A Transmission Critical Peak Pricing Pilot for Manufacturers in Ohio

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ABSTRACT

Energy management practices among commercial and industrial (C&I) energy users have grown from a historical emphasis on shopping to procure the most competitive energy rates to include a more comprehensive suite of tools including traditional energy efficiency, on-site generation, and load management. As C&I customers become more engaged and sophisticated in their approach to energy management, there is concurrent interest amongst policymakers and advocacy groups to better link the time-value of electricity with end users.

In Ohio, energy load reduction practices have progressed from demand response to generation system capacity peak load contribution management, and now to transmission peak load contribution management. However, cutting-edge customers are still testing and figuring out effective management processes to handle critical peak pricing.

This paper presents a case study of transmission peak pilot pricing in Ohio looking at both the utilities pilot pricing structure as well as how C&I customers participate and engage in the programs. The common element has been shifting transmission costs from being billed on monthly facility peak demand, to coincident transmission system peaks. Heretofore, transmission system peak forecasting and alerts have not widely existed in Ohio, though they do for RTO/PJM-wide generation peaks. This paper presents discussion on the state of transmission costing, and the various transmission pilot program structures and tariff designs of Ohio's four investor-owned utilities. Additionally, this paper will characterize transmission pilot program participants, their transmission peak electrical load contributions, and lessons learned to-date.

Introduction

Manufacturers in Ohio have become savvier with energy management over time to reduce costs and emissions. Energy management actions include using procurement specialists to find the best rates, using energy managers to implement efficiency projects and make use of utility rebate programs, and managing PJM capacity market costs, either through demand response or reducing their capacity obligations. Additionally, manufacturers have been investing in on-site generation, such as wind, solar, and CHP. However, an avenue that remains to be thoroughly explored in Ohio is undertaking load reduction during transmission system peak periods.

Additionally, we expect that increased use of renewable energy and increasing electrification of transportation and other fuel-powered systems will increase the importance of electrical load accommodating and adapting to electric system peak demands. Moreover, with the potential for newly added electrical loads, such as the conversion of natural gas water heaters and furnaces to their electric equivalents and the addition of electric vehicles, the nature of electric system peaks and our typical understanding of when they occur will change. Specifically, we expect that with natural gas furnaces being converted to electric heat pumps, more areas may encounter winter peaks in electrical power. Much research has been done on the residential sector that shows what approaches can be used to curtail usage during these periods.

But what about the manufacturing sector? Manufacturers collectively have a great deal of load that they may be able to minimize during system peaks, thus reducing stress on the grid during otherwise critical moments. However, to act, manufacturers need regulatory structures and policies that incentivize peak load reductions. In Ohio, much of the cost causation resulting from peak demand is lost in a myriad of layers of reallocation of costs between rate classes, sister utilities, and billing determinants that manufacturers have little control over and no direct tie to the root of the cost. Changing this dynamic could allow manufacturers to reduce loads during system peaks, creating cost savings for manufacturers, and load reduction that benefits the system.

Transmission in PJM

PJM oversees the wholesale electricity market within the footprint of its participating members, including energy, capacity, and ancillary services. PJM also oversees Regional Transmission Expansion Planning (RTEP). Several components makeup transmission services charges, with Transmission Enhancement Charges (TEC) and Network Integration Transmission Service (NITS) making up the bulk of these costs.

Transmission Enhancement Charges

TEC is derived from PJM's Regional Transmission Expansion Plan (RTEP). Per PJM, RTEP "identifies transmission system additions and improvements needed to keep electricity flowing to 51 million people throughout 13 states and the District of Columbia. Studies are conducted that test the transmission system against mandatory national standards and PJM regional standards. These studies look 15 years into the future to identify transmission overloads, voltage limitations and other reliability standards violations (PJM n.d.)." Thus, TEC can be thought of as the essential upgrades necessary to keep the electric grid functioning. Figure 1 below shows TEC charges for the past five years for the four investor-owned transmission systems in Ohio: American Electric Power (AEP); American Transmission Systems Inc. (ATSI); Dayton (DAY); and Duke Energy Ohio, Inc. & Duke Energy Kentucky, Inc (DEOK). While there are variations between transmission zones, TEC has generally remained stable overtime.

