POTENTIAL FOR PEAK DEMAND REDUCTION IN INDIANA

Prepared for Indiana Advanced Energy Economy by Demand Side Analytics, LLC

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INDIANA
ADVANCED ENERGY ECONOMY

Acknowledgements

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This study was developed using anonymized data from ecobee thermostat customers participating in Donate Your Data.

EXECUTIVE SUMMARY

Energy costs are an important component of the operating budget of homes and businesses across Indiana, giving all Hoosiers an interest in opportunities to reduce their energy costs. Those costs are unavoidably impacted by utility infrastructure investments, which are largely driven by peak loads. Approximately 10% of infrastructure investments focus on serving load in just 1% of hours of the year. As such, strategic peak demand reductions can help avoid or defer capital-intensive system upgrades and save hundreds of millions of dollars over the next decade. This analysis, commissioned by Advanced Energy Economy Institute (AEE Institute) on behalf of AEE Indiana, examines the magnitude and economic opportunity of three specific demand reduction strategies in Indiana.

Demand response (DR) strategies that shave peak loads or shift them to off-peak hours can be cost-effective alternatives to costly construction of new generation resources that sit idle most of the year. Energy storage technologies like batteries achieve similar benefits by storing energy at times when it is plentiful for use during peak hours. These alternatives to additional generating capacity can also avoid the need for transmission and distribution infrastructure investments that would similarly be needed to meet demand during just a relatively few peak hours. DR options can also be added incrementally, to match the need.

The biennial Integrated Resource Planning (IRP) process in Indiana is used as a platform for the state's investor-owned utilities (IOUs) to document the electric power requirements of their service territories and put forth, in transparent fashion, strategies to satisfy those needs. The types of demand reduction strategies included, and the level of incorporation of DR resources in prior IRPs, have varied significantly across the Indiana IOUs. Duke, NIPSCO, and Indiana Michigan Power have secured several hundred megawatts (MW) of load reduction capability from a relatively small number of large industrial customers. Duke, Indianapolis Power and Light (IPL), and Vectren have established residential air conditioner cycling programs that range from 20 MW to 60 MW of load reduction capability.

This paper provides a statewide analysis of three strategies the research team believes warrant focused consideration by system planners in future IRP cycles – commercial and industrial (C&I) load curtailment, residential connected thermostats, and battery storage.

Overall, this analysis shows that cost-effective DR and energy storage in Indiana have the potential to generate net benefits ranging from $448 million to $2.3 billion over 10 years, in scenarios representative of expected avoided costs in Indiana.

The optimal role of DR in the resource mix is largely a function of its costs relative to traditional solutions. A primary goal of the IRP process is to ensure adequate resources to confidently meet demand for electricity at the lowest cost. Ideally, this means supply-side resources and demand-side resources are placed side-by-side and selected based on levelized cost. To illustrate the sensitivity of DR potential to the cost of alternative resources, we modeled DR potential using three avoided cost scenarios:

- **Low Avoided Cost:** Assumes recent historic Midwest market prices for generation capacity avoided by DR investments and no value on the transmission and distribution system. Reductions valued at approximately $15/kW-year.
- **Medium Avoided Cost:** Includes approximately $60/kW-year for avoided generation capacity, consistent with tighter supply, and $10/kW-year each for benefits on the transmission and distribution (T&D) systems.
- **High Avoided Cost:** Assumes the traditional solution is construction of a new natural gas-fired power plant, with $100/kW-year for generation and $20/kW-year for benefits on the T&D systems.

Avoided costs are a key determinant of DR potential because they govern the equipment cost and/or incentive that can cost-effectively be made to participants to secure load reductions. When avoided costs support a more generous offer, participation rates increase and DR potential increases. Several avoided costs for demand-side management (DSM) published by IOUs in their most recent IRPs generally fell in a range between our Medium and High scenarios, indicating that these are representative of expected costs in Indiana.

Commercial and Industrial (C&I) Sectors DR Potential

Indiana's commercial and industrial sectors spent $11.3 billion on electricity in 2015, consuming over 144,000 GWh, according to the U.S. Energy Information Administration. For the Medium Avoided Cost scenario, the research team estimates 2,159 MW of DR potential in Indiana by 2027 for a day-ahead notification program – nearly 20% of forecasted summer peak demand for the C&I sectors, and resulting in savings over ten years of $485 million on a net present value (NPV) basis. For a day-of notification program, the 2027 potential is 1,203 MW – lower than the day-ahead estimate, but still almost 10% of summer peak demand, and providing $272 million in NPV benefits over 10 years. Savings are even greater under the High Avoided Cost scenario: $1.6 billion for the day-ahead program, $907 million for day-of.

Figure 1 shows DR market potential estimates for 2027 by avoided cost scenario, notification level, and sector. Table 1 shows the present value (in 2018 dollars) of the net benefits (benefits minus costs) of a 10-year C&I DR program by avoided cost scenario for day-ahead and day-of notification programs.

Figure 1: 2027 DR Potential Estimates by Avoided Cost Scenario

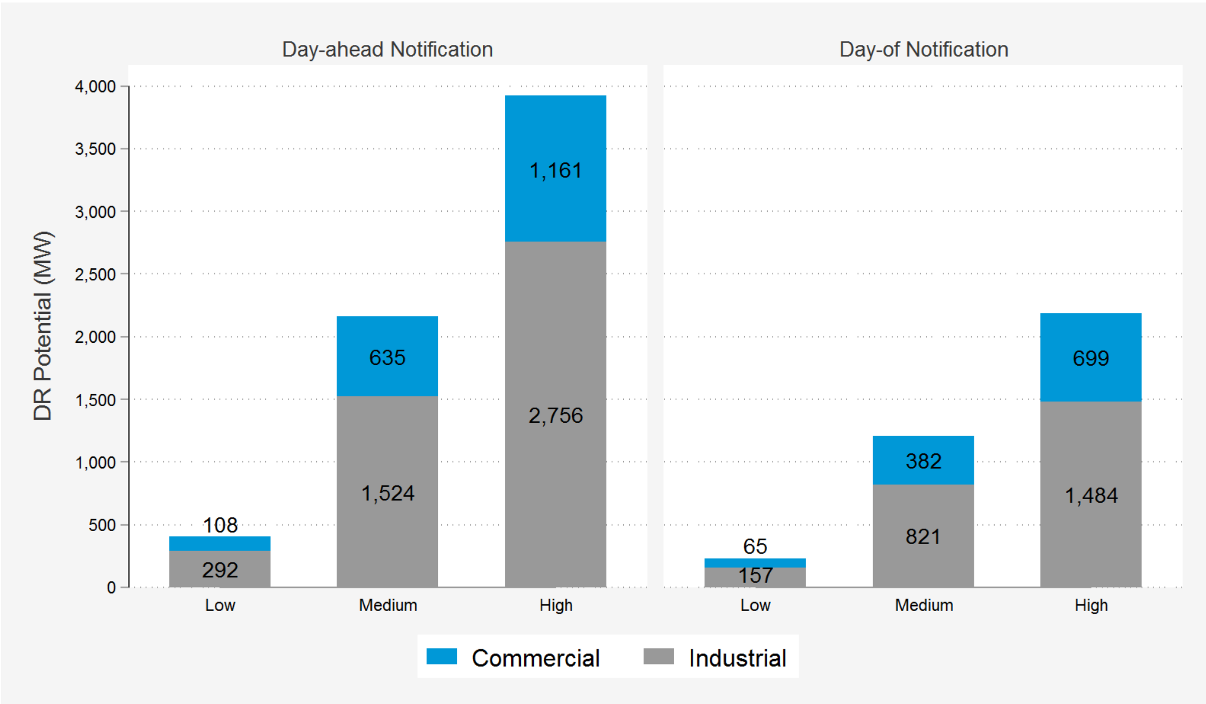

Table 1 - Present Value of Net Benefits by Avoided Cost Scenario - Ten Year C&I DR Program

Avoided Cost Scenario	Day-Ahead Notification ($2018M)	Day-Of Notification ($2018M)
Low	$15	$8
Medium	$485	$272
High	$1,615	$907

All of the DR market potential estimates shown are highly cost-effective by the standard measures applied by utilities and regulators, with Utility Cost Test[1] ratios ranging from 1.61 on the low end to 1.94 on the high end.

Residential Sector DR Potential

The adoption of internet-connected 'smart' thermostats such as those offered by Nest and Ecobee is growing due to customer demand as well as utility support for energy efficiency and DSM investment. These devices present an opportunity to scale residential DR resources at low cost. Because adoption of connected thermostats is driven by customer preferences, the utility costs of equipment and installation are lower than for traditional air conditioner cycling switches, such as those used in existing residential DR programs administered by several Indiana utilities. This presents a significant opportunity for increasing DR penetration in the residential sector. Smart thermostat capabilities like 'pre-cooling' of homes prior to DR events help improve participant comfort and enhance customer satisfaction.

Table 2 shows the significant opportunity presented by smart thermostats in Indiana over the next decade. Statewide, the aggregate estimated cost-effective achievable potential by 2027 is 230 MW under the Medium Avoided Cost scenario, leading to enrollment of 214,000 devices, net benefits of $73 million over the 10-year study horizon, and a strong benefit-cost ratio of 2.44 under the Utility Cost Test. Said another way, reducing peak load by using connected thermostats will lead to lower utility costs and lower customer bills than building new peaking power plants to address power plant retirements or increases in load. Under the High Avoided Cost scenario, demand reductions of over 530 MW – the peak production equivalent of five mid-sized power plants – can be attained, yielding $344 million in savings over the next 10 years.

Table 2 - Connected Thermostat 10-Year Cost-Effectiveness and Market Potential by Avoided Cost Scenario

Avoided Cost Scenario	2027 Enrollment (# thermostats)	2027 MW Impacts	Benefits ($2018M)	Costs ($2018M)	Net Benefits ($2018M)	UCT Ratio
Low	67,000	84	$8.9	$8.8	$0.1	1.01
Medium	214,000	229	$124.5	$51.1	$73.4	2.44
High	515,000	553	$541.4	$197.7	$343.7	2.74

[1] The Utility Cost Test (UCT) assesses cost-effectiveness from the perspective of the utility. Utility system benefits are compared to the cost of acquiring the resource. Any benefit-cost ratio greater than 1 means the program is cost effective.

Emerging Technology: Energy Storage

On energy storage, this report focuses on battery storage potential and cost-effectiveness from a utility perspective. The estimates of battery potential are incremental to the two customer-sited DR options explored in the residential and C&I sections of the report – that is, what cost-effective savings could be obtained from battery storage investments over and above those provided by DR initiatives.

Because energy storage is a relatively new technology, market potential estimates are inherently uncertain. Two key factors drive the potential for cost-effective battery storage – the price trends in battery storage technology and location-specific T&D deferral value. While other benefits from batteries were included in the analysis, in Indiana, avoided energy costs and avoided capacity costs alone are insufficient to make batteries cost-effective at current prices. As a result, cost-effectiveness for battery storage depends on identifying locations where it can help to defer or avoid transmission and/or distribution infrastructure investments. As costs drop, as they are projected to do over the forecast period, battery storage becomes cost-effective in an increasing number of locations – and for a greater share of peak demand.

Table 3 summarizes the estimated cumulative cost-effective potential for battery storage by 2027. For the Medium Avoided Cost scenario, 139 MW of cost-effective battery storage is projected, lowering utility and customer costs by $103 million over 10 years. Under the High Avoided Cost scenario, we estimate approximately 329 MW of cost-effective battery storage potential, delivering $311 million in net benefits. There is no cost-effective battery storage potential under the Low Avoided Cost scenario, which includes relatively low capacity prices and no transmission and distribution avoided costs.

Table 3 – Battery Storage Potential and Cost-Effectiveness

Avoided Cost Scenario	MW	NPV Benefits ($2018M)	NPV Costs ($2018M)	Net Benefits ($2018M)	UCT Ratio
Low	0.0	$0.0	$0.0	$0.0	N/A
Medium	139	$353	$250	$103	1.41
High	329	$917	$606	$311	1.51

Key Findings

Key findings from the analysis include:

There is significant remaining DR potential in the commercial and industrial sectors. Most of the C&I potential identified in the Medium Avoided Cost scenario appears to have been realized by Duke, NIPSCO, and Indiana Michigan Power under existing tariffs. But there remains considerable C&I potential, largely concentrated in Vectren and Indianapolis Power and Light service territories. Our modeling estimates show that, if fully realized, a day-ahead C&I demand response program could create $485 million in net benefits over the next 10 years in the Medium Avoided Cost scenario. In the High Avoided Cost scenario, we estimate $1.6 billion in savings over the next 10 years.

As air conditioning usage is a primary driver of summer peak demand, connected thermostats represent a significant opportunity to reduce residential energy use and provide savings. Over the next 10 years, we estimate that connected thermostat DR could save Indiana ratepayers $73 million in a Medium Avoided Cost scenario and $344 million in a High Avoided Cost scenario.

The potential for cost-effective battery storage to produce savings grows as battery costs decrease. Indiana avoided energy costs and avoided capacity costs alone are insufficient to make batteries cost-effective currently. Battery storage cost-effective potential depends highly on identifying locations where it can maximize its value, and these opportunities increase as the cost of battery storage falls as projected. A total of 139 MW and 329 MW of cost-effective battery storage is estimated under the Medium and High Avoided Cost scenarios, producing cumulative savings of $103 million and $311 million, respectively, over the next 10 years.

Overall, this analysis shows that cost-effective DR and energy storage in Indiana have the potential to generate net benefits ranging from $448 million to $2.3 billion over 10 years, in scenarios representative of expected avoided costs in Indiana.

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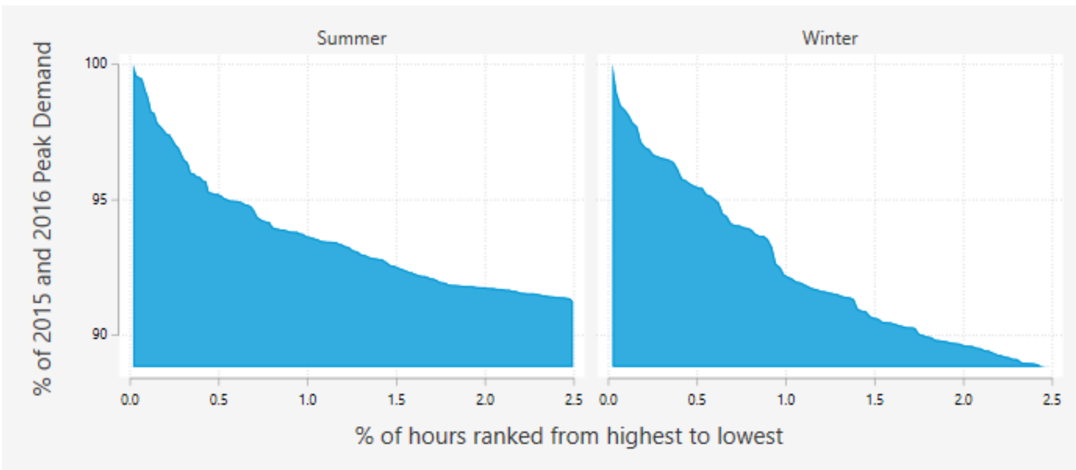
INTRODUCTION

Figure 2 illustrates a fundamental aspect of current power system planning in Indiana – a significant share of the system capacity is built to meet demand in a very small number of hours. Load duration curves sort electricity demand from highest to lowest and are a good way to visualize how 'peaky' a system is. Figure 2 focuses on the top 2.5% of hours in the summer and winter seasons, and shows that Indiana about 8-10% of infrastructure requirements and costs are needed to meet demand in this very small number of hours.

