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

June 21, 2022

Re: Indiana Michigan Power 2021 Integrated Resource Plan

Dear Dr. Borum,

Indiana Advanced Energy Economy ("Indiana AEE") respectfully submits this letter of comment regarding the Indiana Michigan Power ("I&M") 2021 Integrated Resource Plan ("IRP") to the Indiana Utility Regulatory Commission ("Commission").

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

Indiana AEE supports the direction in which I&M is moving its resource planning year over year. This includes I&M's commitment to fully retire its coal generation by 2028 and procure 1,300 MW of solar, 800 MW of wind, and 60 MW of battery storage in the near term. However, we note that I&M's IRP relies heavily upon the addition of new thermal generation, adding unnecessary capital costs and risk for its ratepayers, while industry trends in Indiana and across the country suggest that more aggressive deployment of advanced energy resources on both the supply and demand side would be cost-effective and reliable substitutes for retiring capacity. We also note that the I&M IRP lags behind those of its peers, including that of the Northern Indiana Public Service Company ("NIPSCO"), in developing more sophisticated modeling and projections related to electric vehicle and distributed energy resource ("DER") deployment.

Integrating distribution system planning with the IRP has become a best practice around the country, and I&M should accelerate the development of this approach so that it is not caught unprepared for new forms and temporal patterns of load growth.

In these comments, we offer three main considerations:

1. I&M should further develop its energy efficiency and demand response programs, especially in light of its anticipated near-term capacity shortfall and its recent deployment of advanced metering infrastructure ("AMI");
2. I&M's procurement of new gas peaking and baseload resources in 2028, 2034, and 2037 adds unnecessary risk for its customers, and additional investment in renewable energy, energy storage and DERs can meet the same portfolio needs; and
3. I&M should move expeditiously to more integrated planning to avoid being caught unprepared for growth in DERs and electric vehicles.

I&M should further develop its energy efficiency and demand response programs, especially in light of its anticipated near-term capacity shortfall and its recent deployment of advanced metering infrastructure ("AMI").

Demand side resources, including energy efficiency, are still the most cost-effective energy options for Indiana ratepayers. Given I&M's ongoing investment in AMI across its service territory, it has the opportunity to capitalize on the enhanced functionality of AMI, including the collection and use of granular customer meter data, to create innovative programs that help shape load, reduce peak demand, improve integration of DERs, and enhance opportunities for greater energy efficiency achievement. Improved management and integration of demand side resources can help I&M make better use of existing generation, transmission, and distribution system resources, improve reliability, and avoid or defer the need for investments in new infrastructure and resources.

Right now, energy efficiency is one of the most cost-effective ways to meet energy demand, with an average levelized cost of saved electricity for program administrators of just $0.016/kWh in Indiana.[1] I&M's energy efficiency goal of 0.49% of retail sales is well below what its peer utilities are achieving, including Duke Energy Indiana, AES Indiana, and NIPSCO. Notably, analysis of Energy Information Administration Form 861 data illustrates that reasonably aggressive energy efficiency programs do not appear to have increasing costs per unit of savings for either residential or commercial sales, at least into the range of 3% per year incremental

[1] The Cost of Saving Electricity Through Energy Efficiency Programs Funding by Utility Customers: 2009-2015. Hoffman, Ian, Charles A. Goldman, Sean Murphy, Natalie Mims, Greg Leventis and Lisa Schwartz. Lawrence Berkeley National Laboratory. June 2018. Available at: https://www.swenergy.org/Data/Sites/1/media/lbnl-cse-report-june-2018.pdf

savings.[2] On average in 2018, utilities were only achieving savings of 1.03% of retail sales,[3] demonstrating an overall lack of ambition in energy efficiency programming and a significant level of untapped cost-effective potential. Moreover, I&M is well below average, indicating an even greater potential for the utility. We believe that this data may indicate that the utility's methodology for evaluating and selecting energy efficiency resources is especially conservative. To ensure that I&M is serving its customers at the lowest cost reasonably possible, the Commission should closely scrutinize I&M's approach to energy efficiency and encourage changes ahead of its next IRP. In the meantime, Indiana AEE encourages the utility to pursue all cost-effective energy efficiency, which we believe would support a level of energy efficiency achievement that is beyond the 2021 market potential study's "realistically achievable potential."

