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August 17, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA PURSUANT TO IND. CODE § 8-1-40-16 FOR APPROVAL OF RATE FOR THE PROCUREMENT OF EXCESS DISTRIBUTED GENERATION BY AES INDIANA	**CAUSE NO. 45504**

DIRECT TESTIMONY OF BENJAMIN D. INSKEEP

ON BEHALF OF
INDIANA DISTRIBUTED ENERGY ALLIANCE

AUGUST 17, 2021

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I. INTRODUCTION

Q. Please state your name, business address and current position.

A. Benjamin D. Inskeep, 1155 Kildaire Farm Road, Ste. 202, Cary, North Carolina 27511. My current position is Principal Energy Policy Analyst with EQ Research LLC.

Q. Please describe your educational and occupational background.

A. I earned a Bachelor of Science in Psychology from Indiana University in 2009 and both a Master of Science in Environmental Science and a Master of Public Affairs from the O'Neill School of Public and Environmental Affairs at Indiana University in 2012.

I was employed at the North Carolina Clean Energy Technology Center at North Carolina State University from June 2014 through February 2016, where I co-created and served as lead author and editor of *The 50 States of Solar*, a quarterly report series tracking net metering policies and rate design changes impacting residential solar. I also conducted policy research and contributed to the *Database of State Incentives for Renewables and Efficiency (DSIRE)* project. Finally, I provided technical support, conducted analysis, and led workshops for state and local governments on reducing solar soft costs through the U.S. Department of Energy's SunShot Solar Outreach Partnership.

I have worked for EQ Research LLC, a clean energy policy consulting firm, since 2016. In my current position, I oversee EQ Research's general rate case subscription service, which includes reviewing and analyzing investor-owned electric utility rate case filings, providing summaries to clients, and maintaining a client-facing database of rate case information. I also contribute as a researcher and analyst to other policy service offerings such as a legislative and regulatory tracking services and perform customized research and analysis for clients. I also help clients with their participation in regulatory proceedings, including serving as an expert witness on renewable energy policy issues, such as net metering. My *curriculum vitae* is attached as Attachment BDI-1.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Indiana Distributed Energy Alliance ("IndianaDG").

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC" or "Commission") or as an expert in any other proceeding?

A. Yes. I previously testified before the IURC in Cause No. 45506 (Indiana Michigan Power's excess distributed generation case) and Cause No. 45505 (Northern Indiana Public Service Company's excess distributed generation case). I have also previously testified before the Kentucky Public Service Commission in the following cases:

- Case No. 2020-00174 (Kentucky Power's 2020 rate case)
- Case No. 2020-00349 (Kentucky Utilities' 2020 rate case)
- Case No. 2020-00350 (Louisville Gas & Electric's 2020 rate case)

Q. What is the purpose of your testimony in this proceeding, and how is it organized?

A. My testimony responds to the excess distributed generation rider ("EDG Rider," i.e., Standard Contract Rider No. 16) and accompanying terms and conditions proposed by AES Indiana (the "Company"). It is organized as follows:

- Section II addresses AES Indiana's calculation of the EDG Rider credit rate, describes the flaws in AES Indiana's methodology, and proposes a more accurate methodology for crediting EDG. Next, I address AES Indiana's EDG Rider proposal to end the policy that allowed DG customers to net electricity produced by their DG systems and supplied to the utility against electricity supplied by the utility to the DG customer during a monthly billing period. I detail the flaws of this proposal and describe why it is inconsistent with the principles underlying just and reasonable rates. I also explain why maintaining monthly netting is sound policy, is supported by the plain language of the DG Statutes, and makes logical and practical sense in this case. I then analyze the impacts of AES Indiana's proposal on the financial value provided by DG and discuss various alternative policy options.

- Section III addresses other concerns I have with the terms and conditions of participation under the EDG Rider.
- Section IV contains my concluding remarks and summarizes my recommendations.

Q. What are your recommendations to the Commission?

A. For many reasons, especially but not exclusively the plain language of the DG Statutes, (Ind. Code ch. 8-1-40 and Senate Enrolled Act 309), I recommend that the Commission deny AES Indiana's proposed "no netting" EDG Rider and proposal to end monthly netting. To the extent the Commission disagrees with my recommendation to maintain monthly netting under the EDG Rider, I recommend it consider alternative policies that are less punitive to customers than the "no netting" proposed by AES Indiana.

If the Commission approves AES Indiana's filing as proposed or with limited modifications, I recommend that the Commission direct AES Indiana to provide additional consumer information and education regarding its Cogeneration & Small Power Production tariff to ensure all eligible DG customers have access to and are fully informed of this rate option, which might be more financially beneficial to certain DG customers than the proposed EDG tariff.

I also recommend that AES Indiana modify its calculation of the EDG Rider credit rate to accurately reflect the average marginal price at the daylight times solar DG systems are generating and exporting power to the grid.

Finally, I recommend the Commission reject AES Indiana's proposal to take without compensation a DG customer's earned but unused EDG credits at the end of a DG customer's service.

II. AES INDIANA'S EDG RIDER "NO NETTING" PROPOSAL

A. Description of AES Indiana Proposal

Q. What is AES Indiana proposing in this case?

A. In response to Senate Enrolled Act 309 ("SEA 309"), AES Indiana is proposing a new tariff, EDG Rider, for procurement of excess distributed generation ("EDG") under Ind. Code ch. 8-1-40 ("Distributed Generation Statutes" or "DG Statutes").

