able to continue this trend.

Response of AES Indiana

To clarify the narrative in the 2022 IRP report "Streetlighting" (pp. 44-45), the streetlighting modeled in the IRP load forecasts were held constant at the 2021 level after the LED conversions were complete. Therefore, no efficiency trends attributed to the LED conversions were captured in the IRP load forecast.

Director's Reply
The Director appreciates the clarification.

Question 10

- The residential EV forecasting methodology is discussed on pages 48-49. It appears the EV forecast is based on the percentage of new vehicle sales that are EVs in each year while the total vehicles within the AES Indiana service territory is a function of the number of households multiplied by the number of vehicles per household. It is unclear how the number of new vehicles is determined each year. Is it the incremental additions based on the change in households, or is there a consideration of the replacement of existing vehicle stock? If it is assumed that some existing vehicles will be replaced (either through equipment failure or accidents), the number of new vehicles each year will be higher, as will the number of EVs. On page 54, the vehicle lifespan is briefly mentioned but does little to clarify the basic question. The sentence on page 54 states "The projection of the total number of EVs accounts for the typical 'lifespan' of a vehicle as well."

Response of AES Indiana
The electric vehicle ("EV") forecast accounts for new EV sales from customer growth based on the change in the number of households each year, as well as new EV sales from existing customer vehicle replacements. Essentially, for each year of the forecast, two separate projections are made: 1) The total number of vehicles being replaced due to accidents/failures is calculated and then multiplied by the projected EV sales percentage. 2) The number of new vehicles added due to customer growth is calculated and then multiplied by the EV sales percentage.

The result of adding both projections together is the total number of additional EV's on the AES Indiana system in each year from both existing vehicle replacements and new vehicle sales.

Director's Reply
The additional discussion clarifies how the EV forecast was done.

IV. DSM & ENERGY EFFICIENCY

Demand Side Management (DSM) Section Summary and Overview

AES Indiana's DSM planning process provides DSM opportunities for the 20-year IRP planning period (2022-2042). The opportunities identified were used as the starting point to develop a cost-effective Short-Term DSM Action Plan for the period 2024-2026. This plan targeted an annual average of approximately 1.1% of 2021 sales of energy efficiency (EE).

DSM Market Potential Study (MPS)

For the 2022 IRP, AES Indiana continued to work with GDS Associates to conduct a MPS End-Use Analysis, which began in the fall of 2021. The MPS study included a primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential (which is broken into maximum achievable potential (MAP) and realistic achievable potential (RAP)) savings in terms of MWh and MW for each level of energy efficiency (EE) and demand response (DR) potential. For the assessment of future achievable potential, GDS conducted surveys of business and residential customers with the objectives of gathering primary market data on:

1. Willingness to participate in EE and DR program offerings.
2. Penetration, saturation, and efficiency of energy-using equipment.
3. Program awareness.
4. Market barriers.

The results were used to develop updated estimates of baseline and efficient equipment saturation and expected long-term customer adoption rates for a list of measures using the mix of customers, building characteristics, and efficiency trends for each customer segment in the utility's service territory. Additionally, GDS disaggregated the baseline forecast by sector (residential, commercial, and industrial) and then further divided by the major end uses. The residential forecast was broken out by housing type between existing income qualified and market-rate customers as well as new construction. The commercial forecast was disaggregated based on major business types such as: retail, warehouse, office, etc. The industrial forecast break-down was determined by actual load consumption shares and major industry types. The segmentation analysis was performed by applying AES Indiana-specific segment and end-use consumption shares, derived from customer database, SIC code analysis, and EIA equipment saturation and efficiencies to forecast annual sales.

GDS created the comprehensive list of cost-effective measures with specific maximum adoption rates that reflected the market barriers and difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios. In total, GDS analyzed 353 measure types for this study. That is a lower number compared to the 554 measures analyzed for the 2019 IRP. Several measures were included with multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. GDS considered several specific emerging technologies such as: smart appliances, smart water heater (WH) tank controls, advanced lighting controls, etc. In total, GDS developed 2,106 measure permutations for this study. Each permutation was screened for cost-effectiveness under the Utility Cost Test (UCT). GDS used avoided energy, capacity and T&D costs to monetize savings associated with the measures and screen them for cost effectiveness. For this, AES Indiana provided annual on- and off-peak avoided energy costs assumptions in April 2022. However, these costs did not align with the commodity assumptions used in the IRP modeling due to a time lapse. GDS used this data to create 8,760 hourly avoided cost values for each forecast year and then applied them to the 8,760 savings from each measure to determine the value of measures that save more energy during peak periods. In addition, GDS used avoided capacity costs and transmission and distribution (T&D) avoided costs to estimate coincident peak demand savings for each measure.

DSM Bundles in the IRP Model

In addition to sector segmentation, three different vintage bundles (2024-2026, 2027-2029, and 2030-2042) were developed to optimize the value of EE over different time periods. The first vintage (2024-2026) was designed to align with AES Indiana's next DSM program planning period, and the energy efficiency achievable potential was grouped into program bundles that are similar to AES Indiana's current portfolio. The other two-time vintages were provided at the aggregate sector level (meaning residential and C&I) to minimize the risk that the IRP optimization model would only select low-cost measures in the future, reducing AES Indiana's ability to offer comprehensive programs. Following a review of the initial cost and savings inputs, GDS further segmented the residential sector savings into high-cost measures (Tier 2) and low- and mid-cost measures (Tier 1) across each vintage time-series.

In addition, two adjustments to the RAP EE potential savings and one direct adjustment to costs were conducted prior to inclusion in the IRP analysis. Since all potential estimates, as well as measure level cost-effectiveness screening were conducted in terms of gross savings, the first adjustment was to convert the RAP EE from gross savings to net savings. The objective was to remove EE (MWh and MW) impacts that would have occurred in the absence of DSM programs (e.g., impacts of free-riders and spillover customers were considered). The second adjustment provided the program potential savings at the generator level since the MPS savings are at the meter level. Sector savings were adjusted for line losses.

The IRP Optimization model, EnCompass, does not calculate the avoided T&D benefits associated with DSM measures. To account for this, GDS provided AES Indiana with EE bundle costs that were adjusted to net out the avoided NPV lifetime T&D benefit based on the projected MW savings of the respective vintage-based bundles.

Hourly (or 8,760) shapes reflecting the various measures and end-use mix of each EE bundle were provided to AES Indiana by GDS. This information permitted the EnCompass model to evaluate the value of energy savings on an hourly basis. These shapes were based on residential and commercial end-use load shapes for Indiana from NREL's End-Use Load Profiles database. The shapes are unique for each EE sector and vintage bundle.

RAP, after the adjustments, was the starting point for developing bundles with supply-side resource characteristics (e.g., load shape and levelized costs) that act as model inputs. Twenty selectable decrement "bundles" across three sector categories (residential, income-qualified, and C&I) were developed. EE was bundled by program for selection in 2024 – 2026. DR was bundled by program categories for the entire planning period. The residential and C&I bundles were evaluated using a reasonable least cost economic basis and were modeled as a selectable supply side replacement resource option. The three income-qualified weatherization bundles were treated as a 'going-in' resource predefined in the model.

Finally, for modeling the bundles, instead of the PowerSimm model used in the 2019 IRP, for this IRP, AES Indiana transitioned to use EnCompass Power Planning Software. According to the utility, this capacity expansion model has a proven approach to modeling DSM as a resource, benefits the application of bundling technology and allows the use of end-use load shapes. In the end, the EE costs used as inputs in the EnCompass model included utility costs (incentives and non-incentive costs). Non-Incentive costs were developed using recent 2021-2022 actual program cost data. Program non-incentive costs for each sector and by program were calculated on a gross dollar per first-year kWh saved.

Load Forecasting Model

AES Indiana's load forecast was an important input into the 2022 DSM MPS because it determined the baseline energy and system demand requirements, excluding future EE program savings. AES Indiana needed a load forecast that is free of all future DSM, because DSM was treated as a resource in the EnCompass model. The load forecast for this IRP, similar to the 2019 IRP, was developed using Itron's Statistically Adjusted End-Use ("SAE") methodology. For the residential and commercial sales models, the utility-sponsored DSM was included as a variable to account for historical program savings and to explain historical usage trends. Other model variables included in the models were HDD, CDD, billing days, commercial economic activity variable, price, and end-use intensity trends. In the residential model, DSM was expressed as savings per customer and was included in the residential average use model. The load forecast for the C&I sectors was based on total sales model rather than an average use and customer model. This forecast was adjusted down by the percent of load attributed to large customer opt-out of DSM/EE programs. This opt-out adjustment was held constant for all years of the load forecast. GDS removed approximately 28% of commercial and 76% of industrial energy sales from large opt-out customers. These sales were removed before the MPS assessment of technical, economic, and achievable potential estimates.

Demand Response (DR)

Demand response analysis was conducted using GDS's DR Model. Levels of DR potential for the RAP scenario from the MPS were provided as inputs to the EnCompass Model. For this, GDS determined the estimated savings for each DR by performing a review of all the benefits and cost associated with each program. The UCT was used to determine the cost-effectiveness of each DR program. Benefits were based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. In this analysis, there were no distinct vintage bundles of DR; however, the IRP model assessed DR over the same three defined time periods as the EE input bundles. In the end, DR savings were only divided into four bundles based on sector and resource type (direct load control and rate programs). To determine the optimal incentive level of DR, a simulation was performed where the critical input was the incentive level and the critical output was the net benefit of the DR program. The curtailment/interruptible rate program was analyzed using the Demand Side Analytics (DSA) program, and GDS examined it to shift demand through the selectable DR bundles. For this program two scenarios were evaluated: day of notifications and day ahead notifications. The non-residential sector sub-totals and residential and non-residential combined totals reflected these two scenarios.

Direct load control programs were six of the 10 residential DR programs evaluated by GDS in the MPS. Direct load control programs were five of the 12 C&I DR programs evaluated. The residential rate programs included:

1. Behavioral DR
2. Time of Use with Enabling Technology
3. Time of Use without Enabling Technology

The C&I rate programs included:

1. Ice Storage Cooling Rate*
2. Curtailable (Notice Day Of)
3. Curtailable (Notice Day Ahead)
4. Capacity Bidding
5. Demand Bidding*
6. Time of Use with Enabling Technology
7. Time of Use without Enabling Technology
8. Interruptible Rate

Programs with an asterisk were determined to be uneconomic in the MPS. Residential DR programs evaluated as a resource bundle in the IRP were time of use rates and behavioral DR. The corresponding C&I programs included as a resource bundle were time of use rates and interruptible rates.