We also note here that meter-based pay-for-performance program designs, particularly when enabled by AMI, can enhance the value of energy efficiency and other DERs by increasing the ability of utilities to rely on them to meet grid needs.[4] Recent studies from Lawrence Berkeley National Laboratory have found that even passive peak load reductions from energy efficiency programs, that is, peak demand reductions that occur as a "byproduct" of more general energy efficiency programs, can be substantial. The levelized cost of saving peak demand for residential lighting is just $94/kW; for residential heating, ventilation, and air conditioning ("HVAC") it is $249/kW; and for commercial and industrial prescriptive rebates, it is $148/kW. This demonstrates that energy efficiency programs are a "relatively low-cost way for utilities to meet peak demand, compared to the capital cost of other resources,"[5] including new thermal generation.

In addition to the ability to reduce peak demand from programs that principally target kWh savings, programs that are aimed at shaving peak loads or shifting demand to off-peak hours, including through time-varying rates, have proven to be a low-cost strategy to save electric ratepayers money. Indeed, Indiana AEE's February 2018 report showed that pursuing cost-effective peak demand reduction strategies along with energy storage would produce net benefits for Indiana electric ratepayers (total savings minus costs) ranging from $448 million to $2.3 billion over 10 years.[6] One effective strategy to unlocking these benefits from the residential

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[2] Comments to Duke Energy Indiana regarding Energy Efficiency in DEI's 2021 Integrated Resource Plan. Advanced Energy Economy and 5 Lakes Energy. October 2021. Available at: https://www.in.gov/iurc/files/Indiana-AEE-comments-Duke-IRP-5.10.22.pdf

[3] 2020 Utility Energy Efficiency Scorecard. Grace Relf, Emma Cooper, Rachel Gold, Akanksha Goyal, and Corri Waters. American Council for an Energy-Efficient Economy. February 2020. Available at: https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf

[4] Time-Sensitive Value of Efficiency: Use Cases in Electricity Sector Planning and Programs. Lawrence Berkeley National Laboratory. Frick, Natalie Mims, and Lisa C Schwartz. 2019. Available at: https://emp.lbl.gov/publications/time-sensitive-value-efficiency-use

[5] Peak Demand Impacts from Electricity Efficiency Programs. Lawrence Berkeley National Laboratory. Frick et al. p. 15. 2019. Available at https://emp.lbl.gov/publications/peak-demand-impacts-electricity.

[6] Peak Demand Impacts from Electricity Efficiency Programs. Lawrence Berkeley National Laboratory. Frick et al. 2019. Available at https://emp.lbl.gov/publications/peak-demand-impacts-electricity.

sector is to engage households at scale. For example, with the installation of AMI, and utilizing an opt-out program design, behavioral demand response can turn every residential household (including renters) into grid assets through behavioral nudges alone. Layering price signals on top of the behavioral nudges would have the effect of driving larger peak reductions and load shifting. Behavior-based solutions are delivering peak reduction and load shifting in some of the most constrained parts of the country,[7] and I&M AMI deployment enables it to be used as a resource in Indiana as well.

I&M's procurement of new gas peaking and baseload resources in 2028, 2034, and 2037 adds unnecessary risk for its customers, and additional investment in renewable energy, energy storage, and DERs can meet the same portfolio needs.

New Gas Resources

While we recognize that the energy transition introduces new uncertainties regarding future technologies, and that this IRP intends to remain flexible and responsive to changing conditions (especially with regard to the future of the Cook Nuclear Plant), we caution I&M against the specific inclusion of significant new natural gas resources in either the near- or long-term. This includes the proposed 1,000 MW of peaking resources in 2028, 500 MW in 2034, and 250 MW in 2037, along with the 1,070 MW combined cycle plant in 2037. Deploying alternatives to such peaking resources, both in front of and behind the meter, would be in I&M and its ratepayers' best interest because newly-built fossil resources add significant customer risk. This is because: 1) the 1,070 MW combined cycle, and the 2,820 MW of total new gas foreseen in this IRP, exposes customers to volatile natural gas prices for, presumably, decades; and, 2) there is a significant opportunity cost risk in adding 1,000 MW of near-term capacity instead of investing in and gaining experience with cost-effective, reliable advanced energy resources, especially those that can be added incrementally or that may receive additional federal support in the near future. These risks can be avoided with a different set of resource addition and retirement strategies without sacrificing reliability or affordability.

