May 25, 2018

Beth E. Heline
General Counsel
Indiana Utility Regulatory Commission
PNC Center
101 West Washington Street
Suite 1500 E
Indianapolis, IN 46204

RE: Commission Inquiry on Back-Up, Maintenance and Supplemental Power Rates

Dear Ms. Heline,

Please find enclosed Indianapolis Power & Light Company's ("IPL") response to various parties' comments on Indiana public electric utilities' back-up, maintenance and supplemental power rates[1]. IPL is not responding to every point raised by the commenters. Some of the comments relate to back-up and maintenance service specific to other utilities, which IPL is not well situated to comment upon. IPL agrees with the commenters that back-up and maintenance contracts need to be cost based. This point of view necessitates recognition that each utility should maintain the flexibility to approach back-up and maintenance tariffs in a manner unique to its own cost structure and service territory.

IPL's response begins by responding to some of the general observations in the previous comments with which IPL's experience differs. IPL then addresses several specific comments related to IPL's back-up and maintenance tariff.

Sincerely,

Andrew J. Wells
Regulatory Counsel
AES US Services, LLC

Enclosure: Indianapolis Power & Light Company's ("IPL") Response to Parties' Comments on Backup and Maintenance Service Rates

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[1] In the Indiana Utility Regulatory Commission's Backup, Maintenance, and Supplemental Power rate review, three parties filed comments urging significant revisions to the rates charged by Indiana utilities for standby services. These parties are: the Alliance for Industrial Efficiency ("AIE"), Indiana Industrial Energy Consumers ("INDIEC"), and the Midwest Cogeneration Association ("MCA").

Indianapolis Power & Light Company's ("IPL") Response to Parties' Comments on Backup and Maintenance Service Rates

I. Introduction

Certain parties argue that the IPL rate structures incorrectly assume a standby customer requires costs similar to those of a full requirements customer.[1] However, all of IPL's rate structures are designed so that the standby customer pays the utility a zero-energy charge when the customer generates its own energy. Indeed, the availability of "free" energy produced as a byproduct of other processes is the primary argument for combined heat and power ("CHP") facilities.

The fixed costs of the production, transmission and distribution assets are a different matter since these costs are not avoided if the customer remains connected to the grid and expects to use these services as needed on a standby basis.

Several parties state that backup service is called upon only 5% or less of the time, and suggest that a rate approximately equal to 5% of the regular demand charge should be charged.[2] From a cost perspective, however, the fact that a customer calls upon the service only 5% of the time is far less important than the fact that the utility needs capacity available 100% of the time so that the customer can call upon it as needed.

The suggestion for a greatly reduced demand charge for standby service might reflect costs if there are numerous standby customers with complete diversity in their demands. For example, assume a utility has 20 standby customers that each require 1 MW of backup service. As long as the utility is confident that none of the 20 customers will be requiring standby service at the same time as any other standby customer, the utility would require only 1 MW of capacity to serve the entire group and could charge each of the 20 standby customers only 5% (1/20th) of the cost of generation included in the demand charges for regular customers. However, if there is some likelihood that two of the standby customers would need capacity coincident with the system peak, the utility would need 2 MW of backup capacity. Consequently, each of the 20 standby customers would need to pay 10% of the capacity costs in the rates for full tariff customers. Finally, assume that there is only one standby customer, and that customer requires 1 MW of backup capacity. That customer would need to pay a full demand charge because there are no other standby customers with which to share the costs. Appendix A illustrates the effect that the number of customers and predictably reliable demand diversity can have on the cost of providing standby service.

As these examples illustrate, the concept of charging only 5% of cost for a MW of standby capacity only reflects costs if there is a large number of standby customers with a predictably low probability that they will require service simultaneously at the time of the system peak. In the case of IPL, there are no customers on the standby rate schedules and there would be no demand diversity savings if only one or a few customers were to take the service.

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[1] MCA, p. 6. INDIEC and AIE also suggest that costs of providing capacity for standby service are less than the costs of providing capacity for full requirements customers.

[2] MCA, p. 3. INDIEC (p. 6) also suggests that the demand charge should be tied to the forced outage rate.

One way that standby customers could receive a cost-justified reduction in their demand charge would be to take service on an interruptible basis. In that way, the utility would not need to incur fixed costs of generation capacity on behalf of the customer. The customer, rather than the utility and its other customers, would then take the risk that the 5% of the time that the customer needs backup power does not occur at the time of system peaks.