DIRECTOR'S COMMENTS – DSM & ENERGY EFFICIENCY

Question 1

- The business survey process did not achieve the industry-standard 90/10 statistical significance but met 85/15 statistical significance level. What needs to be improved in the future to achieve that standard? How significant would be the impact in the final results of using this 85/15 level instead of the standard level? One sentence says that "the length of the business survey could have been a factor in the low completion rate." Is there a problem with the design of the survey? *(See Attachment 6-3, p. 10)*

Response of AES Indiana

AES Indiana's contractor, GDS Associates, Inc. ("GDS"), targeted the industry-standard 90/10 statistical significance level for both the baseline end-use survey and the willingness to participate ("WTP") survey. The WTP survey was prioritized for this study, as the data collected is important to understanding which energy efficiency programs may have the highest adoption rate and what the incentive levels need to be for the largest impact. The WTP survey conducted for the MPS did meet the 90/10 statistical significance level overall.[1]

However, the baseline end-use survey had a lower completion rate than the WTP survey and a somewhat lower completion rate than what is typical for this type of survey. This is a common challenge with baseline end-use surveys in the business sector, as many businesses surveyed may not know the specific appliances used in their building or do not have the expertise to answer some of the detailed end-use questions, resulting in partially or fully incomplete surveys. It is possible that dividing the baseline survey into several smaller surveys could boost the completion rate (although in this scenario the survey results for any individual respondent do not provide a full picture of energy end-uses). Another potential avenue for increasing the statistical precision in future iterations of market research would be to increase the incentive for completing the survey. Alternatively, including other modes of delivery for the survey could increase the overall recruitment sample, in an effort to ensure that even with lower response and completion rates the number of completed surveys would be sufficient for a 90/10 statistical significance level. A physically mailed survey may increase the recruitment sample, as customers are enrolled on a "Do Not Email" list.

The overall final results of both the WTP and baseline surveys are still appropriate to incorporate into the study. The impact of achieving a statistical significance level of 85/15 on the baseline end-use survey compared to a level of 90/10 is that we are slightly less confident and there is a slightly higher margin of error when interpreting the results and applying to the general population of businesses served by AES Indiana. As an example, it is possible that the actual population of businesses served by AES Indiana has a higher saturation of electric space heating end-use appliances than the survey results indicate; however, it is equally possible that the actual population of businesses served by AES Indiana has a lower saturation of electric space heating end-use appliances than the survey results indicate. In short, the baseline survey results are still an appropriate estimate for the end-use energy characteristics of the AES Indiana business population.

[1] See AES Indiana's 2022 IRP Report, Volume III, Attachment 6-3, p. 10.

Director’s Reply

The additional discussion provided above helps the Director to better understand the thought process utilized in the modeling.

Question 2

- GDS affirms that the impacts of free riders and spillover customers were considered in the development of DSM inputs. However, there are no details or clear explanation in any of the 2022 IRP Volume documents on how these impacts were estimated or handled. How or where were free-riders and spillover customers potential considered and how did these affect the final efficiency savings estimates, program participation/saturation rates or the adoption incentive levels? *(See Attachment 6-3, p. 27)*

Response of AES Indiana

GDS developed measure-level net-to-gross (“NTG”) ratio assumptions by leveraging the most currently available AES Indiana program evaluation reports at the time of the study. These NTG ratios were then applied to the estimates of achievable potential to develop net savings for the achievable potential scenario, which then formed the basis of the DSM inputs.

The methodological approach taken by the study attempts to recognize that customers that already have efficiency measures installed will not be eligible for participation, while also recognizing that some customers that have not yet installed efficiency measures will be free riders in the future. By leveraging NTG ratios in the analysis, the study also implicitly captures not just free ridership but future spillover as well.

Director’s Reply

The additional information helps the Director to better understand the methodology used.

Question 3

- The development of the bundles considered sector and vintage segmentation to have a more appropriate approach to model DSM measures. However, there is a concern in combining unrelated measures with very different load shapes in the same bundle. How appropriately does the bundle’s load shape reflect the load shapes of the individual measures in the same bundle? Would GDS consider alternative approaches for including only measures with similar load shapes in one bundle?

Response of AES Indiana

Although the IRP bundles are aggregated at the sector/vintage level, GDS did consider the impact of different end-use load shapes in the overall creation of the overall bundle load shape. For each year, GDS calculated the contribution of energy savings by end-use and created a weighted average 8,760 bundle load shape that reflects the contribution of the various end-uses included in each bundle. This was an important step to maintain an understanding of when, throughout the year, the annual energy savings occur.

GDS and AES Indiana developed the large sector-level bundles based on feedback provided by the Citizens Action Coalition ("CAC") (and their consultants) as a way to facilitate the IRP energy efficiency savings selection. More granular bundles could be developed that reflect measures with similar load shapes, but there was concern that some higher cost efficiency measures might not get selected if separated from other lower cost measures. In addition, at some point, the increased granularity will have a negative impact on the IRP modeling run-time, which needs to be considered when developing bundles in IRPs.

AES Indiana and its consultants appreciate the Director's comment and will consider alternative bundling approaches in the next IRP including bundling based on similar load shapes.

Director's Reply

The Director understands that the analysis of energy efficiency resources is complex and continuously evolving. The creation of DSM bundles involves consideration of numerous factors.

Question 4

- The analysis and discussion of rate structures in the MPS is helpful but has limitations that make it difficult to understand exactly what was evaluated. The MPS prepared by GDS includes a brief description of each rate evaluated but little specific detail for the individual rates was provided. For example, there is little or no explanation of the detailed design of the time-varying rates considered beyond a description of the general components of the rates evaluated.

Response of AES Indiana

The following assumptions were made for each of the rate programs analyzed in the MPS. Generalized secondary research was used to determine the rate program designs, program assumptions and calculate potential demand savings. Specific assumptions for each demand response program beyond the below descriptions can be found in the demand response ("DR") Appendix of the Market Potential Study ("MPS") report.

- Residential Behavioral DR: this program was assumed to be similar to a Peak Time Rebate program. Participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply pay the existing rate. There is no rate discount during non-event hours. Customers stay on the standard rate at all hours. GDS assumed there would be approximately 80 hours of on-peak event hours each year. Participants would be paid $1 per kWh they reduced during the control hours.
- Time of Use ("TOU") (with and without Enabling Technology): A TOU rate divides the day into time periods and provides a schedule of rates for each period. The price would be higher during the peak period and lower during the off-peak period, mirroring the average variation in the cost of supply (including marginal capacity costs). In some cases, TOU rates may have a shoulder period, or particularly in the winter season, two peak periods. Additionally, the prices and period definitions might vary by season. With a TOU rate, there is certainty as to what the prices will be

and when they will occur. A TOU rate can be coupled with an enabling technology, such as a smart thermostat. In this instance, the utility would provide a smart thermostat to participants, and in return, would likely get higher savings.

- Curtailable Rate or Interruptible Rate: With the interruptible rate, the utility enters financial agreements with businesses to reduce load when dispatched. Load curtailment potential is driven by incentive payments, the frequency of events, the duration of events, and the level of notification participants are given about pending events. Results were calculated for both a "day-ahead" notification design and a "day-of" notification design. "Day-ahead" notification assumes an approximately 24-hour notice, and "day-of" notification assumes a three- to six-hour notice. The potential is higher under the "day-ahead" notification design, as this provides participants greater opportunities to shift energy-intensive tasks to off-peak periods. The expected control hours for this program are 28 for the year, with a four-hour event duration and a maximum of seven events.

- Capacity Bidding and Demand Bidding: these programs are not considered rates. They are flexible bidding programs offering businesses payments for agreeing to reduce load when an event is called. Participants make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month, plus energy payments based on actual kilowatt-hour ("kWh") energy reduction when an event is called. The amount of capacity nomination can be adjusted on a monthly basis. The program can be internet-based, providing ready access to program information and ease-of-use. Penalties occur if load nominations are not met.

Director's Reply

The Director understands the difficulty of analyzing the impacts of various price structures on customer behavior and how to evaluate price structures and DR more broadly as resource options. Especially problematic is the evaluation of DR and price options as a component of resource portfolios from both a resource planning perspective and an operations perspective. There often seems to be a disconnect between how price options and DR are perceived for resource planning and how these options are seen from a real time operations perspective.

V. SCENARIO & RISK ANALYSIS

Models and Structure of Deterministic Analysis

AES Indiana selected Anchor Power's EnCompass Power Planning Software for capacity expansion and production cost modeling, which provided fast runtimes that allow for more capacity expansion portfolios to be evaluated in the scenario analysis and greater transparency to the model database. AES Indiana utilized fundamentals-based forward curves provided by Horizons Energy.

The Company performed traditional deterministic capacity expansion scenario analysis of five strategies and one Encompass Optimization analysis across four scenarios, resulting in 24 portfolios. The five generation strategies focused on the future of AES Indiana's remaining coal units, Petersburg Units 3 and 4. Those strategies include:

1. No Early Retirement – operating Petersburg Units 3 and 4 on coal through the remainder of their useful lives.
2. Fuel Conversion – Petersburg Units 3 and 4 converted to natural gas in 2025.
3. One Petersburg Unit Retires – Retire Petersburg Unit 3 in 2026 and run Petersburg Unit 4 on coal for remainder of life.
4. Both Petersburg Units Retire – Unit 3 in 2026 and Unit 4 in 2028.
5. Clean Energy Strategy – Both Petersburg Units Retire, but with the additional constraint that the model cannot select thermal resources as replacements.

Those strategies hard-wired decisions related to Petersburg units, while otherwise allowing the model to perform optimization. AES Indiana also conducted a sixth optimization analysis that allowed the EnCompass Model to select a portfolio independently using least cost economics. AES Indiana included four scenarios in the Scenario Analysis. These scenarios are views of the futures defined by external influences like political outcomes, economics, regulations, etc. These scenarios included, from least aggressive to most aggressive on environmental policy:

1. No Environmental Action – Includes relaxed environmental regulation and no subsidies for renewables.
2. Current Trends (Reference Case) – Includes what AES believes is the most likely future environmental regulations including renewable subsidies contained in the Inflation Reduction Act.
3. Aggressive Environmental – Includes a carbon tax starting in 2028 at $19.47 per ton.
4. Decarbonized Economy – Includes a renewable portfolio standard that requires utilities to supply most of the energy from clean energy sources by 2042.

The resource optimization across the scenarios and generation strategies was constrained with the following assumptions:

1. The proposed MISO seasonal construct was modeled for the required reserve margin.
2. Bilateral capacity market risk was reduced by limiting interaction to 50 MW of purchases or sales per season.
3. Energy market risk was reduced by limiting interaction to 10% of load for purchases or sales per year.
4. Selection of new resources was limited to 1) prevent selecting near term resources that cannot practically be executed or not supported by recent RFP responses; 2) prevent selecting more resources than would be practical over the planning period; and 3) prevent an overreliance on a single resource type.
   a. Earliest selectable build is approximately 1,500 MW (ICAP) of solar, storge, and hybrid resources in 2025.
   b. By 2027, the EnCompass model can select approximately 1,000 MW (ICAP) of any technology per year.
   c. Over the 20-year planning period, the model can select to build a maximum of approximately 2,000 MW (ICAP) of any one technology.

The traditional deterministic capacity expansion scenario analysis of five strategies and on Encompass Optimization across four scenarios resulted in 24 candidate portfolios for evaluation. In addition, AES Indiana conducted a sensitivity analysis that optimized the six generation strategies under the Current Trends/Reference Case Scenario at low and high replacement resource capital cost levels. The base capital cost forecasts were included in the base portfolio optimizations described above. The purpose of the sensitivity was to provide an estimate of how the portfolio mixes and affordability to customers changes as the capital cost of replacement resources changes.