Specifically, AES Indiana is proposing that customers taking service under the EDG Rider would not be able to net *any* electricity they export to AES Indiana with electricity they import from AES Indiana:

> Net inflow means the separate meter channel measurement of energy supplied by Company to Customer as recorded on meter Channel 1. Net outflow means the separate meter channel measurement of energy being produced by Customer Generator in excess of the electricity being used by Customer, and which is supplied back to Company as recorded on meter Channel 2. Net outflow is Excess Distributed Generation.
>
> For the billing month, meter will record net inflow and net outflow. Net inflow KWH for the billing period shall be billed in accordance with Customer's rate schedule. Net outflow KWH for the billing month shall be multiplied by the Excess DG rate to determine the Rider EDG credit.[1]

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[1] AES Indiana, Standard Contract Rider No. 16, Excess Distributed Generation (EDG) [Attachment MDF-1 to Supplemental Testimony of Matthew Fields].

I refer to this position in my testimony as AES Indiana's "no netting" proposal, which I believe is an accurate and fair characterization.[2] Instead of applying monthly netting, *all electricity* that a DG customer does not instantly consume on-site behind-the-meter that is exported to AES Indiana under EDG Rider would be credited to the DG customer at a very low rate of $0.02796/kWh, and that rate would change each year.[3] All electricity that a DG customer imports from AES Indiana would be charged at the applicable retail rate.

Q. How does AES Indiana calculate the EDG Rider credit rate for EDG?

A. AES Indiana calculated the average Real-Time Locational Marginal Price ("LMP") for its load zone within the Midcontinent Independent System Operator ("MISO") for all hours of the entire 2020 year at an AES Indiana pricing node, and multiplied that value by 1.25. The Average LMP in 2020 was $22.37/MWh, resulting in a calculated EDG rate of $0.02796/kWh.

Q. Does AES Indiana claim that its customers can access their electricity usage data?

A. Yes. In Supplemental Testimony, AES Indiana Witness Matthew Fields asserted that "Customers can access both the Channel 1 and Channel 2 data for each 15-minute interval through Power View."

Q. Are you a customer of AES Indiana?

A. Yes, I am a residential customer of AES Indiana. I do not currently own a DG system.

Q. Has AES Indiana provided you access to your usage data for 15-minute intervals through Power View?

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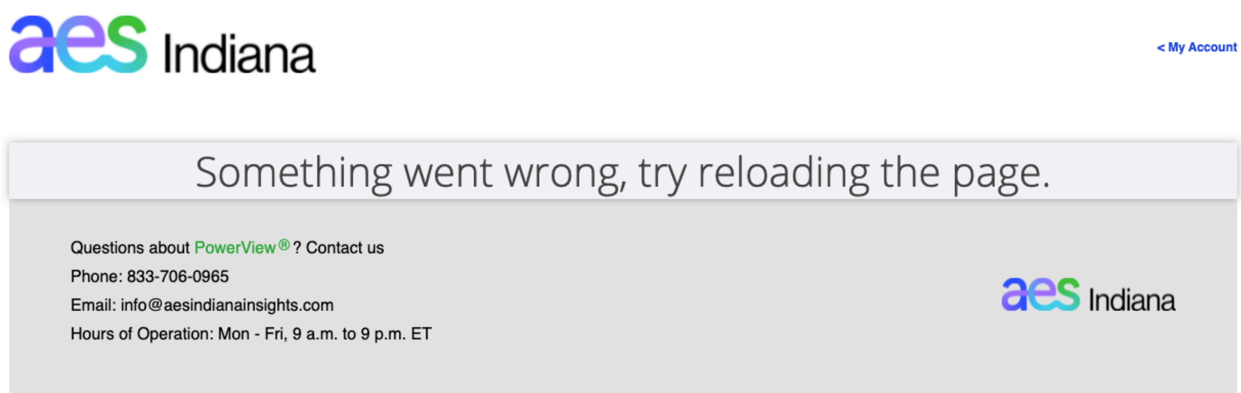
[2] *See, e.g.,* AES Indiana Response to IndianaDG Data Request 1-13.
[3] Direct Testimony of Matthew Fields, p. 5.

A. No, it has not. I have repeatedly attempted to access my granular customer usage data (e.g., hourly, 15-minute, or instantaneous usage) and been unable to do so. When I attempt to download my usage data in Power View, it returns the following error:



Subsequently, I noticed that my premises do not appear to have an AMI meter installed. AES Indiana says that only 69% of its customers currently have AMI meters, and asserts that "customers with AMI meters have the ability to access detailed consumption information through the portal."[4]

Q. Did you contact AES Indiana customer support regarding your inability to access your customer usage data?

Yes, I contacted AES Indiana customer service by phone on August 12, 2021. After being transferred several times, I reached the AES Indiana representative who was able to answer my questions on Power View. The representative put me on hold to confirm answers to my questions with other AES Indiana employees. I was then informed that customers currently only have limited access to their usage information. I was informed that **none** of the detailed information on customer usage is available to residential customers yet. Furthermore, the date for rolling out this feature has been postponed. When asked, the AES

[4] AES Indiana Response to IndianaDG Data Request 1-20.