Midwest Cogeneration Association ("MCA") relies on statistics from a 2002 survey of 121 Distributed Generation ("DG") facilities that was commissioned by Oak Ridge National Laboratory.[3] Although MCA's discussion focuses on the average availability characteristics of these 121 facilities, the underlying data indicate that there was a very wide range of forced outage rates and forced outage durations. Not only do the forced outage data differ widely between different generation technologies, but there is a wide variation within any given technology type. For example, one gas turbine averaged a three-hour outage once every nine days, while another gas turbine experienced a 12-hour outage once every two years. Similarly, the Oak Ridge study included one steam turbine with a 5-hour forced outage once every five days. Contrast the first steam turbine with another steam turbine in the survey that experienced a forced outage only once every three years, but that outage lasted 6 to 7 months.[4] As a consequence, an *average* forced outage rate from the Oak Ridge study cannot be used to make reliable predictions concerning the amount of backup capacity that a given unit, or collection of units, will require. The Oak Ridge study demonstrates that performance of individual DG units is highly unpredictable and that a utility would need to be serving a very large number of such units to make any statistically reliable plans for serving this class with less than the full amount of contract demands. However, IPL has no customers served under its Standard Contract Rider 10 Back-up Power, Standard Contract Rider 11 Maintenance Power, or Standard Contract Rider 12 Supplementary Power, and if it had one, or even a few of these customers, the statistically equivalent amount of capacity required to reliably provide firm backup service to this class essentially would be equal to the full amount of the contract load.

The wide variations in DG performance suggested in the Oak Ridge study also suggest that negotiated standby rates tailored to the technology and needs of the customer may be a more efficient and realistic ratemaking approach. In fact, IPL has negotiated standby service contracts with customers based upon their specific circumstances.

II. Comments on Specific Recommendations of Parties

A. Utilize a daily rate for service or rate proportional to the amount of time the service is actually used[5]

This recommendation appears reasonable if one correctly defines the concept of "the amount of time the service is actually used." Energy costs are avoided whenever the customer does not take energy. However, the fixed costs of Generation, Transmission, and

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[3] Cited in footnote 1 on page 3 of MCA's comments.

[4] "Distributed Generation and Operational Reliability and Availability Database," submitted to Oak Ridge National Laboratory by Energy and Environmental Analysis, Inc., Jan. 2004. Calculated from data on hours shown on page ES-4.

[5] AIE, p. 3; MCA, pp. 3-4.

Distribution facilities cannot be avoided even when the customer chooses not to take energy from the utility. The "service" that the utility provides with these facilities is *reliability*, which should not be confused with energy. A firm backup customer uses reliability 24/7, 365 days per year. When the service is understood to be reliability, it is apparent that the proportional costs of providing that aspect of the service generally will be equal to the cost of providing reliability to full requirements customers.

There are certain characteristics of the service that can reduce the fixed costs of reliable capacity. For example, the backup customer could elect to take an interruptible service to ensure that it does not cause a need for additional generating capacity and that it only uses utility capacity that also is used jointly by other customers much of the time, and that would otherwise go unused when the backup customer wants to use it. Alternatively, the fixed, demand-related costs per customer will be reduced if the utility has a large number of standby customers with sufficient operating history and data to conclude that the standby class will have statistically reliable diversity such that the costs of providing firm standby capacity can be shared to some degree among the customers in the class.

B. Reservation Fees based on CHP's actual Forced Outage Rate[6]

This recommendation assumes that there are a large number of CHP customers with a statistically reliable forced outage rate. However, when there are relatively few such customers who all want firm backup service, the utility cannot rely on diversity of demand to ameliorate the costs per customer. Moreover, a reservation fee based on the CHP's forced outage rate would not reflect the economic cost of providing reliability. For example, if a customer has a forced outage rate of five percent and it requires 1 MW of backup capacity, the utility would be able to provide 50 kW (i.e., 5% of 1 MW) of backup service at 5 percent of cost. However, if the customer actually wants a full 1 MW of capacity available and reserved for its firm use, the cost will be 100 percent of the cost of 1 MW of capacity, regardless of the forced outage rate.

C. Capacity cost should reflect CHP *class* contribution to system peak[7]

This appears to be reasonable if the utility has a large number of standby customers with many years of history in their operations. However, for a utility with few standby customers the past class contribution to system peak may be irrelevant for planning purposes. If a standby customer requires 50 MW of backup capacity and it has random forced outages five percent of the time, the utility will need to provide a full 50 MW of capacity even if the random forced outages happened to occur during off-peak periods in the prior year, or if the customer had no forced outages in the prior year. The uncertainty and randomness of this customer's firm demand imposes a need to provide peak period capacity for this customer even if the customer did not use any energy during peak periods in the preceding year(s).