Figure 2: Indiana Normalized Load Duration Curve 2015-2016



Since the electricity system is sized to meet demand at all hours of the day, peak demand reductions improve the economic efficiency of the system by reducing the need for capital-intensive infrastructure investment and improving the utilization of existing generation, transmission and distribution assets. Demand response (DR) is a demand-side electricity resource that serves as an alternative to traditional supply side electricity resources, including coal, natural gas, and nuclear power plants, or renewable power generation (solar, wind, etc.). DR entails using less electricity during key hours when electricity prices are high, and/or the electric grid is at risk of having demand exceed supply. This can be achieved in a variety of ways across the residential, commercial, and industrial customer classes. Common strategies include reducing air conditioning load by changing thermostat setpoints or restricting Heating Ventilation and Air Conditioning (HVAC) equipment runtime, shifting energy-intensive production to off-peak hours, shutting down production entirely, and by sending price signals that encourage lower usage during defined DR events (e.g., time-of-use rates, peak time rebates, and critical peak pricing). Customers who participate in DR programs typically receive a monetary incentive for their participation.

The primary benefit streams from DR include:

- The need for peaker plants, which sit idle for most of the year, can be deferred or perhaps eliminated entirely. This has both financial and environmental benefits. Not constructing the peaker plants means the costs associated with constructing the plants will be avoided, which translates to fewer costs that need to be recovered from electricity ratepayers. Additionally, any environmental impacts associated with peaker plant construction and operation would be reduced.

- Reducing peak demand helps avoid the use of existing generating units with higher marginal costs. In a competitive market setting, this translates to lower wholesale prices for electricity and in a vertically integrated setting, it translates to lower cost of service. In either market structure, reductions in peak demand help to lower retail electricity rates – which is a benefit to all customers. To illustrate the magnitude of this benefit, the New York Public Service Commission stated in a 2015 Order that, "If, for example, the 100 hours of greatest peak demand were flattened, long term avoided capacity and energy savings would range between $1.2 billion and $1.7 billion per year." [2]

- If demand reductions are targeted to constrained locations of the transmission and distribution network, costly infrastructure upgrades can be deferred, or even avoided. The value of these demand reductions is inherently location-specific.

This report examines the demand response potential for two established strategies at a statewide level – C&I load curtailment and control of residential air conditioning (AC). Indiana has several legacy AC cycling programs that use radio frequency to directly control AC usage, but we have chosen to look at the potential from connected "smart" thermostats, which have several key technical and economic advantages over the legacy direct load control equipment. Examining these strategies on a statewide basis likely misses some of the nuance utilities might wish to consider in an Integrated Resource Plan proceeding, but underscores the importance of considering these opportunities alongside traditional supply-side options to find the right resource mix for each service territory.

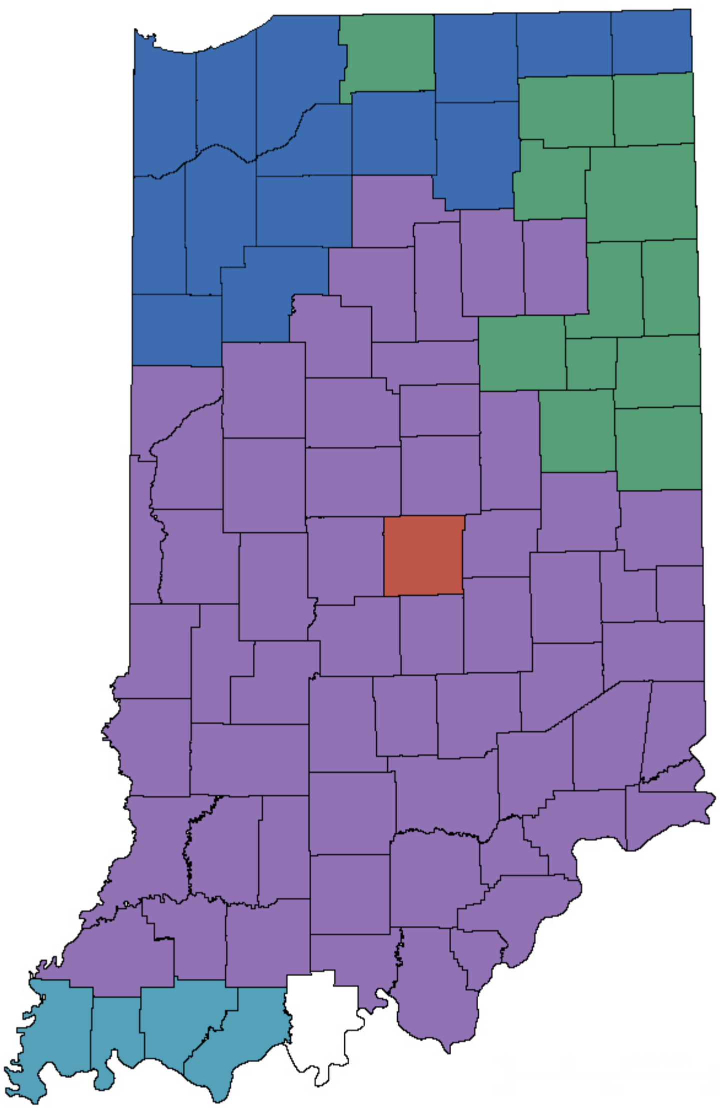
This report also includes an investigation of an emerging opportunity for grid-scale energy storage. Storage technologies like batteries allow electric energy to be stored when it is cheap and/or plentiful and injected back into the system at times when supply is scarce, costs are high, or local areas of the grid are constrained. Like the more established DR strategies, the result is a flattening of the costly peaks shown in Figure 2. As battery prices are forecasted to decline over the study horizon, our estimates of economic potential associated with grid-scale storage increase.

[2] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d

INDIANA LOAD PROFILE

Electricity load in Indiana is served primarily by five investor-owned utilities (IOUs): Indiana Michigan Power (I&M), Northern Indiana Public Service Company (NIPSCO), Duke Energy Indiana (DEI), Indianapolis Power & Light (IPL), and Vectren (formerly Southern Indiana Gas & Elec Co). Figure 3 shows the service territories for these five power companies. Although several counties in Indiana are served by multiple IOUs, for simplicity, the map assigns each county to the primary IOU.

Figure 3: Indiana Electric Utility Service Areas

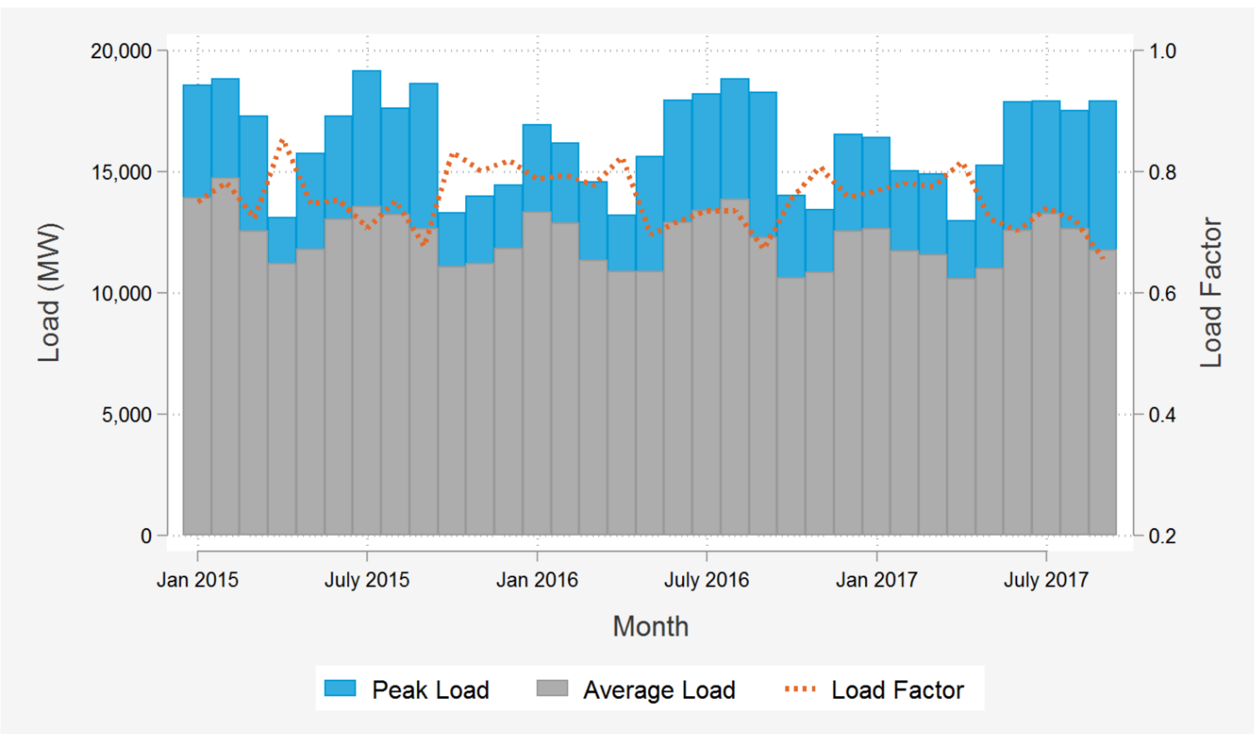


Color	IOU
	Duke Energy
	I&M
	IPL
	NIPSCO
	Vectren

The IOUs in Indiana are served by two regional transmission organizations (RTOs): PJM Interconnection (PJM) and the Midcontinent Independent System Operator (MISO). I&M falls under PJM territory and the other four electric utility companies fall under MISO's load resource zone 6 (LRZ6). LRZ6 also contains a small pocket of northwestern Kentucky.

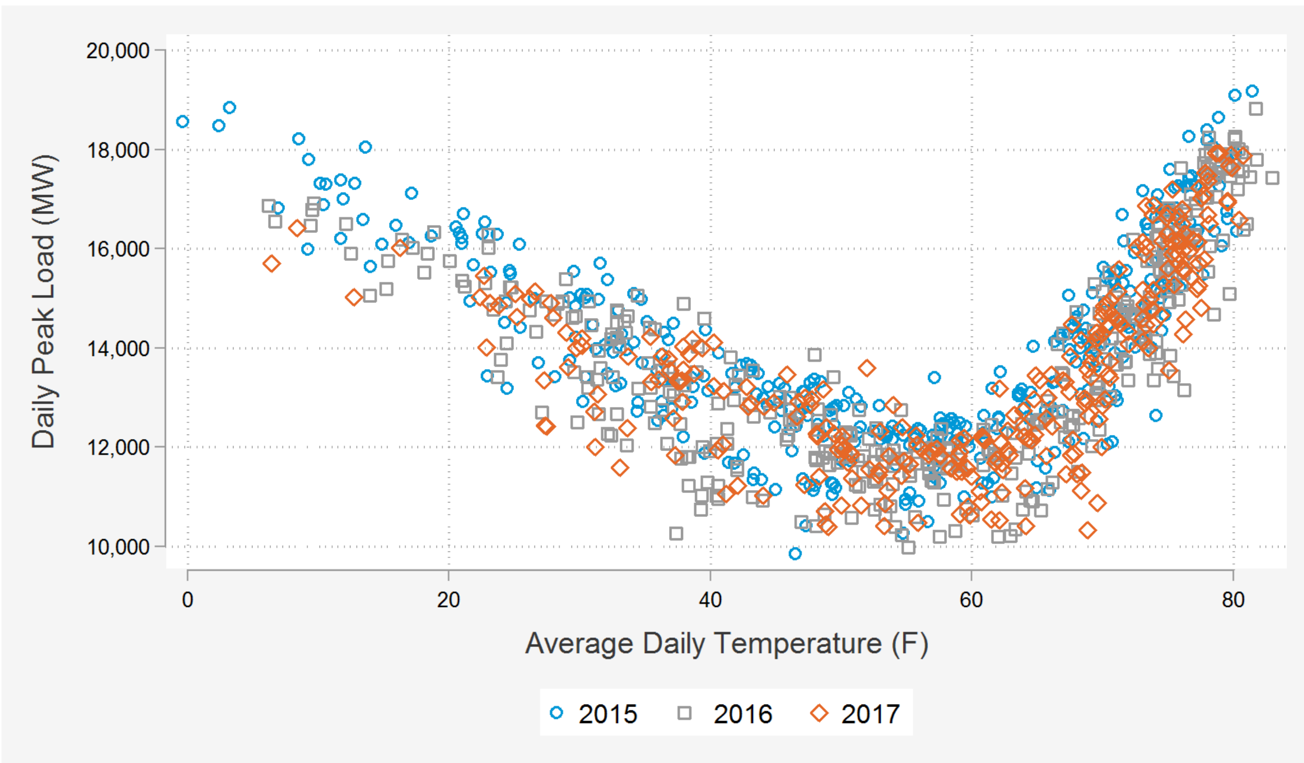
Indiana's electricity demand peaks in both the summer and winter, which implies that system load is associated with outdoor weather conditions. (For details on how the research team assembled a historic load profile for Indiana, see Appendix A.) Figure 4 shows the average load, peak load, and load factor for each month from January 2015 to September 2017. Note that load factor is the ratio of the average load to the peak load and is a proxy for overall plant and T&D asset utilization. Indiana load factors are lowest during summer months, indicating these months have the highest peaks and may benefit the most from DR activities.

Figure 4: System Utilization by Month



To explore the relationship between load and outdoor weather conditions, the research team downloaded historical weather data for several of the largest cities in Indiana, then used the population sizes of these cities to create a weighted weather profile for Indiana. Figure 5 compares average daily temperatures in Indiana to maximum daily statewide demand. Not surprisingly, the figure suggests warmer weather and cooler weather are related to higher demand. End uses that drive the peak, like central air conditioning, are thus excellent targets for demand reduction strategies. Although Indiana's summer peak typically exceeds the winter peak by approximately 10%, the winter peak during the 2014-2015 'polar vortex' approached summer peaking levels, indicating that DR could also be beneficial during winter months.

Figure 5: Weather Sensitivity of Indiana Loads



ECONOMIC MODELING

Market potential studies typically examine potential across technical, economic, and achievable potential scenarios. This report directly models achievable potential by first establishing customer incentives that will lead to cost-effective outcomes, and then estimating the customer adoption at those incentive levels. This section documents the assumptions used in the analysis.

Avoided Costs

The economic potential for demand response is ultimately driven by its cost compared to the alternatives. In a system with a surplus of existing supply-side resources, the monetary value of peak demand reductions is limited. Conversely, when utilities are facing costly system upgrades to meet load, peak demand reductions are quite valuable. This study uses a modeling approach where the avoided cost, i.e., the cost of the traditional solution that is avoided by using DR, is a primary independent variable in the estimation of DR potential. The research team developed low, medium, and high avoided cost scenarios and calculated DR potential for each.