Portfolio Metrics and Scorecard

Candidate portfolios were evaluated using a scorecard evaluation of performance metrics. This framework was based on the "Five Attributes or Pillars of Electric Service" as defined by Indiana's 21st Century Energy Policy Development Task Force. These attributes or pillars as defined by the Task Force are:

1. Reliability – consisting of adequacy and operating reliability.
    a. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonable expected unscheduled outages of system components.
    b. Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric circuits or unanticipated loss of system components.
2. Affordability.
3. Resiliency is the ability of a system or its components to adapt to changing conditions, and to withstand and rapidly recover from disruptions.
4. Stability is the ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbance.
5. Environmental Sustainability.

The scorecard evaluation metrics used by AES Indiana were guided by the five pillars. AES Indiana included two extra categories for Risks and Opportunities and Social and Economic Impact. The Candidate Portfolios' performance was evaluated across five categories. Note that the reliability, resilience, and stability pillars were combined by AES Indiana into one category. Specific metrics for each category are shown below.

1. Affordability
    a. 20-year Present Value Revenue Requirement (PVRR)
2. Sustainability
    a. CO_2 Emissions – total Portfolio CO_2 emissions over 20 years.
    b. SO_2 Emissions – total portfolio SO_2 emissions over 20 years.
    c. NO_x Emissions – total portfolio NO_x emissions over 20 years.
    d. Water Use – total portfolio water usage over 20 years.
    e. Coal Combustion Products (CCP) – total portfolio coal combustion products over 20 years.
    f. Clean Energy Progress – percentage of energy from renewable resources in 2032.
3. Reliability, Stability, and Resiliency
    a. Composite Reliability Score – analysis performed by Quanta.
4. Risk and Opportunity
    a. Environmental Policy Risk and Opportunity – sensitivity analysis that evaluates the Candidate Portfolios' performance under different policy and commodity futures.
    b. General Cost Risk and Opportunity – stochastic analysis of the cost risk and opportunity associated with power prices, gas prices, coal prices, load, and renewable energy generation.
    c. Market Exposure/Interaction – risk associated with general exposure to the power market through sales and purchases.

    d. Renewable Capital Cost Sensitivity Analysis – sensitivity analysis that analyzes the risk and opportunity associated with high or low renewable capital costs.
5. Social and Economic Impact
    a. Generation Employees – total change in the FTEs associated with generation over the planning period. This includes employment for a generation portfolio whether directly employed by AES Indiana or a third-party.
    b. Property Taxes – total amount of property tax paid from AES Indiana generation assets.

For the Scorecard Evaluation, AES Indiana calculated metrics for only the strategies in the Reference Case/Current Trends scenario. AES Indiana argued the Reference Case scenario aligns with the company's policy and commodity assumption outlook. Therefore, the strategies in the Reference Case scenario are ultimately the Candidate Portfolios from which AES selected its Preferred Resource Portfolio.

Portfolio Risk and Opportunity Category

The Portfolio Risk and Opportunity category was based on four metrics that evaluate potential impacts from environmental policy (sensitivity analysis), general cost (stochastic analysis), market interaction and exposure, and renewable capital cost (sensitivity analysis).

For the environmental policy sensitivity analysis, AES Indiana ran production cost analysis (8,760-hour dispatch analysis) of the six candidate portfolios for the Reference Scenario through the other environmental policy scenarios. The generation resource mix for each of the candidate portfolios was dispatched using the assumptions of each of the other scenarios. The intent of the analysis was to evaluate how well the six candidate portfolios performed in a very different policy and commodity future.

To evaluate general cost risk and opportunity, AES Indiana used stochastic analysis to evaluate uncertainty in power prices, natural gas prices, coal prices, load, and renewable energy generation. Stochastic distributions of these variables served as inputs to the EnCompass model for stochastic production cost hourly dispatch runs over all 100 distributions.

AES Indiana tried to measure risk of exposure to the energy market. This metric is based on the annual market purchases and sales for each of the candidate portfolios.

In addition to the capacity expansion Replacement Resource Capital cost Sensitivity Analysis described earlier, AES Indiana wanted to understand how the affordability of the candidate portfolios would change if renewable resource costs ended up being very different than anticipated. AES Indiana varied only the capital costs of the replacement renewable resources in each of the six candidate portfolios in this sensitivity analysis. High and low capital cost sensitivities for solar, wind, storage, and solar plus storage were evaluated.

Reliability, Stability, and Resiliency Category

AES Indiana contracted with Quanta Technology LLC (Quanta) to evaluate the reliability of the candidate portfolios in terms of energy adequacy. Quanta also assessed resilience and system stability of the portfolios.

The following components of reliability, resilience, and stability were assessed by Quanta:

1. Energy Adequacy
2. Operational Flexibility and Frequency Support
3. Short Circuit Strength Requirement
4. Power Quality (Flicker)
5. Blackstart
6. Dynamic VAR Deliverability
7. Dispatchability and Automatic Generation Control
8. Predictability and Firmness of Supply
9. Geographic Location Relative to Load

Quanta measured the performance of each portfolio across these metrics in the year 2031. The analysis determined that each portfolio had reliability concerns, especially under emergency and islanded conditions. Portfolios with the most inverter-based resources generally performed worse partly due to issues with short circuit strength. Portfolios with higher levels of dispatchable generation score better. This is demonstrated by the No Early Retirement, the Petersburg Conversion strategies, and the EnCompass Optimization portfolios scored the highest.
Quanta also proposed mitigation measures that could address the reliability problems in the portfolios. The mitigations include grid-forming inverter technology, additional fast power resources such as battery storage, super capacitors, or combustion turbines, and additional synchronous condensers.

Quanta made clear the analysis of reliability issues was not exhaustive. Topics not covered include:

1. The study assumed that any required grid upgrades will be done as part of the MISO interconnection process, and thus excluded the issue of portfolio deliverability.
2. The study excluded the analysis of resource adequacy.
3. All the assessments applied screening level indicative analyses. Detailed system studies are essential and should be done to properly evaluate system reliability of the short-listed resources.

DIRECTOR'S COMMENTS – SCENARIO & RISK ANALYSIS

<u>Issues Involving AES Analysis</u>
AES Indiana modeled capacity expansion for six strategies under four scenarios, resulting in a total of 24 capacity expansion portfolios. However, without further evaluation, the candidate portfolios were narrowed to the six portfolios generated from the Reference Case only.

AES Indiana simply stated the reason as the Reference Case scenario aligns with the Company's policy and commodity assumption outlook. There is no guarantee that the Company's policy and commodity assumption outlook is the most likely future. That is why scenario analysis is needed. What is the point of generating portfolios from other scenarios but not evaluating them on the same basis? It is necessary that portfolios from all scenarios are tested across various scenarios to see how those portfolios perform under different future situations. There are possibilities that portfolios generated from other scenarios perform better in general and can adapt easily when future situation changes. It seems that conclusions have been made before doing thorough analysis. The scenario analysis by AES Indiana was closer to testing how those six candidate portfolios from the same set of assumptions perform under different scenarios.

The Director appreciates the analysis performed by AES Indiana to understand the impact of a range of capital costs for replacement resources as this is a key uncertainty. However, the Director thinks it would have been helpful to evaluate the resource optimization if the costs of all incremental thermal fuel resources had to be recovered over a 20-year period. This type of scenario is plausible given the policy and technological uncertainty the industry is forced to make decisions in.

Response of AES Indiana

The Scenario Analysis conducted for the 2022 IRP was intended to compare the cost effectiveness of resource mixes developed under the Current Trend/Reference Case scenario to resource mixes developed under more extreme, "bookend" scenario assumptions in the No Environmental Action, Aggressive Environmental, and Decarbonized Economy scenarios. Ultimately, the analysis answered the question, "Which Petersburg strategy performs generally the best across the different potential futures?" The analysis demonstrated that converting Petersburg Units 3 and 4 to operate using natural gas generally performs the best in the No Environmental Action, Current Trends/Reference Case, and Decarbonized Economy scenarios and is more cost effective than continuing to burn coal at Petersburg Generating Station ("Petersburg") in every scenario. AES Indiana performed the final IRP Scorecard evaluation on only the Current Trends/Reference Case portfolios because this scenario assumes the most probable view of the future. This conclusion was not made without analytical support. As noted, the other scenarios were modeled as "bookend" scenarios or scenarios that represent extreme futures that while unlikely are possible. This analysis is further discussed below.

When comparing the resource mixes across the scenarios during the key decision-making time frame or Short-Term Action Plan period, the primary difference is the volume of wind and solar energy resources driven by more or less aggressive environmental policy assumptions. The Petersburg Units 3 and 4 capacity replacements are filled by either the natural gas conversion or battery energy storage systems ("BESS") across all scenarios. In other words, the key capacity replacement decisions are nearly the same regardless of scenario. The scenarios only vary in terms of the volume of wind and solar being added primarily for energy value if the scenario assumptions support it.

To elaborate on this point, AES Indiana refers to the tables contained in the figure below, which compare the resource mixes across scenarios for the 2025-2028 period, and discusses this information further below the tables:

No Environmental Action (Additional MW)

Period: 2025 - 2028

	Conversion	CCGT	Storage	Hybrid	Solar	Wind
No Early Retirement	-	-	180	-	-	-
Pete Conversion	1,052	-	180	-	-	-
One Unit	-	-	620	-	-	-
Retire & Replace	-	325	760	-	-	-
Clean Energy	-	-	640	-	420	100
EnC Opt	1,052	-	180	-	-	-

****Reference Case** (Additional MW)**

Period: 2025 - 2028

	Conversion	CCGT	Storage	Hybrid	Solar	Wind
No Early Retirement	-	-	240	45	-	500
Pete Conversion	1,052	-	240	45	-	500
One Unit	-	-	700	-	-	500
Retire & Replace	-	325	760	-	-	600
Clean Energy	-	-	700	45	280	900
EnC Opt	1,052	-	240	45	-	500

Aggressive Environmental (Additional MW)

Period: 2025 - 2028

	Conversion	CCGT	Storage	Hybrid	Solar	Wind
No Early Retirement	-	-	260	45	65	1,250
Pete Conversion	1,052	-	260	90	845	1,500
One Unit	-	-	700	90	553	1,450
Retire & Replace	-	-	780	45	293	2,100
Clean Energy	-	-	780	45	293	2,100
EnC Opt	526	-	400	45	260	1,900

Decarbonized Economy (Additional MW)

Period: 2025 - 2028

	Conversion	CCGT	Storage	Hybrid	Solar	Wind
No Early Retirement	-	-	260	45	390	500
Pete Conversion	1,052	-	260	45	390	500
One Unit	-	-	680	45	293	600
Retire & Replace	-	325	760	45	260	650
Clean Energy	-	-	1,060	45	293	850
EnC Opt	1,052	-	260	45	423	500

The following paragraphs summarize what is shown in the above figure.