We first note that the long-term use of all four of the proposed gas plants are incompatible with I&M's parent company, American Electric Power's, goal to achieve net-zero carbon dioxide emissions by 2050.[8] This means that the plants, especially the combined cycle unit, will have to be either converted to run on an alternative fuel or shut down within as little as 13 years after they become operational. While I&M leaves open the option to convert these plants to hydrogen,

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[7] In 2019, CPS Energy expanded a pilot program that relied upon behavioral demand response, smart thermostats, and commercial and public customer engagement to 300,000 customers. They achieved 40 MW of additional demand response at peak periods. More information can be found here: https://www.prnewswire.com/news-releases/cps-energy-recognized-as-thought-leader-for-public-engagement-301098990.html, and a thorough evaluation of earlier iterations of the program can be found here: https://www.sanantonio.gov/Portals/0/Files/Sustainability/STEP/CPS-FY2020.pdf.

[8] Clean Energy Future. American Electric Power. Available at: https://www.aep.com/about/ourstory/cleanenergy

the economics of converting a gas turbine to run on hydrogen, and the availability and cost of clean hydrogen gas supply, are both speculative at this time. This creates a heightened risk of asset stranding if the technology either does not materialize or materializes at a cost that is not competitive with alternatives. While green hydrogen will likely have a role in any clean energy future, we caution against over-reliance on it in decision-making today while its optimal use cases, including for large-scale power generation, are still being determined.

Just recently, global natural gas prices have spiked, and some believe that these prices mark a longer-term upward trend.[9] A new gas plant that is intended to operate for decades means that customers will continue to be exposed to price risk and volatility. At the same time, the new plant is at risk of becoming operationally stranded as it becomes cheaper to build and operate new advanced energy resources that can serve the same need. A new report from RMI[10] found that if renewable energy costs continue to decline at their historical pace, a portfolio of clean energy resources designed to serve the same grid needs would outcompete 80% of proposed combustion turbine capacity by the capacity's in-service date. Additionally, RMI found that with higher gas prices, the clean energy portfolios were competitive with nearly 90% of proposed combustion turbine capacity. Finally, even without clean energy resource cost declines, if you incorporate the value of securing firm gas supply, clean energy portfolios become competitive with 92% of combustion turbines. Already, over half of the proposed gas combustion turbine plants that were expected to enter into service in 2018, 2019 and 2020 have been canceled because of shifting economics and increasing support for clean energy. The economics are even less favorable for combined cycle plants, where 90% of proposed gas capacity (as of December 2021) would be out-competed by clean energy portfolios at their in-service date. When RMI considered a high gas price scenario, this rose to 98%.[11]

An additional risk to consider is related to the PJM capacity value of I&M's thermal generators. A new AEE report[12] suggests that the resource adequacy or capacity value of conventional thermal generation, including natural gas, is likely inflated due to four categories of uncertainty and risk that the Equivalent Forced Outage Rate Demand ("EFORd") methodology fails to capture. These include outage variability obscured by the use of annual averages, correlated outage risk, weather-dependent stress on equipment, and fuel availability. If I&M relies upon the current methodology, it may overestimate future capacity payments and therefore overestimate the number of years wherein its plants will be economic. As PJM considers revisiting

[9] The Era of Cheap Natural Gas Ends as Prices Surge by 1,000%. Anna Shiryaevskaya, Stephen Stapczynski, and Ann Koh. Bloomberg, August 2021. Available at: https://www.bloomberg.com/news/articles/2021-08-06/the-era-of-cheap-natural-gas-ends-as-prices-surge-by-1-000

[10] Headwinds for US Natural Gas Power: 2021 Update on the Growing Market for Clean Energy Portfolios. Lauren Shwisberg, Alex Engel, Caitlin Odom, and Mark Dyson, RMI, December 2021. Available at: https://rmi.org/insight/headwinds-for-us-gas-power/.

[11] *Id*.