AVOIDED COST OF GENERATION CAPACITY

From an economic perspective, one of the primary benefits of a demand response program is avoiding, or deferring, generation capacity costs. That is, DR programs are an alternative to construction of new generation plants or securing generation capacity via wholesale markets. The question then becomes: How should these avoided costs be valued? The avoided cost assumption is one of the most critical assumptions in this report, as it will factor into estimates of DR potential, estimates of net benefits, and cost-effectiveness models. To inform this assumption, the research team leveraged historic PJM and MISO capacity market clearing prices and Cost of New Entry (CONE) forecasts for the next three delivery years, as described in more detail below.

In examining historic clearing prices, the research team noted that these varied considerably from year-to-year. For example, over the past fourteen years, PJM clearing prices ranged from $6 per kW-year to $63 per kW-year. Similarly, MISO clearing prices ranged from less than $1 per kW-year up to $26 per kW-year. Instead of trying to forecast a single value stream for this key assumption over the study horizon, the research team elected to estimate DR potential and cost-effectiveness across three different avoided cost scenarios: Low Avoided Cost, Medium Avoided Cost, and High Avoided Cost. By year and avoided cost scenario, Table shows our estimates of avoided cost of generation capacity over the study horizon. A discussion of each scenario follows. Note that our avoided cost estimates escalate by 2% annually over the study horizon.

Table 4: Avoided Cost of Generation Capacity

Model Year	RTO Delivery Year	Avoided Generation Capacity Costs ($/kW-year)		
		Low Scenario	Medium Scenario	High Scenario
2018	2018/2019	$13.89	$56.43	$98.96
2019	2019/2020	$14.17	$57.55	$100.94
2020	2020/2021	$14.46	$58.71	$102.95
2021	2021/2022	$14.75	$59.88	$105.01
2022	2022/2023	$15.04	$61.08	$107.11
2023	2023/2024	$15.34	$62.30	$109.26
2024	2024/2025	$15.65	$63.54	$111.44
2025	2025/2026	$15.96	$64.82	$113.67
2026	2026/2027	$16.28	$66.11	$115.94
2027	2027/2028	$16.61	$67.43	$118.26

The Low Avoided Cost scenario assumes that MISO and PJM clearing prices for the next decade will remain in line with recent historical clearing prices. The starting point for this scenario ($13.89 per kW-year) is a function of the average MISO clearing price over the past four delivery years ($8.55 per kW-year) and the average PJM clearing price over the last fourteen delivery years ($35.61 per kW-year). Market clearing prices for capacity are likely not the best proxy in Indiana where the major utilities are vertically integrated and generation capacity is secured primarily through a regulated Integrated Resource Planning (IRP) process rather than a competitive market. This is particularly true of MISO utilities where the forward capacity auction process is less developed than the one in PJM.

The starting point for the High Avoided Cost scenario ($98.96 per kW-year) is a function of CONE estimates for MISO LRZ6 and for PJM. 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. Simply put, the High Avoided Cost scenario estimates potential and cost-effectiveness of demand reduction strategies assuming the alternative is to construct an infrequently used natural gas plant. Note that our high avoided costs are similar to the avoided generation capacity costs filed by NIPSCO and Vectren in their 2016 IRPs (Table 4). Duke and IPL stated in their most recent IRPs that avoided costs are confidential and thus they did not include values in their public filings.

Table 4: 2017 Avoided Costs ($/kW-year) as Filed in IRP

Utility	Generation Capacity	Transmission Capacity	Distribution Capacity
NIPSCO[3]	$122.92	$2.42	$46.32
Vectren[4]	$91.82	$9.18	

The starting point for the Medium Avoided Cost scenario ($56.43 per kW-year) is simply the average of the starting points for the Low and High Avoided Cost scenarios. The research team feels that the Medium scenario bests represents the options facing system planners in Indiana, so many of the more detailed results presented in the sections to follow will highlight this scenario.

OTHER AVOIDED COSTS

Although avoided generation capacity costs are the primary benefits in reducing peak demand, there are other monetary benefits associated with demand response programs. Table 5 lists the assumptions for avoided costs of transmission and distribution capacity and

Table 6 shows the avoided cost of energy. Our modeling assumes energy neutral demand reductions where demand reduced during peak hours is offset by an increase during off-peak hours. The energy benefit of this shift is monetized as the difference between assumed average summer on-peak and off-peak wholesale energy prices.

The avoided cost of transmission and distribution capacity values shown in Table 5 are system-wide average assumptions. In reality, Indiana's power system is made up of a majority of locations with little or no T&D value and a few pockets where the avoided cost is several hundred dollars per kW-year. System-wide averages are used for the C&I and residential DR modeling, while the energy storage modeling assumes batteries would only be sited in the areas of the grid where expensive upgrades could be avoided or deferred via reductions in peak demand.

[3] Table 5-12 of NIPSCO's 2016 Integrated Resource Plan.
[4] Figure 10.13 of Vectren's 2016 Integrated Resource Plan.

Table 5: 2018 Avoided T&D Assumptions by Avoided Cost Scenario ($/kW-year)

Avoided Cost Scenario	Avoided Transmission	Avoided Distribution	Avoided T&D
Low	$0	$0	$0
Medium	$10	$10	$20
High	$20	$20	$40

(T&D = Transmission and Distribution)

Table 6: 2018 Avoided Cost of Energy Assumptions

Summer Off-Peak Energy ($/MWh)	Summer On-Peak Energy ($/MWh)	Avoided Energy Costs ($/MWh)
$30.00	$50.00	$20.00

Cost Effectiveness

The research team elected to use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to evaluate the cost-effectiveness of the demand response options. A UCT ratio less than one indicates that the program costs exceed the program benefits, a UCT value equal to one indicates that the program costs and benefits are identical, and a UCT ratio greater than one indicates that the benefits exceed the program costs. In calculating UCT ratios, note that all costs and benefits over the study horizon were expressed in 2018 dollars. To this end, a discount rate of 8% was used the reflect a typical weighted cost of capital of an investor-owned utility. For information on the costs that factor into UCT ratios, see Appendix C: Cost Effectiveness.

COMMERCIAL AND INDUSTRIAL DEMAND RESPONSE

Indiana's economy has a large manufacturing component driven by steel production, automotive and farm equipment, petrochemicals, medical equipment, and pharmaceuticals. Energy-intense industrial facilities account for approximately one-third of the summer peak demand for electricity in the state and thus present a significant opportunity for demand response. Many large energy users will commit to shed load upon request in exchange for payment or bill credit.

Existing Resources

The research team reviewed the most recent Integrated Resource Plans submitted by each of the five IOUs in Indiana and documented the amount of non-residential DR in each filing and compared it to summer peak demand forecast for 2018. Table 7 reveals a varied approach to C&I load curtailment across the state.

Table 7: Existing Non-Residential Demand Response by IOU

Investor Owned Utility	C&I DR Total (MW)	2018 Peak Demand Forecast (MW)	C&I DR Capability (Percent of Peak)
Duke Energy Indiana	694	6,613	10.5%
NIPSCO	530	3,160	16.8%
I&M	298	4,434	6.7%
Vectren	35	1,104	3.2%
IPL	1	2,864	0.03%
IOU Total	**1,558**	**18,175**	**8.6%**

While Duke, NIPSCO, and I&M have well-developed portfolios of non-residential DR resources, Vectren and IPL show limited contribution to resource adequacy from C&I demand response. The characteristics of these existing resources also varies across the state:

Duke Energy Indiana's DR strategy includes both day-ahead economic dispatch triggered by market prices and emergency dispatch triggered by MISO.

NIPSCO's portfolio includes a variety of DR options on various tariff riders that dictate the number of hours of availability annually, notification time, and participant compensation via demand charge credit.

I&M secures load reduction commitments from large C&I customers as a capacity resource and the aggregated reductions are factored into PJM's forward planning parameters. I&M's portfolio is concentrated among a small number of large customers, with over 200 of the nearly 300 MWs coming from just three customers. PJM regulations require rapid response (30 minutes), but dispatch has been infrequent historically, with most years having no activity other than a test event.

Vectren's 2016 IRP includes 35 MW of C&I demand response from five large customers. These sites receive a credit for commitment to reduce load under certain conditions. The IRP also notes that Vectren's tariff "*includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market.*"

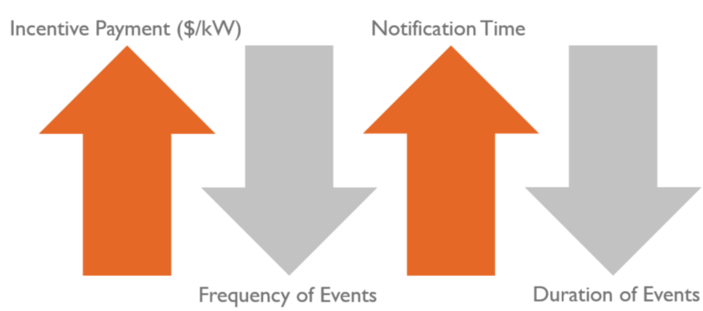
IPL lists just 0.9 MW of non-residential DR in its 2016 IRP, noting that EPA regulations on diesel generators led to the departure of most historic participants.

It is important to note that the estimates of DR potential discussed in the sections to follow are not incremental to these existing programs. That is, we are not estimating how much DR potential exists beyond the existing resources noted in Table 7. Rather, these are estimates of *total* DR potential using a more generalized methodology.

Modeling Demand Response Potential

Demand response potential from large businesses – and the cost to acquire it – is driven by a few key factors. These key factors and the directional effect they have on DR potential are shown in Figure 6.

Figure 6: Drivers of DR Potential



Estimating demand response potential at different levels of these four critical inputs would result in a dizzying array of DR potential estimates. To limit the range of DR potential estimates, the research team made several assumptions regarding program design. Program design refers to how a demand response program is implemented, including how much notification time the participants receive, how many DR events will be called, how long the DR events last, and what sort of incentive payment participants receive. Assumptions regarding each of the four DR levers are discussed in Appendix E: Modeling Demand Response Potential.

Table 8 briefly describes some of the most relevant inputs the research team used in estimating DR potential and cost-effectiveness.

Table 8: Summary of Input Assumptions for C&I DR Potential Modeling

Input Variable	Notes
Avoided Cost Scenario	Three levels considered – Low, Medium, and High. Avoided costs are escalated by 2% annually.
Notification Design	Two levels considered – Day-Ahead notification and Day-Of notification.
Participant Incentive	Each avoided cost scenario has its own incentive level, and incentive levels are escalated by 2% annually. Incentives were derived through a simulation described in Appendix E: Modeling Demand Response Potential
Total Dispatch Hours	Eight events, each three hours long, for a total of 24 dispatch hours. This assumption was informed by historical load data and historical MISO and PJM LMPs.
Indiana Peak Load Forecast	Assembled based on MISO and PJM load forecasts, EIA energy sales records, and assumptions about load factor by sector
Price Elasticity of Demand	Elasticity values are taken from the *DR Potential Study Report for Pennsylvania*, composed by GDS Associates and Nexant.[5]

Results

DEMAND RESPONSE POTENTIAL

As discussed in previous sections, estimates of C&I DR potential are driven by avoided cost assumptions and the amount of notification participants receive. Broken down by sector and by level of notification, Table 9 shows estimates of DR potential across the study horizon for the Medium Avoided Cost scenario.[6] For comparison, Table 9 also shows the peak load forecast that the research team developed for the C&I sectors. As expected, DR potential is significantly greater for the day-ahead notification level, as the extra notification time gives participants more flexibility in adjusting their staffing and operational schedules, which will lead to higher participation levels and larger load reduction commitments. Note that in 2027, which is the final year in the study horizon, the estimated C&I DR potential for the Medium Avoided Cost scenario with day-ahead notification is approximately 2,160 MW – this is just shy of 10% of the estimated peak load in Indiana for that year.

[5] Available at http://www.puc.pa.gov/pcdocs/1345077.docx

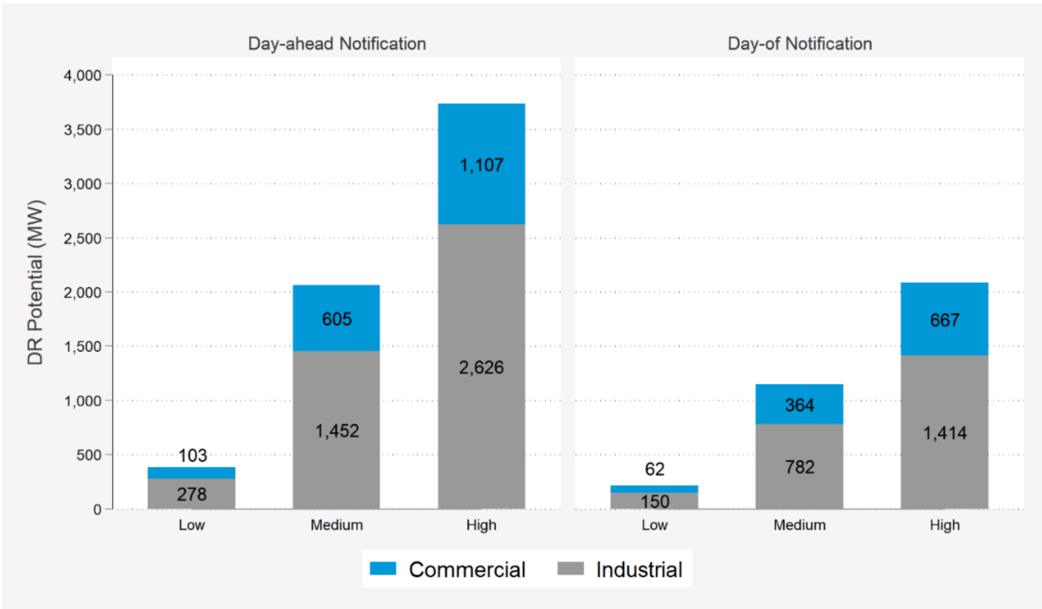
[6] Readers can find similar tables for the Low and High Avoided Cost scenarios in Appendix F: C&I DR Potential Tables.

Table 9: DR Potential (MW) for Medium Avoided Cost Scenario

Year	Peak Load Forecast (MW)		Commercial DR Potential (MW)		Industrial DR Potential (MW)	
	Commercial	Industrial	Day-ahead	Day-of	Day-ahead	Day-of
2018	4,616	6,939	574	346	1,379	743
2019	4,678	7,033	582	351	1,397	753
2020	4,730	7,111	589	354	1,413	761
2021	4,784	7,191	595	358	1,429	769
2022	4,836	7,270	602	362	1,445	778
2023	4,887	7,346	608	366	1,460	786
2024	4,941	7,428	615	370	1,476	795
2025	4,993	7,506	621	374	1,491	803
2026	5,048	7,588	628	378	1,508	812
2027	5,102	7,670	635	382	1,524	821

Figure 7 shows average annual DR potential over the study horizon, broken down by avoided cost scenario, level of notification, and sector. This figure highlights how important the avoided cost and notification time assumptions are. To illustrate the impacts of these assumptions, consider the two ends of the spectrum. For the Low Avoided Cost scenario with a Day-of notification time, our estimate of average annual C&I DR potential is 212 MW, or approximately 2% of the average forecasted C&I peak load over the same period. For the High Avoided Cost scenario with a Day-ahead notification time, our estimate of average annual C&I DR potential is 3,733 MW, or approximately 31% of the average forecasted C&I peak load over the same period.