Indiana representative I spoke to was unable to provide a timeline for when residential customers will be able to access their granular usage data.

I also inquired about the ability of a residential customer to access granular usage data when these features are eventually rolled out to residential customers at an unspecified time in the future by AES Indiana. I was informed that residential customers will only be able to see *daily* usage information – and not their 15-minute usage as AES Indiana has testified in this proceeding, nor the "instantaneous" usage information they asserted customers currently have access to in response to a Data Request made by IndianaDG.[5]

Q. Do you conclude that AES Indiana customers are able to easily determine their instantaneous electricity consumption or obtain granular (e.g., 15-minute) historical usage data from AES Indiana?

A. No. As my personal experience illustrates, some AES Indiana residential customers do not have access to any tool provided by AES Indiana that would provide them with information on what their usage is in real-time, or what their historical usage was at a granular level. At least some residential customers, including my myself – a prospective DG customer – only have access to data on their monthly usage.

This is extremely concerning in the context of this proceeding because AES Indiana has proposed a new "no netting" policy that will, in practice, necessitate that EDG customers, including residential EDG customers, monitor on a *real-time basis* their consumption relative to their generation. Customers will need to closely monitor this information in order to respond accordingly, to the extent they are capable, by shifting load to minimize the amount of their DG generation above their consumption at any moment to

[5] AES Indiana Response to IndianaDG Data Request 1-20.

avoid being credited at the very low EDG credit rate proposed by AES Indiana. Furthermore, all prospective DG customers will need easy access to their historical usage data at a granular level to be able to estimate the financial viability of DG under AES Indiana's "no netting" proposal. Providing this data to customers will still result in estimating the financial feasibility a difficult task, and it will be an exceedingly onerous task for customers to monitor their usage and generation in real-time for the decades that their DG system is operating. But failing to provide this data will result in an even worse outcome by making these tasks not just difficult and onerous, but nearly impossible.

B. EDG Credit Calculation

Q. What does the language in the DG Statutes provide with respect to how the EDG credit rate must be calculated?

A. Please note, I offer no legal conclusions in my testimony. I only describe the plain language of the statutes and related documents I have read. Section 17 of the DG Statutes provides that the EDG credit rate must equal:

> the product of: (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by (2) one and twenty-five hundredths (1.25).

Section 6 provides that marginal price of electricity:

> means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

AES Indiana's proposed hourly market prices are determined in each of the 24 hours in each day, including in daylight hours when customer solar is generating electricity and helping offset daylight demand, and including nighttime hours when solar is not generating electricity and AES Indiana electric demand and wholesale market prices of energy are typically lower.

Q. Is AES Indiana's calculation of the EDG credit rate reasonable?

A. No. AES Indiana has averaged the wholesale electricity price for *all hours* of the year. However, nearly all DG systems are solar facilities that only produce electricity and export power during daylight hours. AES Indiana's calculation using *all hours* including nighttime hours does not align with the hours in which a DG system actually generates electricity, and therefore does not accurately reflect the marginal price of electricity during the hours in which a DG system is providing EDG to AES Indiana. AES Indiana's customers' highest demands for electricity generally occur during the afternoon in summer (e.g., its peak in 2020 occurred at 2 p.m. on July 27),[6] coinciding with when solar is typically generating electricity. Market prices for electricity are generally higher during these hours than the average of all hours over the year. Customer solar output shaves or eliminates their demand for electricity during these higher-priced hours, and their EDG exports help reduce the need for higher-cost market purchases during these hours. It would be an irrational exercise and result to calculate the value of customers' EDG based on hours of darkness when customers' solar facilities are not generating electricity and exporting power to the grid.

Q. What would be a more reasonable way of calculating the marginal price of electricity?

A. AES Indiana could calculate "the average marginal price of electricity paid by the electricity supplier during the most recent calendar year" by using the average marginal price for when DG generation is being exported, i.e. daylight hours which would be more

[6] AES Indiana, FERC Form 1, 2020/Q4, p. 401b.

reflective of what is "paid by the electricity supplier." I recommend calculating the average marginal price of electricity for each hour of the previous year and applying an appropriate factor that weights the average price in each hour according to the amount of generation a typical DG system is expected to actually produce during that hour.

I have conducted such an analysis based on the expected output of a typical residential solar DG system located in Indianapolis, Indiana on Eastern Standard Time using the default assumptions and output produced using the National Renewable Energy Laboratory's ("NREL") PVWatts Calculator.[7] This analysis indicates that expected solar DG generation for systems located in Indianapolis, Indiana, that are not paired with battery energy storage will occur between the hours of 5 a.m. to 8 p.m. For instance, a solar DG system will produce the most electricity during the noon hours, equating to 13.5% of the system's total production on an annual basis. Therefore, the LMP for the noon hour should be weighted accordingly by multiplying the average hourly LMP at noon for the previous year by 13.5%, conducting this same system hourly production calculation for each other hour of the day, and summing each calculated value to arrive at "the average marginal price of electricity paid by the electricity supplier during the most recent calendar year" as it applies to the generation profile of a typical DG customer. In contrast, the solar DG system produces no electricity during the midnight hour, equating to 0% of the system's total production on an annual basis, and therefore the LMP for the midnight hour is weighted by a factor of 0%.