[12] Getting Capacity Right. Advanced Energy Economy. March 2022. Available at: https://www.aee.net/aee-reports/getting-capacity-right-how-current-methods-overvalue-conventional-power-sources

conventional resource accreditation, I&M should adjust its own input assumptions regarding both combined cycle gas turbines and natural gas combustion turbines. At the very least, this risk should be thoroughly explored in I&M's IRP portfolio scorecard and narrative.

These risks are avoidable if I&M pursues a different set of advanced energy strategies and tools, inclusive of both large-scale and distributed resources, energy efficiency, and customer rates that encourage off-peak energy consumption.

Large-scale Renewable Resources

I&M has recognized the potential of large-scale renewable resources with its near-term Request for Proposals for 800 MW of wind and 500 MW of solar. These resources lower costs for I&M's customers and meet Indiana's changing energy needs by supporting electric demand and a more reliable, resilient, and flexible grid. Independent market analysis continues to show that advanced energy resources are the most cost-effective investment. In its latest annual publication analyzing levelized cost of energy ("LCOE"), Lazard, a financial advisory and asset management firm, shows the continuation of a multi-year trend of falling costs for advanced energy technologies, particularly with regard to large-scale solar. In certain scenarios, new renewable energy resources have decreased in cost to the point that the LCOE of new wind and solar is now at or below the marginal cost of existing conventional generation. In other words, the all-in cost of new renewable generation is at or below just the operating cost of existing generation. When federal incentives are also taken into account (namely the Investment Tax Credit and Production Tax Credit), the all-in, levelized cost of new onshore wind ($25/MWh) and large-scale solar ($27/MWh) projects is competitive with the marginal cost of coal ($42/MWh), nuclear generators ($29/MWh), and combined cycle gas generation ($24/MWh). Even without these tax incentives, these resources are competitive, averaging $38/MWh for new onshore wind and $35/MWh for new large-scale solar. Unsubsidized costs for wind and solar have fallen at approximately 4% and 8% per year over the past five years, respectively.[13] And of course, wind and solar energy carry no fuel price risk.

Energy Storage

Utilities around the country are also finding that energy storage resources are increasingly competitive (including when paired with solar and wind resources), flexible to operate, and prudent to invest in. For example, in early 2019, Arizona Public Service announced that it would procure 850 MW of battery storage to meet peak demand and replace natural gas peaking capacity.[14] Importantly, these resources may also receive additional federal support in the near future; the Infrastructure Investment and Jobs Act (2021) includes funding for energy storage

[13] Levelized Cost of Energy and Levelized Cost of Storage - 2020. Lazard. October 19, 2020. Accessed October 21, 2020. retrieved from: https://www.lazard.com/perspective/lcoe2020

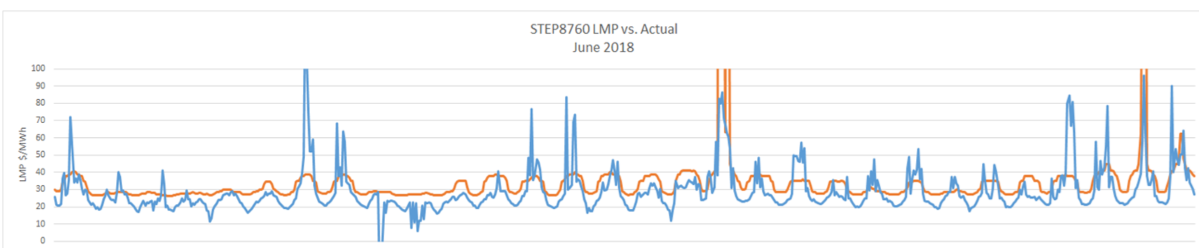
[14] APS to install 850 MW of storage, 100 MW of solar in major clean energy buy. Gavin Bade. Utility Dive, February 2019. Available at: https://www.utilitydive.com/news/aps-to-install-850-mw-of-storage-100-mw-of-solar-in-major-clean-energy-buy/548886/

projects that enhance grid resilience and demonstrations of long-duration storage technologies and "second-life applications" of electric vehicle batteries. And while congressional negotiations around additional legislation are ongoing, proposals under discussion have included provisions for a standalone energy storage tax credit.