Figure 7: Average Annual DR Potential Estimates by Avoided Cost Scenario – Day-Ahead and Day-Of Notification



Finally, Table 10 shows DR potential estimates by avoided cost scenario, level of notification, and sector for just the last year of the study horizon (2027). Table 10 also shows a total C&I DR potential estimate, as well was what percentage of the total statewide 2027 peak (commercial, industrial, and residential) the DR estimate represents. On the high end, the High Avoided Cost scenario coupled with a day-ahead notification design results in an estimate of DR potential that represents about 17.5% of the forecasted peak. On the low end, the Low Avoided Cost assumption coupled with a day-of notification design results in an estimate of DR potential that represents about 1% of the forecasted peak. In the middle, the Medium Avoided Cost scenario coupled with a day-ahead program design results in an estimate of DR potential that represents almost 10% of the forecasted system peak, demonstrating that DR can meet a significant portion of projected peak demand.

Table 10: 2027 DR Potential by Avoided Cost Scenario, Notification Level, and Sector

Avoided Cost Scenario	Notification Level	Commercial DR Potential (MW)	Industrial DR Potential (MW)	Total C&I DR Potential (MW)	Percentage of 2027 Peak
Low	Day-ahead	108	292	401	1.8%
	Day-of	65	157	222	1.0%
Medium	Day-ahead	635	1,524	2,159	9.6%
	Day-of	382	821	1,203	5.4%
High	Day-ahead	1,161	2,755	3,917	17.5%
	Day-of	699	1,484	2,183	9.7%

COSTS AND BENEFITS

All the C&I DR program design and avoided cost variations presented in this study are cost-effective, with UCT ratios ranging from 1.61 on the low end to 1.94 on the high end. Like DR potential, the costs and benefits associated with DR are influenced by the avoided cost assumptions and the level of notification that the DR participants receive. Table 11 shows average annual net benefits over the study horizon by avoided cost assumption and notification design. Appendix G includes a complete set of costs, benefits, and net benefits by avoided cost scenario and notification time. For a medium avoided cost assumption and a day-ahead program design, our model predicts an average annual net benefit of $74.2 million over the 10-year study horizon.

Table 11: Average Annual Net Benefits by Avoided Cost Assumption and Notification Design

Avoided Cost Scenario	Average Annual Net Benefits ($ Millions)	
	Day-ahead Notification	Day-of Notification
Low	$2.3	$1.3
Medium	$74.2	$41.6
High	$247.1	$138.8

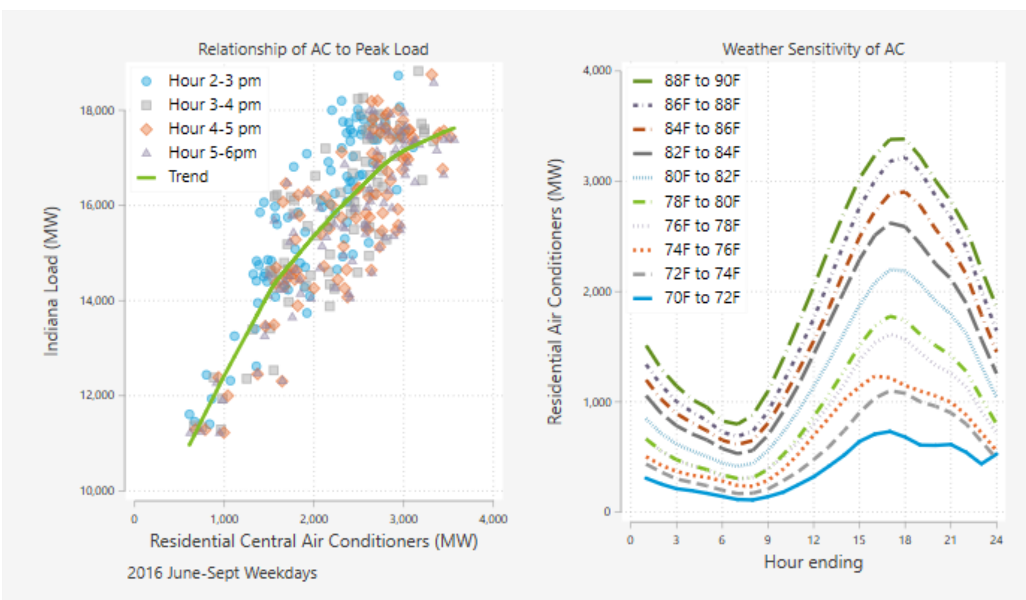
In a utility IRP setting, the net benefits calculation would be performed differently, but would produce a similar result. Planners would likely run two scenarios to fulfill the resource requirements – one with DR options and one without. In the scenario with DR resources available, presumably DR would displace certain higher-cost supply-side resources in the stack and lead to a lower total investment to meet the needs outlined in the IRP. The cost profiles of the two scenarios would then be compared to assess the net economic benefit of including DR in the resource mix.

RESIDENTIAL DEMAND RESPONSE

With a population of 6.6 million, Indiana has 2.8 million residential accounts, who spent $2.85 billion on electricity in 2015 and consumed 32,604 GWh. Approximately 85% of residents in Indiana have central air conditioning. Not surprisingly, residential customers use more power when it is extremely hot and contribute more to peak demand, which drives the need for additional generation, transmission, and distribution infrastructure.

Figure 8 shows the relationship between residential air conditioning and Indiana peak loads. It was developed using system load data from PJM and MISO and air conditioning runtime data from homes with Ecobee thermostats. Indiana weather data is merged to create the right side of Figure 8 and illustrate the sensitivity of air conditioning to weather conditions. Based on our analysis of these data sources, we estimated that residential central air conditioning accounted for approximately 20% of Indiana's peak load in 2016. 2016 was a cooler weather year, suggesting that the contribution of residential air conditioning to peak load is typically higher than our estimate for 2016. Because residential air conditioning is a major driver of the system-wide peak, if managed, it can reduce the need to build additional infrastructure to accommodate additional peak load. Because air conditioner use is higher when weather is more extreme, reductions from residential air conditioners can be larger precisely when resources are needed most.

Figure 8: Residential Air Conditioning, Indiana Peak Loads, and Weather Sensitivity



Existing Programs

Several utilities in Indiana have existing residential customer programs designed to curtail peak demand. These programs focus on recruiting customers to install devices that allow utilities to scale down air conditioner or water heater energy use when demand is high. Table 12 summarizes the characteristics of residential customer load control or smart thermostat DR programs in Indiana.

Table 12: Existing Residential Demand Response Resources in Indiana

Utility	# of Electric Residential Customers (2015)[7]	Central Air Conditioner Saturation Estimate[8]	Number of Program Participants	Existing Load Reduction Capability
Duke Energy Indiana	699,440	74%-90%	54,000	61 MW
I&M	401,544	74%-90%	1,000	1 MW
IPL	431,182	74%-90%	50,000	45 MW
NIPSCO	404,889	74%-90%		
Vectren	129,113	74%-92%	23,000	19 MW
Other	738, 693	74%-92%		
Total	2,804,861		128,000	126 MW

Existing load management programs are expected to be the most cost-effective residential demand response resource over the study horizon because the equipment and installation costs are sunk. Going forward, however, the main residential demand response potential is expected to be connected thermostats, as described below.

[7] 2015 EIA sales data by utility and state (Form 826)

[8] Based on U.S. Census American Housing Surveys from Metropolitan Statistical Areas near Indiana. Since a survey was not implemented in Indiana we used 2015 survey data for Chicago (71.4%), Cincinnati (81.4%) and Detroit (74.1%), and 2013 survey data from Louisville (90.2%). Because of its lower rate of multi-family housing, we expected Indiana air conditioner saturation to be in the upper range of the estimates from the above metropolitan statistical areas.

Market Adoption of Connected Thermostats

Several vendors produce and market internet-connected 'smart' thermostats directly to residential customers nationwide – Nest and Ecobee are two prominent examples. These devices are typically sold as home energy management tools that target energy savings for homeowners through occupancy detection, auxiliary heat lockout, and economizer capabilities. Because the adoption of connected thermostats is driven by customer preferences, the utility costs of equipment and installation are lower and present a significant opportunity for increasing DR penetration. Additionally, most Indiana IOUs already offer energy efficiency rebates for the purchase and installation of connected thermostats.

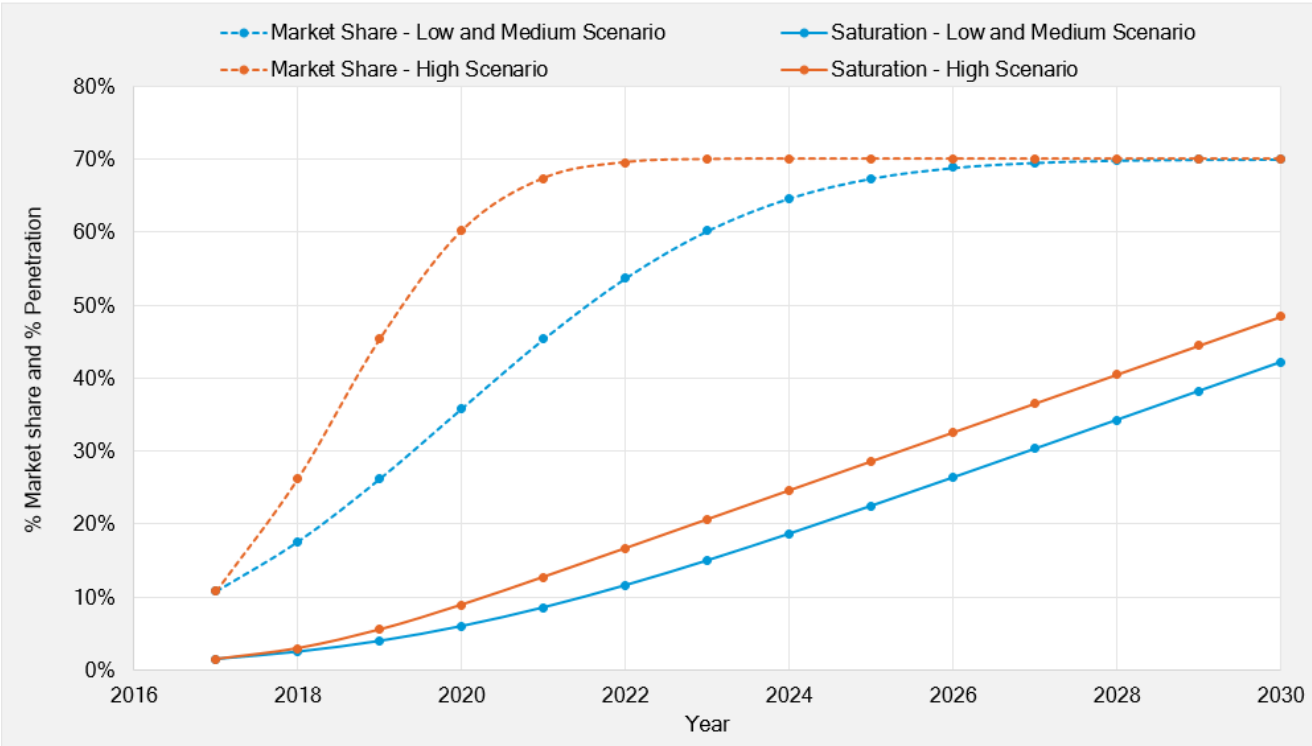
As of August 2017, there were approximately 43,000 Nest and Ecobee thermostats in Indiana and homes with a connected thermostat had an average of 1.2 thermostats per household.[9] Currently, around 1.5% of Indiana households have connected thermostats. However, their penetration is expected to climb significantly – one 2016 study estimates that "In the next decade, smart thermostats are expected to account for almost half of annual thermostat shipments".[10] Still, adoption of smart thermostats in Indiana has been slower. Utility rebates increase adoption, but most residential customers in Indiana do not purchase thermostats of any kind within a year.

Figure 9 shows the projected penetration of connected thermostats. The penetration is driven by two factors: cumulative sales of new thermostats and the market share of connected thermostats. In each year, we assume that 1 in 15 of Indiana's 2.38 million homes with central air conditioners will replace their thermostats. With an average of 1.05 air conditioners per home, this leads to 166,600 new thermostat sales per year. Connected thermostats are projected to grow in market share from 11% of new thermostat sales and reach a limit of 70% of overall new sales. How fast the market share is attained, however, depends on the upfront costs to customers. Rebates and upstream incentives for connected thermostats can drive down customer costs and influence how fast they penetrate households. The Low and Medium Avoided Cost scenarios assume customers who install smart thermostats are recruited after they have made their purchases. Under this assumption, thermostat market share as percentage of total new sales is expected to reach 70% by 2027, leading to 0.89 million connected thermostats in 30.3% of Indiana households. In contrast, the High Avoided Cost scenario assumes a point-of-sale discount, in the form of a rebate contingent on enrollment in DR programs, that covers all or nearly all the thermostat cost. Under this more aggressive scenario, the market share is assumed to reach 70% by 2022, leading to 1.07 million connected thermostats in 36.5% of Indiana households.

[9] Data supplied by Nest and Ecobee via email.

[10] https://www.navigantresearch.com/newsroom/annual-revenue-for-communicating-and-smart-thermostats-is-expected-to-reach-4-4-billion-in-2025

Figure 9: Market Share and Cumulative Adoption of Connected Thermostats



Ultimately, the share of connected thermostats enrolled in demand response programs will depend on incentive levels, marketing intensity, and whether enrollment offers are presented after the fact or at the point of sale. Higher incentive levels and higher enrollment levels are feasible when avoided costs are higher; as a result, the Low, Medium, and High Avoided Cost scenarios assume increasingly generous offers to participants. The existing research shows that larger, one-time incentives are more cost-effective and lead to higher enrollment than smaller recurring payments, but both designs are common. For our modeling, program cost and enrollment assumptions were mapped to the avoided cost scenarios as follows:

Low Avoided Cost – Assumes all enrollment is implemented by utilities with after-the-fact enrollment using a one-time incentive level of $50. Under this tactic, 15% of households with connected thermostats who are made the offer are expected to enroll, assuming multiple marketing attempts.

Medium Avoided Cost – Assumes a higher, one-time incentive level of $100 and collaboration with thermostat manufacturers, with enrollment implemented after the fact. Under this tactic, 30% of households with connected thermostats are expected to enroll, assuming multiple marketing attempts.

High Avoided Cost – Assumes a one-time incentive payment of $250 offered at the time of purchase in the form of a rebate or a free utility-supplied thermostat. To receive the rebate/device, customers must link their device to the demand response program but can override dispatch signals on an event by event basis. Under this tactic, the market share of smart thermostats accelerates and 60% of households with connected thermostats are projected to enroll in demand response.