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[6] AIE, p. 3, INDIEC, pp. 6-7; MCA, pp. 3-4.
[7] INDIEC, p. 5

D. Peak/Off-Peak Rate Differences[8]

IPL offers Standard Contract Rider No. 8 – Off-Peak Service for customers who wish to take service only, or primarily, during off-peak hours. Alternatively, Standard Contract Rider No. 14 – Interruptible Power offers a capacity credit for customers that are willing to be interrupted during a limited number of hours per year. Because maintenance service should be scheduled only during periods when interruption is very unlikely, this option should easily accommodate maintenance service. Similarly, if a backup service customer expects to require service less than 5 percent of the time and it believes that there is a low probability that the 5 percent will coincide with a period of system interruption, the interruptible option should be attractive to customers willing to take the risk of an event that has a low probability from the customer's perspective.

E. Scheduled/Unscheduled Outage Rate Differences[9]

As discussed above, the availability of interruptible service achieves the same result as a stated difference between the rates charged for scheduled and unscheduled outages.

F. Marginal cost of unplanned outages should be offset by benefits to the grid of reduced base load demand[10]

It is unclear what this argument is saying since there are no significant benefits to the grid of reduced base load demand. On the other hand, there might be some reductions in grid costs associated with reduced peak demand, depending on the specific location on the grid, and if the customer can guarantee that it will never use energy during the coincident peak of the system as a whole, or the particular circuit on which the customer is located.

The grid is designed to accommodate peak demand requirements and the costs are fixed regardless of the capacity factor at which they are used. For a customer that desires firm backup and maintenance service, the utility must have grid facilities in place to serve the peak demand regardless of whether the customer takes energy during any given hour, month, or year.

G. Tariff should allow shared transmission and distribution facilities[11]

One commenter made this recommendation, but it is unclear what this means. The transmission and distribution system currently is shared by numerous customers and the costs are spread among them. Distribution facilities are location specific and unless the generators share the same point of interconnection, there is likely no cost saving. Generators may or may not share the transmission system based on interconnection location. Furthermore, to ensure reliability, the maximum amount of load needs to be known in order to adequately design the transmission and distribution systems with enough capacity to serve load 24/7, 365 days per year. For example, if a distribution circuit has

[8] AIE, p. 3: MCA, p. 5.
[9] AIE, p. 3; MCA, p. 5; INDIEC, p. 7.
[10] AIE, p. 3; benefits to the grid also suggested by MCA at p. 3.
[11] AIE, p. 3

the capacity to serve 10 MW of load and a customer has a 4 MW CHP generator, should the utility build new distribution capacity when the circuit reaches a peak load of 6 MW or 10 MW? If the load reaches 10 MW and the CHP trips offline, then the circuit will trip. IPL would require additional information to understand this recommendation.

H. Eliminate demand ratchets[12]

The reason demand ratchets are common is to recognize that there are fixed, annual costs incurred to serve a customer's peak demand during the year. Demand ratchets are a way of allowing the customer to spread the payments for annual peak demand over 12 months. After a month in which a customer hits its annual peak, the demand ratchet charges in IPL's rate structure are also reduced by a factor (e.g., 60% or 75% of peak kW) to ensure that, although a customer does not pay the whole cost of its annual peak demand, it pays at least a minimum level of the annual costs associated with its peak demand. For a backup or maintenance service customer, the demand ratchet is simply a method of ensuring that during a year the customer pays a reasonable share of the fixed costs incurred to provide the customer's desired level of reliability.

Under IPL's rate structure, a backup customer that experiences a forced outage only once every few years would pay a demand ratchet for 11 months after an outage, but then it would pay only the minimum charge for several years until it has another forced outage. Consequently, for a customer that rarely experiences forced outages of its own equipment, the cost of the demand ratchet would be reduced considerably.

I. Provide Interruptible Option for Standby Service[13]

IPL's rates do provide an interruptible option for standby service.

J. Allow purchase of standby service from competitive providers[14]

Allowing purchase of standby power generation service from competitive providers would involve transitioning the grid in Indiana to retail choice. Consequently, moving all utilities in Indiana to such a competitive generation market would require a much more comprehensive study and hearing process to consider all the implications of such a move.