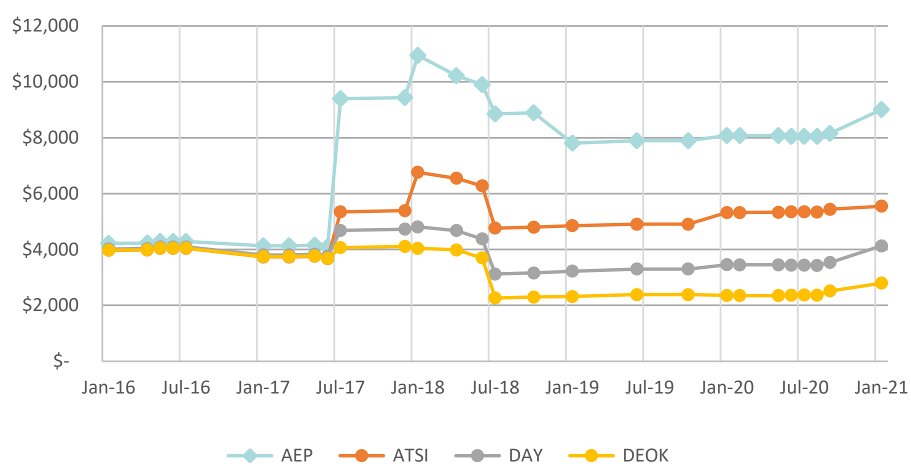

Figure 1. Five-year trend of TEC rates ($/MW-year) for Ohio transmission companies

Network Integration Transmission Service

On the other hand, NITS charges are derived under the jurisdiction and oversight of the Federal Energy Regulatory Commission (FERC) and are administered by PJM. Specifically, transmission owners file transmission formula rates with FERC, which are generally adjusted on an annual basis and include charges associated with operating costs, system loads, or cost recovery requirements for new transmission projects (AEP Energy 2018). This sets the Annual Transmission Revenue Requirement (ATRR) for each transmission zone in PJM's territory. Thus, NITS can be thought of as supplemental upgrades that are allowed by FERC but not necessarily required for the wellbeing of the electric grid. An example breakdown of ATRR charges, excluding credits to be refunded back to customers, for the Dayton transmission zone is shown below.

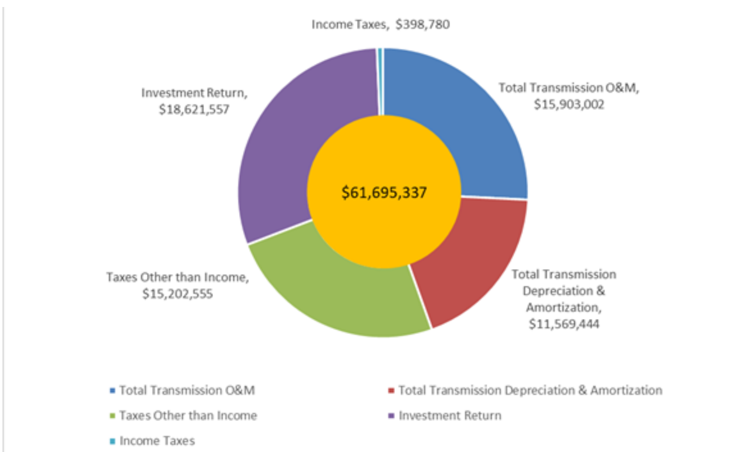

Figure 2. 2021 Breakout of the Annual Transmission Revenue Requirement for the Dayton transmission zone (PJM 2021)

There is one additional step to calculating NITS, which introduces the concept of Network Service Peak Load (NSPL). NSPL refers to the metered demand coincident with the single zonal peak load hour for a given year starting November 1 and ending October 31 (PJM n.d.). NSPL is often colloquially referred to as the one coincidental peak, or 1-CP, especially when referring to an individual manufacturer's contribution to the zonal peak. However, the two terms are often used interchangeably in conversation. The time and value of the NSPL is unique for each transmission zone. To calculate the NITS rate of $/MW-year, the approved ATRR is divided by the respective NSPL.

Figure 3 below shows a time trend for NITS for the four investor-owned transmission systems in Ohio, for the last six years. Like TEC, each transmission zone has a different cost. However, in contrast to TEC, NITS has a significant increase in the rate of growth in some cases. For instance, over the past six years the AEP transmission zone has seen a 130% increase in transmission costs. Annually, this is a growth rate of 26%.