1. The key decision being made in the Short-Term Action Plan period concerns the future of the Petersburg coal-fired Units 3 and 4 (approximately 1,000 MW). This decision boils down to three options, AES Indiana could a) continue to fire these units with coal; b) convert them to burn natural gas as fuel; or c) retire and replace these units with some other capacity. Any other strategies developed beyond the IRP Short Term Action Plan period regarding other AES Indiana resources will be addressed again in the next and future IRPs.

2. Focusing on the first three resource columns (i.e., Conversion, combined-cycle gas turbine ("CCGT"), and storage), notice that across the scenarios, the resource mixes when comparing strategies are approximately the same. The model selects approximately 200 MW of BESS to fill the 200 MW capacity needed for winter capacity under MISO's seasonal resource adequacy construct in every strategy.[2] And, in strategies that retire Petersburg Units 3 and 4, the model replaces the capacity with either BESS or BESS and CCGT. To summarize, the Current Trends/Reference Case

[2] In Cause No. 45920, AES Indiana filed with the IURC for the Pike County Energy Center, a 200 MW/4-hour BESS project to fill this capacity need.

scenario is representative of the other scenarios in terms of capacity strategies at Petersburg.

3. Focusing now on the last three columns (i.e., Hybrid, Solar, and Wind) in the tables. As the environmental policy assumptions become more aggressive, the model selects more clean energy (solar and wind) primarily for its energy value. For example, in the Aggressive Environmental Scenario, a high carbon tax, starting at $19.47 per ton in 2028, was captured in the fundamental power price forecast as higher power prices that are available to solar and wind resources. This drove the model to take advantage of the higher prices and select greater amounts of wind and solar resources for the energy revenue. Additionally, the Decarbonized Economy Scenario assumes a clean energy mandate that requires utilities to serve a percentage of their load from clean energy (wind, solar and storage). This percentage increases to over 80% by the end of the planning period. This mandate drove the model to select higher amounts of wind and solar resources to meet the energy requirement of the mandate.

4. In conclusion, the analysis demonstrates that, regardless of the scenario, the Current Trends/Reference case portfolios provide a good representation of the capacity strategies at Petersburg. The primary difference between the resource additions when comparing across scenarios is that as the environmental policies in the scenarios become more or less aggressive, the model adds more or less wind and solar, respectively, over the planning period. These wind and solar additions are primarily driven by energy benefits and not capacity need. AES Indiana would only add this level of renewable energy resources if environmental policy creates an economic incentive to do so. Considering these points, the decision to only use the Current Trends/Reference Case portfolios in the IRP Scorecard analysis was reasonable but in hindsight AES Indiana understands that a more robust discussion of this analysis in the IRP would have better facilitated understanding.

Director's Reply

The above discussion provides additional insight into the thought process used by AES Indiana in developing the preferred portfolio. It is especially important that the IRP discussion explain how the utility interpreted and applied the large amount of information provided in the IRP development process. The above discussion is helpful in furthering the Director's understanding.

VI. THE FIVE PILLARS

DIRECTOR'S COMMENTS – THE FIVE PILLARS

As described above, the portfolio metrics and scorecard were explicitly based on the Five Pillars of reliability, affordability, resiliency, stability, and environmental sustainability. The discussion of the metrics and the scorecard results were well done and very helpful. Understanding how AES Indiana interpreted and applied the results is critical.

The Director appreciates the debate over how best to analyze the affordability of the candidate portfolios. The Director understands the difficulty of evaluating the affordability of different resource plans over a 20-year planning horizon. The cumulative NPVRR of a portfolio over the planning horizon is informative but does have limitations. One being that the difference between the candidate portfolios is often only a few percentage points. A useful complement is to show the annual revenue requirement of a candidate portfolio for each year of the planning period, both in nominal dollars and real dollars. This was done by AES Indiana using nominal dollars. AES Indiana also calculated the average and levelized rate impacts to customers. These results were not included in the scorecard evaluation because the average and levelized rate impact analysis produced the same portfolio ranking results as the 20-year PVRR results. The Director is open to other means of evaluating affordability but finds the information provided by AES Indiana was helpful.

The reliability, stability, and resiliency set of metrics are a relatively recent addition to Indiana utility IRPs, primarily the investor-owned utilities. The basic methodology is evolving from one IRP to the next as can be expected depending on the specific utility circumstances and as Quanta gains experience both developing the analysis and presenting the results. As is the case with many of the scorecard metrics, the differences across candidate portfolios appears to be small. Given this, it is important that the utility and Quanta assist the other stakeholders in understanding the significance of what is being presented and how it differentiates the candidate portfolios. The addition of estimated mitigation costs helped to differentiate the reliability assessment of the candidate portfolios. But AES Indiana noted that the mitigation "costs were not included in the Affordability calculations due to their uncertainty, as they are far enough out into the future where grid and technology improvements could potentially lower these costs." This statement highlights the complexity of the analyses and the difficulty of interpreting the information developed.

The reliability metrics are helpful and emphasize the need to go beyond traditional concepts of reliability and resource adequacy. Many of the metrics and the specific measures for each metric are conceptually familiar. Examples are energy adequacy, operational flexibility, frequency support, blackstart, dispatchability and automatic generation control, and predictability and firmness. Other metrics are further removed from traditional integrated resource planning. IRP is a complicated process already and the evaluation of the reliability, stability, and resilience metrics is necessary given the evolution of the industry, but explaining what is done, why, and the meaning of the results is challenging.

Quanta also states that the reliability, stability, and resiliency assessments are screening level indicative analyses. Quanta goes on to say that "detailed system studies are essential and should be conducted to properly assess system reliability of the short-listed Portfolios." The Director wonders when these detailed system studies should be conducted and by whom.

The presentation of the Quanta's system reliability assessment results involves the use of a detailed scorecard specific to the system reliability assessment. The IRP presentation involves essentially embedding the detailed system reliability scorecard in the more traditional IRP scorecard. The resulting complexity is probably unavoidable.

The purpose of portfolio metrics and the use of a scorecard is to highlight the tradeoffs across the various metrics for different portfolios under different scenarios and circumstances. Despite the basic difficulties discussed above, AES Indiana provided an excellent discussion of the modeling results and the key takeaways as the modeling progressed. The discussion of the scorecard evaluation results in section 9.4 of the IRP report *(IRP pages 234-252)* was informative and helped the Director to understand how AES Indiana interpreted and used the different modeling results to inform AES Indiana's selection of the preferred portfolio.

Response of AES Indiana
Screening-level assessments are a reasonable means to evaluate and rank the system reliability under each of the candidate portfolios. This approach is also practical due to not only time and resource constraints, but also the uncertainties in the surrounding environments.

AES Indiana recognizes that detailed system studies are necessary. Toward that end, AES Indiana works both as a partner with MISO and within the MISO generator interconnection process framework to develop detailed studies for transmission system generator interconnections. This is consistent with the "reliability imperative" that MISO, its members (e.g., AES Indiana), and states (e.g., Indiana) all share. Some of the detailed studies are driven by MISO, like an overall system impact study, and some are driven by the transmission owner, like a specific facilities study.

AES Indiana engages in this interconnection study process wherever appropriate, either as an interconnection customer or a transmission owner. The timeline for these studies is driven by MISO, as the administrator of the so-called queue. AES Indiana also internally leads distribution system generator interconnection reliability studies.

Finally, as necessary, the Company conducts detailed system studies when evaluating specific projects prior to initiating an investment decision. For example, in preparation for Cause No. 45493, AES Indiana conducted a detailed interconnection study for the Hardy Hills Solar Project.

Director's Reply
The additional discussion provided by AES Indiana above is helpful but highlights the difficulty of understanding and properly considering the different reliability, stability, and resilience metrics that need to be analyzed when considering alternative resource choices. A clear discussion of the analysis and how the resulting information is interpreted and used is key. The Director expects this is an area of IRP development that will evolve significantly over the next few planning cycles.

VII. STAKEHOLDER COMMENTS

The following comments are intended to be a representative sampling of the public input into AES Indiana's 2022 Integrated Resource Planning. There were similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Hoosier Environmental Council (HEC)

HEC has three main points:

1. Energy decision-making is vital for addressing climate change in Indiana. AES Indiana can make a profound impact on greenhouse gas emissions through energy efficiency, renewable energy, demand response, and battery storage deployment.
2. HEC appreciates AES Indiana's commitment to adding 1300 MW of renewable energy by 2027.
3. HEC asks AES Indiana to consider responsible development and management of solar, wind, and storage systems. Implementation of these systems should include secondary benefits to communities through community solar models, multi-land use practices, and redevelopment.

HEC highlighted several aspects of community benefits:

1. Community solar is valuable for increasing MWs of solar developed, developing communities, and increasing grid resilience and reliability.
2. Indiana is a prime location for solar development of any scale. Utility solar and community solar can support farmer, cohabitate with farmland, and power ecosystem services while strengthening community relationships. Also, rural redevelopment of retired landfills and abandoned coal mines limits agricultural land loss and other community benefits.
3. Multi-land use and redevelopment in urban areas has similar community benefits.

HEC made the following recommendations:

1. AES Indiana should adopt a community solar model combined with battery storage to replace energy provided by the Petersburg units.
2. AES Indiana should acquire or use renewable energy developments that provide multiple community ecosystem benefits including pollinator friendly solar and agriculture friendly wind practices.
3. Communities would benefit from the redevelopment of brownfields.

Response by AES Indiana
AES views DERs and Community Solar integration into distribution system planning and the IRP as targets for the next IRP. That in 2022, AES Indiana did not have the appropriate distribution system planning tools in place to sufficiently forecast DERs as a resource. *(AES Indiana Response, p. 18)*

Director's Response
The Director agrees that there needs to be increased evaluation of the potential impacts of DERs of all types. As AES Indiana noted, it is critical that the appropriate tools be used. The process of integrated resource planning is always evolving, and this will continue with greater attention to what customers might do on the customer-side of the meter.

Sierra Club

Sierra Club recognizes that AES Indiana plans to stop burning coal at Petersburg Units 3 and 4 in 2025 but emphasizes that failure to acquire replacement resources in a timely manner can expose customers to additional risks from fuel and energy markets.

<u>Reasons to End Reliance on Coal</u>
AES Indiana provided several general reasons to eliminate as quickly as possible reliance on coal-fired generation. First, environmental requirements will increase the cost of burning coal at Petersburg. EPA's March 2023 Good Neighbor Plan final rule to reduce cross-state ground-level ozone will significantly increase the cost of burning coal at Petersburg. For ozone season 2025, EPA has allocated significantly fewer nitrogen oxide (NOx) emission allowances for Petersburg Units 3 and 4 than the 2021 ozone season. The result being AES Indiana likely having to buy costly NOx allowances to operate the Petersburg units. Furthermore, EPA's pending review of Indiana's Regional Haze plan could impose NOx, sulfur dioxide, and particulate matter reductions at Petersburg.

Second, Sierra Club notes that in recent years, coal units, including Petersburg, are increasingly unreliable. Sierra Club cites forced outage data provided by AES Indiana in the FAC proceedings.

Third, coal plants, including those that rely on Illinois Basin coal like Petersburg, expose ratepayers to risk from fuel price volatility. Coal prices rose dramatically in 2022 before starting to decline. The coal industry will continue to contract so coal price volatility will likely become the norm.