While I&M's approach to modeling storage in the development of this IRP reflects historical practices, we believe that this approach undervalues the resource. Storage thrives on price variability that provides frequent opportunities to buy low and sell high. High peak vs. valley price spreads also increase net revenue. Yet many IRP models fail to recognize the full value of storage for at least three reasons:

- They generally under-represent both the frequency and size of hourly price variation
- They ignore intra-hour price variation
- They typically use reserve margins instead of modelling all ancillary service values, which ignores the agility of storage, in that it can provide responses to grid conditions without scheduling reserve generation.

The following graph[15] illustrates the way in which inter-hour price variation is commonly underrepresented in traditional IRP models. The blue line is actual prices and the orange line is modeled prices; actual prices are simply much more variable than is typically predicted by production cost models because of the unexpected changes in demand, plant or transmission outages, and other phenomena that affect actual prices and are not modeled in temporal detail in a production cost model.



Further, there is significant variation in prices within each hour in actual power markets that is simply ignored in an IRP model that calculates with only hourly granularity. Still further, although good IRP models attempt to account for limitations on ramp rates and other intertemporal constraints on actual power plants, they generally fall short of describing all of the operational limitations of real power plants; these phenomena are typically addressed by planning capacity reserves and scheduling generation reserves which serve to suppress short-term price variation in actual markets but if reflected directly in pricing could be exploited by storage due to its highly flexible operational capabilities.

[15] Indiana Advanced Energy Economy. Comments on Duke Energy Indiana's 2021 Integrated Resource Plan. May 2022. Available at: https://www.in.gov/iurc/files/Indiana-AEE-comments-Duke-IRP-5.10.22.pdf

Because of these limitations, we consider it a virtual certainty that storage has been under-valued, and therefore under-selected, in I&M's current IRP in favor of new gas peaking capacity. We therefore recommend that I&M's near-term procurements be structured so that storage and storage hybrid resources can respond and be properly valued (which includes energy, ancillary services, and capacity values), and that I&M select as much storage as proves cost-effective, including beyond the amounts contemplated in this IRP.

We also recommend that in its next IRP, I&M adopt best practices used in other jurisdictions to better capture the full value of energy storage. There are a variety of ways to do this. In 2018, the National Association of Regulatory Utility Commissioners ("NARUC") passed a resolution on modeling energy storage. The resolution recommended a number of principles to guide NARUC member states in modeling energy storage and other flexible resources, including using tools to model the "full spectrum of services that energy storage and flexible resources are capable of providing, including subhourly services."[16] In 2017, the Washington Utility and Transportation Commission issued an Energy Storage Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition that provided guidance for "how utilities should model energy storage within the traditional construct of hourly IRP models."[17] Other best practices for storage modeling in IRP processes have been identified by researchers at the Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory. A recent paper, "State of the Art Practices for Modeling Storage in Integrated Resource Planning," recognizes that the flexibility and scalability benefits of energy storage are continuously undervalued in the models that utilities currently use.[18] The authors argue that "more accurate inputs (e.g., up to date costs and forecasts) and improved modeling methods (e.g., assessing benefits for a wider range of grid services, incorporating behind-the-meter ("BTM") applications) are needed to better integrate storage into planning processes."[19]

If accurate modeling of energy storage resources is not possible given model limitations, storage benefits can also be incorporated into IRPs using a net-cost-of-capacity approach. Under this method, operational benefits of storage that are difficult to represent accurately within the IRP model (e.g., the value of real-time energy arbitrage or ancillary services) can be estimated using

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[16] National Association of Regulatory Utility Commissioners. EL-4/ERE-1 Resolution on Modeling Energy Storage and Other Flexible Resources. November 2018. Available at https://pubs.naruc.org/pub/2BC7B6ED-C11C-31C9-21FC-EAF8B38A6EBF.

[17] Washington State Utilities and Transportation Commission, Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition, Dockets UE-151069 and U-161024 (Consolidated). Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=237&year=2016&docketNumber=161024

[18] Miller, C., Twitchell, J. and Schwartz, L. "State of the Art Practices for Modeling Storage in Integrated Resource Planning." Innovations in Electricity Modeling: Training for National Council on Electricity Policy. October 12, 2021. Available at: https://pubs.naruc.org/pub/CCBEFC58-1866-DAAC-99FB-3A405315FB9B.