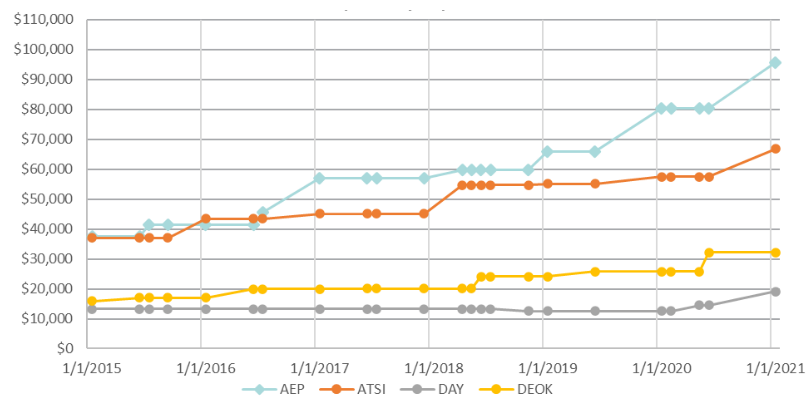

Figure 3. Six-year trend of NITS ($/MW-year) for Ohio transmission companies

TEC and NITS Rates in Ohio, by Transmission Utility

Figure 4 below shows the 2021 combined TEC and NITS rates for the four Ohio transmission zones. In all cases, NITS greatly outweighs the costs of the required TEC.

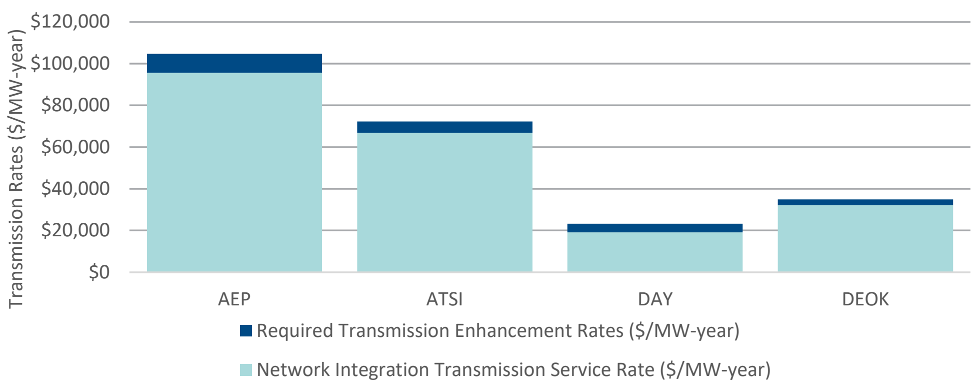

Figure 4. TEC and NITS for the Ohio transmission companies

Given that supplemental NITS charges comprise a dominant portion of manufacturers' transmission bill, and that these charges have increased year-to-year consistently in some cases, it is important that facilities can manage this cost. Thus, the next question is, does the actual recovery of transmission charges form manufacturers allow for control?

Introduction to Ohio Transmission Riders

In the previous section, we discussed the basis for transmission charges and touched on their rate of growth. Here, we will discuss how these charges are actively recouped from manufacturers in Ohio, and what is being done to improve one's ability to manage their transmission costs.

In Ohio, in general electric distribution utilities (EDUs) are charged the TEC and NITS costs based on each EDU's NSPL. Ohio's six investor-owned EDUs are then responsible for determining cost allocation of the transmission charges to classes, and the rate design for each class and customer. The Public Utilities Commission of Ohio (PUCO) has oversight of the allocation and rate design and must approve the EDUs proposals. The manner of collection has changed over time in some cases. For example, prior to June 2015, for AEP Ohio territory, Ohio manufacturers' transmission service was included in their competitive retail electric supplier (CRES) contract, as opposed to on the EDU bill. CRES businesses passed through NITS and TEC directly to the consumer based on their contribution to the NSPL. Indeed, this is still how transmission costs are passed on in several states surrounding Ohio, including Pennsylvania and Maryland (Pennsylvania PUC n.d.) (Maryland PUC n.d.).

