Dr. Brad Borum
Indiana Utility Regulatory Commission
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204-3419

September 28, 2023

Re: CEI South's 2023 Integrated Resource Plan

Dear Dr. Borum,

Advanced Energy United respectfully submits this letter to offer comment regarding Southern Indiana Gas and Electric Company d/b/a CEI South a CenterPoint Energy Company's ("CEI South" and/or "Company") 2022/2023 Integrated Resource Plan ("IRP") submitted to the Indiana Utility Regulatory Commission ("IURC" and/or "Commission").

1. Introduction

Advanced Energy United ("United") is a national business association representing leaders in the advanced energy industry. United supports a broad portfolio of technologies, products and services that enhance U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure, affordable, and reliable. In Indiana, we aim to drive the development of advanced energy by identifying growth opportunities, removing policy barriers, encouraging market-based policies, establishing partnerships, and serving as the voice of innovative companies in the advanced energy sector.

We recognize that CEI South's Integrated Resource Plan ("IRP") is the culmination of an extensive analysis of CEI South's optimal resources for ensuring the availability of electricity to its retail electric customers over a 20-year period at a low cost with consideration for future cost risks. CEI South has indicated that the analysis and its conclusions explained in this IRP demonstrate that CEI South can most cost effectively meet the electric demands of its retail customers by continuing to transition its generation fleet from primarily coal-based generation to a generation mix that is more diverse and relies significantly on renewable energy. CEI South goes on to indicate that its analysis demonstrates that customers receive a better balance of affordability and reliability by investing in new generation resources and transitioning existing resources to new fuel sources compared to the on-going necessary investment and future cost risk of continuing to run its existing coal-fired generation facilities. We commend CEI South for this overall direction, and we urge CEI South to follow through with this stated intention meaningfully.

In looking at CEI South's previous 2019/2020 IRP, the Company concluded "a generation transition was needed, calling for replacement of the majority of CEI South's coal fleet by the end of 2023 with 700-1,000 MW of solar, 300 MW of wind, energy efficiency and two new gas combustion turbines while retaining FB Culley 3 coal resource". The Company's follow-up 2023 IRP merely indicates it has "**begun** implementing the 2019/2020 IRP". We are hopeful that much of what CEI South has begun to implement in its 2019 IRP as well as the implementation of the current 2023 IRP can come to fruition quickly and we recommend that implementation of the 2023 IRP begin promptly and not delay its critical investments in a more diverse, cleaner portfolio. In particular, the Inflation Reduction Act ("IRA") offers unique and consequential federal support for renewable energy and other advanced energy technologies, that should be fully leveraged by a timely transition to clean energy sources, including wind and solar power, and energy storage.

We commend CEI South for beginning the filing process of several cases seeking approval for its investments in solar and wind. Specifically, to (1) purchase a BTA to own and operate a 191 MW solar project located on its system (the "Posey County Solar Project"), (2) purchase a BTA to own and operate a 130 MW solar project located in Pike County (the "Crosstrack Solar Project"), (3) purchase a BTA to own and operate a 200 MW wind project located in MISO ("Midcontinent Independent System Operator") zone 4 (the "Wind Project"), and (4) signed purchase power agreements ("PPA") for 3 solar facilities totaling 430 MWs for the Warrick County Solar Project, the Knox County Solar Project, and the Vermillion County Solar project. We are hopeful that all of these projects are approved and enter service expeditiously. United believes that it is critical that the 2023 IRP serves Indiana ratepayers by reliably and cost-effectively providing electricity with innovative and clean technology solutions.

It is important to balance consumer affordability in the short and long-term by investing in sustainable projects and prioritizing clean energy, all while transitioning away from an overreliance on expensive and volatile fossil fuels. Advanced Energy United supports the proposed addition of significant solar and wind energy resources as well as CEI South's continued investment in energy efficiency and demand response resources. However, there are some aspects of the preferred portfolio that overlook important benefits that certain resources and services can offer which are also beneficial to CEI South's customers. The following observations and recommendations from United serve to support the Company's stated sustainability goals as well as mitigate system risks to strengthen the 2023 IRP.

2. CEI South should be careful not to over-value the reliability and under-value the risk of fossil fuel generation and/or retrofitted conversions of coal plants to natural gas

Advanced Energy United generally supports, with some caveats described below, CEI South in continuing its preferred portfolio evolution of moving away from coal toward a more sustainable portfolio of resources.[1] CEI South's recommendation is to convert the remaining 270 MW of coal generation to natural gas and to provide demand response resources for low-cost capacity, while continue to add clean, renewable wind and solar resources, as well as maintaining energy efficiency programs at current levels. Beyond 2030, the Company believes 400 MW of additional wind is called for. Advanced Energy United urges CEI South to achieve the stated renewable energy and demand management goals sooner rather than later, as we believe that this is a more fiscally responsible path than what is currently proposed. As CEI South has noted, coal plants have not been able to consistently compete on short-term marginal price with renewable energy. The cost of renewable energy has declined dramatically due to improvements in technology. Federal government incentives in the forms

[1] See CEI South IRP Executive Summary submission at 23-26.

of Production Tax Credits ("PTC") and Investment Tax Credits ("ITC") for renewable resources such as wind and solar, further improve the attractiveness of these resources. Both of these incentives have been extended and expanded by the IRA.[2] United agrees with CEI South's assessment, that coal plants have not been able to consistently compete on short term marginal price with renewable energy, and strongly encourages CEI South to take full advantage of both the Infrastructure Investment and Jobs Act ("IIJA") and the Inflation Reduction Act ("IRA") throughout the years of this IRP and beyond, since the fiscal benefits can help ratepayers save millions of dollars.[3]

That being said, receiving the full benefits of the declining costs of renewable energy is not achieved by converting/retrofitting existing coal plants into natural gas plants as proposed in the IRP. As indicated in the below Chart 1.0, CEI South is proposing to change its current 2023 resource mix from 4% natural gas to 19% natural gas by 2030. Given all the fiscal resources offered by the IRA and other savings from renewable resources, the time is now to take advantage of the current transition. Instead of adding more natural gas capacity in place of retiring coal generation, we strongly recommend that CEI South more thoroughly consider coal replacement with advanced energy options including, but not limited to, distributed generation, battery storage, and additional deployment of energy efficiency (EE) and demand response (DR) resources. In particular, we note that CEI South intends to maintain energy efficiency at essentially constant levels, which we believe will leave cost-effective EE "on the table". In addition, we expect DR and other demand management opportunities, such as smart charging of electric vehicles, to provide significantly greater demand flexibility in the future. These best available resources will augment CEI South's portfolio and reflect financial prudence, in part because they will mitigate the risk of overreliance on natural gas capacity. CEI South is already developing renewable energy projects and executing large renewable energy contracts, and these deployments should be complemented with additional emphasis on demand side resources and more deployment of energy storage.

Specifically, while the proposed transition to a 27% wind and 54% solar resource mix in 2030 is laudable, the 2023 IRP is relying on natural gas too heavily in transitioning generation sources. Also, the current plan includes general benchmarks that lack specificity. For example, the IRP states that the contract with Alcoa for the 53-year-old Warrick 4 ("W4") plant ends in just a few months and alludes to a possible contract extension. Presumably, the ending of this joint contract has been known for years and is an excellent example of implementing a planned transition to any of the above-mentioned advanced energy options so that as the company gets closer to the contract end date, a fully approved plan replacing that capacity can be executed. This same sentiment concerning the lack of specificity is also applicable to the Company's stated plan of "placing an emphasis on exploring demand response options" with "a demand response ("DR") aggregator for commercial and industrial DR and plans to request a pilot in its upcoming rate case".[4] While United strongly supports ambitious development of DR, a single pilot only scratches the surface and needs additional detail. Moreover, we recommend that residential and small commercial DR options be more deeply explored and developed so the company can take full advantage of its advanced meter installations.

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[2] See CEI South IRP executive summary submission at p. 13-14.
[3] See https://blog.advancedenergyunited.org/author/harry-godfrey
[4] See CEI South's IRP executive summary submission at p. 5-6.

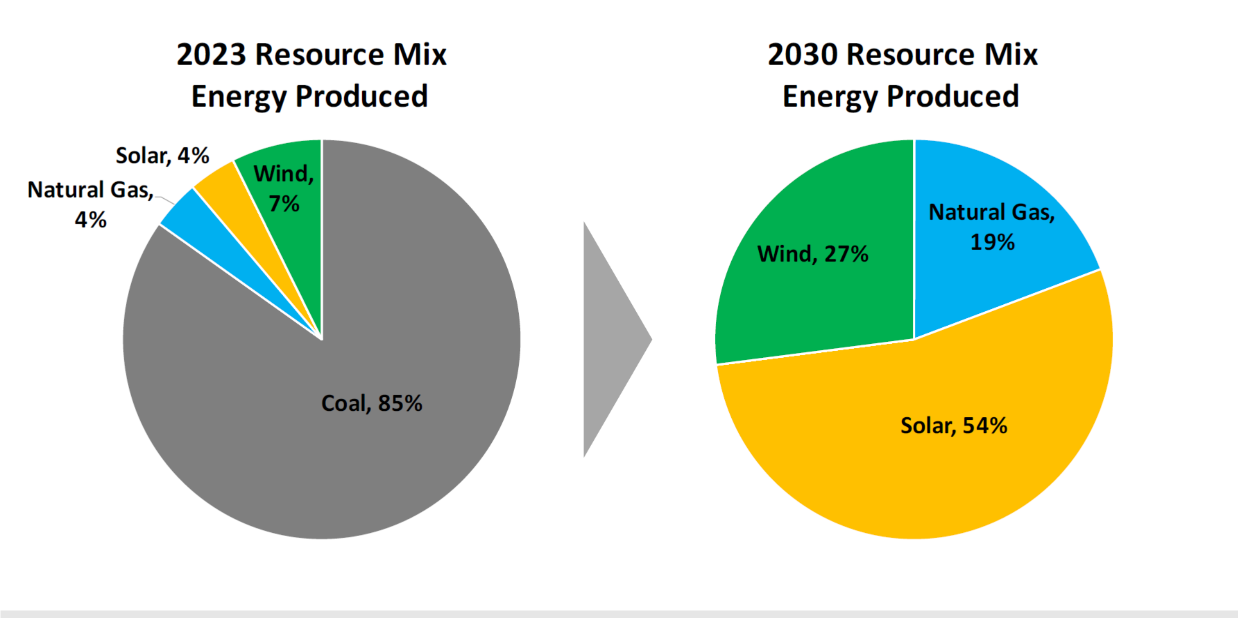

Chart 1.0: Current and Proposed Energy Resource Mix

The Company's above chart ("Chart 1.0") proposing to transition to an 81% renewable energy resource mix by 2030 is heading in a positive direction, however, replacing coal units with natural gas assets could impose reliability risks to customers and also places financial risks on the Company and ratepayers. In December 2022, Winter Storm Elliot demonstrated that thermal resources are not as reliable as is typically assumed. During the storm, gas generation across the country failed to perform as expected and units experienced serious outages due to gas supply constraints and equipment failures. MISO alone reported that 23,000 MW of natural gas generation (about 21% of the system peak load) was lost due to unplanned outages. In a subsequent presentation[5] to stakeholders, MISO stated, "Gas supply availability contributed to increased unplanned outages, particularly in the afternoon, that pushed MISO into emergency procedures". Conversely, clean resources such as solar, storage, and wind performed well[6] during Winter Storm Elliott. Wind power production, in particular, was high over those critical days and its support across the system helped MISO avoid major outages. Cold weather events are often when consumers depend on reliable generation the most. Therefore, converting the Culley 3 unit to natural gas exposes CEI South and ratepayers to reliability risk, as well as the Company to expensive penalties if it fails to perform when needed.

The CEI South 2023 IRP uses overarching categories such as affordability, reliability, and sustainability to guide its planning for customer needs. Advanced Energy United shares these values and encourages CEI South to pursue them in concert. In that light, while it is reasonable to leverage efficiencies such as using existing infrastructure where possible, full consideration of the drawbacks and risks associated with natural gas generation is warranted in light of recent events.

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[5]https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf

[6] https://rmi.org/wasted-wind-and-tenable-transmission-during-winter-storm-elliott/

Beyond extreme weather events and reliability issues, the natural gas market is subject to major price volatility.[7] The gas supply market has become less predictable and fuel prices can swing dramatically for several reasons, making it challenging to protect against such risks and ensure affordability. While recent prices have come down from their 2022 highs, many expect that the era of sustained low gas prices is over. The more CEI South relies on natural gas, the more it exposes its customers to volatile price risk.

Adding gas resources now also risks exposing customers to unnecessary stranded asset risk.[8] In Indiana and elsewhere, coal plants are increasingly uneconomical to operate, even well before the end of their useful lives. There is a significant risk that the operation and maintenance of gas plants brought into service this decade could similarly become stranded assets[9], especially as more zero-marginal cost renewable resources enter the MISO market. Taking this risk is unnecessary given that there are alternatives that can offer predictability, cost-effectiveness, and resource diversity because they are inherently different resource types. Clean energy sources have declined significantly in upfront costs and are much cheaper to operate, and the generous tax incentives from the Inflation Reduction Act offers a unique opportunity to get additional value from these resources, if deployed within the next decade.

Energy storage, also eligible for IRA incentives, should also be considered more thoroughly by CEI South as an alternative to additional gas capacity. Attached to these comments is a study that United commissioned from Strategen that examined four Indiana utilities' IRPs[10], including that from CEI South. After careful analysis, the report concluded that there would be a net cost savings of $1.9-4.9 million if CEI South utilized battery storage over a natural gas combustion turbine ("CT") while still providing the equivalent capacity value.[11]

The Company asserts in its IRP that it needs "additional time to better understand how the Inflation Reduction Act ("IRA") effects the renewables market". However, it bears emphasizing that the IRA is over a year old and should be readily incorporated into planning today.[12] Furthermore, to not pursue those resources for which significant federal funding is available now deprives Hoosiers of significant savings[13] and the Commission has already indicated that they "encourage jurisdictional utilities to explore possible grant and low-cost loan options that would reduce the cost of present and future projects needed to provide utility service."[14] We respectfully request that CEI South provide additional details of how it factored IRA incentives and programs into an analysis of energy storage similar to the analysis conducted in the attached report conducted by Strategen, that clearly documents net cost

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[7] See https://www.eia.gov/todayinenergy/detail.php?id=57200#:~:text=We%20forecast%20Henry%20Hub%20prices,from%20%242.18%2FMMBtu%20in%20June.
[8] See https://info.aee.net/hubfs/2023%20Reports/Assessment%20of%20Clean%20Energy%20Alternatives%20to%20New%20Natural%20Gas%20Resources.pdf
[9] See https://info.aee.net/hubfs/2023%20Reports/Assessment%20of%20Clean%20Energy%20Resources%20Pt.%202_Strategenedits%204.13%20final%20draft.pdf
[10] See https://blog.advancedenergyunited.org/getting-more-from-less-with-demand-side-resources
[11] See attached Strategen report at slide 10.
[12] See https://blog.advancedenergyunited.org/ira-unlocks-savings-for-utilities-and-consumers-that-choose-clean-energy-over-gas
[13] See https://blog.advancedenergyunited.org/topic/indiana
[14] See https://secure.in.gov/iurc/files/ord_GAO2022-02_102622.pdf

savings from utilizing a 551 MW 4-hour battery instead of adding 460 MW of natural gas combustion turbines ("CT") capacity. [15] Additionally, CEI South has indicated that "Due to uncertainty about future resources ability to capitalize on the IRA energy community bonus, it was not included in base modeling assumptions."[16] CEI South goes on to indicate that "Based on the sensitivity analysis this adder would have a limited impact on portfolio NPV." United encourages CEI South to more thoroughly research the impact that the energy community bonus could have over the term of this IRP.

3. CEI South should plan for more Commercial and Industrial demand for clean energy in its IRP.

A growing number of businesses, municipalities, and organizations in the Indianapolis area have set corporate clean energy and sustainability goals as they have learned of its high value to not only potential customers, but it also gives them a competitive edge in our worldwide economy. Commercial and industrial organizations have limited options to pursue these goals. Specifically, businesses and municipalities are interested in requesting that CEI South implement a 'renewable energy tariff' so that large energy customers would be able to purchase new renewable energy directly from CEI South.

Customers use renewable energy tariffs to access cost-competitive renewable energy from the utility without imposing costs on non-participants. A well-designed renewable energy tariff gives customers choice and raises satisfaction with their electricity service. Other states[17] across the country have demonstrated that renewable energy tariffs are a viable method for energy buyers to procure clean energy with long-term certainty while ensuring the market remains efficient and fair for all participants. Renewable energy tariffs have a proven track record of bringing local benefits within a utility's territory, such as new jobs, economic development, tax revenue, and clean air.

Advanced Energy United, and our network of member companies, strongly endorses this approach. CEI South's IRP should reflect 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.