<u>AES Indiana Needs to be Proactive</u>
Sierra Club expressed concern that AES Indiana plans to rely heavily on natural gas. This reliance will expose AES Indiana to fluctuations in natural gas prices. Sierra Club also emphasized that once Petersburg Units 3 and 4 are converted to natural gas that the plants be strictly operated as a capacity resource.

Given the time it takes to site and build solar and wind facilities, just-in-time resource planning is inadequate today and perhaps even more so over the next decade. AES Indiana should push to bring renewable resources online on a rolling basis and whenever economically available, rather than trying to align resource additions perfectly with capacity needs.

Sierra Club appreciates that AES Indiana intends to pursue all resources that the Preferred Portfolio contained through 2027, to account for the challenges of acquiring replacement resources under current market conditions.

Director's Response
The Director appreciates the emphasis placed by the Sierra Club on the need for the utility and other stakeholders to maintain a healthy skepticism of the ability in the future to add resources in a just-in-time manner. Experience demonstrates that all types of resources, both renewable and thermal, can be significantly delayed in ways that are beyond anyone's control. Thorough planning can respond to this uncertainty and risk by adding resources in small increments across multiple developers while maintaining a diverse resource portfolio.

The complexity caused by this uncertainty and risk is more problematic when the problems one utility has adding resources in a timely manner are recognized as being experienced by many utilities across a multi-state region. Making company specific plans and resource choices is made more difficult by the necessity to account for similar decisions being made across the region. The Director thinks the regional aspect of utility planning and resource acquisition needs to be better addressed in the IRP process. Hopefully, the tools will improve, but a strong discussion of the circumstance helps frame any resource decisions.

Reliable Energy

General Concerns
Reliable Energy believes there were two factors that drove AES Indiana's choice of IRP assumptions to support a Preferred Portfolio based on switching Petersburg Units 3 and 4 to natural gas. One being AES Corporation's previously announced plans to end coal generation by 2025. The second being that AES Corporation has adopted performance metrics and potential executive bonuses tied to the shutdown of coal-fired generation capacity.

Reliance on Renewables
Reliable Energy states, except for the proposed conversion of Petersburg Units 3 and 4 to natural gas, the Preferred Portfolio provides for no additional dispatchable resources during the 20-year plan period. That significant reliance on renewable energy resources is problematic for reliability and resiliency. Complications of relying on renewables includes significant increases in renewable/battery pricing and supply chain delays that raise questions about AES Indiana's ability to meet the resource acquisition goals set out for the 2025-2027 period. Making this more problematic is that interconnection queues are long and transmission upgrades are expensive.

Coal Prices
Reliable Energy believes AES Indiana used a coal price forecast that was unreasonably high. That the methodology used by AES Indiana for forecasting coal prices was based on bids received when prices were temporarily inflated to previously unseen levels. Reliable Energy states the problem with this methodology is the assumption that short-lived higher prices for coal would last through the entire critical analysis period for deciding the economics of converting Petersburg Units 3 and 4 to gas.

Ratepayer Impacts
Reliable Energy asserts that AES Indiana knows that net present value (NPV) analysis is not an accurate indicator of full ratepayer cost impacts of generation decisions, yet AES Indiana continues to represent that NPV analysis is an appropriate metric to evaluate affordability. Reliable Energy goes on to say that the alleged savings of the Preferred Portfolio compared to the other candidate portfolios is less than a 3% difference on a NPV basis and is well within the margin of error of any forecast.

Reliable Energy argues that AES Indiana should be doing an analysis of ratepayer impacts by year for at least the first 10 years.

Further Petersburg Considerations

1. Any IRP analysis is a point in time so any requests for a CPCN should be based on an updated analysis to account for change in environmental laws including whether the Good Neighbor Rule Federal Implementation Plan has been stayed by a federal court.
2. The Preferred Portfolio assumes a retirement date in 2042 for Petersburg Units 3 and 4. The economic analysis should reflect closure of the units by 2040 with the undepreciated capital being borne by shareholders.
3. AES Indiana should consider a sale of Petersburg Units 3 and 4 like Hallador's purchase of Merom.

Response by AES Indiana

AES Indiana states it made it clear to stakeholders throughout the 2022 IRP process that the IRP is an objective analysis and that AES Indiana's global parent company's targets would not influence the analysis or the analysis outcomes. AES said the results were driven by reasonable assumptions to which the stakeholders provided input. *(AES Indiana Response p. 3)*

AES Indiana also said the assumptions included in the IRP analysis were reasonable and defensible and were chosen because they were contemporary to the markets and cost estimates at the time. AES Indiana said it intends to update key assumptions in the Petersburg Conversion CPCN, including the estimated cost to convert Petersburg Units 3 and 4 to natural gas, and assess that updated estimate for consistency with its 2022 IRP Preferred Resource Portfolio. *(AES Indiana Response pg. 3 - 4)*

Reliable Energy argues that AES Indiana used a coal price forecast that was unreasonably high. AES Indiana responded that commodity prices in general were experiencing upward pressure at the time of the 2022 IRP preparation. The coal price forecast was determined from bids that indicated higher 2023 prices. These prices decreased materially by 2025 closer to historical levels. AES Indiana also states the long-term growth rates were applied to the 2025 and forward so that inflated market prices in 2023 did not set a long-term upward shift in prices. *(AES Indiana Response pg. 7 - 8)*

AES Indiana responded to Reliable Energy's position that AES Indiana should be doing an analysis of ratepayer impacts by year for at least the first 10 years of the planning period. AES Indiana included in the IRP a comparison of each portfolio's revenue requirements by year. According to AES Indiana, the analysis demonstrates the Preferred Portfolio provides generally a lower revenue requirement in each year over the 20-year analysis period when compared to the other strategy, including the strategy that keeps Petersburg on coal. *(AES Indiana Response p. 7)*

AES Indiana notes that Reliable Energy states there are no dispatchable resources added under the Preferred Portfolio other than the conversion of Petersburg Units 3 and 4. AES Indiana counters that the Preferred Portfolio identifies over 600 MW of dispatchable battery resources during the 20-year planning period. *(AES Indiana Response p. 9)*

Director's Response

The Director understands Reliable Energy's concerns about the motivations of managers within large organizations tasked with important decisions. It is just this type of concern that motivates oversight by commissions of utility operations, investment decisions, and the provision of utility service. The IRP stakeholder process with several public advisory sessions and an opportunity to provide written comments on the utility IRP helps provide an informed check on the exercise of company judgment. An additional layer of oversight comes when the utility seeks a CPCN or approval of a PPA before the Commission. The Director acknowledges that economic regulation is an imperfect process, but it is one designed to improve the information available to the Commission and the broader public to better understand decisions made by the utility and the potential future consequences of those decisions.

As discussed earlier, the Director understands the difficulty of evaluating the affordability of different resource plans over a 20-year planning horizon. The cumulative NPVRR of a portfolio over the planning horizon is informative but does have limitations. One being that the difference between the candidate portfolios is often only a few percentage points. A useful complement is to show the annual revenue requirement of a candidate portfolio for each year of the planning period, both in nominal dollars and real dollars. This was done by AES Indiana using nominal dollars.

The Director has testified (in the distant past) about the small percentage differences in cumulative NPVRR when comparing different resource portfolios over a 20-year period. In those circumstances, he found the comparison of annual revenue requirements informative. It helped to highlight when some plans were more cost-effective in the early years and when other plans became cheaper later in the planning period. This information is not decisive but helps provide more information than is available with the cumulative NPVRR only.

As noted by Reliable Energy, an IRP is performed at a moment in time. AES Indiana acknowledges that numerous assumptions and data inputs will have to be updated and that some of the analysis redone to check if the IRP's preferred portfolio continues to be appropriate.

The Director appreciates Reliable Energy's concern about the growing reliance on renewable energy resources and the possible implications for reliability and resiliency. AES Indiana provided the Quanta analysis which reviewed a set of reliability, stability, and resilience metrics to understand the performance of the candidate portfolios more fully. The Quanta report was addressed by the Director in the Five Pillars discussion earlier in this report.

Response of Reliable Energy

Reliable Energy thinks it is certainly relevant to address in any CPCN filing by AES Indiana the expected resource shortfalls in MISO due to plant retirements outpacing resource additions. Instead of AES Indiana addressing its capacity needs on an individual utility basis, AES Indiana should consider at a minimum the capacity constraints in all of MISO Zone 6, although a larger footprint may be more relevant. According to Reliable Energy, all utilities in Indiana should be similarly required to consider regional capacity concerns.

Reliable Energy argues that a resource evaluation should not be confused with an affordability analysis. A Net Present Value (NPV) of alternative resource options is not equivalent to an affordability analysis, i.e., how customer rates are affected by resource decisions. The string of recent significant rate increases by Indiana utilities has in part been due to accelerated coal plant retirements. Had the utilities been tasked with performing an accurate rate impact analysis in addition to a resource analysis based upon an NPV, the Commission and stakeholders would have better understood the true affordability impact of certain resource plans.

Reliable Energy also has numerous concerns that any updated IRP analysis by AES Indiana includes updated coal prices, and updated commodity and transport assumptions. Reliable

Energy thinks that AES Indiana should consider alternative lives for Petersburg 3 and 4. Recognizing any delay in making commitments at Petersburg 3 and 4 provides the opportunity for greater clarity regarding changing regulations and alternative resource options and reduces stranded costs.

Reliable Energy also had a lengthy discussion of the uncertainty associated with the timing and impact of several environmental regulations in various stages of review by the EPA. The implication being that any updated IRP needs to account for these uncertainties.
Lastly, Reliable Energy believes that PVRR analysis may be appropriate to compare alternative resource options, it is clearly not the appropriate way to consider affordability. Reliable Energy believes that an affordability analysis must focus on rates.

Director's Reply
The Director respectfully disagrees with Reliable Energy's assertion that there is no relationship, or equivalency, between NPVRR and affordability.

Evaluation of affordability requires judgment because it is contingent on maintaining desirable performance on the other pillars. Stated another way, evaluating only for affordability means ignoring the possible impact on reliability, resiliency, stability, and environmental sustainability. For resource acquisition, determination of affordability requires a comparison of different resource portfolios over a 20-year period over a range of alternative potential futures. The primary methodology is to use net present value revenue requirement to evaluate choices on a comparable basis. The process involves identifying known incremental costs of various portfolios over a planning period and determining the incremental revenue requirement effect of these costs in each year of the planning period, then discounting to account for the time value of money. Calculating the NPVRR for different portfolios allows a comparison of the overall incremental cost of each portfolio on all customers over the planning period.

The focus of NPVRR is appropriately on those costs that can be avoided or incurred depending on the resource choices made. The attention is not on those costs that cannot be avoided or undone regardless of the possible resource choices going forward, also known as sunk costs. The assumption is that these sunk costs must be recovered regardless of the resource choices going forward. These sunk costs will be accounted for in customer rates, but their recovery does not depend on resource choices going forward and therefore should have limited impact on future decisions.