However, in the summer of 2015, NITS was transferred from the retail electric suppliers to the EDU, in this case AEP Ohio. This has several important implications. While we have shown that NITS charges do change over time, they do not change from the CRES to the EDU. Thus, the charges a manufacturer pays for NITS in Ohio should not have changed substantively from the change in billing entity (CRES to EDU). However, this was not the case, and the reason for this was that the basis for how the EDUs collected NITS changed from customer's contribution to the NSPL, to a monthly demand charge instead usually based on a 15- or 30-minute peak facility demand.

This changed method of billing is consequential. A manufacturer's monthly 30-minute peak is guaranteed to be the highest period of electricity consumption of the plant and is presumably meant to represent the plant's peak power use for the local distribution system. However, it is unlikely that a plant will be at its peak electricity use during the NSPL system peak. As a result, many manufacturers ended up paying more for transmission costs than they previously did, and in this case, more then what their actual incurred transmission obligation is. This has additional implications, specifically regarding a manufacturer's ability to control costs, either through specific curtailment related activities, or the procurement of on-site generation, that we will touch on later. For example, we show below the cost impact of the two billing approaches for a real, anonymous manufacturer:

NSPL: 0.8 MW x $95,597/MW-year = $76,478/year
Monthly Peak Demand: 4,562 kW x 12 months/year x $6.72/kW-month = $367,880/year

The six investor-owned EDUs in Ohio all bill transmission costs monthly peak demand. Through a combination of intervention by manufacturing advocacy groups, such as the Ohio Manufacturers' Association Energy Group, and increased visibility of the issue of transmission billing, several pilot programs have been created for alternate methods of billing transmission costs to customers. These include:

- AEP Ohio the Basic Transmission Cost Rider (BTCR) Pilot tariff.
- First Energy companies allow a Rider Non-Market Based Services (Rider NMB) opt-out via a PUCO approved "reasonable arrangement" on a case-by-case basis, which allows customers pay their transmission obligation through their CRES rather than the EDU.
- AES Ohio, formerly Dayton Power and Light (DP&L) has submitted a stipulated settlement for up to 50 customers to opt-out of its transmission charge, Rider

TCRR-N, and instead purchase transmission through a customer's CRES (PUCO Staff 2020).

Each of these approaches differs and were created within broader regulatory case stipulations and subsequent PUCO orders. Though, all the approaches generally trend towards billing transmission following the regulatory principle of cost causation, and thus billing customers on their NSPL rather than monthly demand. For instance, the BTCR Pilot is available to only up to 34 participants that were signatories of the stipulated settlement of a specific regulatory case. Rather than being billed on monthly peak demand, which for AEP Ohio is 30-minute, or resulting ratchets, the BTCR Pilot program changes the billing determinant for participants to their NSPL. Thus, manufacturers are charged on their NPSL for the entire program year. This can reduce what manufacturers pay for transmission.

The BTCR Pilot Program has overall been a success. In 2020, 580 MW of manufacturing monthly demand load was enrolled in the program, and manufacturers' demand for BTCR Pilot seats continue to be greater than the supply stipulated in the Pilot. The overall transmission obligation of this group was 145 MW, 75% lower than the same facilities' monthly peaks. This suggests that manufacturers participating in the BTCR pilot are actively managing their facilities power during transmission system peaks. For perspective, this is equivalent to around 435,000 residential houses all effectively using smart thermostats to reduce load during a peak event.[1] In 2020, total dollars saved for these 35 participants amounted to about $22.2 million. This is expected to increase significantly in 2021.

First Energy territory offers a different approach, which follows more of a traditional opt-out of their Rider NMB (Non Market Based Services), which is the rider they use to recover transmission related costs. Participating customers, instead of receiving a different rate, instead opt-out of the Rider NMB and instead procure NITS through their CRES provider. Similar to the BTCR Pilot within AEP Ohio, this was limited to a select group of customers; however, manufacturers can file Reasonable Arrangements, a legal process with the effect of changing how a facility is billed, with the PUCO to essentially achieve the same benefit. These agreements are confidential, so we do not have overall performance in First Energy territory.

Finally, AES Ohio, formerly Dayton Power & Light, also created a pilot program for customers to opt-out of their Rider TCRR-N (Transmission Cost Recovery Rider). However, enrollment was only open for the first 30 days following the stipulation, and there is only one known participant (PUCO Staff 2021). However, AES Ohio has agreed to expand the TCRR-N opt-out to 50 customers, with no enrollment deadline in a recent stipulated settlement that is currently before the PUCO for approval (PUCO Staff 2020).