4. CEI South should better utilize and implement distributed and demand-side resources as powerful tools to serve both customer and grid needs

Electric utilities will need to utilize a range of strategies and technologies to maintain reliability and customer affordability as the energy system transforms. The 2023 IRP should appropriately value and address system resilience and flexibility. It is therefore imperative that CEI South expand integration of customer-sided resources to take advantage of those attributes. This includes working to enable more distributed energy resources ("DERs"), like customer-owned solar and storage, and harness them in the aggregate to be a solution to capacity issues, voltage control, and more. The best way to do so in an IRP

[15] Net cost in this analysis is calculated as the total revenue (including energy revenue and ancillary services revenue, not including capacity revenue) less total costs (including capital expenditure, fixed O&M, variable O&M, and fuel costs from CEI Souths 2020 IRP).
[16] See https://www.in.gov/iurc/files/2022-2023-CNP-IRP-Volume-2-of-2-Part-3.pdf at slide 150.
[17] Green Tariffs have been established across the United States, including in Arizona, Colorado, Georgia, Kansas, Kentucky, Michigan, Nebraska, Nevada, New Mexico, North Carolina, Oregon, Utah, Virginia, Washington, Wisconsin, and Wyoming.

is by characterizing these DERs as supply resources, and appropriately planning for their increasing adoption. The Company may consider using Vibrant Energy's WIS:dom model[18], which does a particularly adept job at modeling behind-the-meter solar and storage, in its next IRP.

As filed, the 2023 IRP does not appear to properly consider behind-the-meter DERs. United strongly recommends that future IRPs explicitly recognize that most, if not all, costs associated with behind-the-meter DER are borne by the system owner, which would clearly impact a cost-effectiveness analysis from the utility's perspective. Future models should even consider cost-effectiveness with relatively small incentives offered by a utility (e.g., $500/kW), under the notion that modest support by a utility to encourage behind-the-meter DER may provide capacity resources and other benefits at far less cost to all ratepayers.

Advanced Energy United believes there is also opportunity to improve how the IRP considers energy efficiency and demand-side management ("DSM"). Effectively incorporating and prioritizing demand-side resources leverages existing infrastructure in a manner that saves customers costs and defers or avoids expensive system upgrades. These resources can also be added incrementally to avoid overbuilding for load that may never fully materialize. Energy efficiency reduces wasteful electricity use while simultaneously improving consumer comfort and satisfaction while lowering their bills.[19]

To explore how DSM might best be used, Advanced Energy United released a report in September 2022, titled "Indiana Opportunities for Demand-Side Resources" prepared by Demand Side Analytics ("DSA").[20] While the study was designed to explore areas of opportunity that other utilities could implement, its main points concerning the advantages of DSM are also applicable to other Indiana utilities, as well as CEI South. Advanced Energy United has linked the report within these comments. According to the DSA team, "Much like a battery on the supply side, DR programs inject no meaningful amount of energy into the system. However, they are adept at shifting energy requirements from one period to another." CEI South as well as the IURC and interested stakeholders are encouraged to reference the report for additional information.

Among the findings, the modelling indicates it would be beneficial to expand consideration of 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, cost, participation, savings per customer, and net benefits.

Second, the report made suggestions on how best to model demand response so that IRP models – not traditionally built to accommodate demand-side resources – do not undervalue and under-select this powerful option.

Lastly, the report offers utilities a new, long-term perspective on energy efficiency and demand response resources that it needs to meet changing daily and seasonal peaks.

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18 See https://www.vibrantcleanenergy.com/products/wisdom-p/
19 See https://blog.advancedenergyunited.org/getting-more-from-less-with-demand-side-resources
20 See *https://blog.advancedenergyunited.org/reports/indiana-opportunities-for-demand-side-resources*

5. CONCLUSION

Advanced Energy United thanks you for considering our reflections and recommendations. The Advanced Energy United team looks forward to working with CEI South and the Commission on these issues. We appreciate the opportunity to provide input on this IRP process and look forward to our continued involvement in this and other important Indiana proceedings. We are always happy to answer any questions as implementation of the IRP continues.

Respectfully Submitted,

Michael D'Angelo
Advanced Energy United
Senior Principal

Links for references to Strategen's and Demand Side Analytics' ("DSA") Reports:
https://blog.advancedenergyunited.org/reports/indiana-opportunities-for-demand-side-resources

https://info.aee.net/hubfs/2023%20Reports/Assessment%20of%20Clean%20Energy%20Alternatives%20to%20New%20Natural%20Gas%20Resources.pdf

https://info.aee.net/hubfs/2023%20Reports/Assessment%20of%20Clean%20Energy%20Resources%20Pt.%202_Strategenedits%204.13%20final%20draft.pdf

INDIANA OPPORTUNITIES FOR DEMAND-SIDE RESOURCES

MODELING CONSIDERATIONS FOR AES INDIANA'S 2022 INTEGRATED RESOURCE PLAN

Advanced Energy Economy
is now **Advanced Energy United**
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ADVANCED ENERGY UNITED

Prepared by Demand Side Analytics

September 8, 2022

INDIANA ADVANCED ENERGY ECONOMY

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ABOUT INDIANA AEE

Advanced Energy Economy (AEE) is a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhance U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure, and affordable. AEE has been operating in the Hoosier state as Indiana AEE since 2016. In Indiana, AEE aims to drive the development of advanced energy by identifying growth opportunities, removing policy barriers, encouraging market-based policies, establishing partnerships, and serving as the voice of innovative companies in the advanced energy sector.

Learn more at www.aee.net.

ABOUT DEMAND SIDE ANALYTICS

Demand Side Analytics (DSA) helps utilities, regulatory agencies, and system operators navigate the technical, economic, and policy challenges of building a smarter and cleaner energy future. We focus on data-driven research and insights and predictive and causal analytics. We deliver data-driven insights into how various technologies and interventions affect the way homes and businesses use energy and how those, in turn, affect grid and system planning. We have a proven record for conducting insightful, high-quality, accurate and unbiased analysis and are meticulous about ensuring that research is useful for policy decisions, operations, and implementation.

Learn more at [http://www.demandsideanalytics.com.](http://www.demandsideanalytics.com)

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EXECUTIVE SUMMARY

AES Indiana's 2022 Integrated Resource Plan (IRP) is an important planning exercise that will set the direction of the company's investments over the next two decades. The 2022 IRP comes amid a significant energy transformation across the electric power sector as utilities like AES Indiana retire coal-fired thermal generation assets and replace them with cleaner resources like renewables and storage. This transition not only brings clear environmental benefits in the form of reduced greenhouse gas emissions, but also creates new planning challenges. Historically, utilities had nearly complete control over the supply side and could ramp production up or down to meet demand for electricity by burning more or less fossil fuel. As intermittent renewables become a larger part of the supply mix, utilities will lose some ability to dispatch production because supply depends, at least in part, on the weather. To adapt to these new resource characteristics, utilities must develop tools and strategies to increase control over the demand for electricity. Flexible and modular offerings that can shift and shape loads and help balance variable supply will be critical as utilities like AES Indiana navigate this transition.

This analysis, commissioned by Indiana Advanced Energy Economy (Indiana AEE), explores some key modeling considerations given the changing landscape AES Indiana faces over the twenty-year IRP study horizon. Indiana's electric system in 2042 will be fundamentally different from the grid of 2023, and will require a fundamentally different resource mix. We anticipate this new resource mix to include flexible demand-side resources at levels not seen today. However, modeling demand-side resources alongside traditional supply has always been a challenging endeavor and expected changes to the grid only complicate the exercise. Based on the market potential study findings shared to date during Stakeholder Advisory meetings, AES Indiana and its consultants have developed a detailed and comprehensive inventory of energy efficiency (EE) and demand response (DR) opportunities. We offer some suggestions for modeling those results to aid AES Indiana in selecting a preferred resource portfolio and short-term action plan that best meets customer and utility needs. Specifically, we recommend that AES Indiana:

- **Deploy time-varying rates in the residential sector to reduce peak demand and improve system utilization.** Time-varying rates are among the most flexible and cost-effective options for managing peak and loads and the associated capacity costs. The TIME VARYING RATES AS A DEMAND MANAGEMENT STRATEGY section of this report includes a detailed analysis of time-varying rates, or dynamic pricing, in the residential sector. The concept of scarcity pricing is not unique to the utility industry and consumers routinely face this pricing model for airline tickets, clothing, ride shares, and recreational activities with seasonal demand patterns. Our findings demonstrate that different levers in the design of time-varying rates can produce outcomes of varying magnitudes, many of which can serve as valuable and cost-effective resource additions to AES Indiana's portfolio.

- **Bundle all Demand Side Management (DSM) offerings by levelized cost**. AES Indiana used a "supply curve" approach for EE in its 2019 IRP, but not for DR. We understand that AES Indiana plans to use EnCompass as its portfolio optimization software for the 2022 IRP. The RESOURCE SELECTION PROCESS FOR DEMAND RESPONSE section of this report includes a summary of DSM modeling approaches from other investor-owned utilities that used EnCompass for their most recent IRP. Each utility employed a bundling strategy to create a manageable number of DSM resources for consideration. Bundling is a necessary step in the analysis, but the bundling approach should not determine the outcome. Since the EnCompass software's optimization algorithm seeks to select the least cost resource mix, it follows that DSM options should be grouped into offerings with similar levelized costs. If the DR bundling strategy results in a series of similarly priced resources, EnCompass will face an "all or nothing" decision with respect to DR expansion and may select well under AES Indiana's own assessment of realistically achievable potential (319 MW). If viable economic DR resources are not selected, the EnCompass software is more likely to suggest new thermal generation to meet AES Indiana's peak load requirements. We recommend a supply curve perspective for DR where resources are organized from lowest to highest levelized cost and bundled accordingly. If DR offerings are not bundled by levelized cost, we strongly recommend removing offerings that failed the Utility Cost Test in the potential study from the bundles presented to EnCompass.

- **Consider the peak load reduction capability of DSM resources in a changing system**. In the preliminary peak load forecasts shared with stakeholders, AES Indiana projects a steady growth in peak demand over the twenty year IRP horizon despite a decade of declining weather-normalized peak load. The authors of this report take no position on the magnitude of the peak demand forecast, but the PLANNING FOR NET VERSUS GROSS PEAK LOADS section of this report raises several important considerations regarding the timing and duration of peaking conditions. For many of the same reasons AES Indiana uses a declining effective load carrying capacity (ELCC) assumption for solar over the next decade, the contribution of DSM resources to system peaks in 2032 or 2042 will not be the same as they are in 2022. As the energy transition unfolds in Indiana, summer peaking conditions will shift later in the evening, causing sharper ramps and net peaks that are narrower than today's gross peaks. This report uses 8760 load shape data and DR evaluation results to illustrate how important the definition of peak load is for several key EE and DR resource types. If AES Indiana is not considering its DSM resources in this dynamic fashion, their actual peak load contribution could be significantly over or understated, and the resources therefore over or under selected.

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INTRODUCTION

Every three years regulated electric utilities in Indiana must file an Integrated Resource Plan (IRP) with the Indiana Utility Regulatory Commission. These detailed plans lay out how the utility will meet its obligation to serve its customers with reliable electric service at just and reasonable rates over the next two to three decades. Key elements of an IRP include:

- Long-term forecasts of energy sales and peak demand.
- An inventory of current generation assets, along with projections of fuel prices and other future operating costs.
- Plans to incorporate renewable energy resources into the supply mix.
- Compliance with current or future state and federal environmental policies.
- Potential reductions in energy sales or peak demand from DSM programs

Because these Integrated Resource Plans direct billions of dollars in capital investment, they are subject to a rigorous stakeholder review process. An open and transparent stakeholder review process ensures that utility plans align with the economic and environmental priorities of the customers each utility serves.

AES Indiana (formerly Indianapolis Power & Light) filed its last IRP in 2019 and plans to file a new IRP in late 2022. Public advisory stakeholders for the 2022 IRP began in January 2022 to update stakeholders on research activities, key modeling inputs, and plan progress.

Indiana Advanced Energy Economy appreciates the careful research AES Indiana has undertaken to date and the detailed presentations made available to the public. Specifically, we commend the AES Indiana planning team and its consultants on their careful consideration of Effective Load Carrying Capacity (ELCC) of renewable resources and the DSM potential from energy efficiency, demand response, and managed electric vehicle charging. We understand that the final preferred resource portfolio is the culmination of many months of work from an interdisciplinary team.

Our intent with this paper is not to suggest changes to any of the foundational research completed to date. Instead, we offer some suggestions for consideration with respect to how those many different pieces come together to form the final comprehensive preferred portfolio of resources. Our recommendations come from modeling efforts by Demand Side Analytics (DSA) and are informed by their experience in Indiana and neighboring jurisdictions. We believe the recommendations are practical and feasible in the EnCompass software AES Indiana intends to use for portfolio optimization and would sharpen the modeling of DSM programs given the significant system changes AES projects over the study horizon.

Figure 1: illustrates an outcome from the 2019 IRP that we hope to avoid in the 2022 IRP. Despite a DSM potential study which found several hundred megawatts (MW) of achievable and cost-effective demand response potential, the final resource portfolio included just 55 MW. Those 55 MW came exclusively from continuation of existing programs. We believe a bundling strategy that obscured price variation was key driver of this outcome and offer some potential alternatives to present the EnCompass software with a supply curve of DR resources.

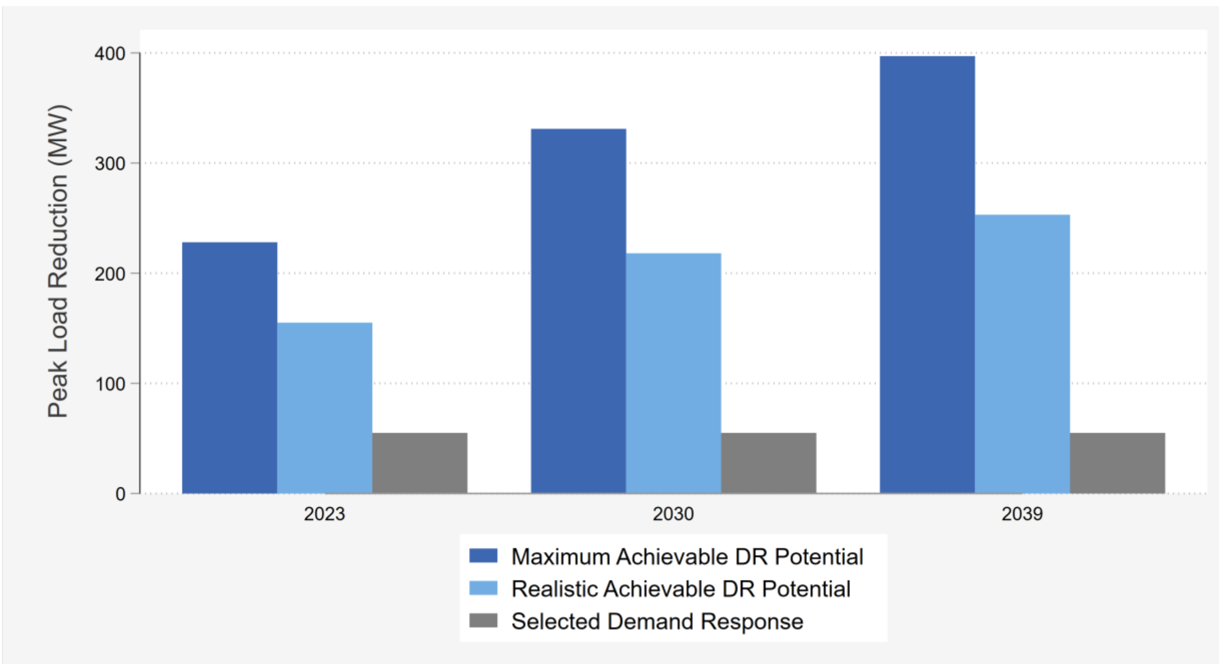


Figure 1: DR Potential versus Selected DR - 2019 IRP

Rollout of Advanced Metering Infrastructure (AMI) is one of many elements in AES Indiana's $1.2 billion "revAMP" transmission, distribution, and storage improvements (TDSIC) plan. According to a 2019 filing, AES plans to invest $56 million of capital to complete the transition from AMR to AMI between 2020 and 2024. TDSIC filings cited a variety of operational benefits from the transition such as outage management, remote disconnects, and power quality monitoring. Indiana AEE and DSA posit that, in addition to these key benefits, AMI deployment creates a powerful opportunity to increase load flexibility through time-varying rate designs. Advanced rate designs allow residential customers to shift their consumption in a way that lowers their bills and improves system utilization. Increasingly, clean technology companies are designing their products with the capability to respond to price signals and shape loads to minimize greenhouse gas emissions. Our modeling efforts consider a variety of rate designs with and without enabling technology. This flexibility will be critical as AES Indiana and other utilities across the Midcontinent Independent System Operator (MISO) system look to integrate more intermittent renewable resources into the supply mix.

Incorporation of intermittent renewables is a central theme in the AES Indiana IRP planning materials released to date and across the country. As more solar photovoltaics enter the system, net load becomes an increasingly important consideration for system planners and load forecasters. Net load, or total energy demand minus the contribution of wind and solar, differs from gross load (total energy demand) in several key respects. Typically, a net peak will be lower and occur later in the afternoon. It will also ramp more sharply across the afternoon hours. AES Indiana has clearly given this issue extensive consideration on the supply side. In this paper, we offer some suggestions for modeling DSM against this changing paradigm.

TIME VARYING RATES AS A DEMAND MANAGEMENT STRATEGY

Deployment of AMI is one of many elements in AES Indiana's $1.2 billion "revAMP" transmission, distribution, and storage improvements (TDSIC) plan. According to a 2019 filing, AES Indiana plans to invest $56 million of capital to complete the transition from AMR to AMI between 2020 and 2024. TDSIC filings cited a variety of operational benefits from the transition (outage management, remote disconnects, and power quality monitoring), but we found no discussion of time-varying rates.