K. Allow interruptible customers to "buy through" from MISO at LMP costs[15]

It is possible for utilities to provide interruptible service to standby customers and allow the customers to "buy through" by using the LMP to price the service. In this scenario, the utility is not providing firm service and would not incur any capacity obligations related to the customer's demand. IPL's Standard Contract Rider No. 14, Interruptible Power, allows interruptible customers that meet the requirements of this rider to avoid curtailment by agreeing to pay the actual hourly market price under certain conditions.

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[12] AIE, p. 4, MCA, pp. 4 and 6; also implied at INDIEC, p. 7.
[13] AIE, p. 4.
[14] AIE, p. 4.
[15] INDIEC, p. 8.

L. Unbundle G,T,D charges[16]

The generation, transmission and distribution cost components of the demand charges can be unbundled using data from the allocated cost of service study filed in IPL's rate case. However, if the purpose of this proposal is to enable standby customers to purchase service from competitive providers, stating separate charges for each service is only necessary if the Commission decided to move Indiana utilities to a competitive generation market. In that case, the comments on competitive generation discussed above would apply.

M. Allow CHP users to offer a self-supply option for reserves[17]

It is unclear what this suggestion means. CHP users already have the option to disconnect from the grid and supply their own backup service. Additional information would be required in order to provide comments.

N. Mandate uniform statewide revisions to standby rates[18]

Uniform statewide standby rates would not reflect the individual circumstances of individual utilities or the economic costs of serving such customers. For example, each utility will have a different load pattern, resource mix, network configuration, and level of demand that can be interrupted in order to accommodate firm backup customers. In addition, each utility will have a different number of standby customers with different levels of diversity, and the size of expected standby customers is likely to be radically different between different service territories (e.g., NIPSCO very large heavy industry vs. IPL small, light industry and commercial). Moreover, because the potential range of size and reliability of different self-generation technologies can be very different, it may be most appropriate to use negotiated contracts that address the specific economic costs of the customers' needs. IPL has negotiated standby service contracts with customers based upon their specific circumstances.

O. Adopt Something Like the NIPSCO Model

Several parties cite the NIPSCO backup and maintenance service as an example of the type of pricing they would like to see all Indiana utilities adopt. For example, Alliance for Industrial Efficiency ("AIE") states:

> "NIPSCO's Rider 776 embodies many (but not all) of these best practices. This rider better reflects best practices of proportionality of costs imposed on the utility by standby use, than do the other tariffs, which are based on the assumption that a standby customer imposes the same costs as does a

[16] AIE, p. 4
[17] AIE, p. 4
[18] INDIEC, p. 10

> full-time customer. The IURC should look to replicate these best practice elements in other tariffs."[19]

It is essential to understand, however, that the NIPSCO rates are able to assume that a standby customer imposes less costs than a full-time customer because the standby services are "curtailable" (i.e., interruptible). According to NIPSCO's tariff, Rider 776 is:

> "... available to Customers taking service under either Rate 732 or Rate 733 who desire to take service subject to Curtailments from the Company on a temporary basis, including for Back-up or Maintenance purposes, subject to Curtailments. Back-up, Maintenance and Temporary Services under this Rider shall be subject to Curtailments when curtailment of the Company's interruptible service customers under Rider 775 is insufficient." (Emphasis added).

Pricing of *firm* backup service is a different matter altogether. Consequently, MCA's comment that "... Vectren's and Indianapolis Power & Light's standby tariffs result in charges that are many times higher than NIPSCO's 776 Rider ..." may not reflect fundamental differences in the nature and quality of services. Nor do those comments consider the extent to which certain fixed costs may be assumed to be recovered through the rates that these same NIPSCO customers pay for service under Rate 732 or Rate 733.