Duke Energy does not currently offer any version of a Pilot program.

A clear obstacle to transmission critical peak pricing within all of Ohio's EDUs stems from the lack of accessibility. Even the AEP Ohio BTCR Pilot, which has to our knowledge the best participation of any of the Ohio programs, is gatekept by regulatory intervention groups, specific number of seats and capacity caps, and burdensome regulatory processes. We will make the case later that it is important both to manufacturer's, and the grid, that facilities are able to easily make the switch back to NSPL based billing for NITS.

[1] Assuming 1 kW reduced per home, applied to a reduction of 435 MW

Characterization of Pilot Participants, Peaks, and Load Management

The AEP transmission zone extends beyond Ohio into neighboring states including West Virginia, Kentucky, Virginia, and Indiana. As such, this zone spans somewhat differing climates with different technology mixes. The end result, interestingly, is a transmission zone that peaks around 50% of the time in the winter, with the remaining 50% of the time in the summer. Of course, this changes the nature of the peak as well: the time it occurs (morning versus afternoon) and the duration of high load shoulder hours.

This is not necessarily unique to the AEP transmission zone. In 2016, eight other transmission zones in PJM peaked during winter months (PJM 2016). In 2017, only a single zone, Eastern Kentucky Power Company, peaked during the winter (PJM 2017). There is increasing attention on winter peaks, especially following the polar vortex that reached Texas as well as the implications of electrification of both vehicles and heating for thermal comfort. Research shows that winter peaks will likely become more pronounced in areas that have traditionally been summer peaking (Sun, et al. 2020).

This presents a challenge. How do we effectively mitigate these peaks? What do demand response or curtailment technologies look like? Manufacturers' response to transmission peak pricing offers good insight into the variety of methods that can be used to reduce their transmission obligation.

Load Curtailment

Some of the largest manufacturer participants utilize the same strategies that they would use for a demand response call, or for managing their PJM capacity obligations. It is worth noting that responding to transmission is not demand response in the traditional sense: assuming that the traditional sense is the Demand Response product within PJM. Rather, this is a process that reduces one's obligation, like reducing capacity.

Manufacturers identified key processes that can be turned down or delayed during peak hours. Specific roles are identified for managing and tracking. Lead times have been established. For instance, an hour may not be enough time for a facility to prepare to curtail. Sometimes the decision must be made that morning, for an afternoon peak, or the previous day, for a morning peak. Thus, predicting oncoming peaks, and notifying the proper command chain is crucial, especially for very large operations.

Load Curtailment – Melt Furnaces

Several companies have access to transmission critical peak pricing have electric melt operations, including arc furnaces. Electric load of melt furnaces can be substantial and can exceed 100 MW. Melt furnaces can be quickly curtailed and restarted. In many cases, there is no damage to the product if the melt furnaces shut down and restarts. And, in some cases there is no overall impact to production output of the plant, as the few hours of lost production can be shifted to weekend or evening hours. For example, an electric arc furnace operation following a successful peak prediction and implementation of their curtailment strategy, can reduce its facility load by over 100 MW, or an 85% reduction in electrical power. At AEP's 2021 NITS of $95,597/MW-year, this is worth approximately $9.6 million to this company (PJM 2021).[2]

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[2] 100 MW x $95,597/MW-year = $9,559,700/year

The notification process is very important in ensuring the facility has the proper amount of time needed to respond. For these facilities, they at minimum need several hours warning in order to curtail. Ideally though, the decision to curtail or not curtail on any given day is likely made 24 hours prior based on grid load projections.

Shift Scheduling

One Southern Ohio casting company in the AEP Transmission Zone anticipates peak events with a clever and simple strategy. They operate with a two-shift operation, followed by a third maintenance shift. In the summer, the maintenance shift takes over the traditional second shift times, which for them covers the afternoon. This helps ensure they have a reduced electrical load during the typical 4 – 6 PM system peaks. This is also their approach for reducing their PJM generation capacity obligation. In the winter, the maintenance shift swaps with first shift, which covers the 7 AM to 9 AM morning peaks that can occur with AEP Transmission.