Time-varying rates are a logical demand-side management option given the sunk costs of the meters themselves, demonstrated ability of rates to shift demand in other jurisdictions, and AES Indiana's interest in managed charging in the transportation sector. Time-varying, or dynamic, rates provide an economic incentive for customers to reduce electricity usage during high-system-cost periods. Typically, utilities design the rates to be revenue neutral under current load patterns. Response to the price signals then lowers customer bills and avoids future investment and operating costs for the utility by improving the efficiency of the system.

As evidenced by the meta-analysis discussed in the PRICE RESPONSE section of this chapter, industry pilots and studies have repeatedly found demand for electricity to be elastic. An elastic product means that the quantity demanded changes in response to changes in the price. Dynamic rates have been commonplace for commercial and industrial customers for many years but have recently gained more widespread acceptance in the residential sector. Relevant examples include:

- In 2021, Consumers Energy enrolled its 1.5 million residential electric customers on an opt-out basis onto its time-varying Summer Rate. Customers pay a higher price per kWh from 2pm to 7pm on summer weekdays and a discounted price all other hours of the year.

- Between 2019 and 2021 California utilities enrolled most residential customers onto a time-of-use rates unless they elected to opt-out.

- In 2018, Fort Collins Utilities in Colorado transitioned residential electric customers to a time-of-day rate with a summer on-peak to off-peak price ratio of almost 4:1.

Figure 2: overlays a typical AES Indiana load profile for a summer weekday on top of a traditional flat volumetric rate and a dynamic rate. The time-varying rate is lower for most hours of the day at 9 cents per kWh compared to the flat rate at 12 cents per kWh. However, during the late afternoon

when the cooling loads are highest and the grid is most constrained, the dynamic rate jumps to 20 cents per kWh. With the same load shape, these two rates result in the same bill amount for the day. However, if a household facing the dynamic rate were to shift energy consumption from "on-peak" hours to "off-peak" hours, their bill would go down and the utility's peak demand, and associated capacity costs, would go down.

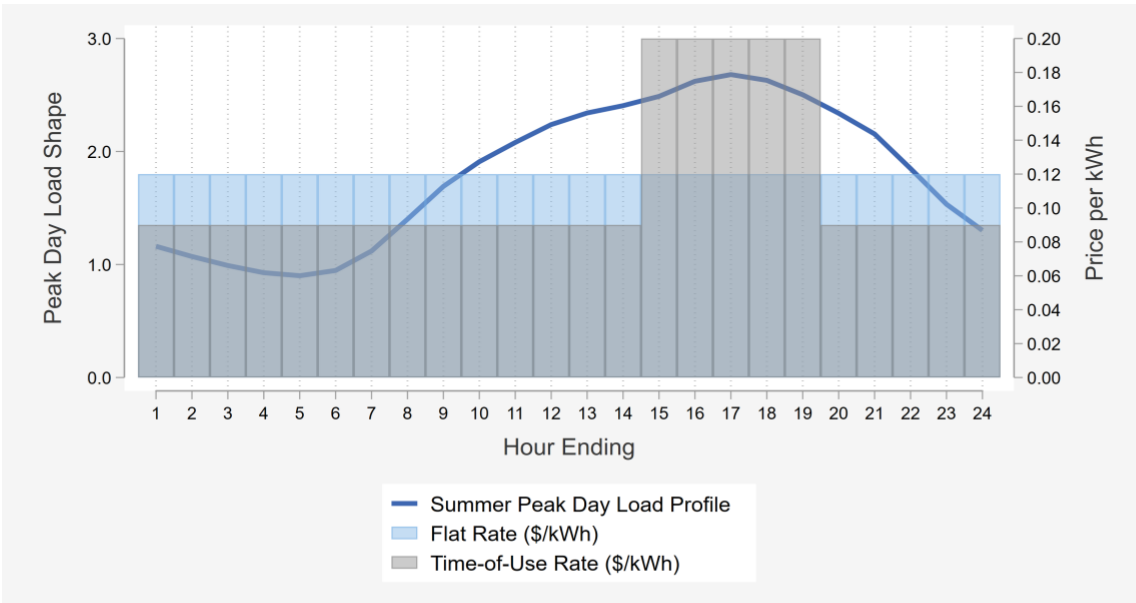


Figure 2: Sample Time-Varying Rate Design

Dynamic rates are intriguing in an IRP context because they are so flexible and customizable. While there are nearly endless possible permutations and designs, an IRP model can only consider a limited number of options. Among the attractive features of dynamic rate designs are:

- They are not tied to a specific end-use within the home like most other load control offerings. Dynamic rates provide a price signal to manage all electric loads within a home.
- They can be used to manage both summer and winter peaking conditions.
- Rates are adaptable. If summer peaks shift later in the evening due to widespread adoption of solar photovoltaics, the "on-peak" rate period can be adjusted accordingly. Similarly, winter season rates can target morning or evening hours depending on load characteristics and system need.
- Periods with higher marginal prices tend to also be when the marginal emissions rate of the grid is most carbon-intensive so optimization of loads to price signals will generally have environmental benefits.

- Hardware and software options that allow consumers to manage their connected devices and respond to price signals continues to improve and should advance exponentially in the coming decades. The Developments in Enabling Technology section of this report includes an overview of recent developments for several types of connected devices.

The illustrative rates examined in this paper vary with respect to the four key dimensions shown in Figure 3: .

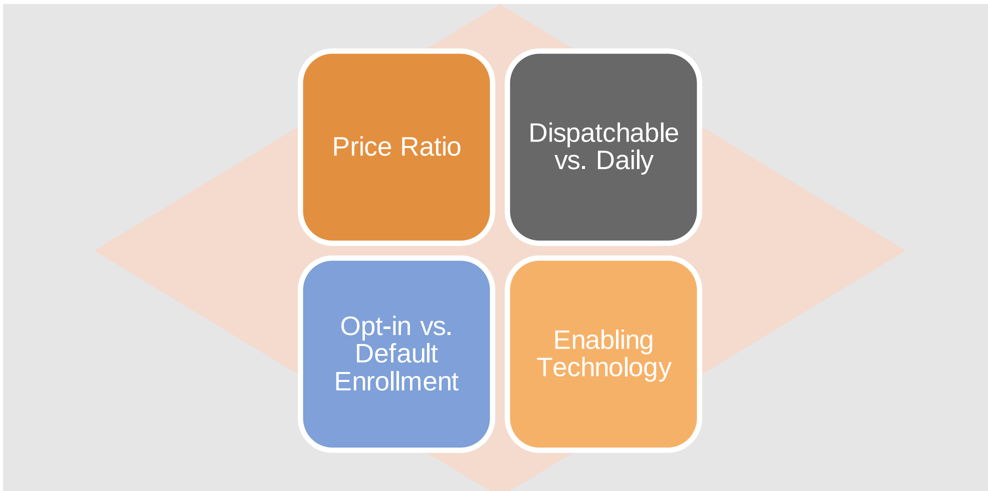


Figure 3: TVR Modeling Dimensions

- Price Ratio. The ratio of the on-peak rate to the off-peak. The larger the price ratio, the stronger the incentive to consumers to shift their consumption.
- Dispatchable versus Daily. Utilities can choose to implement "on-peak" pricing on a daily or event basis. Three of the rates we model are a dispatchable Critical Peak Pricing (CPP) rate and the other four are daily time-of-use (TOU). Often utilities elect for steeper price ratios with dispatchable rates since the on-peak price only takes effect for a limited number of event days.
- Opt-In versus Default Enrollment. An opt-in rate is marketed to consumers for voluntary adoption. Conversely, a default rate is assigned to all customers unless they choose to opt-out. Adoption levels are much higher with default enrollment.
- Enabling Technology. Smart devices capable of storing and managing operations based on price signals lead to larger load impacts than time-varying rates alone

This analysis considers seven distinct rates. Table 1 summarizes key attributes of each rate. More aggressive price ratios and other design elements with more performance risk and reward are generally reserved for opt-in designs or offerings with enabling technology to help manage to the price signal.

Table 1: Time-Varying Rates Modeled

Rate Name	Price Ratio	Dispatch	Enrollment	Enabling Technology
TOU Default No Tech Short-Run	1.5	Daily	Default	No
TOU Default with Tech Long-Run	2.0	Daily	Default	Yes
CPP Default with Tech Short-Run	2.6	Event	Default	Yes
TOU Opt-In No Tech Short-Run	1.5	Daily	Opt-In	No
TOU Opt-In with Tech Long-Run	2.0	Daily	Opt-In	Yes
CPP Opt-In No Tech Short-Run	2.6	Event	Opt-in	No
CPP Opt-In with Tech Long-Run	6.0	Event	Opt-in	Yes

Price Ratio

There are two perspectives regarding how to set the price ratio for a time-varying rate. Both perspectives are cost-reflective and seek to align the price of electricity with the costs of service. A **short-run** perspective suggests the differential between the on-peak and off-peak price should reflect difference in the utility's marginal energy costs during each period. This approach focuses on the energy (fuel) component of electricity service and exposes customers to the same variable energy production costs the utility faces. A **long-run** perspective sets the price ratio higher than the differential in variable production costs to deliberately target capacity savings and the associated avoided fixed costs for generation, transmission, and distribution infrastructure.

To estimate the price ratio for cost-reflective rates in AES Indiana service territory, DSA retrieved hourly real-time location marginal price data from MISO for IPL load zone and examined the wholesale price of energy. The left side of FIGURE 4: shows the average hourly prices during summer 2021 and 2022 (through July). The right side of the figure looks at prices on five days with high system loads due to extreme weather. The shapes are similar, but the scale of the y-axis is much different. The vertical orange lines demarcate a four-hour period a dynamic rate would presumably target with on-peak pricing.

Table 2: shows the average on-peak and off-peak marginal energy prices for the two day types.

Table 2: On-Peak and Off-Peak Prices

Day Type	Off-Peak ($/MWh)	On-Peak ($/MWh)	Ratio
Average	$47.33	$72.65	1.5
Peak Day	$84.34	$218.47	2.6

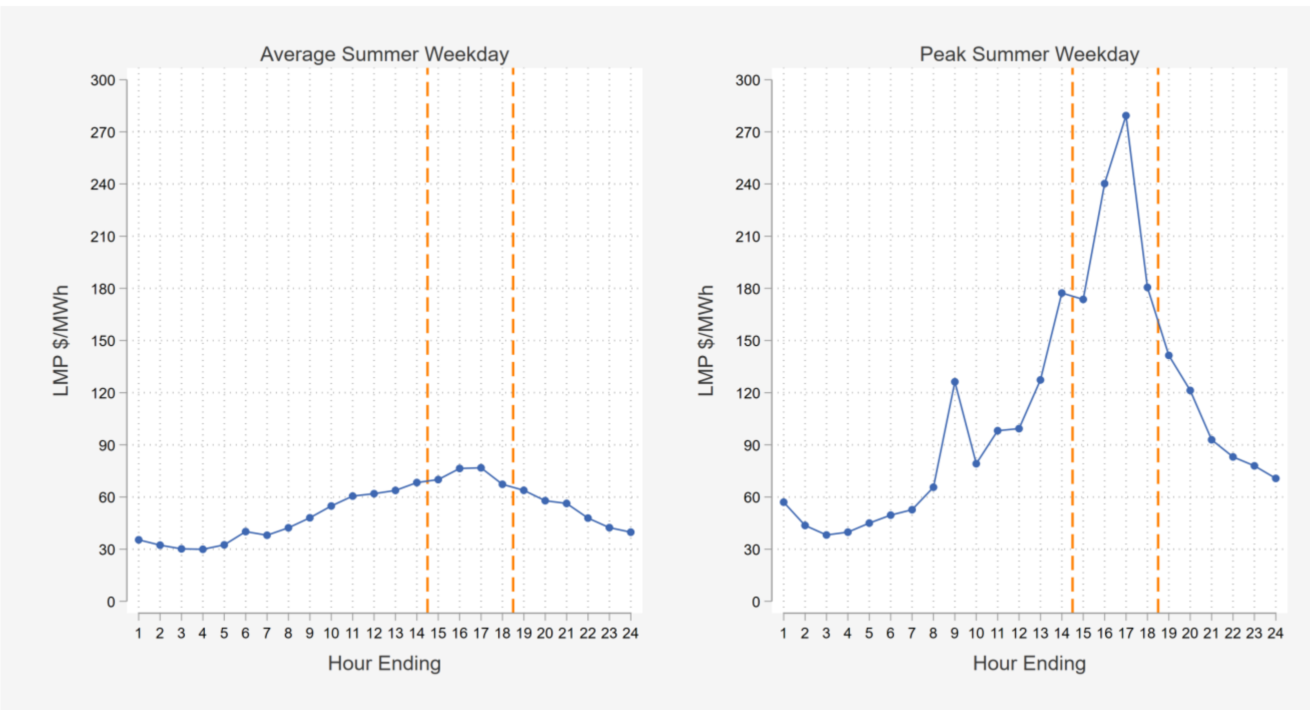


Figure 4: Marginal Energy Prices on Average and Peak Summer Weekdays

A key takeaway from the market pricing data shown in **Table 2**: and **Figure 4**: , is that the difference between peak and off-peak hours is more pronounced on peak days. However, the difference between on-peak variable energy costs on peak days and off-peak hours across the season is even more pronounced. In this data set the ratio is $218/$47 = 4.6. **This means that a short-run dispatchable rate like CPP will have a larger price ratio than its daily TOU counterpart.**

For this analysis, we set the price ratio of short-run cost-reflective rates at 1.5 for the daily TOU options and 2.6 based on the intra-day ratio on peak days. For the long-run perspective, we raise the TOU price ratio to 2.0 and the CPP price to 6.0 based on the general magnitude of the assumed capacity benefits in **Table 4**: . AES Indiana's rate design personnel would need to leverage cost-of-service data to craft a truly cost-reflective long-run price ratio. We reserve the long-run price ratios for rates with opt-in enrollment, enabling technology, or both.

Price Response

Given the underlying premise that electricity is an elastic product, a percent increase in price should result in a percentage decrease in the quantity demanded. We derive our load impact assumptions for each rate from the regression coefficients shown in **Table 3**: . These model coefficients come from a meta-analysis of 335 time-varying rates compiled by the Brattle Group in its Arcturus 2.0 database. We use the second model specification, which includes an indicator variable for opt-out designs (default enrollment). The practical interpretation of the regression coefficient for the 'Opt-Out Binary' term is that a default enrollment results a 3.9% lower peak demand reduction compared to the same rate offered on an opt-in basis.

Table 3: Arcturus 2.0 Regression Coefficients

	Dependent variable:	
	Peak Impact	
	(1)	(2)
Log of Peak/Off-Peak Ratio	-0.065***	-0.058***
	(0.007)	(0.007)
Log of Peak/Off-Peak Ratio x Technology	-0.046***	-0.047***
	(0.008)	(0.008)
Opt-Out Binary		0.039***
		(0.009)
Constant	-0.011	-0.028***
	(0.007)	(0.009)
Observations	335	335
R^2	0.569	0.588
Adjusted R^2	0.566	0.584
Residual Std. Error	0.064 (df = 332)	0.063 (df = 331)

Figure 5 shows the arc of price responsiveness for the four combinations of enrollment type and enabling technology. On a per-participant basis, an opt-in design with enabling technology produces the largest estimated change in peak demand across all price ratios. Default enrollment without enabling technology leads to the lowest peak demand reductions across all price ratios. At modest price ratios (less than 2:1), an opt-in design without technology produces larger demand reductions than default enrollment with enabling technology, but the trend reverses at more aggressive price ratios.

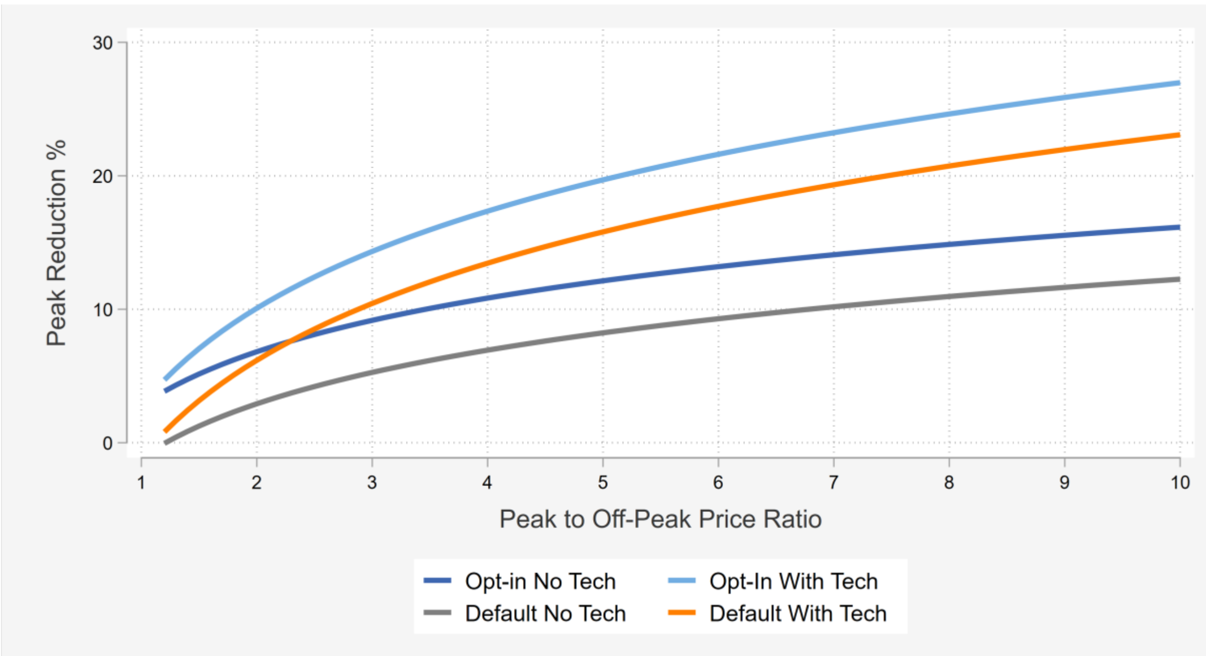


Figure 5: Arcturus Price Response Curves

Reference Loads

The price response curves shown in the previous section return a percent change in peak demand, so to quantify the savings opportunity in MW, we need to know the average peak load of an AES Indiana household. The peak load forecast materials shared to date have not included class-level projections that could be simply divided by the number of households so the study team leveraged publicly available secondary data. For this analysis, we used the [National Renewable Energy Laboratory (NREL) End-Use Load Profiles for the U.S. Building Stock](). This rich data set includes estimates of diversified 15-minute loads across each hour of the year for a wide range of end-uses. For this application, we are interested in the total consumption across all electric end uses. The study team blended the Indiana profiles across five building geometry types and extracted the highest load days, by season, to calculate the average profiles shown in **Figure 6**: .