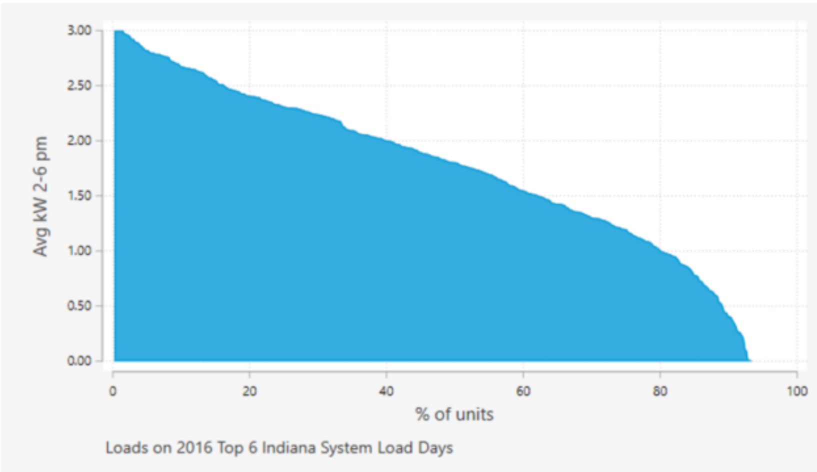
Analysis of Regional Heating and Cooling Loads

To estimate the potential load reduction per device, the research team relied on Ecobee's Donate Your Data portal. The Ecobee data included anonymized thermostat run time and temperature setting data on a five-minute basis from over 560 devices in Indiana, Ohio and Illinois (minus Chicago). Run time data describes the share of total seconds in a time interval an air conditioner is on. The runtime data was converted to kW (assuming a connected load of 3 kW) and used to better understand the diversity of air conditioner use and temperature set points.

Targeting high-use customers and avoiding ones who use little or no air conditioning when the system peaks can have a substantial impact on the net benefits and achievable potential. Because of the large number of customers, the Ecobee dataset was well-suited for exploring the diversity of air conditioner use and assessing if specific segments are or are not cost-effective. For each device, the load patterns were analyzed on the top six Indiana system load days of 2016, assuming sustained load reductions of four hours per event.

Figure 10 shows the distribution of air conditioner use coincident with Indiana system load peaks. Indiana system loads peak between 2pm and 6pm, and most residential air conditioners peak around the same time. Less than 10% of air conditioner units are off on peak days. In addition to customers who keep their air conditioner units off, some households operate air conditioners in the evening, after the system peak has occurred. The implications for targeting and market potential is simple – avoiding homes with little or no coincident air conditioner usage leads to larger per-device reductions and is more cost-effective than enrolling all customers. Without smart meters, however, the ability to precisely target is imperfect because analysis of billing data can only reveal the magnitude of cooling loads, not the timing (e.g. a home may use a lot air conditioning, but not at times that are coincident with system peaks).

Figure 10: Distribution of Air Conditioner Demand (kW) Coincident with Indiana System Peaks

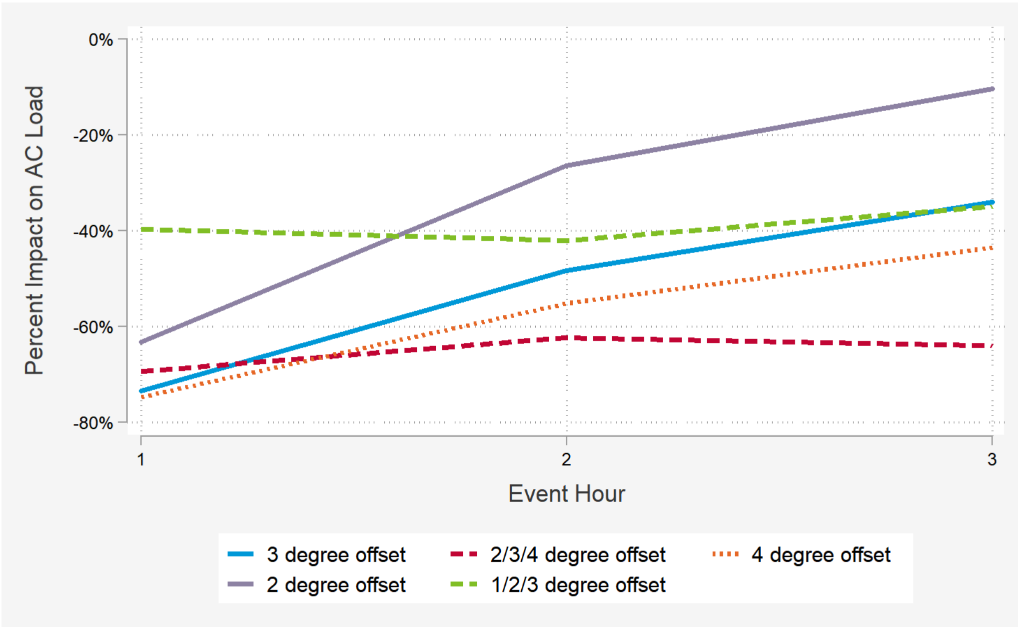


Group	AC Load	Marginal Impact per Device	Running Average Load Impact
Top 10%	2.85	1.41	1.41
10-20%	2.55	1.26	1.34
20-30%	2.32	1.15	1.27
30-40%	2.12	1.05	1.22
40-50%	1.90	0.94	1.16
50-60%	1.69	0.84	1.11
60-70%	1.43	0.71	1.05
70-80%	1.18	0.58	0.99
80-90%	0.77	0.38	0.92
Bottom 10%	0.08	0.04	0.84

Figure 11 is drawn from an ongoing connected thermostat pilot in a state in the U.S. Southeast that is testing different thermostat temperature setback strategies during 3-hour DR events. The plot shows the results for all thermostats inclusive of customers who opted out partway through events. In all cases, the demand reductions exceed 50% when temperature setpoints were set back 4 degrees, but the 2/3/4[11] degree offset strategy provided the most consistent reductions across events. Based on these actual thermostat DR performance estimates, the research team assumed attainable air conditioner load reductions to be 55% of air conditioner demand. This is reduced slightly to account for those customers who may opt out during the demand reduction events.

[11] During the first hour of a DR event the thermostat setpoint is increased 2 degrees (F). In the second hour it is increased an additional 1 degree to 3 degrees above normal. In the third hour, the setpoint is increased an additional 1 degree to 4 degrees of the scheduled setpoint for the hour.

Figure 11: Percent Reductions from Connected Thermostats using Different Operating Strategies

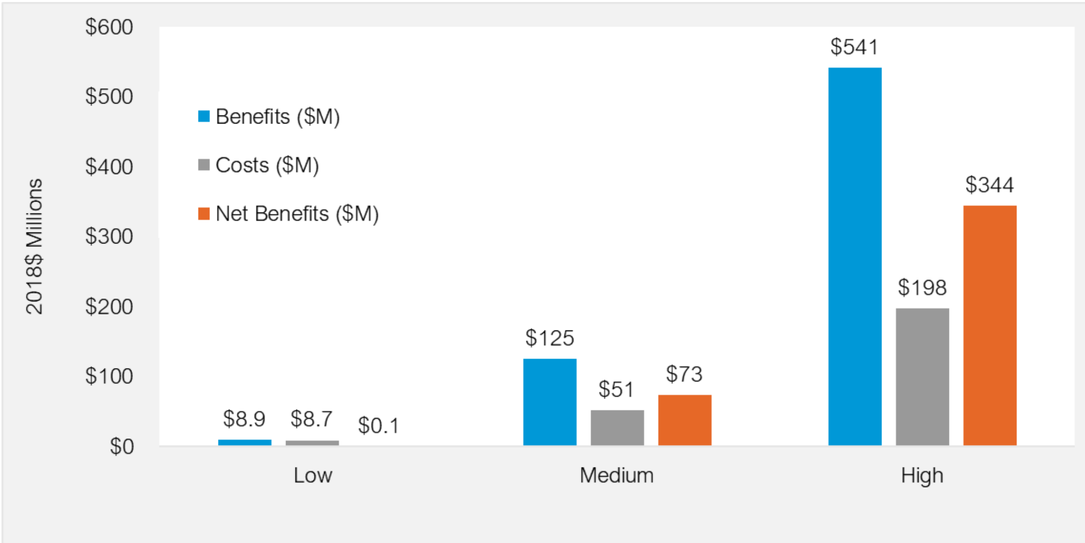


Cost Effectiveness

Figure 12 summarizes the results and lists the 10-year costs, benefits, and net benefits (benefits minus costs). Costs and benefits from 2019 to 2027 are converted to net present value ($2018) using an 8% discount rate. In aggregate, the estimated cost-effective achievable potential by 2027 is 230 MW at the generator[12] under the Medium Avoided Cost scenario, based on an enrollment of 214,000 devices, yielding net benefits of $73 million and a strong benefit-cost ratio of 2.45 under the Utility Cost Test. Reducing peak load by using connected thermostats will lead to lower utility costs and lower customer bills than building new peaking power plants to address power plant retirements or increases in load. Under the High Avoided Cost scenario, demand reductions of over 580 MW – which is the peak production equivalent of five mid-sized power plants – can be attained, yielding $374 million in savings over 10 years with a similarly strong benefit-cost ratio of 2.73.

[12] A line loss factor of 8% is assumed in the model.

Figure 12: Residential Cost-Effectiveness and Market Potential



These results are based on estimates of demand reduction potential for each of ten equally sized groups, based on coincident air conditioner use. Table 13 shows the cost-effectiveness of enrolling customers in each of these groups. Customers who were not cost-effective were not included in the estimate of achievable market potential.

Table 13: Per Device Cost-Effectiveness by Air Conditioner Use Group

Group	AC Load	Load Impact per Device	Low Avoided Costs			Medium Avoided Costs			High Avoided Costs		
			Marginal Benefits	Marginal Costs[1]	UCT Ratio	Marginal Benefits	Marginal Costs	UCT Ratio	Marginal Benefits	Marginal Costs	UCT Ratio
Top 10%	2.85	1.41	$161	$102	1.57	$827	$230	3.60	$1,493	$380	3.93
10-20%	2.55	1.26	$144	$102	1.40	$740	$230	3.22	$1,336	$380	3.52
20-30%	2.32	1.15	$131	$102	1.28	$675	$230	2.93	$1,218	$380	3.21
30-40%	2.12	1.05	$119	$102	1.17	$614	$230	2.67	$1,109	$380	2.92
40-50%	1.90	0.94	$107	$102	1.05	$552	$230	2.40	$997	$380	2.62
50-60%	1.69	0.84	$95	$102	0.93	$490	$230	2.13	$885	$380	2.33
60-70%	1.43	0.71	$81	$102	0.79	$415	$230	1.81	$750	$380	1.97
70-80%	1.18	0.58	$67	$102	0.65	$342	$230	1.49	$618	$380	1.63
80-90%	0.77	0.38	$43	$102	0.42	$223	$230	0.97	$403	$380	1.06
Bottom 10%	0.08	0.04	$4	$102	0.04	$22	$230	0.09	$39	$380	0.10

[1] Marginal costs do not include non-volumetric overhead costs associate with administering programs.

ENERGY STORAGE

The electric grid is unique among our major energy sources in that the system always must be in balance – supply must match demand, essentially in real time. Because the cost of energy storage was, for the most part, prohibitive in the past, generation, transmission, and distribution infrastructure was sized to meet extreme peak demand. While generation and transmission are typically sized based on system peak, distribution infrastructure is sized based on local peaks, which can be quite diverse. The result has been large investments in infrastructure to meet extreme peaks that occur rarely, once every five or ten years.

Battery energy storage technology has advanced rapidly in the past five years and costs have been declining. In several locations, substantial amounts of behind-the-meter storage are being used to alleviate constraints. The most prominent example is Southern California Edison's procurement of 235 MW of battery storage to help alleviate constraints created by the sudden retirement of over 2,000 MW of nuclear power.

Batteries can be located behind-the-meter at customer facilities or on utility property such as substations. Energy storage can provide concrete benefits to customers – in the form of reliability improvements and bill management – and concrete benefits to the utility, including reductions in the need to build additional generation, deferred or avoided transmission and distribution infrastructure costs, and the ability to store cheaper electricity generated off-peak for use during higher-cost periods. In addition, batteries can deliver fast response services required to ensure reliability and power quality and can enhance the ability of the grid to integrate higher levels of variable resources such as wind and solar.

Because it is a relatively new technology, market potential estimates for battery storage are inherently uncertain. This assessment focuses specifically on battery storage potential and cost-effectiveness from a utility perspective. It includes reductions in the need to build additional generation, deferred or avoided transmission and distribution infrastructure costs, and lower energy costs. The battery storage potential is incremental to the demand response potential from C&I and residential customers. Two key factors drive the potential for cost-effective battery storage – the price trends for the technology and the location-specific T&D deferral value. Cost-effectiveness for battery storage depends highly on identifying locations where it can deliver value by helping defer or avoid transmission and/or distribution infrastructure costs. In this study, the avoided cost of generation capacity and difference between on-peak and off-peak energy prices are not sufficient benefits streams at current battery prices – concentrated T&D avoided costs are needed.

Indiana is home to a Battery Innovation Center[13] and has a substantial manufacturing economy. Thus, increased adoption of battery technology presents an opportunity both for the electric system as well as the state's manufacturing sector, if the state continues to position itself as a leader in grid-scale storage technologies.

Battery Storage Costs and Price Trends

Battery storage costs have been decreasing due to active competition among battery manufacturers and are projected to continue decreasing due to efficiencies of production at larger scales. Batteries can be produced from several materials, but based on recent trends, Lithium-Ion batteries have outpaced other materials in lowering costs.

For battery storage costs, we relied on existing research on battery storage costs based on a recent study for the utility PacifiCorp. The costs are driven by three main components: the maximum output of the battery (kW), the total storage capability (expressed in kWh), and the installation, operation, and maintenance costs. Appendix H shows the battery cost estimates by battery material and battery component as well as the projected battery storage cost curves.

For this study, the costs for a battery capable of sustaining maximum output for 4 consecutive hours was estimated and converted to a levelized cost per kW-year expressed in 2018 dollars. In doing so we assume the cost for equipment – the battery, inverter, control system, and balance of system – decrease over time as battery production scales, while installation and operation and maintenance cost remain stable. In addition, we assume a battery life of 10 years over the course of which the battery storage capacity degrades to 90% of the initial installed kW due to use.

Table 14 shows the 10-year levelized cost by year, inclusive of operations and maintenance cost, assuming a battery capable of sustaining the maximum output for four continuous hours, if needed.

[13] http://www.bicindiana.com

Table 14: Estimated Battery Storage 10-year Levelized Cost per kW-year

Installation Year	Levelized Cost per kW-year
2018	$345
2019	$319
2020	$295
2021	$274
2022	$255
2023	$238
2024	$223
2025	$209
2026	$197
2027	$186
2028	$176

Battery Storage Locational Benefits

Although T&D avoided costs estimates historically have been estimated on a system-wide basis, in practice T&D infrastructure investments associated with system expansion are highly location-specific and associated with specific pockets of growth. In areas with excess distribution capacity – or areas where local, coincident peaks are declining or growing slowly – the value of distribution capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of distribution capacity relief can be quite substantial, especially if it is possible to delay or defer infrastructure upgrades for a substantial period of time. The same is true of transmission related constraints.