[7] National Renewable Energy Laboratory, PVWatts Calculator, available at https://pvwatts.nrel.gov/.

This approach results in a 2020 average LMP of $25.34/MWh, or $0.02534/kWh, which produces an EDG credit rate of $0.03167/kWh, which is 13.3% higher than AES Indiana's proposed EDG credit rate that incorrectly includes non-solar-generating hours in its calculation.

This would be a rational approach to applying the hourly wholesale market price to an EDG rate calculation that aligns with the time when solar DG facilities are generating electricity and would be consistent with the plain language of the DG Statutes. An alternative approach would be to take the hourly LMP price for each of the solar-generating hours and average them. But that approach would fail to give fair consideration to the hours that solar DG generation produces the most electricity. An even less accurate approach is the one taken by AES Indiana where the individual 24 hours of LMP are averaged with total disregard to when solar DG is actually producing electricity.

Q. Would it be reasonable to apply the EDG credit rate you propose to biomass and wind EDG customers?

A. Yes. AES Indiana reported that 5.436 MW out of 5.486 MW (99.1%) of its net metering capacity are solar resources, and that 100% of new capacity additions in 2020 were solar resources.[8] Based on current total deployment and deployment rates, biomass and wind resources currently have an immaterial effect on the overall value of DG on average, and recent trends do not indicate this is likely to change in the foreseeable future. Therefore, it is reasonable to use the methodology I propose that is based on the generation profile of a solar facility in Indianapolis, Indiana.

[8] Indiana Utility Regulatory Commission, "2020 Year- End (2020YE) Net Metering Reporting Summary," March 2021, available at https://www.in.gov/iurc/files/2020-Year-End-Net-Metering-Required-Reporting-Summary.pdf

Q. Does calculating the EDG rate based on daylight hour solar electricity production result in a rate that reflects the value of solar EDG exports and reach an overall just and reasonable EDG rate proposal?

A. Calculating the solar EDG rate based on daylight hours (i.e., solar-producing hours) simply avoids the irrational calculation of solar EDG based in part on the non-solar producing nighttime market price of wholesale electricity. But it does not result in a just and reasonable EDG rate as it still seriously undervalues electricity exported by an DG customer. More importantly, it will not yield a just and reasonable EDG framework or result. The slightly higher solar EDG credit from my calculation is an improvement on AES Indiana's EDG credit calculation, but it is not sufficient to offset to a meaningful degree the far more substantial negative impact of the "no netting" proposal. As I calculate below, the "no netting" proposal is the primary driver for significantly prolonging solar DG payback periods. In other words, while I believe correcting the EDG credit rate calculation as I describe above is logical, it is not a remedy for the harm to DG customers that will result from AES Indiana's "no netting" proposal.

C. Measurement of EDG

Q. How does the language in the DG Statutes define EDG?

A. Section 5 of the DG Statutes provides:

> As used in this chapter, "excess distributed generation" means the difference between:
>
> (1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and
>
> (2) the electricity that is supplied back to the electricity supplier by the customer.

Q. How does the language in the DG Statutes specify the compensation rate for EDG be calculated?

A. Section 17 of the DG Statutes requires the Commission to approve a "rate" for compensating EDG that:

> equals the product of (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by (2) one and twenty-five hundredths (1.25).

Q. Do you see any language in the enacted DG Statutes that specifies a change in netting methodology or prescribes a new method for measuring EDG; or otherwise directs the Commission to review and approve a new measurement or netting methodology?

A. No, I do not see such language. There is no language in the statute that says monthly netting should stop. Notably, the language in the DG Statutes requires the Commission to approve a *rate* – not consider a new methodology or netting measurement for determining EDG. I do not see language that requires or asks the Commission to consider a new methodology or netting measurement for determining EDG.

Q. Have you researched the legislative evolution of SEA 309 from publicly available documents?

A. Yes, I have. The variations of the bill and video of legislative public hearings on the bill are publicly available on Indiana General Assembly's website.

Q. What has your research found with respect to provisions addressing the issue of netting in the legislative history of the SEA 309 DG Statutes?

A. As introduced ("Version 1," which is my Attachment BDI-2), Section 15 of SEA 309 would have changed the netting methodology by expressly removing all netting.

Specifically, it would have established a buy-all, sell-all tariff to replace net metering by providing that:

> all distributed generation produced by the customer shall be purchased by the electricity supplier at the rate approved by the commission under section 13 of this chapter; and (2) all electricity consumed by the customer at the premises shall be considered electricity supplied by the electricity supplier and is subject to the applicable retail rate schedule.[9]

This definitional language makes clear that netting would not be permitted, since "***all*** distributed generation produced by the customer" is being credited at the specified rate and "***all*** electricity consumed by the customer" is subject to the applicable retail rate charges (emphasis added). A buy-all, sell-all tariff would have the DG customer pay retail rates for their full electricity usage, receive a set EDG rate for their electricity production, and their usage would not be offset by any of their own on-site DG generation output. A buy-all, sell-all policy would have been a change from the existing measurement methodology of monthly netting.