[19] Ibid.

a separate analysis outside the IRP model and credited to storage within the IRP model as a reduction in the installed cost of storage.

Finally, we note that adding properly-valued storage in an IRP portfolio, especially in hybrid implementation with renewables, improves the economic benefits of high levels of renewables and leads to including higher levels of renewables in an optimal portfolio.

Distributed Energy Resources

Alongside widespread deployment of large-scale advanced energy resources, customer DER adoption will grow over time. These technologies can also serve as a meaningful grid resource. I&M's IRP modeling shows an addition of 121 MW of demand response and 71 MW of DERs,[20] but we believe this estimate is low, especially given growing customer interest in pairing at-home storage with rooftop solar systems and the proliferation of electric vehicles that will be able to serve as a flexible load. DER participation via aggregation services in wholesale markets, including PJM, will create new value streams for DERs that may further accelerate adoption.[21] Furthermore, new research is demonstrating that even simple customer behaviors and choices related to distributed energy resources, energy efficiency, vehicle and appliance electrification, and demand management can have a measurable aggregate impact on utility resource portfolios.[22] Indiana AEE recommends that the utility begin to engage with aggregation service providers in the near term.

By promoting these clean and distributed technologies, along with additional procurements of wind, solar, and energy storage resources, I&M may be able to avoid the need to add new gas capacity and gain experience managing a system with greater amounts of distributed energy resources. Because these resources can be added more incrementally, such a strategy can also protect the utility and its customers against over-investment if the expected load never fully materializes.

Together, these resources present an alternative and lower-risk way to meet the utility's energy and capacity needs. Studies continue to show that advanced energy resources, when used together and paired with utility programs and rates that encourage smart and more flexible electricity usage, can replace most, if not all, of the fossil fuel generation currently serving electric customers.[23] A newly published report from the National Renewable Energy Laboratory

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[20] Integrated Resource Plan Report. Indiana Michigan Power, p. 8. January 31, 2022. Available at: https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/2021IMIRPReportRevised.pdf

[21] As required by FERC Order 2222 (2020).

[22] The Customer Action Pathway to National Decarbonization. Sanem Sergici, Ryan Hledik, Michael Hagerty, Ahmad Faruqui, and Kate Peters. Brattle. September 2021. Available at: https://www.oracle.com/a/ocom/docs/industries/utilities/customer-action-pathway-report.pdf

[23] *2035: The Report*. Goldman School of Public Policy at the University of California Berkeley. June 2020. Available at: http://www.2035report.com/wp-content/uploads/2020/06/2035-Report.pdf?hsCtaTracking=8a85e9ea-4ed3-4ec0-b4c6-906934306ddb%7Cc68c2ac2-1db0-4d1c-82a1-65ef4daaf6c1

found that high storage penetration scenarios, often accompanied by high variable generation, "successfully operate with no unserved energy and low reserve violations, showing no concerns about hourly load balancing through the end of 2050."[24] It also finds:

> On an annual basis, storage effectively provides time-shifting and peak-load reduction services in all configurations and grid mixes. Although storage has a low annual capacity factor, which is inherently limited by its need to charge, it has a very high utilization (in many cases over 75%) during the top 10 net load hours across scenarios and years–when the system needs capacity and energy the most–indicating a strong contribution to the system's resource adequacy.[25]

Given the foregoing, Indiana AEE urges I&M to consider other resource options, especially those that could meet the same capacity needs incrementally, and/or consider delaying a decision to procure new natural gas capacity. The longer it is able to do so, the more attractive the alternative options, which will be better for Hoosiers over the next several decades, will become.

I&M should move expeditiously to more integrated planning to avoid being caught unprepared for growth in DERs and electric vehicles.