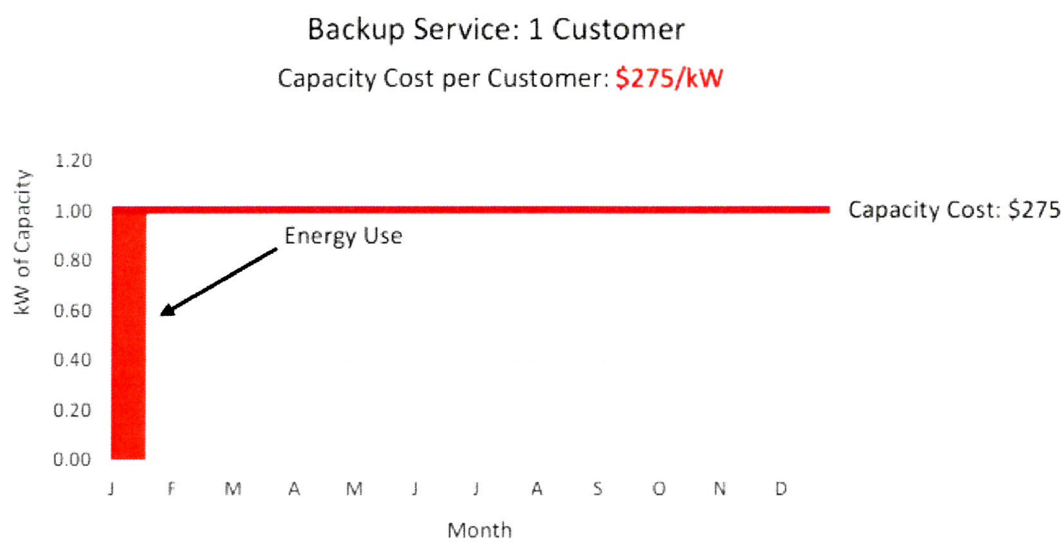
[19] AIE Comments, p. 4. Similarly, MCA states: "... NIPSCO's Rider 776 – applicable to large industrial customers only - stands out as a model reflecting proportional charges and other best practices." (p. 2).

APPENDIX A

The Effect of the Number of Customers and Demand Diversity on the Annual Cost of Standby Service

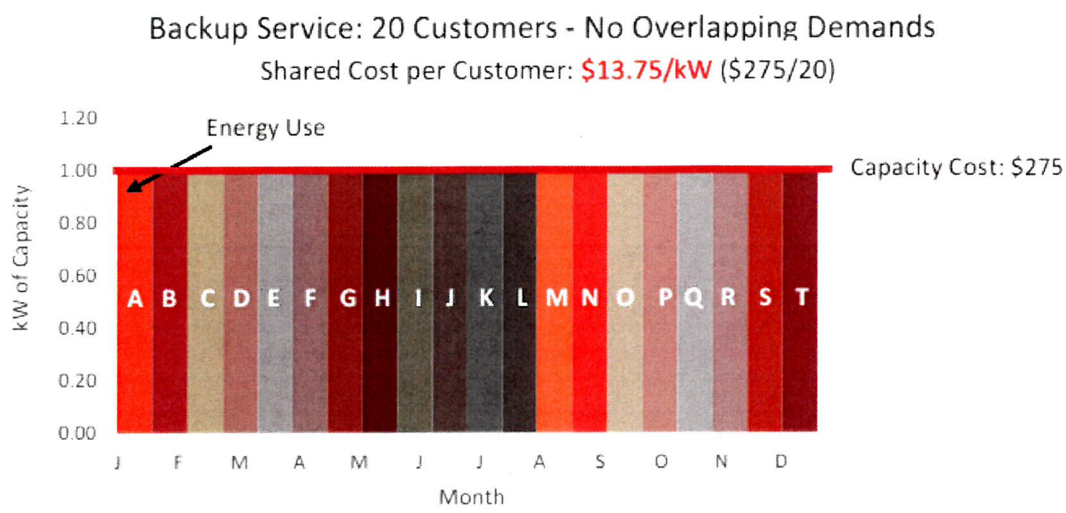
1. One Standby Customer

The exhibit below illustrates that when a utility has only a single standby customer a cost-based rate will be equal to the full annual cost (e.g., $275/kW) to provide standby capacity. The fact that the customer uses energy only 5% of the time does not change the fact that the customer relies on backup capacity for reliability purposes 100% of the time.



2. 20 Standby Customers – No Simultaneous Demands

If the utility has 20 standby customers <u>and there is no possibility that more than one of the customers will use the standby capacity at the same time</u>, it is possible for the utility to charge only 5 percent of the cost (e.g., $13.75/kW) to each of the 20 customers that share the capacity. In the example below, the 20 standby customers each take energy 5 percent of the time with no overlap in the times that they take energy from the standby capacity, thereby reducing the cost per kW of standby capacity. In this highly unlikely example of 100 percent demand diversity and the capacity being used 100 percent of the time, the cost-based demand charge (5% x $275) would be proportional to the five percent outage rate of the 20 customers, as some parties recommend.



3. 20 Customers – Some Simultaneous Demands

However, if there is a chance that two of the standby customers ("A" and "B") will use standby capacity at the same time, the utility will need twice as much standby capacity and the costs per kW for standby capacity will be doubled (e.g., $27.50). In the example below, there is a cost saving in being able to share the capacity among standby customers, but the cost savings is less than one would calculate by simplistically multiplying the 5% expected outage rate of DG facilities times the regular service demand charge.