This method returns an average peak load contribution of 2.6 kW per household on a peak summer weekday. In aggregate terms, that translates to approximately 1,250 MW across AES Indiana's approximately 450,000 residential accounts after adjusting for line losses. On a percent basis, this suggests that residential sector represents approximately 43% of AES Indiana's total peak load forecast, which is typical for the region.

Since the analysis in this report focuses on summer demand reduction potential, we apply all estimated price responses to the assumed 2.6 kW per household summer value. Interestingly, the NREL Indiana statewide data set projects slightly higher per-home peak loads on peak winter mornings and evenings than on peak summer afternoons. This finding would be highly sensitive to the amount of electric space heating and water heating in AES Indiana service territory but brings up an interesting feature of time-varying rates. If winter peaks become an increasingly important planning consideration for MISO and AES Indiana, dynamic rates can easily be modified to encourage households to shift load out of constrained periods. Approximately one-third of the studies leveraged in the Brattle Group's Arcturus database tested winter or year-round rates.

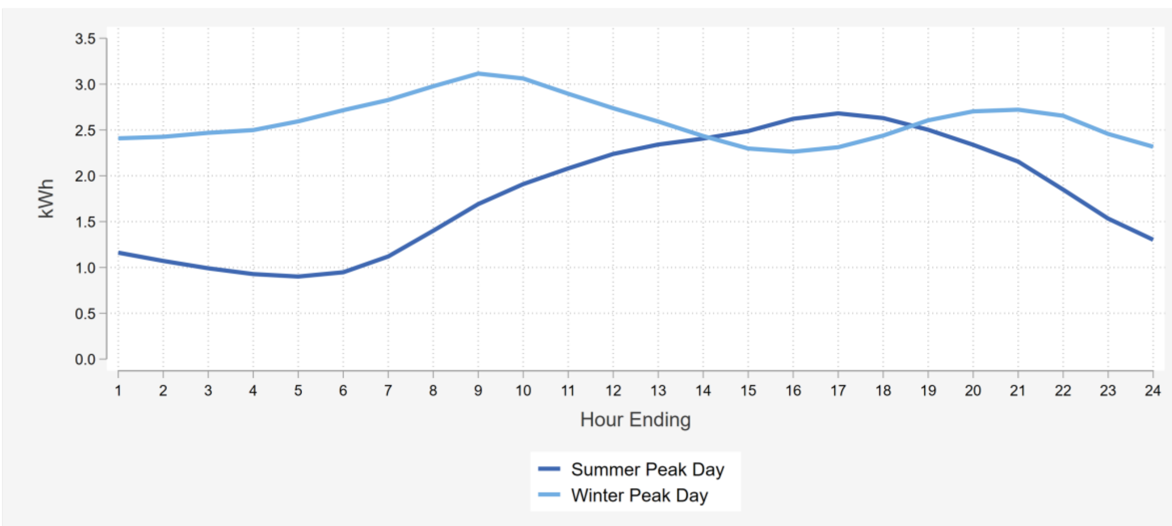


Figure 6: Average Residential Peak Day Load Profile by Season

Other Modeling Assumptions

Modeling the economics of dynamic rate offerings in AES Indiana service territory also requires assumptions about the avoided costs to the system that come from a reduction in peak demand. These assumptions allow us to estimate benefits, compare them to projected costs, and calculate benefit-cost ratios. **Table 4**: shows the assumed values for generation, transmission, and distribution capacity. The clearing price for generation capacity is equal to Cost of New Entry (CONE). Cost of New Entry (CONE) is an industry planning parameter that estimates the first-year revenue needed to build a new power plant based on expected capital construction costs, and lifetime earnings and maintenance assumptions. The avoided cost of transmission and distribution capacity can vary widely across a service territory. For simplicity, we used the assumptions from the 2019 IRP, although we believe these assumptions are a conservative estimate of true avoided costs, especially regarding the distribution system.

Table 4: Avoided Costs

Capacity Type	Value ($/kW-year) in $2024	Source
Generation	$86.38	MISO 22/23 Planning Resource Auction Results
Transmission	$10.00	2019 IPL Market Potential Study
Distribution	$10.00	2019 IPL Market Potential Study

This analysis does not consider the differential in marginal energy costs associated with shifting loads from higher price hours to lower price hours. An energy benefits stream would increase the benefit-cost ratio but requires assumptions about the frequency and duration of peak pricing hours. Similarly, the type of load shifting dynamic rates promote would presumably result in a reduction in emissions, although quantifying and valuing avoided greenhouse gas emissions is outside the scope this study. It is safe to frame our estimated benefits as "conservative" based on the decision to exclude energy and emissions benefits.

Ultimately, the portfolio optimization exercise in the EnCompass software will determine which resources are economic and which ones are not and reveal the actual marginal costs. In an IRP context, the levelized cost metric ($/kW-year) is the most important economic indicator. Levelized cost is a useful metric because it allows for direct comparison across a wide range of resource types and does not require avoided cost assumptions. The formula is shown below, and the discount rate used to calculate the net present value (NPV) of future spending and reductions is among the parameters presented in **Table 5**: .

$$Levelized\ Cost = \frac{NPV\ of\ Lifetime\ Costs\ (\$)}{NPV\ of\ Lifetime\ Demand\ (kW)}$$

Table 5: General Assumptions

Parameter	Value	Source
Nominal Discount Rate	6.24%	2019 IPL Market Potential Study
Line Loss Factor	5.28%	2019 IPL Market Potential Study
Inflation	2.0%	General long-terms assumption
Customer Count Annual Growth Rate	0.6%	Stakeholder Advisory Meeting #2 Presentation

Enrollment assumptions determine the share of offered households that will accept the dynamic rate. In a default design, this is the share of homes that do not opt out. In an opt-in design, it is the share of homes that accept the offer to change rates voluntarily. We assume a 15% adoption rate for opt-in rate designs an 80% adoption rate for default rates. FIGURE 7: shows our assumed trajectory to reach the final adoption rate. The opt-in trajectory is more gradual because AES Indiana would need to promote and recruit households onto rate rather than simply changing a tariff and transitioning accounts onto it.

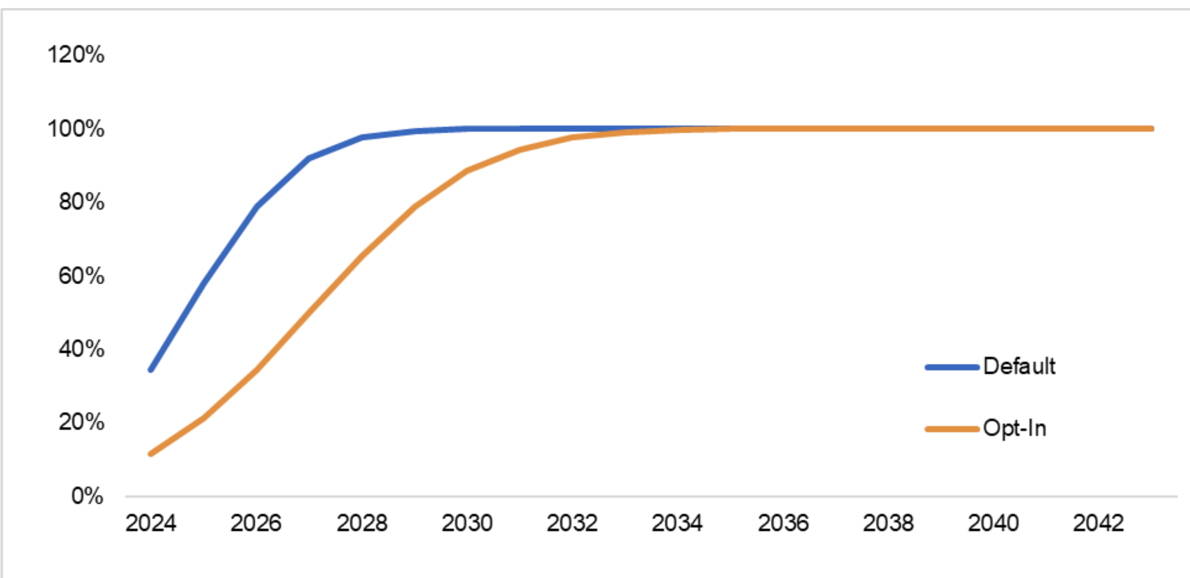


Figure 7: Ramp Rates

For opt-in rates, we assume a 5% annual attrition rate. For CPP rates, we assume that 10% of homes will not respond to any given event call.

The final, and most challenging, set of modeling assumptions for this analysis is the cost to AES Indiana of administering the rates to its residential customers. We consider and apply the four categories of cost listed below and apply the value shown in **Table 6**: .

- **Fixed One-Time**. Upfront costs to design and launch the offering. This includes IT, rate design, and communications with customers. Fixed costs do not vary based on the number of households enrolled in the program.

- **Fixed Recurring**. These costs are not dependent on program size but are incurred each year that the offering is active.

- **Volumetric One-Time**. Volumetric costs scale up or down depending on the number of participants. Marketing costs, sign-up incentives, and free/discounted enabling technology are the primary cost centers for this category.

- **Volumetric Recurring**. Also dependent on the number of participating households but incurred annually instead of once.

The general trend across cost assumptions is that default programs have more fixed cost than opt-in programs due the amount of messaging, testing, and opt-out handling required. The offerings with enabling technology have higher costs across all four categories. While the $80 price differential in volumetric one-time costs would not support a free high-end connected thermostat with installation for all homes, it would allow AES Indiana to cover most of the upfront equipment cost for a basic connected thermostat like the new Amazon smart thermostat for households interested in HVAC optimization.

The cost of the AMI network required to support dynamic rate offerings is not included in any of these categories. We treat the metering infrastructure as a sunk cost that does not factor into the economic analysis.

Table 6: Program Delivery Cost Assumptions

Rate	Fixed One-Time	Fixed Recurring	Volumetric One-Time	Volumetric Recurring
TOU Default No Tech Short-Run	$250,000	$75,000	$20	$1
TOU Default with Tech Long-Run	$500,000	$150,000	$100	$2
CPP Default with Tech Short-Run	$750,000	$200,000	$100	$2
TOU Opt-In No Tech Short-Run	$100,000	$50,000	$20	$1
TOU Opt-In with Tech Long-Run	$200,000	$100,000	$100	$2
CPP Opt-In No Tech Short-Run	$125,000	$62,500	$20	$1
CPP Opt-In with Tech Long-Run	$250,000	$125,000	$100	$2

Results

Table 7: shows the modeling results for the three rates with a default enrollment model and **Table 8**: shows the results for the four opt-in rates. Although we use a twenty-year horizon when calculating costs and benefits, the rates all reach a plateau level in ten years, so we report the number of participating households and summer peak demand reduction potential in 2033.

The motivation for examining seven distinct time-varying rate offerings was to illustrate the sensitivity of the results to different design levers. Several trends emerge when comparing the key outcomes across rates.

- Each of the rate offerings are cost-effective according to the Utility Cost Test, but the UCT ratios range from 1.3 to 5.8. Similarly, the levelized cost of the designs range from $22/kW-year to $97/kW-year.

- The rates with default enrollment tend to have larger MW potential despite more modest per-household impacts due to the sheer volume of adoption. However, the range is wide even within the default enrollment category. With a cost-reflective price ratio of 1.5 and without enabling technology, the aggregate estimated peak demand reduction in 2033 is 13 MW. The more aggressive default CPP rate with enabling technology returns an estimated 86 MW of summer demand reduction potential.

- While the designs with enabling technology generally show increased demand reduction potential and improved economics, the magnitude of program investment is higher as shown in the NPV of Lifetime Costs rows.

Table 7: Modeling Results for Default Rates

Metric	TOU Default No Tech Short-Run	TOU Default With Tech Long-Run	CPP Default With Tech Short-Run
System-Level MW (2033)	13.4	66.2	86.1
Levelized Cost ($/kW-year)	$97	$72	$56
NPV of Lifetime Benefits (2024$)	$17,986,503	$88,776,543	$115,526,253
NPV of Lifetime Costs (2024$)	$13,814,303	$50,417,420	$51,365,452
Present Value of Net Benefits ($2024)	$4,172,199	$38,359,124	$64,160,801
Participants in 2033	390,141	390,141	390,141
UCT Ratio	1.30	1.76	2.25
Average kW Savings per Participant	0.03	0.17	0.22

Table 8: Modeling Results: Opt-In Rates

Metric	TOU No Tech Short-Run	TOU With Tech Long-Run	CPP No Tech Short-Run	CPP With Tech Long-Run
System-Level MW (2033)	9.8	19.2	14.3	37.1
Levelized Cost ($/kW-year)	$30	$51	$22	$28
NPV of Lifetime Benefits (2024$)	$13,186,271	$25,795,748	$19,216,865	$49,789,598
NPV of Lifetime Costs (2024$)	$3,098,883	$10,470,668	$3,298,391	$10,869,685
Present Value of Net Benefits ($2024)	$10,087,389	$15,325,080	$15,918,474	$38,919,914
Participants in 2043	69,494	69,494	69,494	69,494
UCT Ratio	4.26	2.46	5.83	4.58
Average kW Savings per Participant	0.14	0.28	0.21	0.53

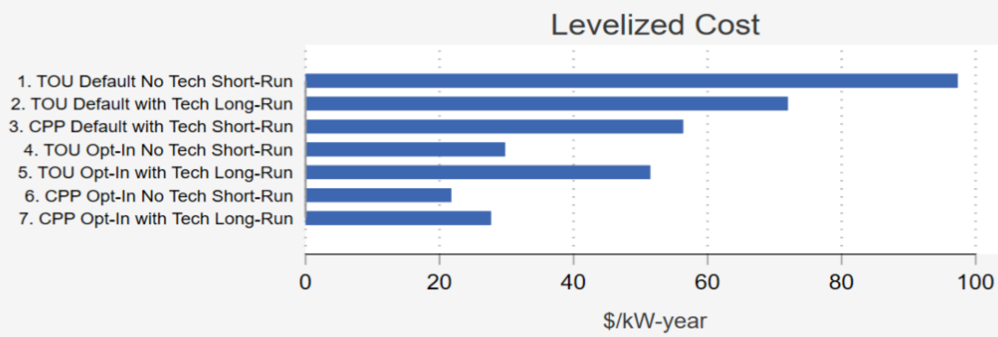
Figure 1 summarizes the findings across four key dimensions.

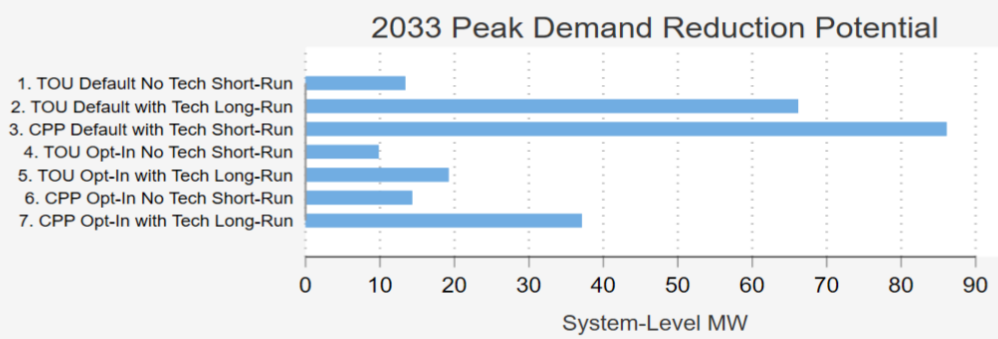
- **Levelized Cost**: the present value of lifetime costs divided by the present value of annual lifetime demand reductions. This metric allows for simple comparisons across resource types and is a key focus of the Resource Selection Process for Demand Response chapter of this report.