Growth related T&D investments tend to affect only 5% to 10% of a utility's service territory over the course of a 5-year period. Without targeting those locations, the T&D avoided cost potential is unrealized or diluted. The implication is that T&D avoided costs are highly concentrated and are only realized if resources are placed in the right locations and are reliably available at the right times. For example, if the system-wide avoided T&D value is an average of $20/kW-year but is concentrated in 5% of the utility service territory, it means that, on average, the value is $400/kW-year at those locations. This is a more involved analysis than the more traditional use of system-wide avoided T&D costs, which was employed for the residential and C&I DR potential. Because battery storage potential is highly dependent on targeting the right locations, a more granular approach was employed.

The value of avoided T&D costs varies significantly across local areas because of:

- Load growth rates and anticipated changes in load curve shapes, which affect whether infrastructure upgrades can be avoided or for how long they can be deferred;

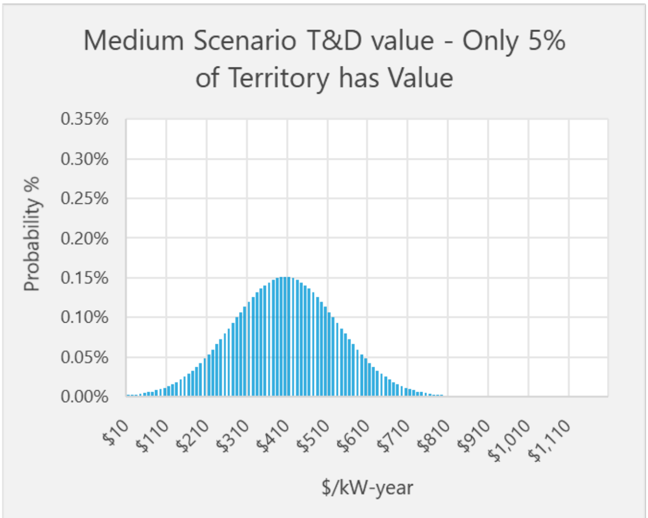
- The amount of existing capacity and its ability to support additional load without upgrades;
- The magnitude, timing, and cost of projected T&D infrastructure upgrades; and
- The design of the distribution system (e.g. radial vs. networked)

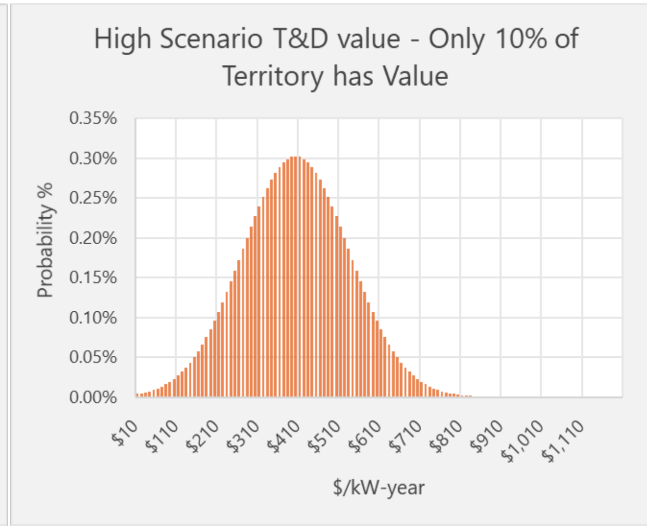
The main conclusion is that battery storage can be cost-effective if placed at the right locations and used to defer or avoid T&D infrastructure costs in addition to providing system benefits such as peaking capacity and shifting of energy use from high cost to lower cost periods. The following assumptions drive the results for the Medium and High Avoided Cost scenarios, which include T&D avoided costs. The Low Avoided Cost scenario assumed no T&D benefits so was excluded from the storage analysis because without T&D value, it was assumed for this study that there is no cost-effective battery potential.

Medium Avoided Cost Scenario - T&D avoided costs are concentrated in 5% of the service territory. Given the $20/kW-year combined value of T&D avoided costs, on average, the location specific value at these locations is $400/kW-year ($20 ÷ 5%). Because there is some variation by location, the value was assumed to have the distribution show in Figure 13. Where T&D infrastructure can be deferred or avoided, we assume that on average batteries can help defer projects by 5 years by shaving 10% of the peak value. The generation capacity values and on-peak/off-peak energy price differential from the Medium Avoided Cost scenario, detailed in the Section Economic Modeling, were also applied.

High Avoided Cost Scenario - T&D avoided costs are concentrated in 10% of the service territory. Given the $40/kW-year combined value of T&D avoided costs, on average, the location specific value at these locations is $400/kW-year ($40 ÷ 10%). Because there is some variation by location, the value was assumed to have the distribution show in Figure 13. The distribution is the same as in the Medium Avoided Cost scenario, but a larger share of the territory has T&D value. In other words, the cost of T&D equipment is the same but more equipment overall is needed in the High Avoided Cost scenario. Where T&D infrastructure can be deferred or avoided, we assume that on average batteries can help defer projects by 5 years by shaving 10% of the peak value. All other system values from the High Avoided Cost scenario were also applied.

Figure 13: Assumed T&D Locational Value Distribution





Cost-Effective Potential

Table 15 summarizes the results. Not surprisingly, the amount of incremental cost-effective battery storage grows as battery costs are projected to decrease. Because of the diversity in locational value, battery storage is not cost-effective in most locations, but as costs drop it becomes cost-effective in an increasing share of the territory. By 2027, in the Medium Avoided Cost scenario we estimate there is 139 MW of battery storage potential yielding $102.9 million in net benefits to ratepayers. Under the High Avoided Cost scenario, 329 MW of cost-effective battery potential is estimated, producing net benefits of $311 million. Table 16 shows the cost-effectiveness on per kW basis. Very importantly, we assume that only cost-effective locations are targeted.

Table 15: Estimated Cumulative Battery Storage Potential and Cost-Effectiveness

Installation Year	Medium Avoided Cost Scenario					High Avoided Cost Scenario				
	MW	NPV Benefits ($2018M)	NPV Costs ($2018M)	Net Benefits ($2018M)	B/C Ratio	MW	NPV Benefits ($2018M)	NPV Costs ($2018M)	Net Benefits ($2018M)	B/C Ratio
2018	6	$19	$17	$2	1.14	22	$67	$56	$11	1.19
2019	15	$43	$37	$6	1.17	48	$145	$119	$26	1.22
2020	26	$73	$61	$12	1.19	78	$231	$185	$46	1.25
2021	39	$107	$88	$19	1.22	111	$323	$252	$71	1.28
2022	54	$145	$116	$29	1.25	145	$419	$318	$101	1.32
2023	69	$184	$144	$40	1.28	181	$517	$381	$135	1.36
2024	86	$225	$172	$53	1.31	217	$616	$442	$174	1.39
2025	103	$267	$199	$68	1.34	254	$716	$500	$216	1.43
2026	121	$310	$225	$85	1.38	292	$816	$555	$262	1.47
2027	139	$353	$250	$103	1.41	329	$917	$606	$311	1.51

Table 16: Battery Storage Cost-Effectiveness per kW (assumes only cost-effective locations are targeted)

Install-ation Year	Levelized cost per kW-year	Medium Avoided Cost Scenario				High Avoided Cost Scenario			
		% of cost-effective locations [1]	NPV Benefits per kW	NPV Costs per kW	B/C Ratio	% of cost-effective locations	NPV Benefits per kW	NPV Costs per kW	B/C Ratio
2018	$345	1.69%	$2,950	$2,580	1.14	5.75%	$3,063	$2,580	1.19
2019	$319	2.27%	$2,829	$2,383	1.19	6.89%	$2,965	$2,383	1.24
2020	$295	2.88%	$2,719	$2,206	1.23	7.87%	$2,882	$2,206	1.31
2021	$274	3.44%	$2,622	$2,048	1.28	8.64%	$2,815	$2,048	1.37
2022	$255	3.82%	$2,558	$1,906	1.34	9.08%	$2,774	$1,906	1.46
2023	$238	4.14%	$2,503	$1,779	1.41	9.40%	$2,742	$1,779	1.54
2024	$223	4.40%	$2,457	$1,666	1.47	9.56%	$2,725	$1,666	1.64
2025	$209	4.54%	$2,431	$1,564	1.55	9.73%	$2,705	$1,564	1.73
2026	$197	4.65%	$2,408	$1,473	1.64	9.81%	$2,695	$1,473	1.83
2027	$186	4.74%	$2,390	$1,391	1.72	9.87%	$2,688	$1,391	1.93

[1] While the sites are cost-effective, because of the traditional 5 years planning horizon, it was assumed that only 1 in 5 projects were completed in a year.

CONCLUSIONS

This report provides a technical and economic analysis of three peak demand reduction strategies that have the potential to play a significant role in Indiana's electric resource mix in the future. Key findings from the analysis include:

There is significant DR potential among the commercial and industrial sectors. Most of the C&I potential identified in the Medium Avoided Cost scenario appears to have been realized by Duke, NIPSCO, and Indiana Michigan Power. The remaining non-residential potential is largely concentrated in Vectren and Indianapolis Power and Light service territories. Our modeling estimates show that, if fully realized, a day-ahead C&I demand response program could create $485 million in net benefits over the next ten years in the Medium Avoided Cost scenario. In the High Avoided Cost scenario, we estimate $1.6 billion in savings over the next ten years. C&I DR potential is lower in our analysis of a day-of notification program design, but still significant at 1,203 MW in the Medium Avoided Cost scenario and 2,183 MW in the High Avoided Cost scenario.

As air conditioning usage is a primary driver of summer peak demand, connected thermostats represent a significant opportunity to reduce residential energy use and provide savings. The increased adoption of connected thermostats presents a significant opportunity to shape the loads of this key end-use. By incentivizing adoption of the devices in exchange for permission to modify setpoints during peak hours, IOUs can accelerate the penetration of connected thermostats and have several hundred MW of controllable demand that is highly coincident with peaking conditions. Over the next ten years, we estimate connected thermostat DR could save Indiana ratepayers $73 million in a Medium Avoided Cost scenario and $344 million in a High Avoided Cost scenario. Avoided costs are a major driver of connected thermostat potential: we estimate 84 MW, 229 MW, and 553 MW in the Low, Medium, and High Avoided Cost scenarios, respectively.

The potential for cost-effective battery storage to produce savings grows as battery costs decrease. Siting battery storage installations in areas of the grid where upgrades can be avoided or deferred through reductions in peak demand is critical. If the right locations are identified, we estimate an opportunity for 139 MW of cost-effective battery installations – at a cumulative savings over ten years of $103 million to Indiana ratepayers in the Medium Avoided Cost scenario. The opportunity grows in the High Avoided Cost scenario to 329 MW of battery installations saving a total of $311 million.

Overall, this analysis shows that cost-effective DR and energy storage in Indiana have the potential to generate net benefits ranging from $448 million to $2.3 billion over 10 years, in scenarios representative of expected avoided costs in Indiana.

APPENDIX

A. Historical Load Profile for Indiana

The research team leveraged two publicly available sources to assemble a load profile for Indiana. The first source was MISO's historical load database.[14] From this database, the research team downloaded LRZ6 hourly load data from 1/14/2015 to 9/30/2017. So that our 2015 record would be complete, loads for the first thirteen days of January 2015 were estimated. Because LRZ6 contains Indiana and also a small part of Kentucky, the research team distributed 90% of LRZ6 load to Indiana and 10% to Kentucky.

The second source was PJM's historical load database.[15] From this database, the research team downloaded hourly load data for Indiana Michigan Power (I&M), which services the areas of Indiana that are not part of MISO's LRZ6. To distribute I&M load between Indiana and Michigan, the research team used I&M's customer distribution as a proxy for load distribution. Approximately 78% of I&M customers are in Indiana[16], so we attributed 78% of the I&M's historical load data to Indiana. The I&M load data covered a period from 6/1/2015 to 9/30/2017. To obtain a complete record for 2015, the research team leveraged load data from American Electric Power (AEP), which was available for the entirety of 2015. (Note that I&M is a subsidiary of AEP, so load for AEP is equal to the sum of load for I&M and the load for several other utilities.) The relationship between I&M load data and AEP load data was then used to estimate I&M load for the first five months of 2015.

Finally, we constructed hourly estimates of Indiana's statewide load from 1/1/2015 to 9/30/2017 as follows:

$$Indiana\ Load = 0.90 * (LRZ6\ Load) + 0.78 * (I\&M\ Load)$$

B. Peak Load Forecast and Disaggregation

The research team assembled a peak load forecast for Indiana in a manner that emulated the way we assembled the historical load profile – retrieve and then combine publicly available MISO and PJM data. The peak load forecast draws primarily from two sources: MISO's 2016 Independent Load Forecast and PJM's 2017

14 https://www.misoenergy.org/Library/Repository/Market%20Reports/YYYYMMDD_df_al.xls

15 http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx

16 https://www.indianamichiganpower.com/info/facts/Facts.aspx

Load Forecast Report.[17,18] From MISO's 2016 Independent Load Forecast, the research team drew summer and winter non-coincident peak demand forecasts for LRZ6. The authors of the Independent Load Forecast provided two sets of forecasts – one set contained adjustments for energy efficiency, demand response, and distributed generation while the other did not. For our study, the research team is using the unadjusted forecasts. Note that all forecasts in the 2016 Independent Load Forecast run through 2026.

From PJM's 2017 Load Forecast Report, the research team drew summer and winter peak forecasts for American Electric Power (AEP). Note that PJM's 2017 Load Forecast Report reports peaks for each month rather than each season, so the research team treated the peaks of the summer months and winter months as the overall summer and winter peaks, respectively. Also note that I&M is a subsidiary of AEP, so the research team used historical PJM data to help assign a portion of the AEP peak forecast to I&M.

With peak load forecasts for LRZ6 and I&M, the research team used the formula 0.90*(LRZ6 Load) + 0.78*(I&M Load) to estimate peak load forecasts for Indiana. Table 17 shows our summer and winter peak forecasts, as well as the components used in creating the forecasts. Note that 2027 LRZ6 peaks were not part of MISO's 2016 Independent Load Forecast, so those are estimated based on the observed growth rate in LRZ6's summer and winter peaks.

Table 17: Estimated Indiana Peak Load Forecast

Year	LRZ6 Summer Peak	LRZ6 Winter Peak	I&M Summer Peak	I&M Winter Peak	Indiana Summer Peak	Indiana Winter Peak
2018	18,354	17,825	4,855	4,645	20,306	19,665
2019	18,635	18,079	4,881	4,690	20,579	19,929
2020	18,904	18,320	4,864	4,686	20,808	20,143
2021	19,166	18,552	4,863	4,680	21,043	20,347
2022	19,408	18,764	4,878	4,703	21,273	20,557
2023	19,643	18,967	4,895	4,723	21,497	20,755
2024	19,879	19,171	4,927	4,757	21,734	20,965
2025	20,115	19,373	4,949	4,777	21,963	21,162
2026	20,354	19,578	4,982	4,811	22,204	21,373
2027	20,596	19,811	5,008	4,842	22,443	21,607

17 https://www.misoenergy.org/Library/Repository/Study/Load%20Forecasting/2016%20Independent%20Load%20Forecast.pdf

18 http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx

The next step in our analysis was to disaggregate the peak load forecast by sector (residential, commercial, and industrial). The goal in this effort was to inform DR strategies for the various sectors, as DR potential is certainly related to peak load. The primary source used in disaggregating the peak load forecast was the U.S. Energy Information Administration's (EIA) 2016 Monthly Electric Power Industry Report.[19] This report estimates monthly sales dollars and monthly MWh for each utility in each state and includes separate monthly estimates for the residential, commercial, and industrial sectors. The research team used this information to calculate *energy* shares for each sector. Because each sector has a unique load factor, we could not assume that the distribution of peak load is equal to the distribution of energy consumption. To convert energy shares to peak load shares, the research team had to make assumptions regarding the load factor for each sector. Our estimates for the peak load share[20] of each sector are shown in Table 18. We are assuming the distribution of peak demand remains static over the study horizon.