SEA 309 was subsequently amended four times ("Version 2," "Version 3," "Version 4," and "Version 5," respectively; see Attachments BDI-3, BDI-4, BDI-5, and BDI-6), with Version 5 ultimately enacted as the DG Statutes. None of the subsequent versions retained the buy-all, sell-all framework or stated a new netting or no netting methodology, i.e., something different from the existing monthly netting, or otherwise instructed the Commission to evaluate any need for a different netting proposal.

Q. What was the public reaction to Version 1 of SEA 309, which included revising the existing monthly netting methodology?

[9] Indiana General Assembly, 2017 Session, Senate Bill 309 (As Introduced), available at http://iga.in.gov/legislative/2017/bills/senate/309#document-6bef29ba

A. There was strong opposition with letters to the editors sent to newspapers and opposition voiced to the bill's author, Senator Brandt Hershman.[10]

Q. How did the author of SEA 309 and the General Assembly respond to the public reaction to Version 1?

A. Senator Hershman amended Version 1 of SEA 309. Version 2 and all subsequent versions of SEA 309 removed what had proved to be the highly contentious and controversial buy-all, sell-all provisions that had been included in Version 1, which neither allowed for on-site consumption, nor any form of netting exported electricity against imported electricity. Version 2 and all subsequent versions of SEA 309 contained the same definition for "excess distributed generation" that the General Assembly enacted through Section 5 of the DG Statutes, with no mention of altering the current monthly metering and netting.

Q. What statements did the author of SEA 309 make regarding the intent of the bill and its provisions with respect to EDG?

A. After amending Version 1 to remove the buy-all, sell-all provisions, Senator Hershman submitted a letter to the editor (Attachment BDI-7) in response to the strong public opposition to Version 1 of SEA 309, explaining that the buy-all, sell-all provisions had been removed from the bill and describing his view of the other aspects of SEA 309.[11] He

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[10] *E.g.*, John Russell, "Bill Alarms Solar-Power Advocates," *Indianapolis Business Journal,* January 23, 2017; Dennis Shock, "Ending Net Metering Bad for Hoosiers" [Letter to the Editor], *The Indianapolis Star*, January 29, 2017; "A Bright Idea: Resist Urge to Tie Solar-Energy Producers' Hands," *The Journal Gazette*, January 27, 2017; Paul Steury, "Senate Bill 309 Could Kill Solar Buyback Program," *The Goshen News*, February 4, 2017; Christopher Rohaly, "Strengthen Solar Industry, Legislature" [Letter to the Editor], *Kokomo Tribune*, February 7, 2017; and Ray Wilson, "Don't Kill Indiana's Solar Industry" [Letter to the Editor], *The Indianapolis Star*, February 7, 2017.

[11] Brandt Hershman, "Utility Fairness for Hoosier Customers," *The Star Press,* available at https://www.thestarpress.com/story/opinion/contributors/2017/02/23/utility-fairness-hoosier-customers/98318350/.

characterized the amended bill as still "encourag[ing] renewable energy generation" while stepping down the compensation *rate* for EDG. He responded to the vocal opposition by clarifying in his letter that SEA 309 "has already been amended to address many of these concerns."[12]

Notably, none of the bill versions introduced after Version 1 was amended, including the enacted DG Statutes, have language that mentions, suggests, or contains provisions implying a change to the monthly netting methodology. What is clear is that the DG Statutes' language changes the *rate* at which EDG is compensated, moving from the full retail-rate rollover crediting under Net Metering to a credit rate based on an average marginal price, plus 25%. It also included provisions allowing existing net metering customers to continue to take service under net metering for a specified period of time, depending on when the system was installed.

In hearings on SEA 309, Senator Hershman made the following statements about SEA 309 (emphasis added):

- "That is what this tries to do: by stepping us down over a fairly long period of time, **so that we don't kill the solar industry, but we do start to transition them to a market-driven rate**, and as I said, I think the technology is going to allow that to happen and for them to continue to be a viable means of generation."[13]
- "The language in the bill itself is not all that complicated. It has the IURC determine the wholesale rate for a particular utility and then adds 25% to it, which you and I can do on the back of an envelope right here […] [A]nything that's even close to a ratemaking procedure at the IURC is an exhaustive and expensive process that oftentimes takes years […] **Simplicity and certainty was actually my goal in doing it this way**."[14]

[12] *Id.*
[13] Indiana Senate Utilities Committee, February 9, 2017, First Reading of SEA 309 [Timestamp 13:40].
[14] Indiana Senate Utilities Committee, February 9, 2017, First Reading of SEA 309 [Timestamp 25:30].

- "The only real issue here is how many people may sell their excess power back to the utility, and at **what rate they will be paid** […] That's it."[15]
- "…that **[25% above average wholesale prices] premium recognizing that we do assign a public policy value to renewable power**."[16]
- "We are providing **a very, very slow ramp-down of the rates** while we provide a substantial grandfathering for anyone who is currently participating in the program, and **we move ourselves, recognizing the advances in technology, closer to a market rate over a very long period of time**."[17]
- He described the 25% premium above wholesale rates as "**putting in law a public policy preference for alternative energy**."[18]

Although Senator Hershman spoke frequently in these hearings of modifying the ***rate*** by which EDG is compensated to slowly begin to align it with "market-based rates," I did not observe him or other members of the General Assembly in these hearings discuss any intent in the bill to modify the methodology or measurement for determining EDG. Senator Hershman's words are clear that the changing compensation rate was meant to be a gradual change, and not produce a devastating impact to the distributed solar industry in Indiana. Senator Hershman made clear that he was not opposed to distributed solar – in fact, he states this bill was enshrining in Indiana law a *preference* for technologies like distributed solar – and that the bill was not designed to harm the distributed solar market, but rather gradually align the State's policy based on the maturation of this technology.