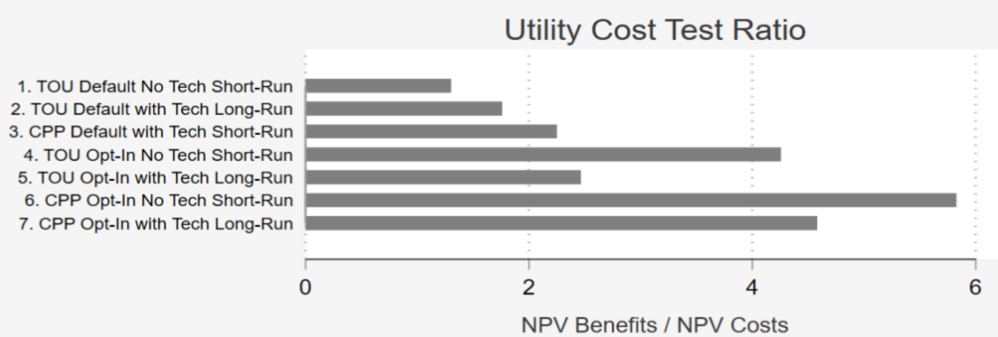
- **Peak Demand Reduction Potential in 2033**: We assume different adoption trajectories for opt-in and default rate designs, but all options reach full adoption by 2033. This metric is a function of the number of enrollments, the average peak demand reduction per enrolled household, and an assumption about line losses.

- **UCT Ratio**: The Utility Cost Test is the primary cost-benefit perspective in Indiana. This metric compares the net present value (NPV) of lifetime benefits to the NPV of lifetime costs. An offering with a ratio greater than 1.0 is cost-effective and ratio less than 1.0 indicates that the offering is not cost-effective.

- **Present Value of Net Benefits**: Any offering with a UCT ratio greater than 1.0 has benefits that exceed its costs. This metric is the difference, calculate as NPV Benefits minus NPV Costs.


Levelized Cost
1. TOU Default No Tech Short-Run
2. TOU Default with Tech Long-Run
3. CPP Default with Tech Short-Run
4. TOU Opt-In No Tech Short-Run
5. TOU Opt-In with Tech Long-Run
6. CPP Opt-In No Tech Short-Run
7. CPP Opt-In with Tech Long-Run
0
20
40
60
80
100
$/kW-year


2033 Peak Demand Reduction Potential
1. TOU Default No Tech Short-Run
2. TOU Default with Tech Long-Run
3. CPP Default with Tech Short-Run
4. TOU Opt-In No Tech Short-Run
5. TOU Opt-In with Tech Long-Run
6. CPP Opt-In No Tech Short-Run
7. CPP Opt-In with Tech Long-Run
0
10
20
30
40
50
60
70
80
90
System-Level MW


Utility Cost Test Ratio
1. TOU Default No Tech Short-Run
2. TOU Default with Tech Long-Run
3. CPP Default with Tech Short-Run
4. TOU Opt-In No Tech Short-Run
5. TOU Opt-In with Tech Long-Run
6. CPP Opt-In No Tech Short-Run
7. CPP Opt-In with Tech Long-Run
0
2
4
6
NPV Benefits / NPV Costs

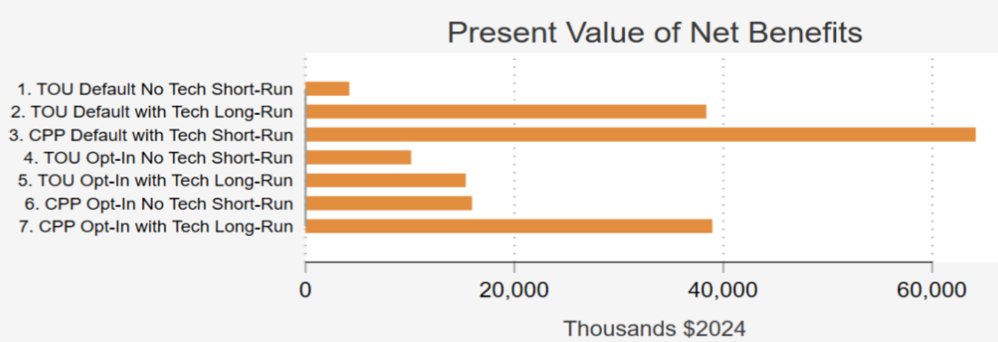

Present Value of Net Benefits
1. TOU Default No Tech Short-Run
2. TOU Default with Tech Long-Run
3. CPP Default with Tech Short-Run
4. TOU Opt-In No Tech Short-Run
5. TOU Opt-In with Tech Long-Run
6. CPP Opt-In No Tech Short-Run
7. CPP Opt-In with Tech Long-Run
0
20,000
40,000
60,000
Thousands $2024

Figure 1: Time-Varying Rate Modeling Results Summary

The net present value (NPV) and levelized cost metrics are highly useful for comparison of resources but can obscure the budgetary requirements over time. Figure 9: shows estimated summer peak demand reduction potential and projected expenditures in nominal dollars over the study horizon. This figure is for the TOU Default with Tech Long-Run rate, but the cost trend is similar for all seven rates. The key takeaway is that utility costs for rolling out a dynamic rate design are heavily front-loaded. The utility incurs most of the one-time costs to set up, market, and deploy the rate in the first 2-3 years. Once the upfront deployment costs are past and demand savings reach full levels, the ratio of annual expenditures to peak demand reduction is quite low.

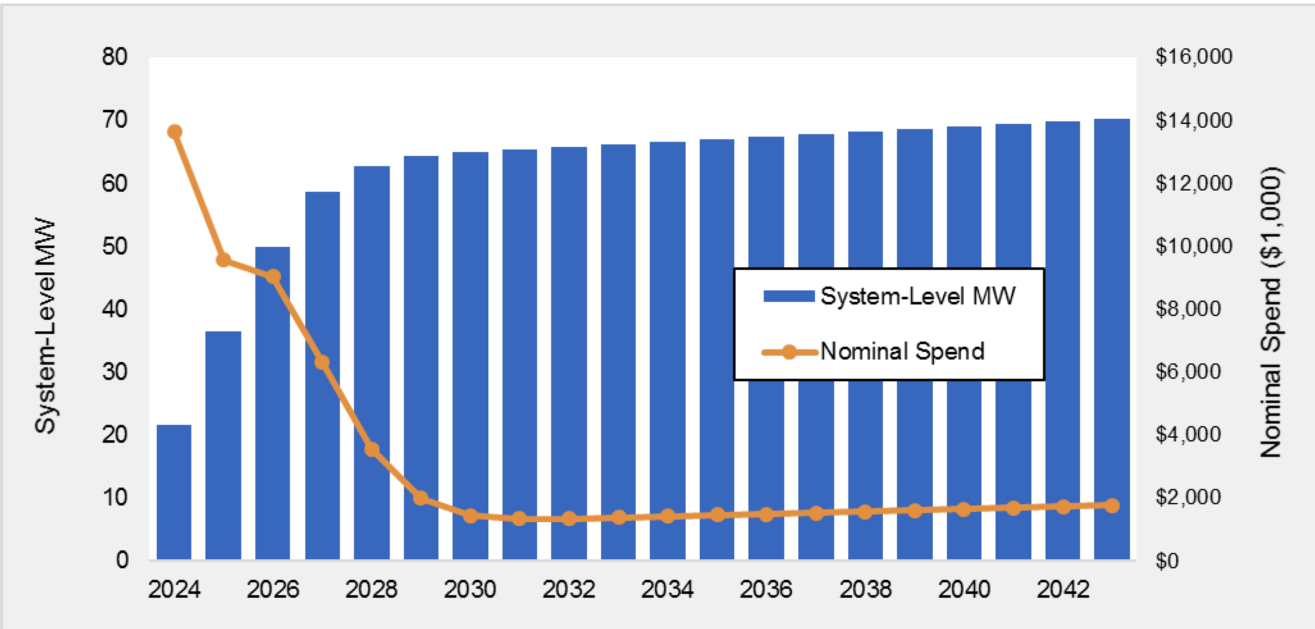


Figure 9: Peak Demand Reduction Potential and Expenditures by Year

Developments in Enabling Technology

The "with or without" enabling technology heuristic used for this analysis is useful to illustrate the power of prices-to-devices. However, it is an oversimplification of the market within which AES Indiana operates. The fact of the matter is no utility can offer a dynamic rate that is truly free of enabling technology because smart device manufacturers have incorporated TOU optimization into their product designs. The choice utilities face today is how much to encourage, subsidize, and leverage these enabling devices.

Over half of the time-varying rate deployments cataloged by the Brattle Group in its Arcturus database are over a decade old. Enabling technology has become far more sophisticated over the last decade with respect to optimizing end use loads to price signals. These developments come from improved communications with devices and investment from the private sector to build out optimization capabilities.

Wi-Fi connected smart thermostats control the largest end uses within most residential homes (heating and cooling). Two of the largest manufacturers in the space now offer TOU optimization at no charge and other vendors in the space have plans to follow suit. These services use sophisticated algorithms that factor in energy prices, comfort preferences, and the homes' thermal performance to balance cost savings and comfort automatically. The "set it and forget it" aspect is important for this type of offering because consumers have limited time and attention.

- The Nest Renew optimization service is currently available to Nest thermostat owners by invitation. The free optimization features automatically prioritize usage of cleaner or less expensive energy. The Energy Shift optimization feature currently supports TOU rates from over 100 different utilities in the United States.

- Ecobee's eco+ thermostat optimization platform includes features for EE, DR, and TOU response. The features are available to all ecobee owners on an opt-in basis and users can customize the aggressiveness of the algorithms based on their savings and comfort preferences. In 2020, DSA completed an impact analysis of the offering.

Using the thermostat runtime and actual TOU impact results from the ecobee study, DSA developed a Microsoft Excel calculator that models thermostat optimization bill impacts and peak demand savings for a user-defined state, season, and rate design. **Figure 10**: shows the output from that tool for this study's TOU Default with Tech Long-Run rate. The average bill savings is $7 per month and the peak demand savings is 0.38 kW, which is over double the 0.17 kW per-participant assumption for the same rate in **Table 7**: . Of course, not every household will install a connected thermostat and enable its TOU optimization features, but the difference in kW reduction per household illustrates the power of enabling technology for price response.

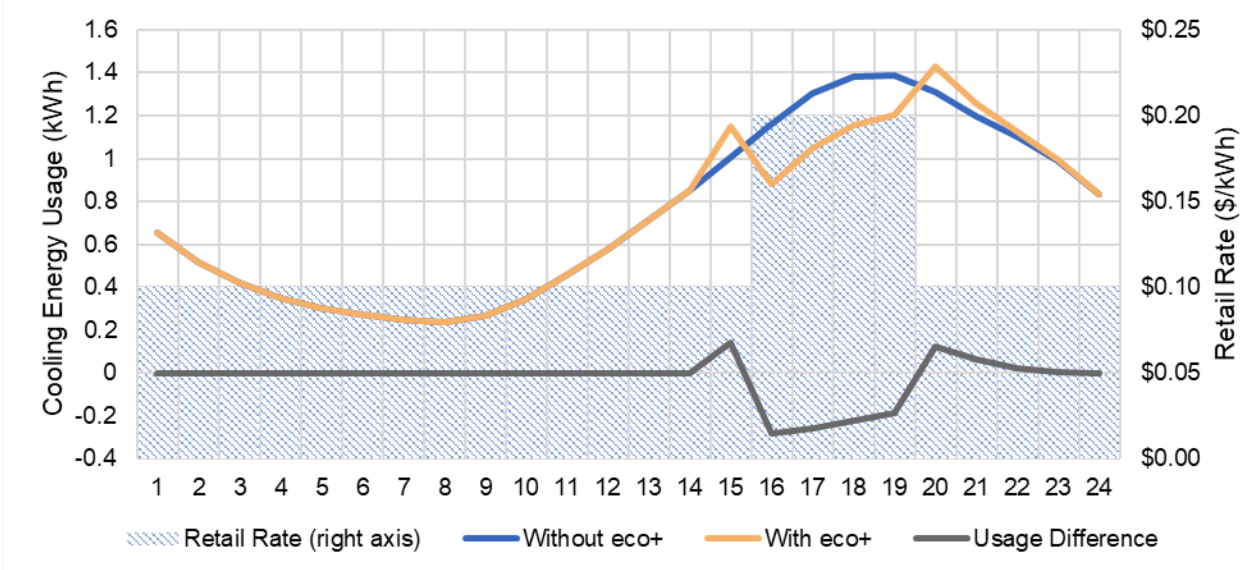


Figure 10: Thermostat Optimization Estimates - TOU Default with Tech Long-Run

Connected thermostats may be the most ubiquitous enabling technology on the market today for TOU optimization, but they are certainly not the only connected device capable of automated price response.

- **Electric resistance and heat pump water heaters** increasingly have the capability to use the water tank as a thermal storage device. Water can be safely pre-heated a certain amount in the hour or two prior to on-peak pricing. If the hot water is used during the on-peak pricing period, heating of incoming water can be postponed until the off-peak pricing is in effect. This type of scheduling is ideal for daily TOU rates because the shift is largely invisible to residents. Sample study link.

- **Behind-the-meter batteries** are often paired with rooftop solar installations for resiliency. Batteries are the ultimate load flexibility tool because they can be configured to charge and discharge accordingly to almost any signal. Batteries can charge overnight or store excess solar during the day and keep utility-supplied load to zero through the evening, or even discharge back to the grid if there is it is economically beneficial for the homeowner to do so. Sample study link.

- **Electric Vehicles and Electric Vehicle Chargers** are a new and highly flexible load. Utilities have tested direct load control, passive rewards, and time-varying rates to encourage off-peak charging. A price signal via rates is a simple and effective to foster vehicle charging behavior at times when it is most beneficial to the grid. EV rates can be applied to charger itself or the whole home. Sample study link.

- **Smart Panels** are a relatively new offering that opens any electric circuit in the home to advanced control techniques. Like batteries, smart panels tend to follow adoption of rooftop solar. Ethernet or Wi-Fi communications allow for remote management and deployment of artificial intelligence algorithms from the cloud. Dynamic response to price or emissions signals will be a selling point for these devices to consumers. Sample product link.

Conclusion

The study team is encouraged by the modeling of dynamic rates by GDS Associates in the 2022 DR Potential Study and hopeful that AES Indiana will include time-varying pricing in its preferred resource plan. Our analysis illustrates how flexible and modular price signals can be as a demand management strategy. Ultimately, dynamic rates tap into load reduction potential across all end-uses, during both summer and winter, and can be adapted to meet the needs of a changing system. Advancements in enabling technology will only increase the capability of dynamic pricing over the IRP planning horizon.

RESOURCE SELECTION PROCESS FOR DEMAND RESPONSE

Introduction

Power system modeling software packages are quite sophisticated with respect to optimization of generation assets, power market conditions, and electric load patterns. However, DSM options can be challenging to integrate into the modeling framework. A DR program is not a power plant. On one hand DR has no fuel cost so it can look like cheap energy to a planning model. Conversely, DR has significant limitations on availability and duration compared to a combustion turbine which can make it an unattractive capacity resource to modeling software. Many jurisdictions end up making business or policy decisions about the amount of DSM to pursue and just decrement the load forecast because of these challenges. Indiana utilities have taken a more dynamic approach in recent IRPs and allowed DSM to compete with other resource types for selection. While this approach is objectively the right way to model DSM, the outcome can be sensitive to certain modeling procedures. In this section we offer some suggestions based on observations from recent planning studies completed in other jurisdictions.

IPL IRP 2019 DSM Modeling

The 2019 demand response potential study prepared by GDS Associates and DSA identified 218 MW of realistic achievable potential (RAP) and 331 MW of maximum achievable potential (MAP) from DR programs by 2030. Despite the significant amount of cost-effective and achievable DR potential identified in the potential study, the 2019 IRP selected just 55 MW of demand response resources. This 55 MW was made up exclusively of existing DR resources, so the IRP modeling exercise effectively concluded that new DR offerings, or expansion of existing DR offerings, was not the least cost resource.

The 2019 IRP modeled demand-side resources on a comparable basis with supply-side resources per IRP rule 170 IAC 4-7-8©(4) including consideration of safety, reliability, risk and uncertainty, cost effectiveness, and customer rate impacts. To evaluate DSM on a consistent and comparable basis with supply-side resources, the total DSM potential identified by the market potential study had to be disaggregated into smaller bundles with supply-side characteristics that act as model inputs. This was accomplished by taking the Realistic Achievable Potential (RAP) results from the Market Potential Study and creating model inputs with a levelized cost and load shape like a supply-side resource. Energy efficiency results were divided into eight bundles, each providing a 0.25% reduction in IPL load totaling in an 2% load reduction. Bundles were rank-ordered by cost ($/MWh), with each 0.25% decrement becoming more expensive. This approach reflects that fact that higher DSM targets are more expensive to achieve. Each bundle was set to span between 2021-2039 planning periods. Bundles were loading into the PowerSimm modeling software as negative load items with hourly energy profiles for the 20 years of the IRP study window.

If the projected IPL Load Zone LMP was greater than the levelized cost of the bundle, the PowerSimm software interpreted that as a net benefit to the portfolio based on the energy savings. Capacity credit for each DSM bundle was established by determining its contribution to the IPL peak load, which was forecasted to occur in July of each year from 2pm to 6pm, where each bundle's hourly contribution across the event time was averaged to arrive at the decrement capacity credit. These capacity credits increased with time as the energy saving accumulated but were held constant within the year. These capacity credits from each bundle counted towards IPL's Planning Reserve Margin Requirement.