Table 18: Peak Load Disaggregation

Sector	Energy Share	Load Factor	Peak Load Share
Residential	33%	0.50	43%
Commercial	25%	0.60	23%
Industrial	42%	0.80	34%
Total or Average	**100%**	**0.65**	**100%**

C. Cost Effectiveness

The research team elected to use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to evaluate the cost-effectiveness of the demand response options. The costs that factor into the UCT ratio include participant incentives and estimates of the administrative costs tied to operating the DR program. Note that participant incentives represent most of the total cost associated with the DR program. Examples of administrative costs are fees paid to an implementation contractor and salaries of utility staff. Any costs related to marketing or recruiting would be categorized as administrative costs as well.

The benefits that factor into the UCT ratio include the avoided cost of generation capacity, the avoided cost of transmission and

[19] https://www.eia.gov/electricity/data/eia861m/xls/f8262016.xls

[20] Calculated as energy share/(sector load factor/total load factor)

distribution capacity (where appropriate), and the on-peak/off-peak differential in energy cost. Each of these benefits was discussed in some detail in Section 0. It is important to note that the modeling approach taken in this report does not seek to maximize demand reduction potential. Instead, our goal is to maximize net benefits. A design that results in a UCT ratio of 1 would maximize DR potential, but create no net economic benefit for the state, as measured by the UCT.

D. Elasticity of Demand

The analytical approach used for C&I demand response is a 'top-down' method that uses price elasticity of demand coefficients to model DR potential under various conditions. Price elasticity of demand is the percentage change in the quantity of electricity demanded divided by the percentage change in the price of DR (e.g. factoring the DR incentive into the cost of power). Elasticity of demand coefficients will be negative, meaning the quantity of electricity demanded goes down when the price goes up. This can also be thought of as the amount of DR supplied going up when the incentive increases. The formula for elasticity is:

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price}$$

A general formula for the percentage change in quantity (which can also be applied to the percentage change in price) is shown below.

$$\%\ change\ in\ Quantity = \frac{(New\ Quantity - Original\ Quantity)}{Original\ Quantity} * 100\%$$

In the context of demand response (DR), this formula becomes:

$$\%\ change\ in\ Quantity\ (kW) = \frac{(Summer\ peak - \ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

Note that the elasticity formula presented at the beginning of this section can be rearranged as follows:

$$\%\ change\ in\ Quantity = (Elasticity) * (\%\ change\ in\ Price)$$

Two distinct formulas for the percentage change in quantity have been presented. Setting these formulas equal to one another yields the following equation:

$$(Elasticity) * (\%\ change\ in\ Price) = \frac{(Summer\ peak - \ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

The terms in this equation can be rearranged so that the only variable on the left-hand side of the equation is DR potential:

$$DR\ Potential = -\frac{(Elasticity) * (\%\ change\ in\ Price) * Summer\ Peak}{100\%}$$

With the proper inputs, this equation can be used to estimate how much DR potential exists. To implement this equation, three inputs are needed: elasticity values, the percentage change in price of DR, and the summer peak. The research team developed estimates of summer peak demand in Appendix B. The percentage change in the price of DR is a function of retail electric rates, DR incentive payments, and the number of DR dispatch hours. These three items are either known or are being held constant in our analysis. Finally, the elasticity estimates used in our analysis are drawn from the Demand Response Potential Study Report for Pennsylvania[21] and are shown in Table 19.

The elasticity estimates for that report were calculated by Nexant based on data from non-residential DR programs in California. The variables included in the California analysis were (1) the level of load reduction, (2) the incentive level, and (3) the DR dispatch type – a measure of the time between the DR event and when participants were notified of the event. One useful feature of elasticity coefficients is they are unit-less (percent changes in load and price), so the differences in retail electric costs between California and Indiana do not create an issue.

Table 19: Elasticity Estimates by DR Dispatch Type

Sector	Segment	Day-Ahead Notification	Sector Average Day-Ahead	Day-Of Notification	Sector Average Day-Of
Commercial	Education	-0.009	-0.015	-0.003	-0.009
Commercial	Grocery	-0.010		-0.009	
Commercial	Health	-0.021		-0.007	
Commercial	Lodging	-0.010		-0.005	
Commercial	Office	-0.010		-0.005	
Commercial	Other	-0.011		-0.006	
Commercial	Restaurant	-0.010		-0.005	
Commercial	Retail	-0.010		-0.009	
Commercial	Warehouse	-0.036		-0.045	
Industrial	Industrial	-0.013	-0.013	-0.007	-0.007

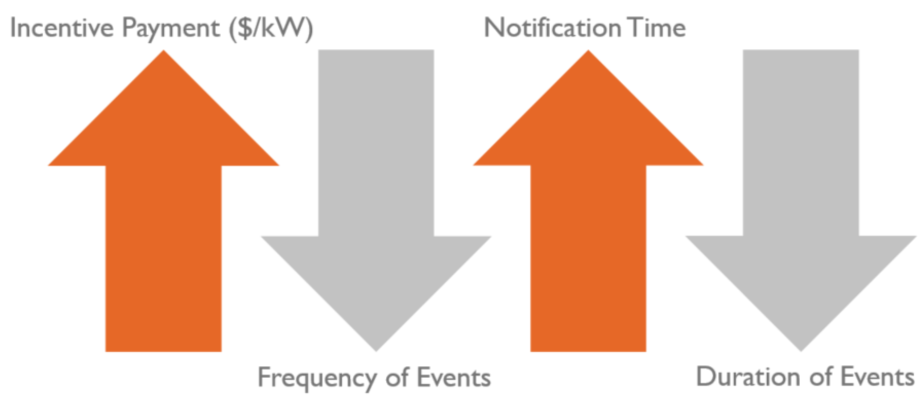
[21] GDS Associates and Nexant, Inc, *DR Potential Study Report for Pennsylvania*, Table 6-2, February 15, 2015, *available at* http://www.puc.pa.gov/pcdocs/1345077.docx; Note that the Pennsylvania report expressed the coefficients as positive (elasticity of DR supply).

Rather than divide the peak demand forecast into separate components for each commercial segment and model the potential separately, an average elasticity value was calculated for the commercial segments and applied to the entire sector.

E. Modeling Demand Response Potential

Demand response potential from large businesses – and the cost to acquire it – is driven by a few key factors. These key factors and the directional effect they have on DR potential are shown in Figure 14.

Figure 14: Drivers of DR Potential



Estimating demand response potential at different levels of these four critical inputs would result in a dizzying array of DR potential estimates. To limit the range of DR potential estimates, the research team had to make several assumptions regarding these four aspects of DR program design. In the sections to follow, assumptions regarding each of the four DR levers will be discussed.

NOTIFICATION TIME

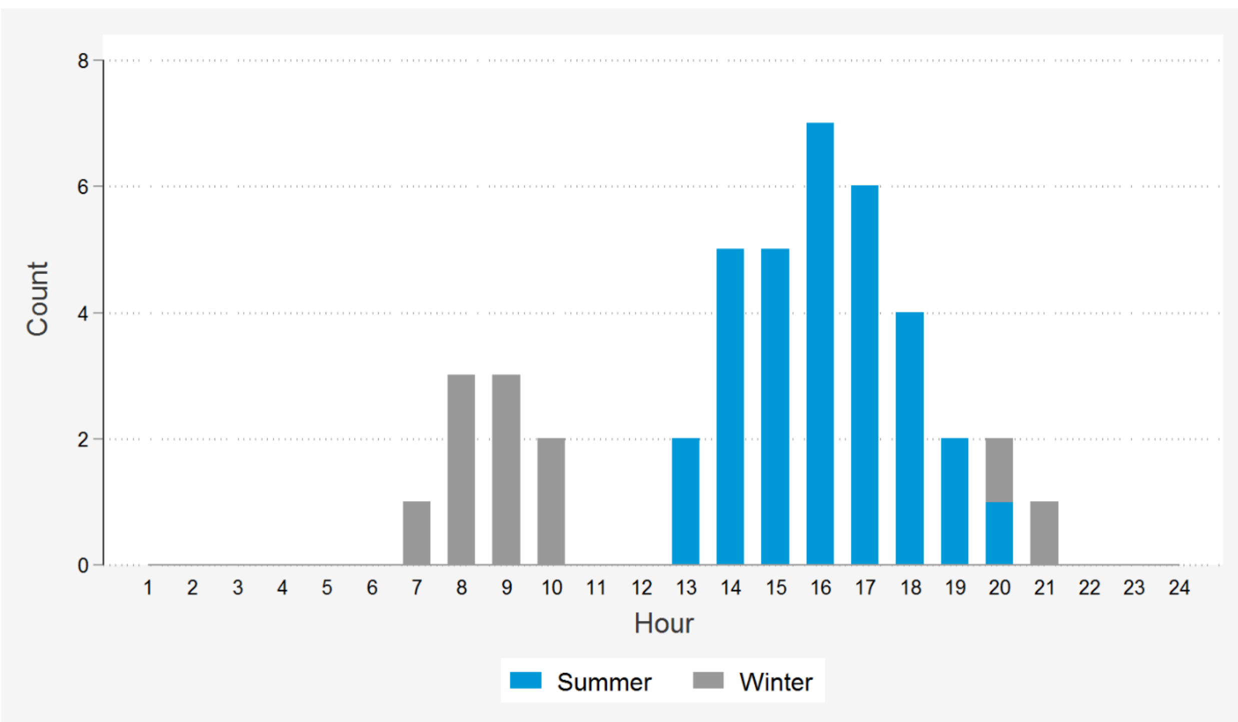
The amount of notification time that program participants are given prior to an event affects their ability to respond, as more notification time allows production and staffing schedules to be modified around the dispatch period. For this report, C&I demand response estimates are presented for two levels of notification time: day-ahead and day-of. A day-ahead notification assumes participants are given approximately 24-hours' notice. A day-of notification assumes that participants are notified in the morning or afternoon that a demand response event will occur later that same day. Under this scenario, participants would receive a 3-to-6-hour notice.

EVENT FREQUENCY AND DURATION

When DR events are infrequent and brief, facilities can shift energy intense processes away from peak hours with limited disruption to the primary business. Longer and more frequent dispatches can become burdensome to participants and could act as a deterrent to demand response participation. Additionally, the greater the expected commitment in days or hours, the larger the financial incentives given to participants will need to be to offset the disruption in operations. To craft assumptions regarding event frequency and duration, the research team leveraged historical load data and historical pricing data.

According to the load profile that the research team assembled for Indiana, the state's peak demand was recorded at 19,167 MW on July 29, 2015. Figure 15 shows the distribution of hours where statewide demand exceeded 95% of the overall peak by hour of the day and by season (from 1/1/2015 through 9/30/2017). That there were 43 such hours. During summer, these hours are concentrated between 2:00 PM and 6:00 PM. This makes sense, as demand during the summer season typically peaks in the afternoon. During winter, the hours when demand exceeded 95% of the system peak typically occurred in the morning between 7:00 AM and 10:00 AM.

Figure 15: Distribution of Hours Above 95% of the Peak Load by Hour of Day

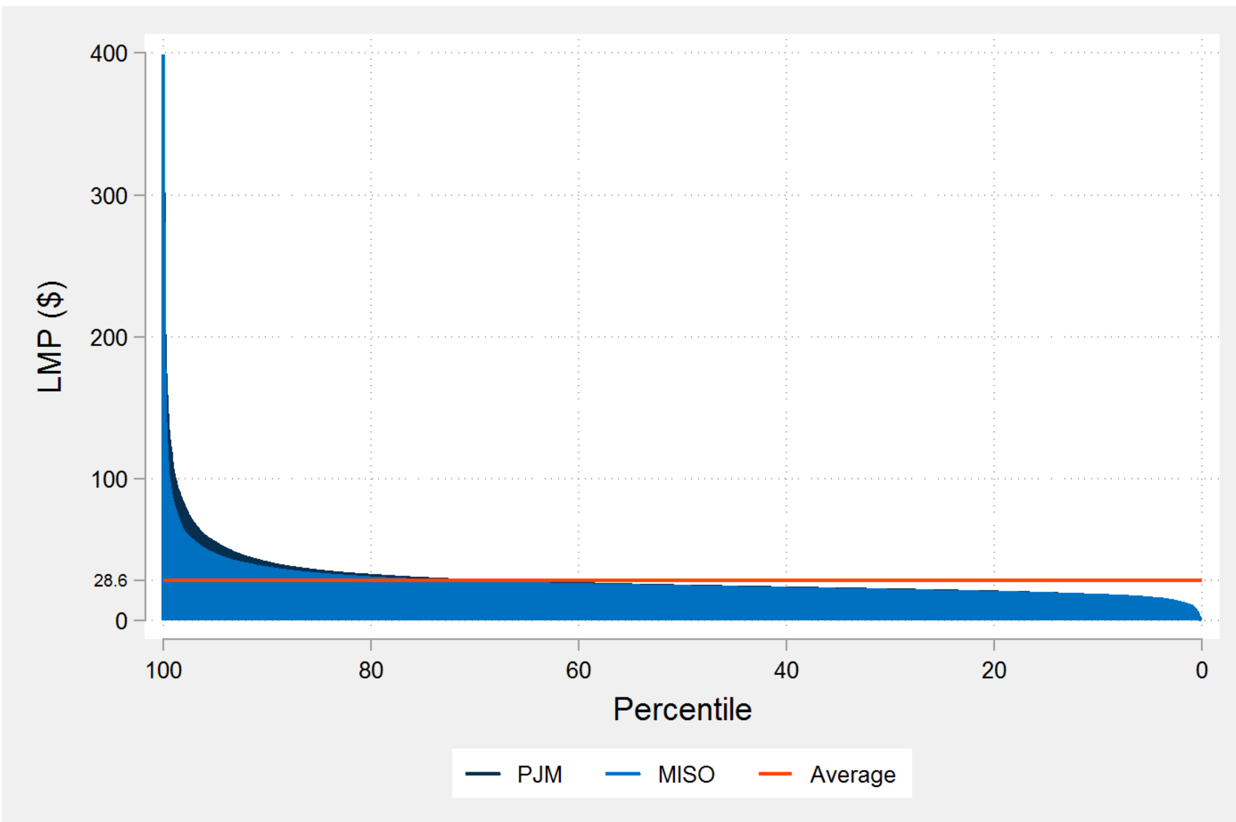


The 43 hours represented in Figure 15 were spread across 13 days (4 winter days and 9 summer days). So, on average, these days saw 3.3 hours where demand exceeded 95% of the system peak. This suggests relatively short DR events – 3 or 4 hours – would serve the region better than relatively long DR events.

Because peak loads are often associated with peak locational marginal prices (LMPs), the research team also examined historical hourly LMPs in the region. Price duration curves for the MISO[22] and PJM portions of Indiana are shown in Figure 16. The dotted reference line shows the average hourly LMP across both systems from 1/1/2015 through 8/23/2017 ($28.60).