Thus, the facility is never in danger of starting a melt operation during a potential peak event, simply because of how shifts are scheduled. At full load, this facility's average monthly demand is approximately 11.2 MW. During maintenance shift, this is only 1.0 MW, or a reduction of 91%, which, in 2021 is worth around $975k based on AEP's 2021 NITS.[3]

Distributed Energy Resources

Distributed Energy Resources (DER) are a means of generating electricity in a non-centralized manner and are generally located near customer load on a local distribution system. Common examples of DER include both solar and wind, as well as combined heat and power (CHP) plants. A multitude of manufacturers have begun investing in DER for reduced electricity costs and environmental benefits. For these manufacturers, transmission critical peak pricing offers another avenue to increase their return on investment in DER.

Behind-the-Meter Solar PV

A manufacturer in Northern Ohio (ATSI Transmission Zone) utilizes a combination of load shaving and on-site solar to significantly reduce their transmission obligation. The load shaving component is relatively small at 0.5 MW. This includes turning off production freezers and office AC during grid peak hours, since there is adequate thermal mass to keep the offices and freezer space cool for some time without the mechanical equipment running.

An onsite solar array provides the bulk of load reduction. In 2020, the solar array generated 6.2 MW of electricity during the summer peak (PJM 2020).[4] [5] The figure below shows solar generation, facility load, and total net load during the peak hour for 2020. The critical peak hour is represented via the shaded portion of the chart.

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[3] 10.2 MW x $95,597/MW-year = $975,089/year
[4] PJM NSPL for 2021 – ATSI 7/9/20 Hour Ending 17
[5] This falls within NREL's stated solar coincidence range of 50% to 80% of nameplate capacity, depending on the tracking technology and climate (NREL 2013)

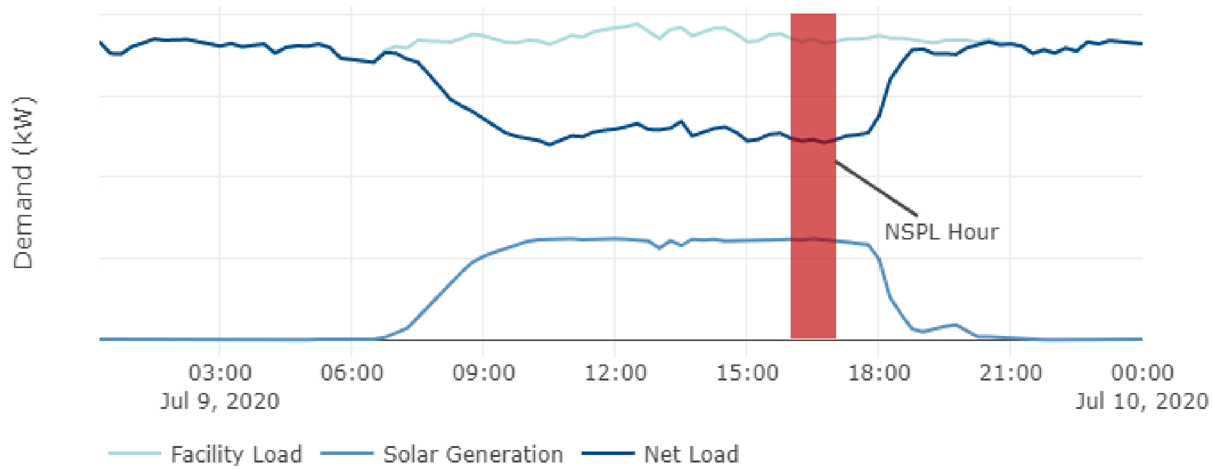

Figure 5. Facility Load and Solar Generation on July 9, 2020. Demand units are hidden to protect the confidentiality of the manufacturer.

Overall, the combined contributions of the solar production and curtailment add up to 6.7 MW. At an average monthly demand of 21.3 MW, this represents a load reduction of 32%, and given ATSI's 2021 NITS of $66,744/MW-year, this is equivalent to $447k in benefit (PJM 2021).[6] Not only does this help the facility achieve their corporate sustainability goals, but site electrical costs are significantly reduced. Thus, this manufacturer is considering expanding their solar array as well as diversifying into wind to further reduce their critical peak usage.

Of course, the next question to discuss is how reliable is solar in reducing their peak load. First, solar is intermittent, and local weather conditions can significantly reduce the output of an array during a peak event. Looking back through five years of historical data for this facility, we find that the average difference between monthly peak demand and their NSPL is 5.7 MW. Assuming that the load shaving component is a constant 0.5 MW, this equates to an average coincident solar contribution of 58%.