The distribution grid is the backbone of a reliable electricity system and plays a critical role in integrating new distributed technologies, including electric vehicles. In order to continue to provide reliable and cost-effective electric service while leveraging technology developments and adapting to changing customer preferences, utility distribution system planning will need to be more nimble, transparent, and integrated with other planning processes. Indiana AEE supports I&M's procurement of an Advanced Distribution Management System, and its movement towards more fully integrated generation, transmission, and distribution planning via its new Regulated Investment Planning Team. While we acknowledge that these changes can take time, we encourage I&M to move expeditiously. The sooner I&M is able to gain additional visibility into its system and begin making decisions, such as using non-wires alternatives ("NWAs") to defer distribution system upgrades, the sooner it will avoid making investments that are not truly least-cost or that are not compatible with the direction of technology evolution and customer preferences. It will also be able to plan for necessary distribution grid upgrades to keep up with customer needs and create new rate plans and programs that encourage efficient use of existing infrastructure. These new initiatives may take time to fine-tune for optimal grid benefits but they are necessary as the system becomes more dynamic and customer-centric. As part of this, we strongly encourage I&M to engage directly with the advanced energy industry, so that it can

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[24] Storage Futures Study: Grid Operational Impacts of Widespread Storage Deployment, p. viii. A. Jennie Jorgenson, Will Frazier, Paul Denholm, and Nate Blair. National Renewable Energy Laboratory. January 2022. Available at: https://www.nrel.gov/docs/fy22osti/80688.pdf

[25] *Id*.

better understand all the capabilities of the products and services available, so that they can be fully accounting for in planning.

As needs are identified through distribution system planning, I&M should be encouraged to procure one or more NWA solutions to meet these needs, provided that the NWA solutions would yield greater net benefits than a comparable wired solution. Competitive NWA needs-based solicitations that include third-party ownership and service-based solutions can maximize customer value and be streamlined to provide a more expedited sourcing process to meet targeted grid needs. This method allows the utility to find the least-cost, best-fit DER or service solutions based on market response, and to ensure that the benefits of competition accrue to all customers. Such needs-based solicitations would not presuppose an exact technology solution, but instead would leverage the competitive energy industry to come forward with solutions based on the identified need. For example, a specified need could be met using multiple contracts with DER providers and aggregators – some of which may be providing load reduction via targeted energy efficiency deployment while others may be aggregating distributed storage and distributed generation. Any NWA framework should also include appropriate compensation mechanisms that incorporate localized incentives targeted at areas of the grid where DER can provide the most value.[26] And finally, solicitations should include specific performance requirements to ensure the non-wires solution reliably meets system needs.

In the case of certain grid needs for which a NWA solicitation may not be appropriate, I&M can pursue pilot programs that align with the overarching goals of NWA investments. These newer approaches to small grid challenges should evolve via an iterative "test, learn, and adapt approach" over a sufficient period to ensure that DER services can similarly solve reliability issues in a cost-effective manner that minimizes adverse impact to customers. All industry participants, stakeholders, and local jurisdiction authorities can learn from those efforts, and learning from other jurisdictions should also help accelerate this process.

In sum, we recommend exploring initiatives that rely upon NWAs, DER aggregators, and other energy service providers to gain experience with and confidence in new resources and business models. This will allow the utility to act more quickly and effectively as DER deployment grows in I&M's service territory.

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[26] To evaluate DERs on a level playing field with traditional resources and infrastructure investments, a regulatory structure should be developed to properly value and source services from DERs. We recommend consulting the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, which provides a comprehensive framework to help policymakers design cost-effectiveness tests that fully consider the costs and benefits of various DERs. Rate designs for DERs, and utility programs for compensating DERs for the services they provide are also being used and refined in various jurisdictions, and should also be considered in conjunction with comprehensive benefit-cost analysis ("BCA") and distributed resource planning. *See The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. National Energy Screening Project. August 2020. Available at:* https://www.nationalenergyscreeningproject.org/wp- content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Conclusion

Over the past three years, economic and technological conditions have changed dramatically. Three years from now, IRP modeling results will likely look different again as advanced energy resources continue to evolve and state and federal laws and regulations change. Above all, we encourage I&M and the Commission to exercise extreme caution when making investment decisions that would lock the utility into expensive infrastructure that could soon become obsolete. Instead, the utility should look to leverage new and existing technologies, rates, programs, and services to meet the same grid opportunities and challenges.

Indiana AEE appreciates the opportunity to comment on the I&M 2021 IRP.

Respectfully submitted,

Sarah Steinberg
Policy Principal
Indiana Advanced Energy Economy