DR was assessed similarly to EE in the potential study. Direct load control and rate programs were analyzed to determine estimated savings and cost-effectiveness. Benefits for DR programs are based off avoided demand, energy, wholesale cost reductions and T&D costs. The assessment of DR offerings was used to determine the RAP and MAP for these load modifying resources. While the process for assessing DR offerings was like EE, the method of input into the PowerSimm model was different. While EE was organized into eight bundles based on tranches of levelized cost, DR was categorized into two bundles based on seasonal availability. The first bundle consisted of residential and commercial air conditioner load management measures with all load impacts occurring during the summer. The second bundle was comprised of residential and commercial water heater control measures with both summer and winter load impacts.

The DR modeling method resulted in 55 MW of (UCAP) Unforced Capacity from existing demand response resources. As shown in **Figure 1**:, the 55 MW of DR selected is only a small fraction of the 218 MW of RAP and 331 MW of MAP identified in the 2019 market potential study. While capacity was not as tight in MISO in 2019 as it is today, we believe the bundling strategy was a key driver of this outcome.

While effective DR programs were identified, they may have not been integrated into the PowerSimm model in an optimal methodology. Tables 8-5 and 8-6 on page 60 of the 2019 IPL provide the net present values (NPV) of Demand Response programs with Utility Cost Test (UCT) ratios. The 13 DR offerings show a wide range of UCT ratios, from 0.13 to 4.74. **Our hypothesis is that bundling highly cost-effective offerings together with clearly cost-ineffective options resulted in bundles that were not economically viable as a whole. Based simply on the UCT ratios in the tables, a bundling strategy which group measure into 'above' and `below' a threshold like 1.5 or 2.0 would have resulted in selection of the cost-effective options and passing on the cost-ineffective options.**

Consumers Energy 2021 IRP DSM Modeling

As required by Michigan Act 341 of 2016, Consumers Energy prepares and files an IRP every three years. In preparation for the 2021 IRP, Consumers Energy commissioned a market potential study to quantify the magnitude and cost of acquiring additional energy efficiency and demand response potential.

Like AES Indiana, Consumers Energy uses the Utility Cost Test to evaluate DSM cost-effectiveness and allows DSM to compete alongside traditional resource for selection.

In total, the Consumers Energy potential study included eight categories of demand response programs such as direct load control, time-varying pricing, and load curtailment agreements. For different segments of each program, the potential study team provided Consumers Energy with the demand response potential and the levelized costs (in 2021 dollars) for different segments of each program. A total of 1,090 MW of summer DR potential was provided to the Consumers Energy IRP modeling team for consideration.

Calculating the levelized cost of each DR option allowed the Consumers Energy Resource Planning Team to directly compare DR offerings to other supply-side resources for selection in the 2021 IRP. The potential study identified a supply curve of 592 MW of new demand response resources shown in **Figure 11**: above and beyond the 498 MW of existing demand response resources.

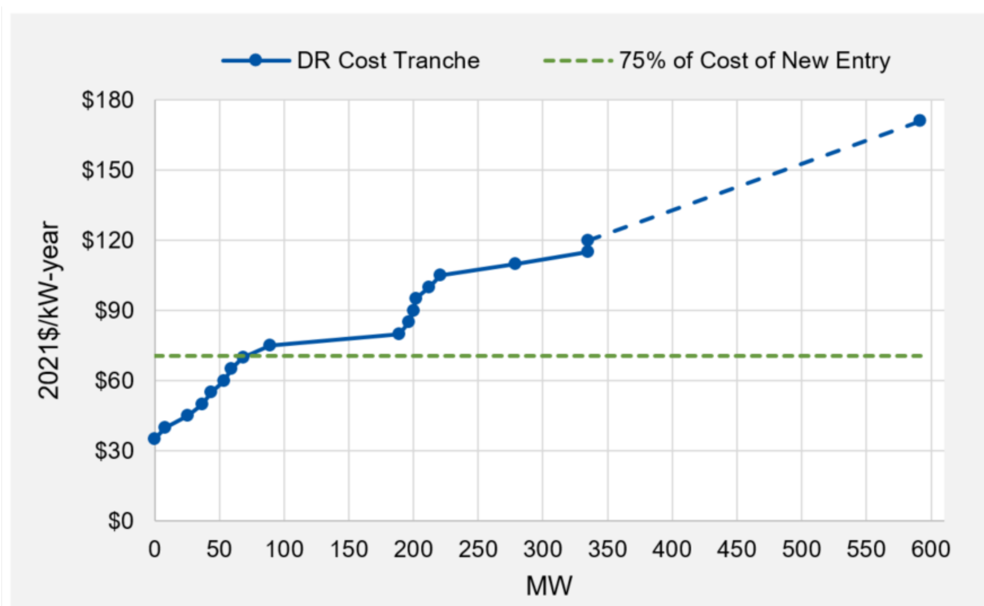


Figure 11: DR Supply Curve

The Consumers Energy IRP modeling team then grouped the granular DR options into bundles by ascending levelized cost in blocks of $10 per kW-year. While Michigan cost-effectivenss rules at the time required use of 75% of CONE for UCT calculations, the IRP model ended up selecting most of the DR resources priced under CONE and passing on the resources priced above CONE. We think this supply curve method where price is the bundling parameter is the most economically efficient way to present DR options to the planning model because it allows the model to select the most competitive options. It also aligns better with AES Indiana's 2019 bundling approach for energy efficiency.

DSM Modeling in EnCompass

AES Indiana intends to utilize the EnCompass modeling software for the 2022 IRP, potentially providing more flexibility compared to the PowerSimm package used for the 2019 IRP. For background, the study team reviewed the DSM modeling process for several recent IRPs conducted using the EnCompass Software.

There are multiple methods for modeling DR and EE programs for use in simulation software for evolving power markets. In energy systems with large penetrations of variable renewable energy, DR can play a large role due to the flexibility that it provides the system. DR programs have a complex set of attributes that can be a challenge to model. Much like a battery on the supply side, DR programs inject no meaningful amount of energy into the system. However, they are adept at shifting energy requirements from one period to another.

One common theme among energy efficiency modeling is to group offerings into a manageable number of bundles by the levelized cost of energy (LCOE) for a program. The LCOE represents the average cost per unit of electricity generated from the resource, allowing for the recovery of all costs over the lifetime of the resource. When calculating the LCOE for a resource, a few key factors need to be identified such as the capital to run and produce the resource, the fuels required, and the operation and maintenance of the resource. A simplified LCOE can be calculated by:

$$LCOE = \frac{NPV\ of\ \text{Lifetime}\ Total\ Costs}{NPV\ of\ \text{Lifetime}\ Electricity\ Produced}$$

DR is also often modeled as a supply side resource, as the potential to reschedule a part of electricity demand is a large opportunity to improve the efficiency of a system. From a supply point of view, the added flexibility of DR programs can bring significant improvements to the dispatch of resources. Modeling DR as a supply side resource allows the EnCompass model to select programs based on when it is cost-effective and optimal to do so.

The Utility Cost Test is also often used to calculate the cost-effectiveness of DSM portfolios for reporting or planning studies. The UCT takes as an input an assumed cost of additional supply-side resources (e.g. a new gas plant) and calculates the benefits to the utility and its ratepayers of avoided the investment. While the UCT is a useful metric, our review suggests most DSM modeling in a competitive IRP context focuses on a levelized cost method rather than an assumed avoided cost.

Table 9: summarizes the DSM modeling procedures for Duke Energy Indiana, Xcel Upper Midwest, Public Service Company of New Mexico, and Minnesota Power who all recently produced IRPs utilizing the EnCompass software for DSM modeling.

Table 9: DSM Modeling Using Encompass at Other Utilities

Utilities	EE Modeling	DR Modeling	Results
Public Service New Mexico	EE is bundled into groups based on price alongside supply-side resources. EE is bundled in levelized cost tranches of similar $/MWh, EnCompass selects EE bundles based on specific modeling scenarios.	DR is modeled as a resource with specific contract limits including availability, hours per call, calls per season, with existing/planned programs, including all programs beyond planned amounts. DR programs are treated as portfolio supply options for modeling.	Every forecasting case indicates a high value for EE measures and suggests investment in cost-effective DSM resources beyond statutory requirements. For DR, existing programs will run through 2023 and then be replaced by DR offerings with broader availability characteristics (e.g., weekends and non-summer).
Duke Energy Indiana	EE was priced in ten bundles which were optimized and selected based on economics. Bundles were designed to be treated similarly to supply-side resource option for selection by IRP models. Annual MWh and costs for bundles were used to calculate levelized cost in $/MWh.	Like EE, DR was modeled as a supply-side resource with selectable bundles and included continuation of existing programs as well as three additional DR bundles that include the additional cost to entice greater participation into DR programs.	Duke's 2021 IRP recommends increasing EE by 20% and sustaining high levels of DR to avoid the addition of 400 MW of new resources in the process. The preferred portfolio includes year-over-year DR of approximately 600 MW, and continuation of current DR contracts.
Xcel Energy Upper Midwest	More than 40 EE programs were bundled into three groups to be evaluated alongside other resources. EE is modeled as a supply-side resource as opposed to an adjustment to future load. EE costs are expressed in $/MWh and bundled based on program potential.	Incremental DR resources were bundled into three groups to be evaluated alongside other supply-side resources as optimized economic alternatives. For supplemental modeling, bundles were updated to account for time and observed historical performance of various programs included in the bundles.	DR and EE Bundles were evaluated in different combinations via optimizations and were selected for cost effectiveness. Each bundle represents a combination of program achievements expected to lead to a certain amount of avoided load or energy per year, at an estimated blended cost. The first two EE and DR bundles are locked in all scenarios to produce peak load savings. 400 additional MW of DR were planned for deployment from 2019-2023.
Minnesota Power	EE programs were modeled as supply-side resources based on Baseline, High, and Very High Scenarios. EE Scenarios each have a levelized $/MWh and begin in 2024 with new programs being implemented each year through 2029. EE was carried forward for further analysis within the	DR programs were also modeled as supply side resources, allowing selection by EnCompass. DR programs are modeled as $/MW, EnCompass selects perfect fit for market capacity prioritizing lower cost options. DR was evaluated against supply-side options in later	Minnesota Power preferred resource plan included implementation of DR for industrial customers to meet the projected long-term capacity needs. The action plan pursues 50 MW of long-term DR by 2030 to address future resource adequacy changes.

	EnCompass Capacity Expansion Analysis due to low LCOE compared to other options.	capacity expansion analysis using EnCompass.	

Bundling Strategies

The goal of effective DSM modeling is to create results where optimization models will pick the most cost-effective and efficient scenarios to meet load requirements. DR is tricky to model because it has no fuel costs but has limitations on when it can be implemented. Ultimately DR programs help with capacity and planning reserve margin requirements but contribute little energy. As a result, the optimization model needs to consider DR on a $/kW-year basis.

Figure 12: presents a hypothetical scenario of 20 DR offerings and their levelized cost in $/kW-year. These offerings are split into Residential and Non-Residential programs. Like most potential studies, this example includes offerings with a wide range of costs. This figure will be used for discussion of bundling methods.

Figure 12: Hypothetical Roster of DR Offerings

There are several strategies for inputting DR offerings into power planning software. Take the roster of DR offerings from Figure 12: for example. If all offerings are aggregated into a single group, the bundle would have an average cost of $93.70 per kW-year. The optimization model's selection criteria of $/kW-year would mean that the levelized cost value of that single bundle would need to be less than other resource options for the DR bundle to be selected as part of the model. The bundling of all DR offerings in one group defaults to a scenario where DR selection will include either all or none of the offerings.

Table 10: presents an alternative bundling method based on sector and divides the list into residential and non-residential offerings. This is a logical grouping strategy for cost recovery or program design. However, it obscures the variation in cost amongst the underlying options. If the 20 offerings are bundled based on sector, the levelized cost of the two bundles is similar. A least cost selection procedure would likely either select both bundles or neither bundle because both include a mix of high cost and lower cost options.

Table 10: Bundling by Customer Group

Bundle Type	Levelized Cost $/kW-year
Non-Residential	$92.65
Residential	$94.73

Table 11: illustrates the concept of bundling demand response offerings by cost tranches. This bundling method splits the twenty offerings into four groups. The five offerings with the lowest levelized cost are assigned to Tranche #1. The offerings with the highest levelized cost are assigned to Tranche #4. Tranche #2 and #3 included the 6th to 15th offerings on the supply curve. This method allows the EnCompass model to select offerings on the basis of cost and reduces the chance that inclusion of high cost offerings in the potential study will prevent low cost DR options from being selected.

Table 11: Bundling by Cost

Bundle	Levelized Cost $/kW-year
Tranche 1	$29.07
Tranche 2	$48.33

Tranche 3	$88.92
Tranche 4	$208.46

Conclusions and Recommendations

AES Indiana currently registers 64.2 MW of Load Modifying Resources with MISO. A recent potential study by GDS associates identified 319 MW of realistic achievable potential (RAP) DR potential and 555 MW of maximum achievable potential (MAP) within AES Indiana service territory. We understand AES Indiana currently plans to create four DR bundles based on the customer and program type: Residential Direct Load Control, Residential Rates, C&I Direct Load Control/Aggregator and C&I Rates.

The study team applauds AES Indiana for continuing to model DR offerings competitively as a resource. A supply curve perspective that bundles offerings by the levelized cost will allow DR options to compete more directly for inclusion in the portfolio**. If AES Indiana elects to stick with its current four bundle approach, we recommend removing offerings that fail the UCT prior to presenting the bundles to EnCompass so that "dead weight" doesn't cause EnCompass to pass on economic options that might avoid or defer costly capital investment in generation.**

The issue with bundling DR programs "logically" is that it can obfuscate the economics of the underlying components. High-cost DR offerings influence the cost of the entire bundle and may result in lower cost DR programs being omitted from the portfolio. If DR is modeled as a supply-side resource, the most economic efficient modeling approach is to organize resources based on a levelized dollar per unit basis.

PLANNING FOR NET VERSUS GROSS PEAK LOADS

The electric power sector in Indiana and across the Midwest is changing quickly with increased proliferation of renewables like solar and wind. Systems with high penetration of renewable resources experience instances of system under-generation, over-generation, and increased ramping rates. This naturally leads to new considerations for utility planning activities, including how demand side resources, such as DR and EE, can bolster resource adequacy.

We understand that the AES Indiana IRP process is well underway and appreciate the transparent and involved stakeholder process to date. **Figure 13**: shows historic and projected peak load figures from recent [Public Advisory Meetings](). Despite a decade of steadily declining weather-normalized peak demand, AES Indiana projects steady growth in peak demand over the IRP horizon. The study team takes no position on the forecast methodology or the likelihood of this forecasted reversal of recent trends. However, we wish to stress some planning considerations around the **timing and duration of peaking conditions** as the energy transition unfolds in Indiana.

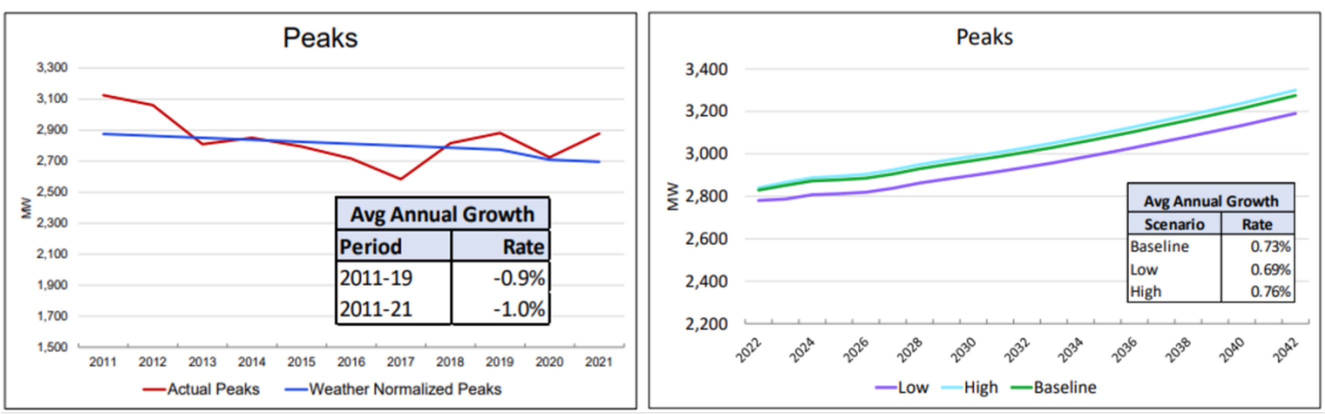


Figure 13: Historic and Projected AES Indiana Peak Loads

In its 2019 IRP, AES Indiana completed a solar potential study and [created load forecasts]() to map the impact of increasing solar resources on the grid (**Figure 2**). This study was used to estimate the changing capacity value of solar at current and future peak hours. The study focused on how the increase of solar on Indiana's grid would lead to a later and steeper (but lower overall) system peak, and consequently decrease solar power's potential capacity value. As a result of this research, the 2019 IRP includes a thoughtful discussion about the impact of solar on the net load curve and timing of future system peak hours. AES Indiana is clearly tuned into this topic from a resource selection standpoint, however it's important to look at implications for forecasting with DSM resource modeling as well.