Both curves indicate that high prices are infrequent – see the steep peak in the top left corner of each price duration curve. On days where the MISO LMP exceeded $50 for at least one hour, the LMP stayed above $50 for an average of 2.38 hours. On days where the PJM LMP exceeded $50 for at least one hour, the LMP stayed above $50 for an average of 3.04 hours. Thus, responding to these hours with the high LMPs would not require exceptionally long DR events.

Figure 16: Price Duration Curves for Indiana Portions of MISO and PJM



[22] The LMPs shown for the MISO territory represent an average of the LMPs for the six local balancing authorities that make up MISO's LRZ6.

The above analyses show that, from both an economic standpoint and a capacity standpoint, the data suggest a small number of DR dispatch hours will serve the region better than DR events spanning several dispatch hours. For this report, we have chosen to present results holding the frequency and duration of events constant at 8 events, each of 3-hour duration. This design yields 24 total hours of curtailment per year. This relatively limited commitment is an increase over how DR resources have generally been used in Indiana historically, as MISO has not dispatched emergency resources since 2006 and PJM has not made any emergency calls most years.

INCENTIVE PAYMENTS

The incentive offered by the utility could take several forms, including direct incentive payments and bill credits. Compensation can be based on capacity, energy, or a mix of the two. This analysis models the incentive as a "reservation payment", where the utility pays an annual incentive to the facility to curtail when called upon. We modeled three levels of payment – one each for the Low, Medium, and High Avoided Cost scenarios. Table 20 shows these payment levels for 2018. Incentive payments are escalated by 2% annually over the study horizon. A discussion of how these payment levels were determined follows.

Table 20: 2018 Incentive Payment Assumptions

Avoided Cost Scenario	Incentive Payment ($/kW-year)
Low	$7
Medium	$29
High	$51

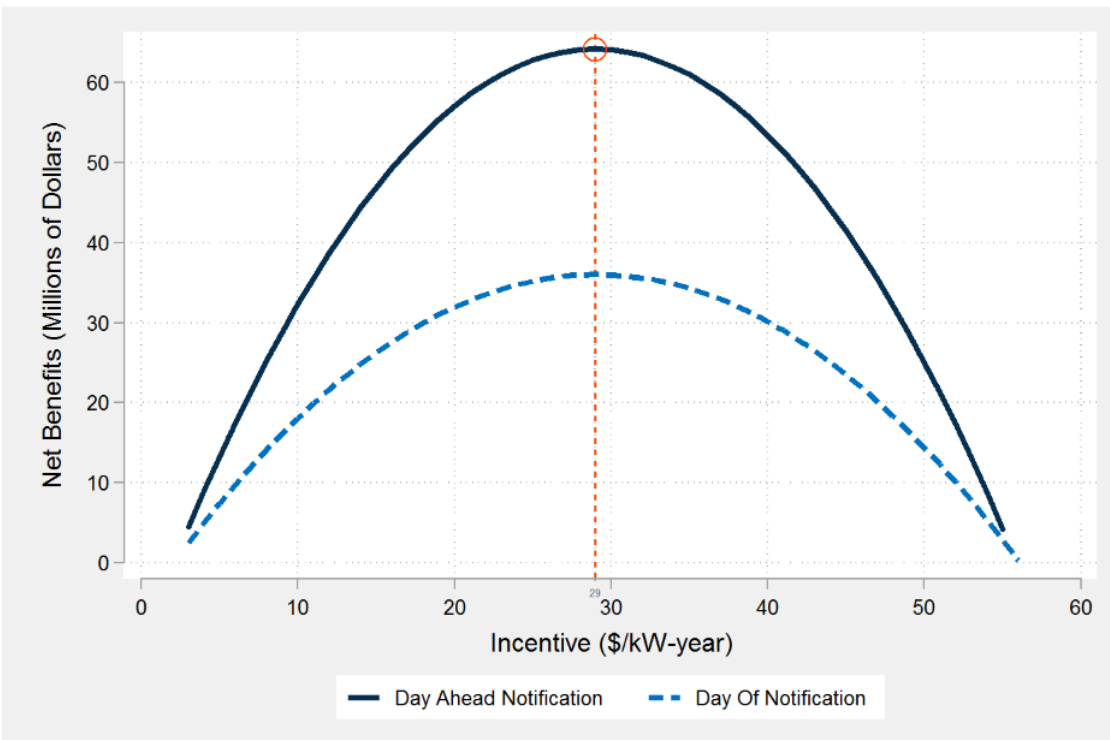
The research team's approach to setting incentive levels involved optimizing net benefits (benefits minus costs). In other words, our goal was to answer this question: What incentive level maximizes the net benefits to ratepayers? Note that this question is not the same as: What incentive level maximizes DR potential? Setting incentive levels too high results in high program costs that outpace the financial benefits of a demand response program. Similarly, if the incentive levels are too low, program costs will drop but program participation will drop as well. As a result, financial benefits will be hamstrung by the limited amount of DR potential.

To solve for the optimal incentive level, the research team performed a simulation where the critical input was the incentive level and the critical output was the net benefit of the DR program. Other inputs included DR potential, number of dispatch hours (held constant at 24), avoided energy benefits, capacity benefits (avoided generation, transmission, and distribution costs), program management costs, and total incentive costs. Note that several of these inputs are tied to the incentive level. For example, as the incentive level increases, DR potential increases. This, in turn, influences the capacity benefits.

For the Medium Avoided Cost scenario,

Figure 17 shows the relationship between the two critical variables – incentive level and net benefits. Note that the curve peaks when the incentive is $29 per kW-year. Thus, this value was used as the incentive level for the Medium Avoided Cost scenario. The research team ran identical simulations for the Low and High Avoided Cost scenarios. Those scenarios landed on optimal incentive levels of $7 per kW-year and $51 per kW-year, respectively.

Figure 17: Optimizing Net Benefits



F. C&I DR Potential Tables

The tables below provide a summary of the estimates of C&I DR market potential for all three scenarios. As discussed in the previous section, these are the estimates of the level of DR potential to corresponds to the highest net benefits to Indiana residents.

Table 21: DR Potential (MW) for Low Avoided Cost Scenario

Year	Peak Load Forecast (MW)	Commercial DR Potential (MW)		Industrial DR Potential (MW)	
		Day-ahead	Day-of	Day-ahead	Day-of
2018	20,306	98	59	264	142
2019	20,579	99	60	268	144
2020	20,808	101	61	271	146
2021	21,043	102	61	274	148
2022	21,273	103	62	277	149
2023	21,497	104	63	280	151
2024	21,734	105	63	283	152
2025	21,963	106	64	286	154
2026	22,204	107	65	289	156
2027	22,443	108	65	292	157

Table 22: DR Potential (MW) for Medium Avoided Cost Scenario

Year	Peak Load Forecast (MW)	Commercial DR Potential (MW)		Industrial DR Potential (MW)	
		Day-ahead	Day-of	Day-ahead	Day-of
2018	20,306	574	346	1,379	743
2019	20,579	582	351	1,397	753
2020	20,808	589	354	1,413	761
2021	21,043	595	358	1,429	769
2022	21,273	602	362	1,445	778
2023	21,497	608	366	1,460	786
2024	21,734	615	370	1,476	795
2025	21,963	621	374	1,491	803
2026	22,204	628	378	1,508	812
2027	22,443	635	382	1,524	821

Table 23: DR Potential (MW) for High Avoided Cost Scenario

Year	Peak Load Forecast (MW)	Commercial DR Potential (MW)		Industrial DR Potential (MW)	
		Day-ahead	Day-of	Day-ahead	Day-of
2018	20,306	1,051	633	2,493	1,343
2019	20,579	1,065	641	2,527	1,361
2020	20,808	1,077	648	2,555	1,376
2021	21,043	1,089	656	2,584	1,391
2022	21,273	1,101	663	2,612	1,407
2023	21,497	1,113	670	2,640	1,421
2024	21,734	1,125	677	2,669	1,437
2025	21,963	1,137	684	2,697	1,452
2026	22,204	1,149	692	2,727	1,468
2027	22,443	1,161	699	2,756	1,484

G. Cost and Benefit Tables

The tables below provide a summary of the costs and benefits associated with the estimates of C&I DR market potential for all three scenarios. In calculating these average annual net benefits, the dollar amounts were not discounted to net present value – each year's costs and benefits were compared in the year they occur.

Table 24: Costs and Benefits ($Million) for Low Avoided Cost Scenario

Year	Day-ahead Notification			Day-of Notification		
	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits
2018	$3.2	$5.2	$2.0	$1.8	$2.9	$1.1
2019	$3.3	$5.4	$2.0	$1.9	$3.0	$1.1
2020	$3.4	$5.6	$2.1	$1.9	$3.1	$1.2
2021	$3.6	$5.7	$2.2	$2.0	$3.2	$1.2
2022	$3.7	$5.9	$2.2	$2.0	$3.3	$1.2
2023	$3.8	$6.1	$2.3	$2.1	$3.4	$1.3
2024	$3.9	$6.3	$2.4	$2.2	$3.5	$1.3
2025	$4.0	$6.5	$2.5	$2.2	$3.6	$1.4
2026	$4.1	$6.7	$2.5	$2.3	$3.7	$1.4
2027	$4.3	$6.9	$2.6	$2.4	$3.8	$1.4

Table 25: Costs and Benefits ($M) for Medium Avoided Cost Scenario

Year	Day-ahead Notification			Day-of Notification		
	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits
2018	$72	$136	$64	$40	$76	$36
2019	$75	$141	$66	$42	$79	$37
2020	$77	$146	$69	$43	$81	$38
2021	$79	$150	$71	$44	$84	$40
2022	$82	$155	$73	$46	$87	$41
2023	$84	$160	$75	$47	$89	$42
2024	$87	$165	$77	$49	$92	$43
2025	$90	$170	$80	$50	$95	$45
2026	$93	$175	$82	$52	$98	$46
2027	$95	$180	$85	$53	$101	$48

Table 26: Costs and Benefits ($M) for High Avoided Cost Scenario

Year	Day-ahead Notification			Day-of Notification		
	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits
2018	$231	$444	$214	$128	$249	$120
2019	$238	$459	$221	$133	$257	$124
2020	$246	$474	$228	$137	$265	$128
2021	$253	$489	$235	$141	$273	$132
2022	$261	$504	$243	$146	$282	$136
2023	$269	$519	$250	$150	$291	$140
2024	$278	$536	$258	$155	$300	$145
2025	$286	$552	$266	$160	$309	$149
2026	$295	$569	$274	$165	$319	$154
2027	$304	$587	$283	$170	$328	$159

H. Battery Storage Current and Projected Costs Detail

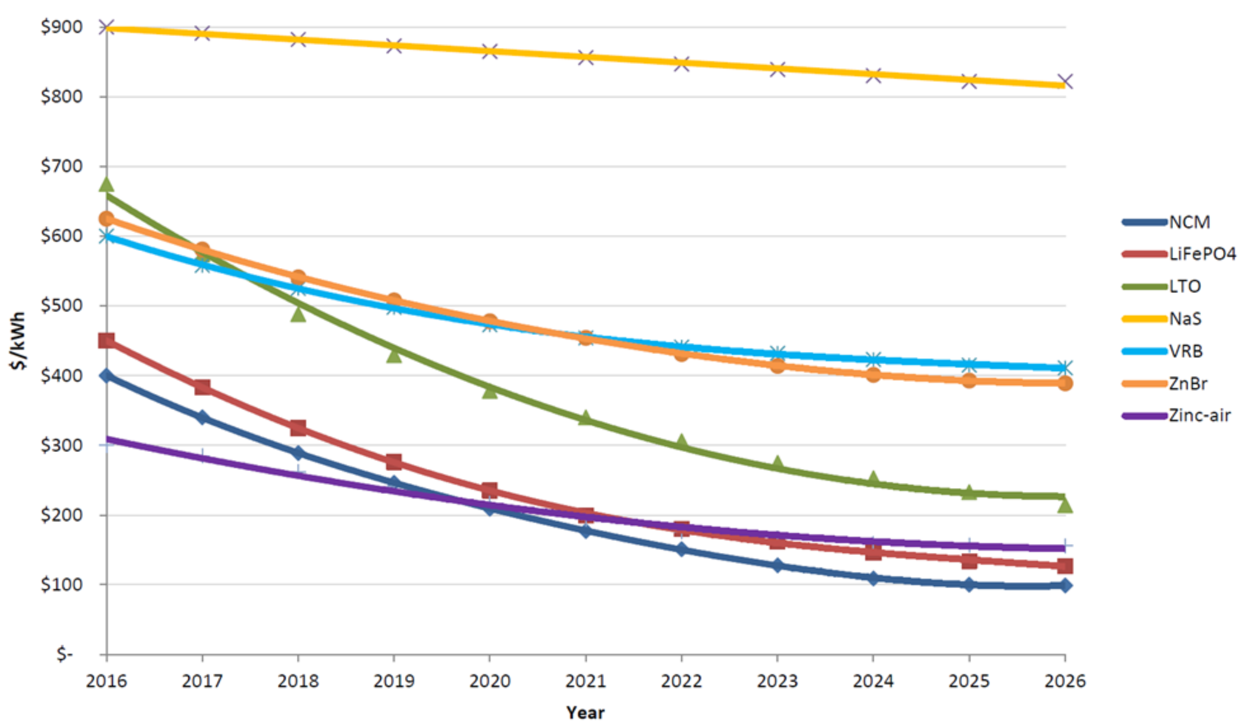
For battery storage costs, we relied on existing research on battery storage costs based on a recent study for the utility PacifiCorp that included costs for seven different battery technologies. Because lithium NCM and LiFePO4 batteries are currently more cost-effective, we relied on their average cost in estimating market potential. However, the table and figure below include costs and cost trends for all seven battery technologies included in the PacifiCorp study.

Table 27: Energy storage system cost estimates

Cost Parameter/ Technology	Lithium-Ion NCM	Lithium-Ion LiFePO4	Lithium-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Energy storage equipment cost ($/kWh)	$325-$450	$350-$525	$500-$850	$800-$1000	$500-$700	$525-$725	$200-$400
Power conversion system equipment cost ($/kW)	$350-$500	$350-$500	$350-$500	$500-$750	$500-$750	$500-$750	$350-$500
Power control system cost ($/kW)	$80-$120	$80-$120	$80-$120	$80-$120	$100-$140	$100-$140	$100-$140
Balance of system ($/kW)	$80-$100	$80-$100	$80-$100	$100-$125	$100-$125	$100-$125	$80-$100
Installation ($/kWh)	$120-$180	$120-$180	$120-$180	$140-$200	$140-$200	$140-$200	$120-$180
Fixed O&M cost ($/kW-yr)	$6-$11	$6-$11	$6-$11	$7-$12	$7-$12	$7-$12	$6 - $12

Source: DNV GL (2017). Battery Energy Storage Study for the 2017 IRP. Prepared for PacifiCorp.
All cost estimates provided in mid-2016 dollars.

Figure 18: Battery Storage Equipment Cost Trends



Source: DNV GL (2017). Battery Energy Storage Study for the 2017 IRP. Prepared for PacifiCorp
All cost estimates provided in mid-2016 dollars