It is worth noting that ATSI, at least over the last five years, has never once peaked during the winter. This has significant implications for a solar resource. The figure below shows the average solar production as a percent of nameplate capacity, by hour, for the month of July. Superimposed is the most common hour for a summer peak over the past five years for the ATSI transmission zone. The shaded regions represent approximately a single standard deviation away from the average. As you can see, the transmission peak reliably falls within the maximum production hours of the solar array.

[6] 6.7 MW x $66,744/MW-year = $447,185/year

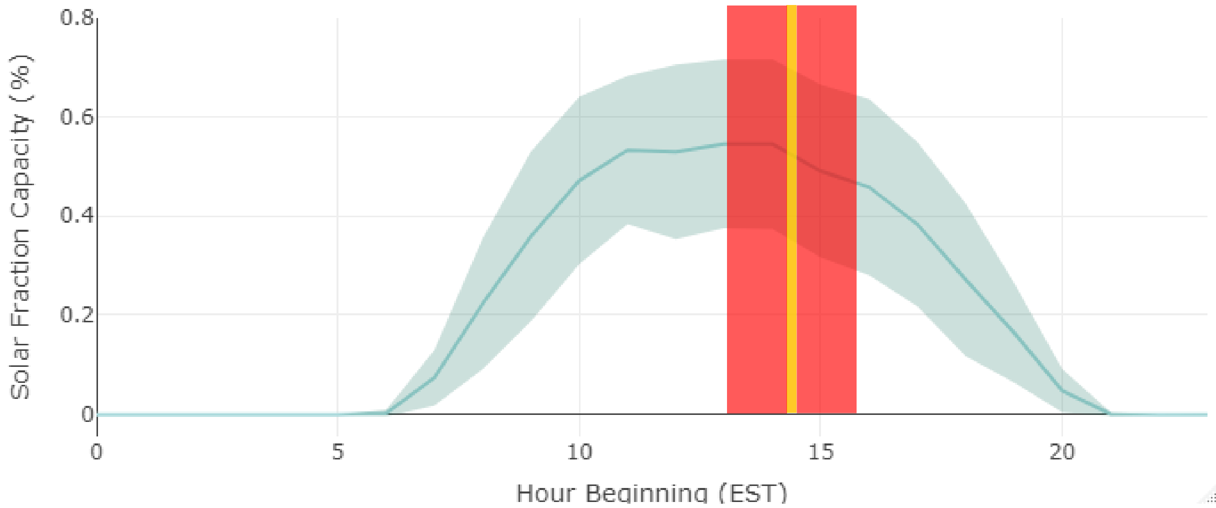

Figure 6. July average solar fraction capacity and transmission peak hour with standard deviations.

Now, let us imagine that in the future, ATSI sets a winter peak that shares the time and curve characteristics of AEP's winter peaks. Shown below is the same chart, but this time reproduced using generation data for the month of January. Again, superimposed is the most common hour for a winter peak, utilizing AEP data, for the past five years. The shaded regions represent a single standard deviation away from the average. Additionally, in the AEP transmission zone, winter peaks have only ever occurred at 7:00 – 8:00 AM. Unlike in summer peaking, the solar array makes zero contribution to a morning winter peak.