Q. What is the significance of the EDG definition with respect to determining the appropriate EDG measurement for compensation under the specified rate?

A. The DG Statutes expressly provide that the measurement of EDG requires a calculation between the "difference between" two values: (1) electricity supplied by the utility

[15] Indiana Senate Utilities Committee, February 16, 2017 [Timestamp 14:45].
[16] Indiana Senate Utilities Committee, February 16, 2017 [Timestamp 17:10].
[17] Indiana Senate Utilities Committee, February 16, 2017 [Timestamp 17:10].
[18] Indiana House Utilities, Energy and Telecommunications, March 22, 2017 [Timestamp 25:30].

("imports" of electricity from the DG customer's perspective) and (2) the electricity supplied by the DG customer to the utility ("exports" of electricity from the DG customer's perspective). Instead of calculating that difference, AES Indiana proposes that EDG be measured so that ***all*** kWh supplied by a DG customer to AES Indiana at any instant is credited at the low EDG Rider credit rate of $0.027960/kWh, and ***all*** kWh supplied by AES Indiana to the DG customer is charged to the customer at that customer's applicable full retail rate – and not by first taking the *difference between* these kWh values and then applying the EDG rate to the total EDG. AES Indiana distorts the plain language of the statutory definition of EDG beyond recognition by conflating a DG customer's exports (called "net outflow" in its tariff, although nothing is actually being netted and this is really a measurement of gross outflow, or exports, from the DG customer to AES Indiana) with EDG. It does so by defining "net outflow" as "energy being produced by Customer Generator in excess of the electricity being used by Customer, and which is supplied back to Company as recorded on meter Channel 2. Net outflow is Excess Distributed Generation." The DG Statutes defines EDG as "the difference between" DG customer imports and exports – and *not* as all gross exports.

Although the EDG Rider is distinguishable from a buy-all, sell-all tariff in that it does allow a DG customer to self-consume electricity generated by its own private DG equipment behind the meter, by treating each of the two components of EDG in isolation, AES Indiana's "no netting" proposal resembles the provisions of the initial Version 1 of SEA 309 that were subsequently removed. In contrast, the adopted statutory language functionally defines EDG as occurring over a period of time, and necessarily requires a netting calculation. *Netting*, by definition, is taking the *difference between* two values – in the context of net metering or the DG Statutes, the difference between electricity imports and exports over the billing period.

Finally, since electricity flows in one direction, a DG customer does not and cannot both supply electricity to the utility and receive electricity from the utility at the same instance – they are either providing electricity to the utility, or they are being supplied electricity by the utility at any given time. Therefore, a utility cannot calculate EDG as defined by the DG Statutes without measuring imported and exported electricity from a DG customer over a period of time. As further explained below, that period of time is the monthly billing period.

Q. Please provide a simple diagram to help visualize the statutory definition of EDG?

A. Figure 1.A provides a diagram of how a DG customer and a utility are connected through the utility meter. Everything to the left of the meter in this diagram is "behind the meter," and everything to the right of the meter is "in front of the meter," i.e., the utility's grid. The meter records electricity flows from the utility to the DG customer and from the DG customer to the utility, respectively, through Channel 1 and Channel 2 meter recordings.

Figure 1.A. Diagram of DG Customer Interactions with Their Utility

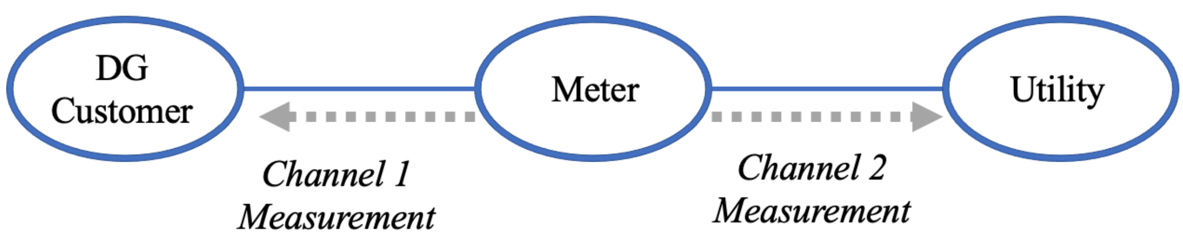


Figure 1.B and 1.C, respectively, correspond to the two components of the definition of excess distributed generation in the DG Statute. Figure 1.B illustrates part one of the statutory definition of EDG, i.e., "the electricity that is supplied by an electricity

supplier to a customer that produces distributed generation." Meter Channel 1 records the amount of electricity (in kWh) supplied by AES Indiana to the DG customer.