Also, utility IRPs usually include the evaluation of various resource choices with a particular focus on the options for existing coal-fired units. It is in this circumstance that a useful complement to the traditional 20-year NPVRR is to show the annual incremental revenue requirement of a candidate portfolio for each year of the planning period, both in nominal dollars and real dollars. The Director thinks additional affordability metrics can be informative but does not see these as substitutes. Rather, these other potential affordability metrics would complement the two described above – the traditional NPVRR over the planning period and the annual revenue requirement for each year of the planning period.

The Director agrees with Reliable Energy that utility resource planning needs to include consideration of regional capacity concerns. However, it is not obvious what this consideration means in practice. For example, the MISO performs annually a

		Regional Resource Assessment (RRA) based on utility IRPs and the MISO's own modeling. The RRA is helpful for better understanding the regional resource portfolio and likely changes over time. How might a utility account for this knowledge in its IRP planning and resource acquisition process? Again, the Director agrees more needs to be done to account for broader regional conditions, but it is not obvious how this can best be done. Furthermore, better price signals from the RTOs regarding the value of dispatchable generation resources will help bolster the reliability of the interregional grid. When to update an IRP and how extensively is a complicated decision that every utility faces, especially when contemplating filing a CPCN request or other formal actions to acquire new resources. The Commission, in the relevant review process, will judge the adequacy of the utility's IRP and the associated analysis supporting any proposed resource action. Finally, the Commission recognizes that affordability is a key facet of Indiana's energy policy and an important factor for all ratepayers. The IRPs are meant to help chart possible courses that balance affordability and reliability along with the other three pillars and the Director appreciates Reliable Energy's emphasis on those considerations and how to conceptualize them in future IRPs.

Solar United Neighbors

Solar United Neighbors (SUN) believes AES Indiana's IRP is missing some critical inputs, especially a need to focus on optimizing the distribution grid and further incentivizing customer adoption of DERs like solar and batteries.

<u>Allow DG Solar and other DERs to be included as Resources in Model Optimization</u>
According to SUN, DG Solar and other DERs have traditionally been treated as a decrement to load forecasts (or an increase to load in the case of EVs) and outside the control of utilities when developing resource plans, but experts are increasingly calling for DERs to be included as a selectable resource with other more traditional resources in the planning optimization process. That this method of inclusion of DERs is what is done by AES Indiana for modeling additional energy efficiency.

Tools are available today that allow for predictably modeling customer adoption of DERs based on market conditions and policies that impact the return on investment.

According to SUN, more fully integrating DERs into the planning process as resources that can be selected and modeled in the portfolio evaluation process can unlock previously untapped value to provide more affordable, reliable, and sustainable electricity service.

<u>Integrated Distribution Planning</u>
SUN was encouraged by AES Indiana's inclusion of several areas for improvement in distribution level planning for consideration in the next IRP. SUN said that AES Indiana should take the following actions to better align bulk power resource planning and distribution planning processes:

1. Set DER deployment targets consistent with current IRP high adoption scenarios.

2. Conduct advanced forecasting to better project the levels of DER deployment at the feeder level, leveraging the capabilities of advanced planning tools.
3. Proactively plan investments in hosting capacity to allow distributed generation and EV additions consistent with DER deployment targets.
4. Improve non-wires alternative analysis.
5. Plan for aggregated DERs to provide system value including energy/capacity during peak hours. AES Indiana should explore customer aggregations as a tool to avoid traditional distribution upgrades.

Director's Response
The Director concurs with SUN on the desirability of thinking of DERs as resource options that should be more fully accounted for in the IRP process. Fortunately, the relatively low current level of DER penetration makes possible a timely future inclusion of distribution system planning in the broader IRP.

Indiana Office of the Utility Consumer Counselor

The OUCC had several areas on which it commented.

Capacity Credit and Energy Adequacy
The OUCC noted that AES Indiana began looking extensively at reliability characteristics in the 2022 IRP, and the OUCC encourages AES Indiana to continue to improve and refine the analysis. The OUCC also recommended the addition of stress testing to existing and potential portfolios during IRP modeling to evaluate customer impacts from changes in capacity accreditation.

The OUCC also thinks evaluation of energy adequacy should include the impact of reliability constraints in all future IRPs.

Transmission and Distribution Planning
The OUCC discussed several considerations. AES addressed reliability with factors including black start, volt-ampere-reactive (VAR) deliverability, and frequency support. The OUCC noted that the analysis resulted in similar scores for four of the five strategies. With respect to the reliability analysis performed by AES, the OUCC recommended reviewing the impact on candidate portfolios when a constraint is introduced, or a capability is disabled; for example, if a black start capable resource becomes disabled for an extended period. Also, AES Indiana should explain if there is a significant risk if renewable resources cannot be in proximity to load because of permitting trends. According to the OUCC, AES Indiana should include avoided cost calculation for the DSM programs, including avoided transmission and distribution capacity costs. The information provided should include the methodology and assumptions used along with justifications.

The OUCC suggests AES Indiana either reduce its projected residential customer growth rate or provide more justification for the current estimate. Since population and residential customers are closely correlated, the OUCC thinks AES Indiana should explain why residential customer growth outpaces population growth and how this growth affects load.

EVs and Distributed Solar
Section 5.4.2 of the AES Indiana IRP provides information at the national level. The OUCC wants to see this information at the local or regional level for the AES service territory, or, at a minimum, the state level.

The OUCC would like to understand how AES' Electric Vehicle Portfolio filing in Cause No. 45843 will impact AES's IRP in the near term and whether the assumptions in this filing were included in the IRP load forecast.

AES states the number of residential customers is essentially the number of households served by AES Indiana. Therefore, the number of residential customers can be multiplied by the number of vehicles per household to estimate the total number of vehicles in the service territory. The OUCC thinks this methodology exaggerates the number of EVs forecasted, as lower middle and low-income customers will be unlikely to purchase an EV in the near term.

Demand Side Resource Options
According to the OUCC, AES Indiana needs to reevaluate its energy sales forecast. Between 2011 and 2021, energy sales declined on average 1.0% annually. But Table 1-1 shows a projected annual average increase of 0.5% over the planning period. AES Indiana needs to use a lower forecast or justify the current projected growth rate.

Resource Portfolio Modeling
The scorecard metrics such as Reliability/Resiliency, Environmental, and Affordability did not have significant differences among the five strategies evaluated. The differences according to the OUCC were typically less than 3%. The OUCC recommended weighting the metrics or stress testing them to identify meaningful differences between scenarios.

The stochastic analysis of energy price, fuels, and load also had low variability among the scorecard metrics, typically -3% to +3.5%. The OUCC recommends stress testing these variables by introducing the impact of a significant event on the portfolio. An example is a significant generator outage or weather event.

The OUCC recommends discussing the risk analysis from a customer rate affordability perspective. Also, AES Indiana needs to discuss how forecast accuracy can affect the consumer and the proposed portfolio.

Response of AES Indiana
The OUCC noted that the composite scores in the reliability analysis performed by Quanta Services, Inc. were very close. AES Indiana responded this was driven by certain categories of the reliability analysis. AES Indiana also noted that Quanta provided greater score differentiation by providing the cost of mitigation (mitigations which improve the reliability score to the highest level). Greater reliability disparity between the portfolios was seen when scores are monetized using mitigation costs.

AES Indiana said it considered weighting metrics for the 2022 IRP scorecard but believes use of a weighting process might create an appearance of subjectivity. AES Indiana will consider ideas for weighting in the next IRP and working with the OUCC on a reasonable approach.

The methodology used in the avoided cost calculations has not changed since AES Indiana's 2019 IRP. The calculation and calculation details are included in AES Indiana's 2022 IRP filing as Attachment 1-1 – T&D avoided costs.

According to AES Indiana, planned DSM was removed from the load forecast resulting in projected load growth when AES Indiana historical load has been relatively flat. When DSM selected in the model optimization is included in the load forecast, the load forecast exhibits a flatter trend that is more consistent with history.

AES Indiana notes the OUCC comment that AES either reduce its projected residential customer growth rate or provide more justification for the current estimate. In response, AES Indiana states the driver for the residential forecast is the number of households. To project the number of households, population is divided by the average household size. Marion county's average household size steadily decreases over the forecast period, so the number of households is projected to increase. AES Indiana says the compounded annual growth rate of households in Marion County is 0.98, which closely matches the projected customer growth rate over the planning period.

AES Indiana said that GDS Associates developed base, high, and low forecasts for solar and base, low, high, and very high forecasts for EVs. These forecasts were used to vary the load forecast in different IRP scenarios. According to AES Indiana, the different EV forecasts were intended to capture the impacts of different policies that would significantly impact EV adoption in the AES Indiana service territory.

The OUCC expressed concern about the methodology used by AES Indiana to estimate the total number of EVs within the AES Indiana service territory. The OUCC thought the methodology used exaggerated the number of EVs forecasted, as lower middle income and low-income customers are unlikely to purchase EVs in the near term.

AES Indiana responded the base EV adoption forecast used in the IRP was realistic, if not conservative. AES Indiana provided a comparison using Bloomberg New Energy Finance's (BNEF) market share outlook for new EV passenger vehicles. The BNEF projection for 2040 is that EVs are expected to account for 78% of the new passenger vehicle market share across the United States. The base forecast for AES Indiana is approximately 40% EV market share by 2040. AES Indiana also notes that the EV forecast model does include the affordability of EVs.

Director's Response

The Director appreciates the OUCC's interest in knowing how the different components of avoided costs were calculated and the underlying data and assumptions. This information is helpful to begin to understand the evaluation of DERs and EE in the IRP process. Of course, there is no single correct avoided cost for evaluating new resources. Avoided costs varies with the future being evaluated. It is for this reason that EE, DR, and DERs more generally should be considered options in the resource optimization process. Avoided costs is one more uncertainty in the planning process.

The evaluation of the reliability, resiliency, and stability characteristics of the candidate portfolios is a helpful addition to the IRP process. The evaluation of these characteristics will evolve.

The OUCC expressed concern about aspects of the load forecast including the number of residential customers and the growth in EVs in the AES Indiana service territory. The Director sees the load forecast as a critical part of the IRP process, but also one that is subject to extensive uncertainty. Future load is inherently unknowable with any precision. This is especially the case given the potential range and timing of development of DERs and EVs. For example, the methods and data available to project EV saturation and usage is limited and any resulting projections should be viewed with a critical eye. Hence, the need to consider the implications of a range of potential futures. None will be right, but the totality of the analysis can inform resource choices.

Response of the OUCC

Load Forecasting

The OUCC agrees with the Director's comments on load forecasting and recommends continued caution in approaching various methodologies to project vehicle electrification and growth of distributed energy resources (DERs), as well as their associated impact on load and load service. Because of uncertainty in timing, trend, and scale, it is critically important to test and understand the impacts of electric vehicle (EV) adoption and how DERs may affect the AES Indiana system.

The OUCC encourages AES Indiana to provide more analyses on its candidate portfolio's performance under high and low EV load growth and assumption scenarios in conjunction with DER entrants. This would provide more detailed descriptions and clarifications. The OUCC also suggests these analyses test the boundaries of candidate generation portfolio capabilities coupled with reasonable transmission, distribution, and storage improvement charge (TDSIC) options. This methodology would address uncertainties inherent in forecasting techniques by highlighting undesirable modeling outcomes that result from testing.