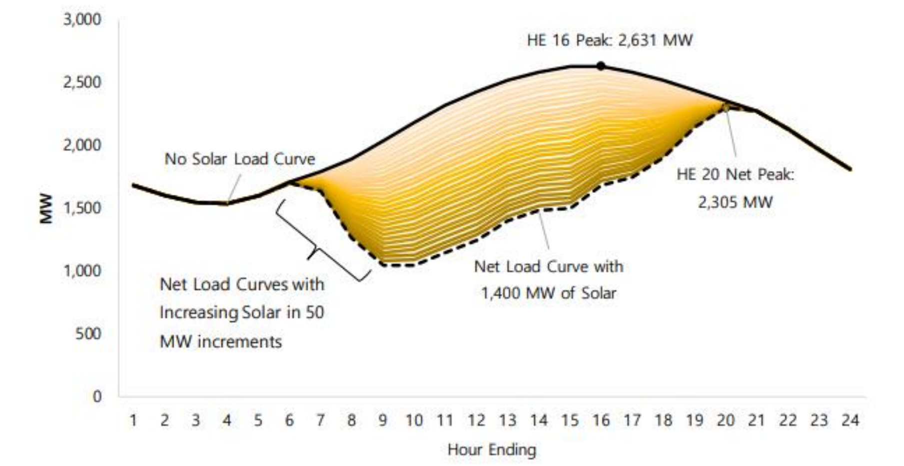


Figure 2: IPL Net Load Curve with Increasing Solar Levels

For future IRPs, it will be important to consider how demand-side resources line up, and don't line up, with the patterns of renewable energy load. Indiana utilities have historically estimated and valued peak load reductions from energy efficiency using a 3pm to 6pm summer weekday peak. A system with high penetration of renewables will prioritize load reductions between 5pm and 9pm. illustrates the net load issue for a recent day in California. While the gross load peak occurs around 5pm, the net peak does not occur until around 8pm. The net load curve is also sharper, with a steeper ramp and a narrower peak than the gross load curve. Importantly, the net load peak is around 10% lower than the gross load peak in both **Figure 2** and **Figure 3**. While the distinction may be academic today in AES Indiana service territory, it is likely to matter much more in the second half of the IRP study horizon. Plans for any large capital investment in new generation should consider the forecasted need and utilization on a net load basis at some point in the life of the asset.

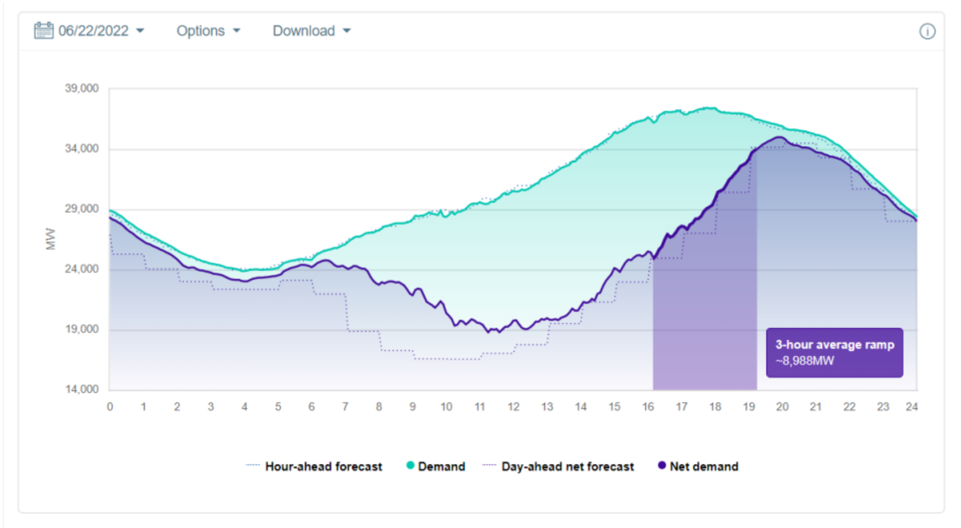


Figure 3: CAISO Gross and Net Load Curve

This peak load shift has implications in energy efficiency and demand response resources. **Figure 16**: , sourced from the [2021 load impact evaluation]() of Southern California Edison's (SCE) Summer Discount Program (SDP), illustrates this point. This figure shows that the correlation between residential cooling loads and SCE gross peak and CAISO gross peak are strongly linear on non-event days. However, the correlation between residential cooling loads and CAISO net loads is not as strong and changes by the hour. For example, this figure shows that potential AC load reduction is higher in the early peak period from 4-7PM than the later hours from 7-9PM. Underlying this trend is the fact that residential cooling load is a better predictor of gross system peaks than net system loads. In a system focused on gross peaks, direct load control of central air conditioning is an ideal resource because its capability is highest when the need is greatest. With a later net peak, residential air conditioning is still a key driver, but the available load for curtailment has started to wane by the time the system peaks.

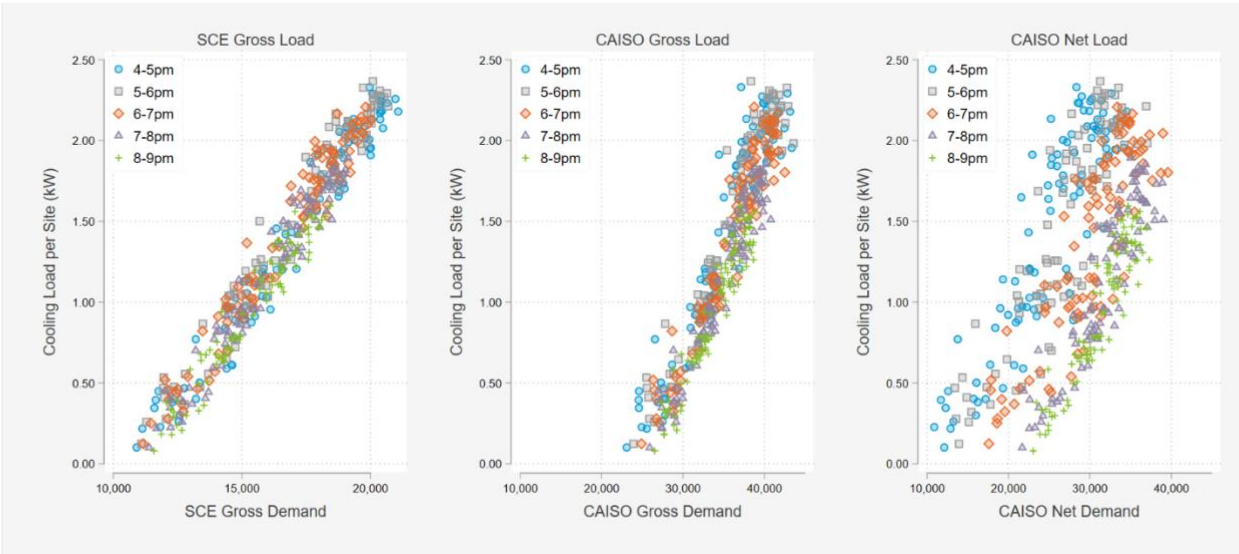


Figure 16: Relationship Between Cooling Loads and System Peaking Conditions

These patterns naturally lead to a few additional planning questions:

- The addition of solar PV at scale onto the AES Indiana and MISO systems will eventually shift the planning focus from gross loads to net loads. What are the implications for load forecasting? Does the current IRP forecast consider the timing of peaks or just the magnitude? How does timing change in the "high solar" forecast? Or does the "high solar" forecast exclude solar production like the primary peak forecast on slide 21 of the Advisory Meeting #2 Presentation?

- What is the interplay between the peak load forecast and the Effective Load Carrying Capacity (ELCC) for solar? At what point does AES Indiana need to start looking at DSM resources and how their capacity value changes with moving peaks?

- What are the implications for DSM resources associated with later peaks, narrower peaks, and the likelihood of more frequent DR dispatch?

- How can DSM resources help meet later peaks?

In the following sections we explore potential impacts for both EE and DR and use examples to illustrate resource prioritization considerations against the backdrop of a changing system.

Energy Efficiency

In the same way that AES Indiana looked at the changing ELCC for solar as the peak shifts, planners should look at different EE measure contributions to peak as it's currently defined, and how it might be defined in the future. It's expected that different resources will become more and less valuable at different peak definitions. **Figure 17**: shows a heat map of [hourly load on the MISO system] in 2021. Heat maps use color as a third axis to represent changes in level across days of the year (y-axis) and hours of the day (x-axis). As expected, currently the highest load is observed in the summer from June to September in the late afternoon to early evening hours. This section investigates different EE end-use load shapes that reduce demand and dives into how different reductions in different end-uses from both residential and commercial buildings will be valued as peak shifts. [NREL's database of end-use load profiles] for the U.S. building stock was used for Indiana-specific end-use load data.

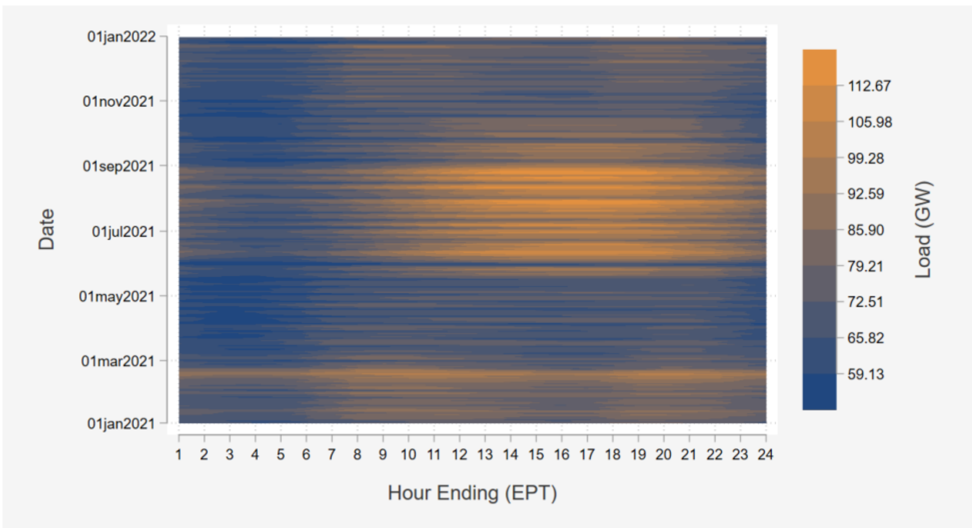


Figure 17: MISO System Load - 2021

Residential Load Shapes

Figure 18: shows the average summer load shape for different end-uses in Indiana's residential building stock. The first two red lines highlight an earlier system peak during hour ending 4pm. The second red lines show a later peak at hour ending 8pm. This helps to highlight how the potential EE value for each end-use changes at later hours. For example, it's clear that as system peak shifts, interior and exterior lighting energy efficiency impacts will be more valuable while cooling and pool pumps will decrease relative to current system peak definitions.

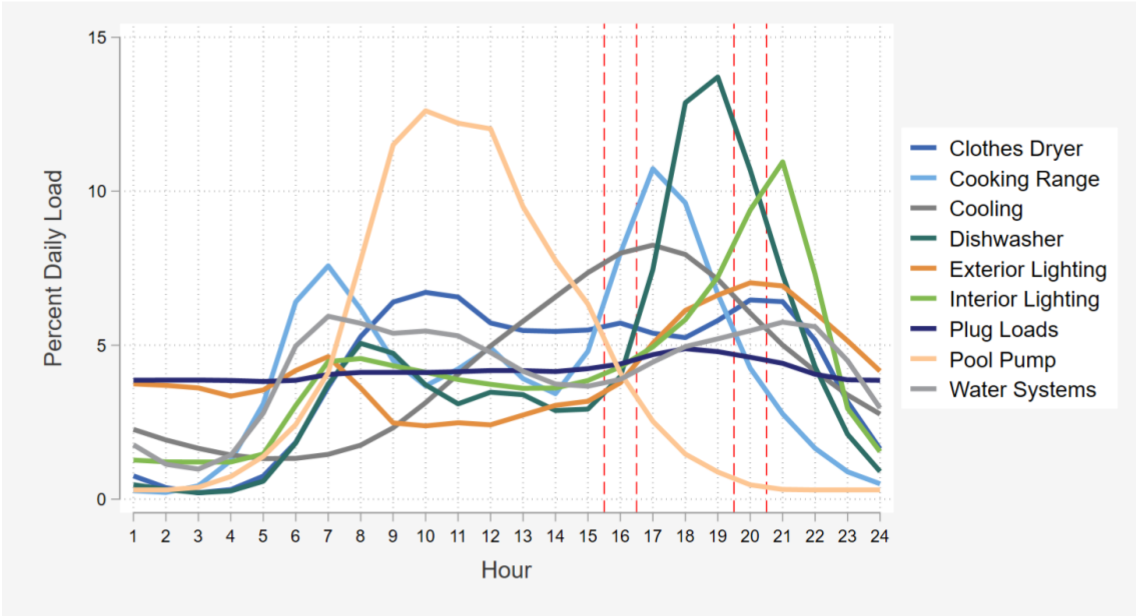


Figure 18: Summer End Use Load Shapes

To further highlight this point, we calculated a metric of capacity value (kW) per annual MWh of energy at different hours in the afternoon/evening for each residential end use (Table 12:). For Interior Lighting, the capacity kW/MWh more than doubles from 0.10 at 4pm (HE16) to 0.22 kW at 8pm (HE20). Inversely, the pool pump ratio decreases from 0.10 kW/MWh to 0.01 kW/MWh, showing more potential for capacity savings under an early peak definition compared to a later peak.

Table 12: Residential kW/MWh by End-use and Different Peak Definitions

End-use	kW/MWh 3-4 pm peak	kW/MWh 5-6pm peak	kW/MWh 7-8pm peak
Clothes Dryer	0.15	0.13	0.16
Cooking Range	0.20	0.25	0.11
Cooling	0.56	0.55	0.42
Dishwasher	0.10	0.31	0.27
Exterior Lighting	0.09	0.14	0.16
Interior Lighting	0.10	0.14	0.22
Plug Loads	0.11	0.12	0.12
Pool Pump	0.10	0.04	0.01
Water Systems	0.10	0.12	0.13

Figure 19: shows a heat map of annual residential cooling electric consumption in Indiana. It's apparent that AC resources contribute the most demand during summer afternoon and early evening hours. This closely follows the peaking pattern of the MISO system. We see that cooling will remain a relatively valuable source of capacity reduction through the early evening hours, but it starts to drop off by 8pm.

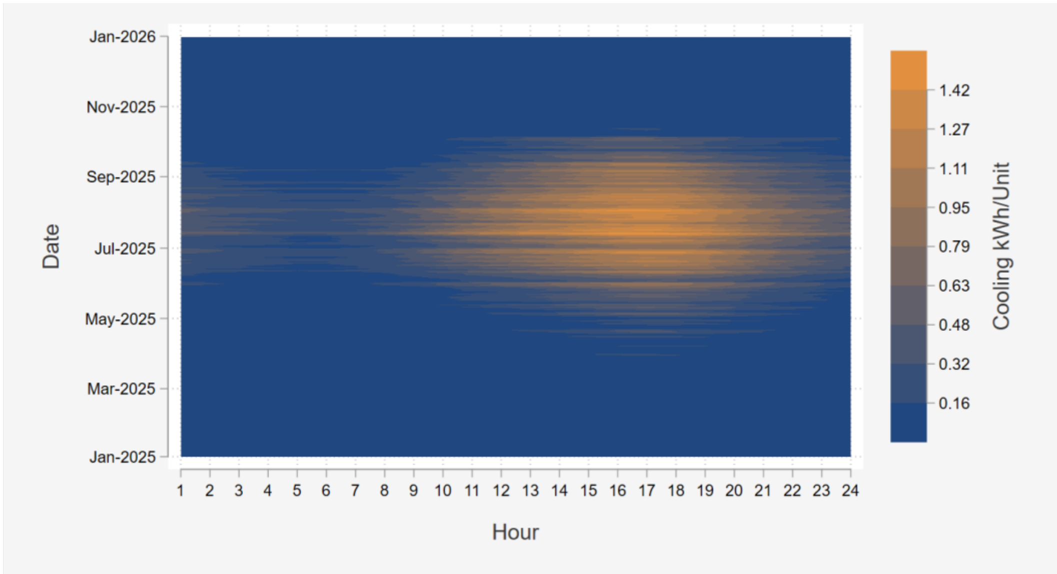


Figure 19: Indiana Cooling Heat Map

Figure 20: shows an 8760 load shape for residential annual interior lighting load. This resource predictably peaks in the evening hours between 7pm and 10pm as the sun goes down and households turn on more lights in the home. Given that profile, the capacity value of this resource will become more valuable as the peak shifts later into the evening. Although the DSM program opportunity from lighting is shrinking due to changing federal standards, it has been a significant share of historic program efforts.