Figure 1.B. Electricity Supplied by an Electricity Supplier to a DG Customer

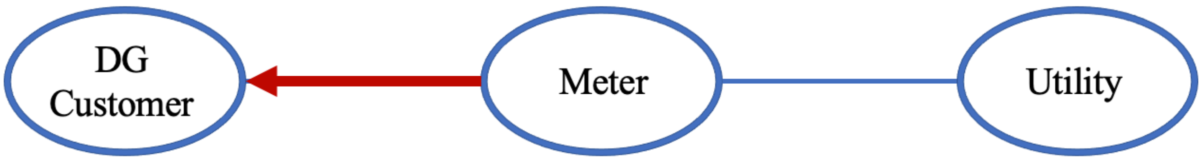
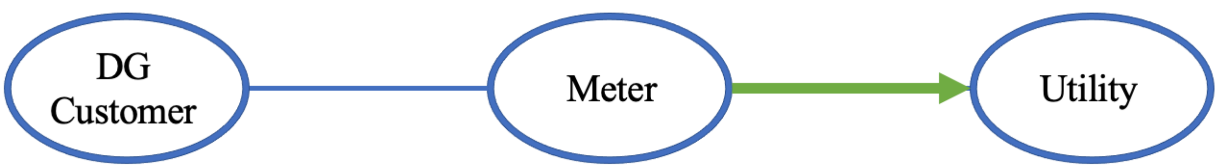


Figure 1.C. illustrates part two of the statutory definition of EDG, i.e., "the electricity that is supplied back to the electricity supplier by the customer." Note that the plain language of this part of the statutory definition only refers to electricity that passes through the customer's meter ("supplied back") to the utility. It does not include a customer's consumption behind the meter of generation produced by the customer's DG facility, as this electricity is being immediately consumed by the customer and is <u>not</u> being "supplied back" to AES Indiana.

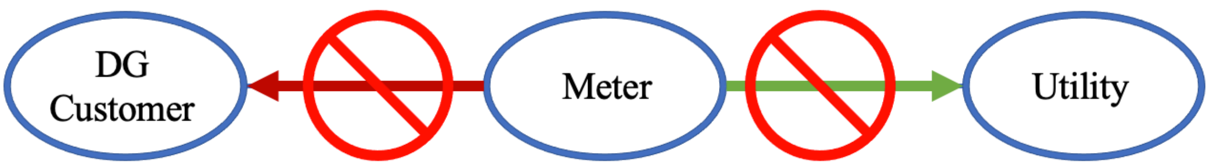
Figure 1.C. Electricity that Is Supplied Back to an Electricity Supplier by the Customer.



Finally, when a DG customer is neither receiving electricity from the utility, nor supplying electricity to the utility, no flows of electricity occur in either direction, and both meter Channels 1 and 2 will record a value of 0. This could occur if the DG customer is not using any electricity in that instant, or if the DG customer is meeting their electricity needs through behind-the-meter generation that perfectly matches their demand in that instant.

According to AES Indiana, at any moment, electricity flows through AES Indiana's bidirectional meter in only one direction (Figure 1.D).[19] Therefore, the situation represented in Figure 1.D – of having flows of both electricity being supplied by the utility to the DG customer and from the DG customer to the utility at the same time – <u>will never occur</u>, so the utility would never need to do any netting calculation of taking "the difference between" these two values for any moment, as it is physically impossible.

Figure 1.D. Part 1 and 2 of the EDG Definition Never Occur at the Same Instant

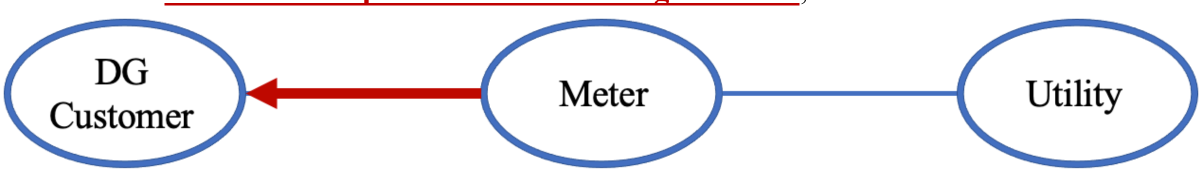


NEVER occurs at the same time

In Figure 1.E below, I have color coded the EDG definition to clearly connect the representations in my diagrams to the statutory definition of EDG:

Figure 1.E

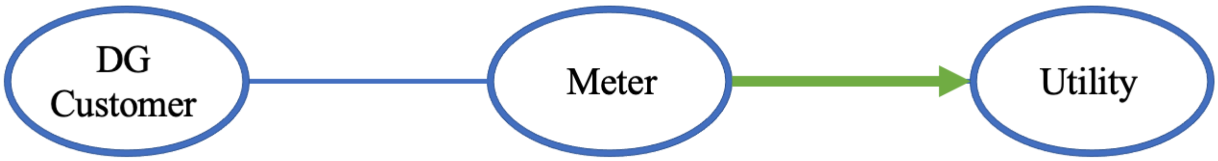
> As used in this chapter, "excess distributed generation" means **the difference between**:
>
> <u>**(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation**</u>; and



[Channel 1]

[19] Supplemental Testimony of Fields, p. 3.

> **(2) the electricity that is supplied back to the electricity supplier by the customer**.