Demand-Side Resources

The OUCC shares the Director's concern about combining unrelated measures with very different load shapes in the same bundle. The OUCC suggests only evaluating alternatives with similar load shapes in each bundle. The OUCC also seeks greater transparency and documentation of the important impacts of free riders and spillover effects in DSM inputs.

Scenario/Risk Analysis

A more diverse scenario selection process is needed, and the OUCC agrees with the Director's comments on the way AES Indiana has narrowed the field of candidate portfolios. As the Director explains, certain scenarios may not necessarily be aligned with AES Indiana's outlook but may perform better in some modeling futures. The OUCC encourages the Director to strongly reenforce the importance and need to have diverse options for consideration.

The OUCC also agrees that thermal resources should be evaluated in other recovery scenarios and not limited to 20-year evaluations. Complete cost estimates in the NPVRR portfolio analysis would also be beneficial. All significant costs should be included in the calculation, including but not limited to mitigation, TDSIC, interconnection, decommissioning, salvage, battery augmentation, and others. Net present value (NPV) sensitivity analyses on the size of regulatory asset and expense driven revenue requirements can be performed. Estimates need to be made, at least to some extent, to allow for an understanding of complete cost models. AES Indiana's portfolio scorecard ratings show room for improvement. The utility's final portfolios did not reflect significant differences in scoring. Probabilistic and importance ratings that weight scorecard metrics are important issues for stakeholder discussion and for the Director's consideration. The inclusion of zero weighting and testing or sensitivity analysis of weighting methods will provide valuable insight into the scenario and risk analysis.

Director's Comments on Prior OUCC Comments
The OUCC shares the Director's support for a more expansive form of planning that brings together traditional IRP planning with distribution and transmission planning, as well as better evaluation of DER, EV, total cost evaluation, and rate design interactions. We also continue to support full evaluation utilizing scenario analyses, sensitivity analyses, and stochastic analyses to provide a better foundation for evaluating risks and making resource decisions.

Director's Reply
The Director interprets the OUCC comments on load forecasting as highlighting the need to evaluate a broad range of load projections given the numerous sources of load growth uncertainty today that go beyond consideration of EVs. This type of analysis will provide greater insight into the sensitivity of candidate portfolios to different load projections. The type of analysis required depends on the type of planning being done. Distribution system planning requires detailed projections of load at the distribution circuit level, something quite different from traditional resource planning at the bulk power level. Obviously, the assumptions should be consistent between the distribution level planning and the more traditional bulk power system planning. Hopefully, Indiana utilities will move toward an integrated distribution system planning process.

The Director has questions about what the OUCC means by the phrase "complete cost estimate." For example, the focus in IRP modeling is on the incremental costs and costs avoided depending on the resource choices being made. The idea is to focus on what may be thought of as the incremental revenue requirement of alternative resource portfolios. Sunk costs cannot be changed by resource choices going forward and are, as a result, reasonably ignored. Also, it would be helpful for the OUCC to provide more explanation regarding some of its examples of specific costs.

Advanced Energy United

Be Careful not to Over-Value the Reliability and Under-Value the Risk of New Fossil Fuel Generation
Advanced Energy thinks the AES Indiana 2022 IRP offers limited details on the expected refuel process for Petersburg Unit 3 and 4. Transitioning generation sources can vary significantly in cost depending on the approach. That AES Indiana needs to provide more information to clarify how the company expects to coordinate the fuel conversion.

Winter Storm Elliott demonstrated, according to Advanced Energy, that thermal resources such as combined cycle and combustion turbine gas generators are not as reliable as is typically assumed. Converting Petersburg Units 3 and 4 to natural gas exposes AES Indiana and ratepayers to potential stranded assets risks, as well as incur expensive penalties if the units fail to perform when needed.

Natural gas is also subject to major price volatility. The operation and maintenance of new gas plants could make these resources uneconomic, especially as more zero-marginal cost renewable resources enter the MISO market.

According to Advanced Energy, taking these risks is unnecessary given that there are alternatives in the form of clean energy resources that can offer predictability, cost-effectiveness, and resource diversity because they are inherently different resource types.

AES Indiana Should Plan in the IRP for C&I Demand for Clean Energy

Advanced Energy says a growing number of businesses, municipalities, and organizations in the Indianapolis area have set corporate clean energy and sustainability goals. AES Indiana's IRP should account for corporate driven renewable additions, and to the extent that corporate commitments offset costs of acquiring new resources, those contributions should be factored into calculations of the costs of different portfolios to the full customer base.

AES Indiana Should Evaluate Distributed and Demand-Side Resources as Powerful Tools to Serve both Customer and Grid Needs

Advanced Energy wants AES Indiana to expand integration of customer-side resources. AES Indiana needs to work to enable more DERs and harness them in the aggregate to be a solution to summer capacity issues, voltage control, and more. The best way is to characterize DERs as supply resource options in the IRP modeling.

The AES Indiana 2022 IRP does not appear to properly consider behind-the-meter DERs. According to Advanced Energy, the IRP does not appear to reflect passage of the Inflation Reduction Act. Also, there is no indication the IRP considers that DER owners, rather than AES Indiana, pays for the investment. Future IRPs should explicitly recognize that most, if not all, costs associated with behind-the-meter DERs are borne by the DER owner.

Advanced Energy released a report in September 2022, titled "Indiana Opportunities for Demand-Side Resources" prepared by Demand Side Analytics. The report was included as an attachment to Advanced Energy's comments. The study found that it would be beneficial for AES Indiana to expand DSM in the IRP. First, the study found meaningful potential to increase load flexibility using time-varying rate designs, examining the trade-offs between different rate design decisions in terms of system-level capacity, cist, participation, savings per customer, and net benefits.

Second, the report made suggestions on how best to model demand-side resources to avoid undervaluing and under-selecting this powerful tool.

Lastly, the report offered AES Indiana a new long-term perspective on EE and DR resources that is needed to meet changing daily and seasonal resource needs.

Response of AES Indiana

AES Indiana views DER and community solar integration into the distribution system planning and the IRP as a target for the next IRP planning process. AES Indiana did not have the appropriate distribution system planning tools to sufficiently forecast DERs as a resource. The expectation is to use products like LoadSEER and DSMore to aggregate and model DERs as a supply-side resource option in the next IRP. AES Indiana looks forward to working with Advanced Energy United, Solar United Neighbors, Vote Solar, CAC, and Hoosier Environmental Council to implement this DERs-as-a-resource approach in the next IRP.

AES Indiana is working to coordinate PowerClerk, LoadSEER, and CYME for forecasting modeling, and analyzing DER growth and impacts. PowerClerk enables customers, DER developers, and AES Indiana to manage and track the status of multiple interconnection requests submitted at the same time. AES Indiana is pursuing technologies which allow for more DER penetration within the distribution system while maintaining system reliability and power quality.

Director Response

The Director shares with Advanced Energy the perspective that DERs should be viewed more as an opportunity and a resource in the IRP process. AES Indiana is moving to acquire and use the tools to better project DERs and the integration with distribution system planning. The Director looks forward to implementation of this new analysis in the next IRP.

The Director wants to highlight Advanced Energy's discussion of the benefits of using time-varying rate structures to increase load flexibility. The potential impact of different rate designs is often underappreciated. As discussed above, AES Indiana did include rate designs as options in the IRP process, but there is much room for improvement. Analysis of the role of rate design in long-term planning is a weakness across the industry. Increased use of time varying rates and the resulting data will provide a base on which to improve the modeling of time-varying rates.

The Director recognizes how customers respond to different rates has a certain level of uncertainty but the use of rates to increase demand flexibility can be used to respond to other sources of uncertainty.

Response of Advanced Energy

Advanced Energy's comments were focused on a few areas.

1. AES Indiana should be careful not to over-value the reliability and under-value the risk of new fossil fuel generation.
    a. More specifically, Advanced Energy respectfully requests that the final Director's report encourage AES Indiana to more fully consider the advantages of relying on renewable energy resources and energy storage over natural gas.

2. AES Indiana should plan for commercial and industrial demand for clean energy in its IRP.
    a. Advanced Energy respectfully asks that the final Director's report encourage AES Indiana to develop a green tariff for its customers and, when developing its next IRP, factor associated renewable energy resources into calculations of costs of different portfolios to the full customer base.

3. AES Indiana should elevate distributed and demand-side resources as powerful tools to serve both customer and grid needs.
    a. Advanced Energy strongly agrees that the potential impact of rate design is often underappreciated. In addition to emphasizing time-varying rate structures, Advanced Energy respectfully submits that the final Director's report should recommend that in future integrated resource plans AES Indiana should explicitly recognize that the costs associated with behind-the-meter DERs are often borne by the system owner, which clearly impacts

a cost-effectiveness analysis from the utility's perspective. Given the multiple benefits of DERs, Advanced Energy further urges the final report to encourage AES Indiana to examine the impact of offering modest incentives (*i.e.*, $500/kW) to promote DER development. Such investments may result in meaningful capacity resources and other benefits at far less cost to AES Indiana customers than wholly owned utility investments providing the same or similar benefits. Advanced Energy cannot overestimate the potential value of demand-side resources.

Director's Reply

The Director appreciates the emphasis by Advanced Energy on the need to fully evaluate alternatives to the acquisition of more traditional utility resources. Indiana utility IRPs all reflect major improvements in the analysis of alternative resources and will continue to improve with each iteration. The benefit of requiring utility IRPs to be redone at least once every three years is that the models, methodologies, data, and assumptions can all be updated to better account for best practices and new learnings.

Citizens Action Coalition, Earthjustice, Solar United Neighbors, and Vote Solar

Joint Commenters were disappointed in several aspects of the AES Indiana IRP.

1. Planning – The Joint Commenters were disappointed that AES Indiana waited too long to seriously plan for the near-term retirement of Petersburg Units 3 and 4. At which time AES Indiana claimed it was too late to find clean energy replacement resources if the units were retired quickly.

   According to Joint Commenters, AES Indiana represented that replacing all the remaining capacity at Petersburg with clean energy alternatives could not be achieved sooner than 2028.

2. Portfolio Strategies – The preliminary portfolios proposed by AES Indiana did not include a strategy of replacing Petersburg Units 3 and 4 with clean energy resources. This created an impression that AES Indiana's leadership had already decided not to pursue a clean energy strategy.

   The Joint Petitioners believe AES Indiana initially used an implausibly low capital cost for converting Petersburg Units 3 and 4 to gas giving the impression that AES Indiana was predisposed to converting the units to gas.

3. Fuel Diversity – AES Indiana has very little renewable energy online and already significantly relies on natural gas.

4. Reliability – AES Indiana's existing natural gas units have not been demonstrated to be reliable sources of generation, calling into question the decision to select additional investments in gas-fired resources.