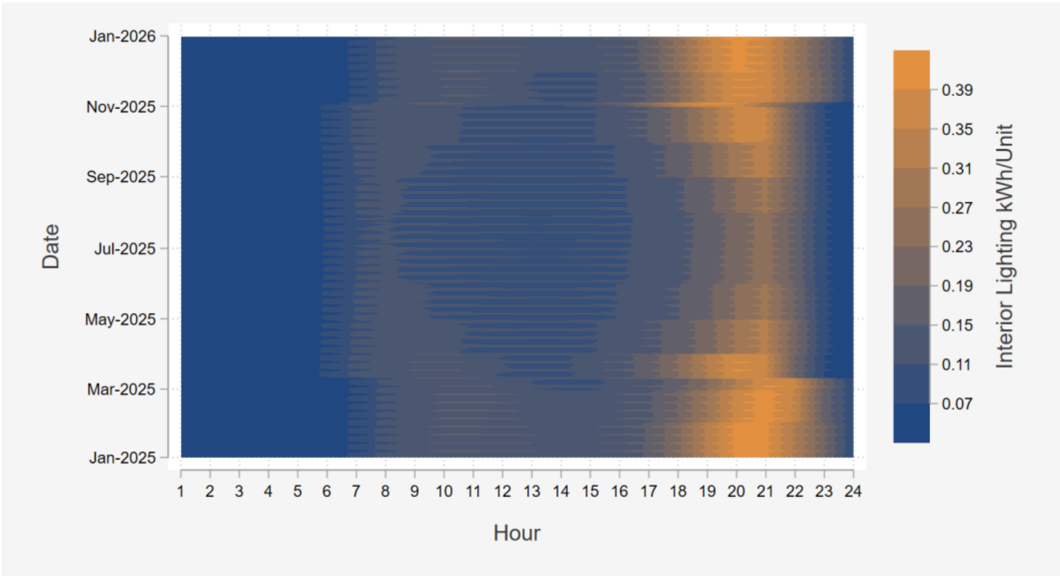


Figure 20: Interior Lighting Heat Map

Alternatively, **Figure 21**: shows a heat map of annual residential pool pump load for Indiana, which NREL assumes to operate year-round. Not all homes have pool pumps, so the magnitudes reflect the size of the load for homes with pool pumps multiplied by the percentage of homes that have the end use. This resource peaks in the late morning and early afternoon. With this consumption pattern, the capacity value of pool pumps might be expected to decrease as peak shifts later.

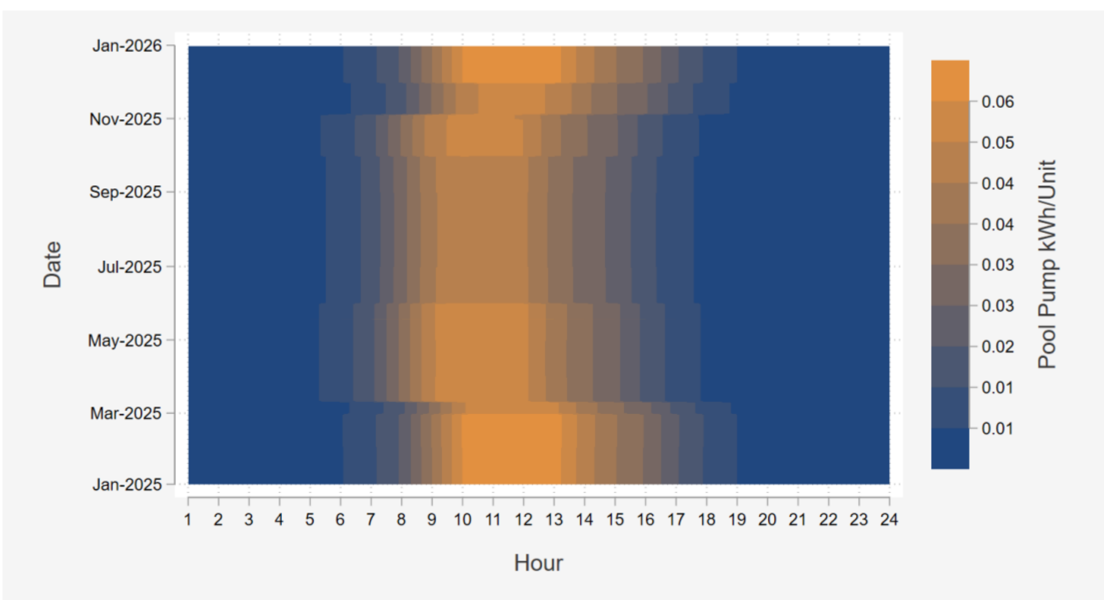


Figure 21: Indiana Pool Pump Heat Map

Commercial Load Shapes

Each commercial building/industry type has different energy use patterns, and therefore planners have an additional layer of detail to consider when looking at end-use capacity value in the commercial sector. For example, **Figure 22**: shows the normalized load shapes for interior lighting for eight major commercial building types. It's easy to see a pattern where, for many building types, interior lighting's capacity value will decrease as the peak shifts to later in the evening. However, for hotels, restaurants, and retail buildings, lighting end-use loads remain high or increase in the evening hours relative to their afternoon levels.

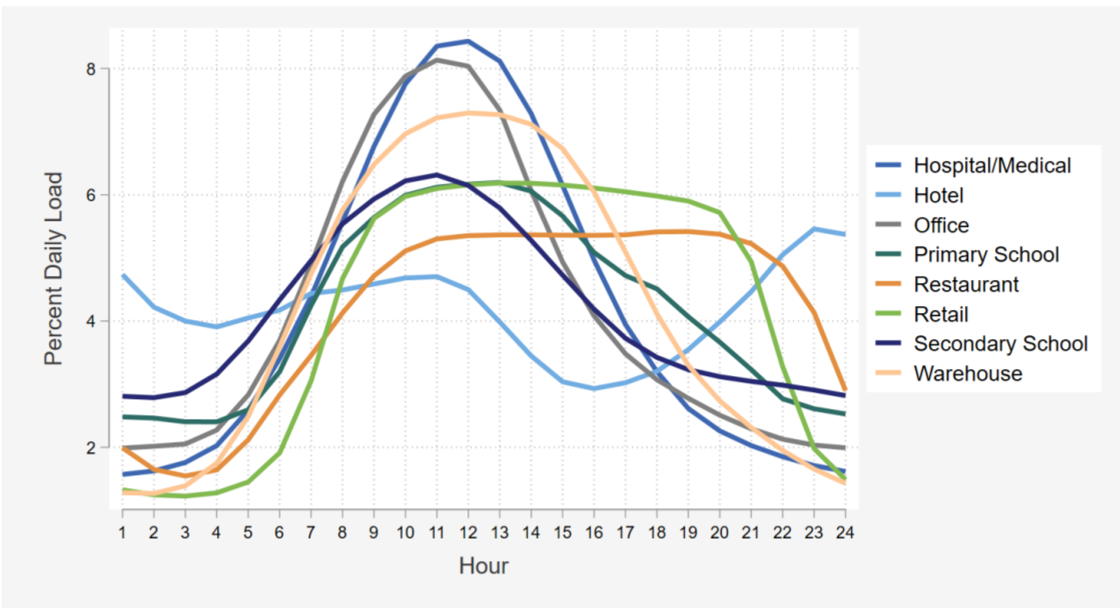


Figure 22: Normalized Commercial Interior Lighting Loads, by Building Type

Table 2 shows the estimated peak kW per annual MWh for interior lighting in each building type during summer months (June-September) from 3-4pm, 5-6pm, and 7-8pm (Hour Ending 16, 18, and 20, respectively). These values show both the pattern of load impact over time as well as each building type's potential capacity savings per MWh of EE impact. As expected, the kW/MWh impact remains relatively steady over these hours for retail and restaurant buildings, while hotel impact increases. Alternatively, the expected capacity savings for warehouses decreases towards the later hours, but their magnitude of impact relative to other commercial building types still remain high.

Table 2: Commercial Lighting kW/MWh

Building Type	kW/MWh 3-4 pm peak	kW/MWh 5-6pm peak	kW/MWh 7-8pm peak
Hospital/Medical	0.135	0.087	0.062
Hotel	0.081	0.088	0.110
Office	0.111	0.083	0.068
Primary School	0.119	0.106	0.087
Restaurant	0.147	0.148	0.147
Retail	0.167	0.164	0.156
Secondary School	0.099	0.081	0.074
Warehouse	0.164	0.112	0.074

Cooling load is another end use worth exploring for commercial buildings. **Figure 23**: shows the normalized load profile for cooling by building type. Cooling loads peak around 3pm-4pm in most building types and start to drop off sharply across the evening hours.

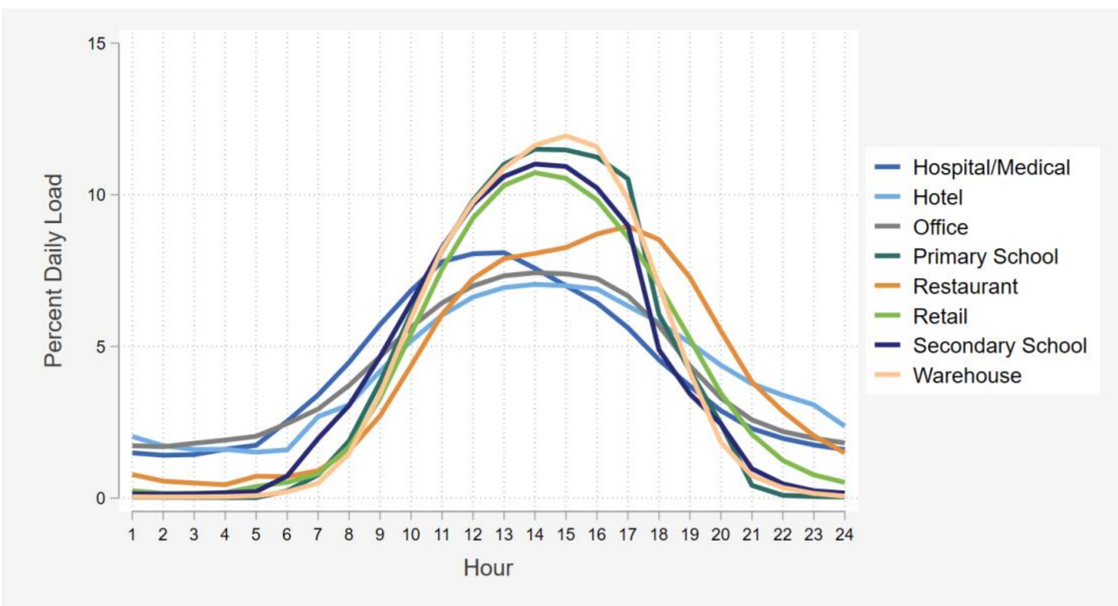


Figure 23: Commercial Normalized Cooling Loads by Building Type

Table 14: shows the estimated peak kW per annual MWh for cooling at each building type during summer months (June-September) from 3-4pm, 5-6pm, and 7-8pm (Hour Ending 16, 18, and 20, respectively). The values in **Table 14**: are generally higher than the values in **Table 2** due to the seasonal nature of air conditioning.

Table 14: Commercial Cooling kW/MWh

Building Type	kW/MWh 3-4 pm peak	kW/MWh 5-6pm peak	kW/MWh 7-8pm peak
Hospital/Medical	0.385	0.275	0.175
Hotel	0.375	0.317	0.241
Office	0.382	0.300	0.174
Primary School	0.736	0.376	0.158
Restaurant	0.578	0.565	0.370
Retail	0.654	0.470	0.234
Secondary School	0.621	0.281	0.141
Warehouse	0.757	0.465	0.123

Demand Response

Each year, California utilities are required to file forecasted impact estimates for their DR programs under different weather scenarios and system peak days, like the Load Modifying Resource accreditation process in MISO. In 2019, California changed its resource adequacy definition from 2pm-6pm to 4pm-9pm. They also report on two different weather conditions – typical and extreme. DSA compiled the capability estimates for long-running programs to better understand the DR program types that do better, worse, or about the same in the evening compared to late afternoon during both typical and extreme weather. Documenting the expected load impacts of an event across a wide range of weather conditions and time-of-day is an incredibly useful tool for modeling DR across scenarios. In addition to the peak shifting later in the evening over the study horizon, AES Indiana may want to model DR capability at both typical and extreme weather conditions.

Pacific Gas and Electric's SmartAC program is a residential DR program that is dispatched during energy supply emergencies. Customers need to have smart thermostats or smart switches installed so that when this resource is dispatched the AC automatically responds to the signal and lowers cooling demand. This type of DR resource will vary in its total impact depending on weather and time of day.

Table 15: shows the forecasted impact of the PG&E SmartAC program over an eight hour window. This data was pulled from 2017 and 2019 ex-ante load impact tables filed before and after the resource adequacy window change. Stitching together planning estimates from before and after the change return projected DR capability from 1pm to 9pm. The table shows the expected difference in performance is across a typical (1-in-2) and extreme (1-in-10) summer. During more extreme weather conditions, the SmartAC program impact is expected to peak around 5pm. During more mild

weather conditions, the SmartAC program is expected to deliver the most impact between 6pm and 7pm.

Table 15: PG&E SmartAC Forecasted Per-Participant Impact

Hour	Impact (kW) 1-in-10 Weather	Impact (kW) 1-in-2 Weather
14	0.46	0.20
15	0.58	0.30
16	0.66	0.38
17	0.71	0.43
18	0.62	0.52
19	0.61	0.52
20	0.49	0.40
21	0.31	0.24

Southern California Edison's (SCE) Summer Discount Plan (SDP) is a voluntary DR program that provides incentives to residential and non-residential customers who allow SCE to curtail their air conditioner when grid conditions require additional resources. **Table 16**: shows the predicted peak load impacts from this program for an extreme and typical summer. For both types of weather days, capability peaks during hours 17 and 18 and incrementally decreases each hour before and after.

Table 16: SCE SDP Forecasted Per-Participant Impact

Hour	Impact (kW) 1-in-10 Weather	Impact (kW) 1-in-2 Weather
14	0.65	0.56
15	0.78	0.67
16	0.92	0.79
17	1.03	0.89
18	1.06	0.91
19	0.94	0.80
20	0.76	0.63
21	0.71	0.59

The values in **Table 15**: and **Table 16**: reveal two important trends.

- Load management of residential AC delivers bigger impacts at extreme conditions.
- Impacts grow through the afternoon and peak around 6pm. Then they begin to wane through the evening hours. This will be important to consider as planning shifts to net peak, which is likely to occur after 6pm as shown in **Figure 24**: .

This dynamic way of looking at expected DR impacts allows planners to easily consider impacts at different peak times and weather conditions. Thinking of estimated DR impacts in the form of a time-temperature matrix, like **Figure 24**: , is a logical next step if peaking conditions are expected to change or if multiple weather scenarios are part of the stochastic IRP modeling process. **Figure 24**: comes from the DR planning and evaluation work for Public Service New Mexico, which was one of the utilities discussed in **Table 9**: which use the EnCompass software for its most recent IRP.

Temp	Hour Ending MDT					
	15	16	17	18	19	20
105	0.53	0.69	0.77	0.86	0.78	0.72
104	0.52	0.67	0.75	0.84	0.76	0.69
103	0.51	0.65	0.73	0.81	0.73	0.66
102	0.5	0.63	0.71	0.78	0.71	0.63
101	0.49	0.62	0.69	0.76	0.69	0.6
100	0.48	0.6	0.67	0.73	0.66	0.57
99	0.47	0.58	0.65	0.7	0.64	0.54
98	0.46	0.56	0.63	0.68	0.61	0.51
97	0.45	0.54	0.61	0.65	0.59	0.48
96	0.44	0.52	0.59	0.62	0.56	0.45
95	0.42	0.51	0.57	0.6	0.54	0.42
94	0.41	0.49	0.56	0.57	0.52	0.39
93	0.4	0.47	0.54	0.54	0.49	0.36
92	0.39	0.45	0.52	0.51	0.47	0.34
91	0.38	0.43	0.5	0.49	0.44	0.31
90	0.37	0.41	0.48	0.46	0.42	0.28
89	0.36	0.39	0.46	0.43	0.4	0.25
88	0.35	0.38	0.44	0.41	0.37	0.22
87	0.34	0.36	0.42	0.38	0.35	0.19
86	0.33	0.34	0.4	0.35	0.32	0.16
85	0.32	0.32	0.38	0.33	0.3	0.13

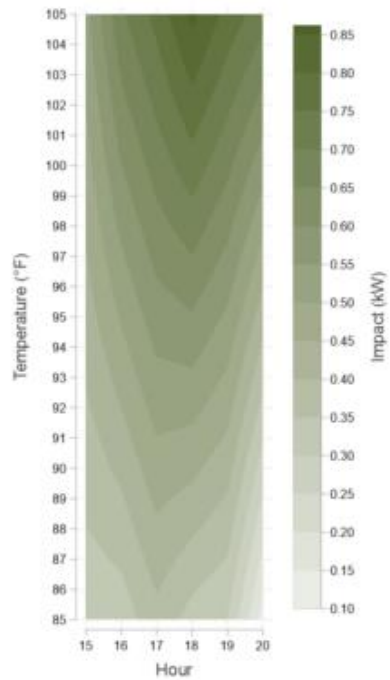


Figure 24: Sample Time-Temperature Matrix

Conclusion

As the energy transformation unfolds in Indiana, summer peaking conditions will shift later in the evening and have a steeper ramp up period. This is the premise behind AES Indiana's declining ELCC projections for solar resources over the study horizon. This section of the report highlights DSM modeling considerations which become increasingly important in a system where net peaks, rather than gross peaks, are the primary planning constraint. Both EE and DR are highly modular resources that can be used to defer capital investments during this transition period. However, both have dynamic responses over different hours and weather conditions. A firm understanding of these patterns will help planners better prepare to meet changing peaking conditions and provide reliable, clean, and affordable energy to AES Indiana customers. We recognize that the 2022 IRP process is well underway and there is limited runway left to develop more dynamic inputs. However, developing these structures and gaining experience in the near term will help the AES Indiana team in future planning endeavors. We would caution AES Indiana against finalizing any significant capital investment plans for new generation assets until more advanced peak load forecasting and DSM modeling procedures can be put in place.