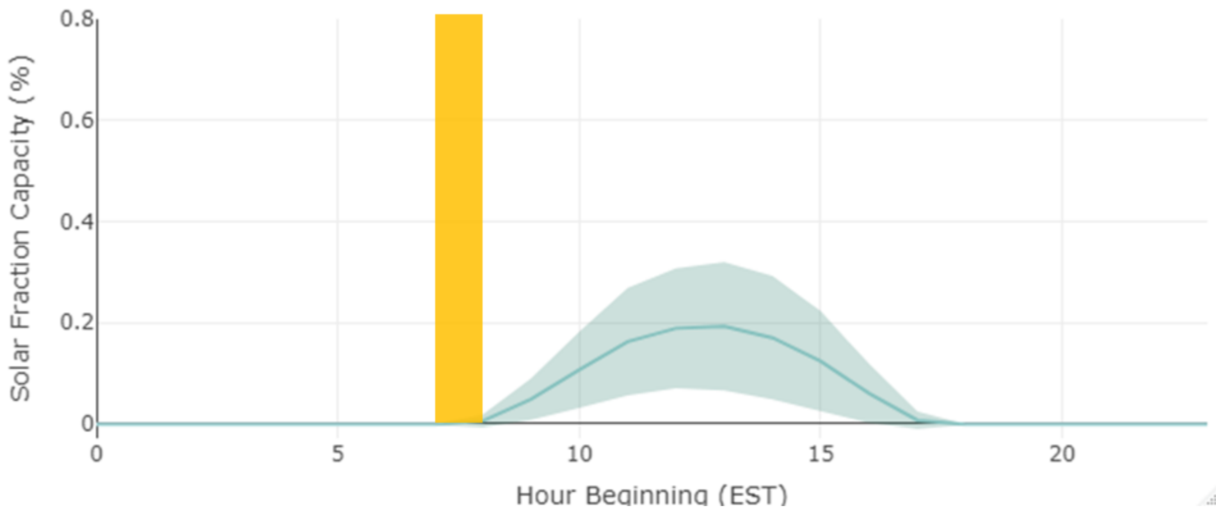

Figure 7. July average solar fraction capacity and transmission peak hour with standard deviations.

Behind-the-Meter Wind Turbines

Another manufacturing facility in Northwestern Ohio (AEP Transmission zone) invested in three on-site wind turbines as part of their commitment to procure renewable energy. In aggregate, the 4.5 MW of nameplate capacity provides most of the facility's energy requirements and often exports excess energy produced to the distribution grid under a net-metering agreement.

In 2019, the AEP Transmission Zone peaked in the winter on January 31, hour ending 8:00 AM (PJM 2019). The wind farm generated energy exceeding the facility's load and resulted in energy exports. The result was a 0 MW billing determinant for their transmission obligation. Unfortunately, one's transmission obligation can never go negative, meaning that every MW produced beyond the plant's demand (outside of their net-metering agreement) no longer received additional benefit.

Combined Heat and Power (CHP)

Finally, yet another manufacturer installed a natural gas fired turbine to generate electricity and steam on-site at a lower cost then procuring these resources separately. The CHP plant provides approximately 60% of the facility's total electrical energy requirements.

In 2020, this facility's NSPL was 5.9 MW, compared to an average monthly demand of 12.3 MW. This is a reduction of 8.4 MW, or a curtailment rate of 52%. At a 2021 NITS of $95,598/MW-year, the market value of this curtailment is $803k.[7]

CHP has a fairly high availability. According to ORNL, the availability for a baseload CHP plant is about 93.4% on average (Energy and Environmental Analysis, Inc. 2004). However, while not intermittent like solar and wind, CHP does vary output seasonally. For example, in January the average net plant output for this CHP plant was 6.9 MW, compared to 5.2 MW in July. Thus, while the CHP plant is will significantly contribute to a reduction in this facility's transmission obligation, additional benefit is realized during winter peaking seasons. This is a difference of about $160,000.

Conclusions

The six case studies described above, as well as our experience working with manufacturers looking to reduce their transmission costs, have show us without a doubt that manufacturers have both the ability and desire to reduce load either through active management or investment in DER technologies.

However, good rate design is essential to promoting this behavior. The current status quo in Ohio of billing out transmission on monthly peak demand prohibits manufacturers from responding to transmission critical peaks. The pilot rate structures and opt-outs have changed this, but only for a limited set of manufacturers. Ohio needs to adopt transmission billing that is based on the NSPL, rather than monthly demand.

Additionally, this rate design is essential to the increasing adoption of DER technologies. In Ohio, a significant value stream is not realized due to current billing methodologies. With transmission becoming an increasingly large component of electrical bills, technologies that reduce a customer's transmission load should receive a commiserate benefit. Moreover, this shows the importance for vendors and facility managers of doing deep dives into tariff analysis for savings projections when investing in facility upgrades. Blended rate analyses do not accurately capture how costs are allocated

Finally, the ability to engage with the transmission system should help to provide additional oversight for transmission investment. Continuing investment in transmission

[7] 8.4 MW x $95,598/MW-year = $803,023/year

infrastructure will be necessary with electrification, but the institutions overseeing this investment should ensure that upgrades are necessary and essential to the grid, rather than gold plating to generate additional return for investors.

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