A separate report prepared for the Joint Commenters raised the following main points of concern:

1. EE was not modeled beyond the minimum levels identified in the MPS.
2. DR excluded some cost-effective measures and was not modeled beyond the minimum levels identified in the MPS.
3. AES Indiana delayed studying the retirement and conversion of Petersburg Units 3 and 4 until it was nearly impossible to take any action other than conversion to gas.
4. There was little difference between the base and high load forecast.

<u>Stakeholder Processes</u>
Joint Commenters believe the process AES Indiana conducted for this IRP is a best-in-class approach for how utilities can conduct their stakeholder processes, and the Joint Commenters encouraged other Indiana utilities to review AES Indiana's approach and consider making changes to their IRP processes accordingly.

Three important steps towards transparency are particularly worth highlighting:

1. AES Indiana created a timeline for sharing modeling inputs, outputs, and supporting data with stakeholders.
2. AES Indiana generally included sufficient time for stakeholders to review those data, provide feedback, and for AES Indiana to incorporate that feedback into its modeling.
3. AES Indiana sought input on and was clear about the criteria it would use to judge resource portfolios.

According to Joint Commenters, AES Indiana set a tone that encouraged stakeholder feedback and generally made stakeholders feel as though their opinions were taken seriously.

In the Joint Commenters opinion, the transparency and collaboration led to an overall high-quality IRP.

<u>Energy and Demand Forecast</u>
Joint Commenters note there is little difference between AES Indiana's base and high peak demand forecast. They conclude the base forecast is either too high or the high forecast provides little value. The Joint Commenters say AES states that the projected growth rates are largely caused by anticipated growth in demand by EVs. The Joint Commenters recommend that AES Indiana make transparent the impacts of EV load by disaggregating it from total peak and energy forecasts; and that AES Indiana also focus on making EV load as flexible as possible.

<u>Energy Efficiency and Demand Response</u>
The Joint Commenters said the opportunity for Oversight Board input into the MPS through regular and frequent meetings was valuable and appreciated. The Joint Commenters also found the development process for the MPS was open and collaborative.

A notable inconsistency between the IRP and the MPS is that the MPS did not consider the avoided cost of carbon. Had the MPS included carbon assumptions like the IRP, the utility cost test scores would have improved, making more measures cost-effective. This would have also reduced the gap between technical and economic potential.

The Joint Commenters agree with the process to bundle and model realistic achievable potential (RAP) savings, they disagree with the approach to use RAP as the only source of EE savings for the model optimization. The Joint Commenters recommended that AES Indiana also model EE savings up to maximum achievable potential (MAP) for low-cost measures such as within the C&I segment. C&I savings in the MAP scenario are roughly 30% higher than the RAP savings. According to the Joint Commenters, these additional savings were inappropriately excluded from the IRP modeling. The Joint Commenters commend the inclusion by AES Indiana of emerging technologies in the MPS; however, the relatively small number of measures resulted in a very limited impact. Failure to better reflect emerging technologies results in a conservative and unrealistic view of potential savings.

DR potential was evaluated as part of the MPS with DR potential grouped into maximum and realistic achievable scenarios, as was done for EE. The Joint Commenters thought some aspects of the DR bundles modeled in the IRP were odd. They note the residential space heating and water heating direct load control measures were highly cost-effective in the MPS but excluded from Bundle 1. Meanwhile the DLC EV measure was not cost effective but was still included in Bundle 1. Bundle 3 omits C&I DLC space heating despite being cost-effective in the MPS under the RAP scenario and even more so under the MAP scenario.

Also, the DR potential was only modeled in the IRP at the RAP level. The Joint Commenters said the MAP scenario includes greater levels of cost-effective DR. According to the Joint Commenters, AES Indiana should have modeled DR potential from the MAP scenario. Absent this modeling, the Joint Commenters believe the DR potential underrepresents what can be achieved.

<u>EnCompass Modeling</u>
The Joint Commenters state the current IRP accelerated the timeframe for retirement of Petersburg Units 3 and 4 compared to the previous IRP and added as an option the conversion of both units to gas. That the 2019 IRP demonstrated the timing and need for replacement capacity just to retire one of the Petersburg units in 2026. Despite these learnings, according to the Joint Commenters, the length of time in which alternatives could be brought online was shortened both because the analysis waited until the 2022 IRP and because retirement was brought forward by one year for Petersburg Unit 3 and by five years for Petersburg Unit 4. The Joint Commenters think this largely foreclosed any alternative to conversion of both units in 2025. In the Joint Commenters opinion this demonstrates Indiana utilities need to explore alternatives to existing generation facilities thoroughly and quickly so that flexibility and optionality is maintained.

The Joint Commenters also recommend that AES Indiana consider the changing accreditation of its thermal units across the seasons as AES Indiana did for renewable resources. That the accreditation of Eagle Valley and other AES Indiana thermal units be based on the unit's performance consistent with the MISO requirements rather than assume what amounts to a UCAP value. The Joint Commenters provided a table showing the MISO Schedule 53 Class Averages for the 2023/2024 Planning Year. These class averages show the seasonal accreditation across the different resource technologies within the MISO.

The Joint Commenters note that table indicates that the seasonal risk associated with thermal units is not uniform – generally lower in the winter and higher in the summer. The Joint Commenters recommend that AES Indiana include the most recent information on the MISO seasonal construct and resource accreditation from MISO in in any proceedings relying on the 2022 IRP and future IRPs.

AES Indiana modeled the replacement of Harding Street Units 1 and 2. These units are scheduled for age-based retirement in 2024 and are part of AES Indiana's black start plan. According to the Joint Commenters, AES modeled either a reciprocating engine or a diesel unit to replace Harding

Units 1 and 2. The Joint Commenters asked that AES Indiana consider the ability for some or all of the capacity be replaced with battery resources. That battery resources with grid-forming inverters can provide black start.

The Joint Commenters recommend that AES Indiana add surplus interconnection projects at the Petersburg location if AES Indiana converts Petersburg Units 3 and 4 to gas. In other jurisdictions, some utilities have used surplus interconnection capability for solar and wind projects at existing thermal generation sites. According to the Joint Commenters, the surplus interconnection renewable generation facilities would not receive capacity credit until the thermal facilities retire. But the surplus interconnection renewable generation resources could operate when the thermal facility is not.

The Joint Commenters found confusing the scorecard metric developed by AES Indiana to measure market exposure risk for the various candidate portfolios. AES Indiana calculated the average of the absolute value of the annual sales and purchases and then added the sales and purchases together over the 20-year planning period. The Joint Commenters recommended as an alternative use of market purchases as a percentage of annual energy and market sales as a percentage of annual energy.

<u>Consideration for Next IRP</u>
The Joint Commenters look forward to collaborative discussions with AES Indiana about the resources to be modeled for the replacement of the Harding Street Units. They would like for AES Indiana to model longer duration battery storage resources, such as 8- and 10-hour batteries, as well as options for multiday storage.

The Joint Commenters recommend that AES Indiana have a specific meeting to discuss modeling approaches for battery storage. The Joint Commenters recognize that AES Indiana discussed in the 2022 the future use of IRP sub-hourly modeling to capture more benefits of battery storage and reciprocating engines. The Joint Commenters also note that the work of other utilities to evaluate battery storage could be informative.

<u>Response of AES Indiana</u>
AES Indiana notes the Joint Commenters mention that there is little difference between the AES Indiana base and high peak demand forecasts. AES Indiana responds that the peak load forecasts were constructed using Moody's Analytics Alternative Scenarios given the 10th and 90th percentile of economic performance for the Indianapolis MSA. The idea was to capture changes in load resulting from different economic futures. However, load is not very responsive to changes in economic inputs. AES Indiana says the differential between the base, low, and high load forecasts increases when the impacts of EVs and behind-the-meter solar projections are included.

According to AES Indiana, the MPS cost effectiveness modeling had already concluded by the time AES Indiana decided to include a carbon tax in the current trends (reference case) scenario. AES Indiana did not have time to remodel the DSM in the MPS with a carbon tax included. AES Indiana also said it was worth noting, in the commercial sector, most measures were cost-effective and the gap between technical and economic was minimal, so increased avoided costs would not have had a significant impact. AES Indiana went on to say it looks forward to working with the Joint Commenters in the future on the MPS/DSM/IRP work and will try to better align timing of the MPS modeling and IRP modeling of avoided costs.

AES Indiana also said it considers only modeling the RAP in the IRP optimization to be appropriate. When constructing the RAP estimates, GDS closely calibrated its assumed incentive levels with historical levels but was not constrained by any previously determined spending levels over the 20-year analysis timeframe. In comparison, MAP estimates the achievable potential on paying incentives equal to 100% of measure incremental cost and uses aggressive adoption rates. AES Indiana anticipates challenges in achieving the RAP level of savings selected in the planning model, much less a higher MAP level. Including the MAP would result in significant increases to incentive and implementation spending relative to the overall increase in savings and associated benefits.

GDS acknowledged that the emerging technologies that were considered were not an exhaustive list; however, GDS considered many of the known technologies that are available today but may not have widespread market acceptance or availability. The list of emerging technologies considered by GDS was constructed with the assistance of stakeholders. GDS's analysis did not make any explicit assumptions about unknown future technologies. The methodology used assumes that subsequent equipment replacement, which occurs over the course of the study timeframe and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings relative to improved baselines and at similar incremental cost. This simplifying assumption attempts to capture the complexities of different technologies entering and exiting the DSM portfolio while not developing a false sense of precision.

AES Indiana said it was not able to include the seasonally accredited capacity (SAC) for thermal resources because the SAC methodology is dependent on calculations made by MISO. AES Indiana says it did not have the necessary MISO calculations or history of these calculations to apply the methodology. The necessary information is now available so AES Indiana can update its analysis performed for the CPCN for the Petersburg conversion to natural gas and include the SAC methodology in future IRPs.

Also, AES Indiana intends to update the Eagle Valley accreditation to be consistent with the MISO SAC methodology which will include the historical outage impacts. AES Indiana says it included estimates for winter and summer accreditation for all resources modeled in the IRP. Thermal resources were based on the XEFORd/UCAP approach and non-thermal was based on the ELCC and peak-hours based approach.

Harding Street Units 1 and 2 are part of AES Indiana's black start plan and reach age-based retirement at year end 2024. AES Indiana selected a 3.5 MW diesel generator as the least cost option. AES Indiana responded that there are technical issues with using a battery storage resource to start Harding Street Units 4 and 5. The gas turbines have large motors and battery storage resources cannot supply adequate in-rush power to start the motors. AES Indiana also said that modeling showed that it is cost prohibitive to install sufficiently sized inverters to be able to start the large motors.

Director's Response

The Director agrees with the Joint Commenters that the stakeholder process used by AES Indiana was excellent and sets a high bar for future IRP processes by AES Indiana and other Indiana utilities. Especially important was AES Indiana's commitment to making available modeling inputs, outputs, and supporting data to stakeholders in a timely manner.

The issue of how to include emerging technology in the measures evaluated in the MPS and then in the IRP modeling is complicated and involves significant judgement that cannot be avoided.

Joint Commenters have one perspective and the analysis in the MPS and the IRP reflect the perspectives of GDS and AES Indiana. The Director does not have a reason to think one perspective is somehow more "right" than the other. There is no objective metric to make such a judgment.