[Channel 2]

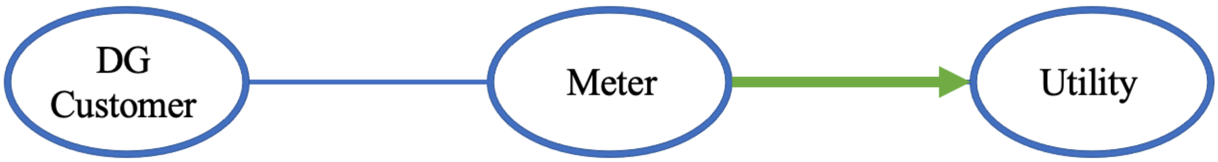
As illustrated in the above figures, the plain language of the statutory definition of EDG provides that EDG is a netting calculation between the difference in the amount of electricity (in kWh, as the definition refers to "electricity" and not "the monetary value of electricity," for instance) recorded on Channels 1 and 2.

Q. Does AES Indiana's "no netting" policy align with the plain language of the DG Statutes with respect to the definition of EDG?

A. No. AES Indiana's "no netting" policy does not take "the difference between" part one and two of the EDG definition. Instead, AES Indiana's "no netting" policy completely ignores the first part of the EDG definition and compensates *all* "electricity that is supplied back to the electricity supplier by the customer" at the low EDG credit rate. AES Indiana's "no netting" proposal re-imagines the DG Statutes to essentially "strike out" portions of the statutory definition of EDG by defining EDG as "energy being produced by Customer Generator in excess of the electricity being used by Customer, and which is supplied back to Company as recorded on meter Channel 2," as illustrated in Figure 1.F.

Figure 1.F. AES Indiana's "No Netting" Policy Incorrectly Measures EDG as All Electricity that Is Supplied Back to an Electricity Supplier by the Customer, Rendering Part 1 of the EDG Definition Meaningless

> As used in this chapter, "excess distributed generation" means ~~the difference between~~:
>
> > **~~(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation~~**~~; and~~
> >
> > ~~(2)~~ **the electricity that is supplied back to the electricity supplier by the customer**.



Q. Is AES Indiana "no netting" policy a reasonable application of the plain language of the definition of EDG?

A. No. AES Indiana's application of the definition of EDG would render part 1 of the definition meaningless and extraneous. In other words, there is no real "difference between" any values ever being calculated, since AES Indiana is assigning the value of the first number as 0 (zero). It would be a nonsensical interpretation of the plain language of the statutory definition of EDG to adopt a definition where only one part of the definition ever actually applied or had an effect. However, this is what AES Indiana is proposing in this case – it will never actually take "the difference between" part 1 and 2 of the EDG definition because it admits they can never both occur at the same time. In my view, this contradicts the plain language of the statute and therefore the Company's "no netting" proposal must be rejected for failing to comply with the DG Statute.

Q. Does AES Indiana's recordings of Channel 1 and 2 flows on a 15-minute period basis impact its "no netting" proposal?

A. No. It is important to distinguish that the meter *recording* intervals (e.g., 15 minutes) are a separate issue from the *netting* intervals (e.g., monthly netting, 15-minute netting, no netting, etc.). Using a different meter recording interval, such as a recording interval of every second or minute, would not impact the actual amounts recorded on Channels 1 and 2 over the monthly billing period or the calculation of EDG under AES Indiana's "no netting" proposal.[20] AES Indiana is not proposing to "net" Channel 1 and 2 recordings on a 15-minute basis (or over any time period), but rather record Channel 1 and 2 measurements to *separately* bill those measurements at the applicable retail rate or the EDG credit rate, respectively.

Q. What other support do the DG Statutes' plain language provide for continuing to use a monthly netting period for DG customers?

A. First, by defining "excess distributed generation" as the "difference between" exports and imports, the plain language of the DG Statutes suggests a netting calculation to determine the "difference." Had the General Assembly intended for *all* exported generation from a DG facility to be compensated at the EDG Rider rate, it could have easily done so by defining "excess distributed generation" as "the electricity that is supplied back to the electricity supplier by the customer" – i.e., using only the second part of the definition of EDG that was adopted, and completely omitting any reference to the first part of the definition regarding "the electricity that is supplied by an electricity supplier to a customer that produces distributed generation." Version 1 of SEA 309 contained provisions that would have required all generation by a DG facility to be credited at a prescribed rate, but

[20] AES Indiana Response to IndianaDG Data Request 1-13.

in totally removing that provision without any similar replacement language in subsequent amendments, it is clear that these provisions were not endorsed by the General Assembly.

Second, Section 3 defines "distributed generation" to include DG facilities that are:

> sized at a nameplate capacity of the lesser of: (A) not more than one (1) megawatt; or (B) **the customer's average annual consumption of electricity on the premises**

(emphasis added). In other words, a key limitation for becoming eligible for service under the EDG Rider is that the customer's DG system is sized to meet their "average annual consumption." There is no requirement – indeed, there is no indication in the statute's language – that the DG facility should be designed in a manner to limit exports on an *instantaneous* basis; instead, it expressly requires that DG systems be designed to generate electricity to meet a customer's *average annual* energy needs.

In addition, Section 18 of the DG Statutes provides, in relevant part, that:

> An electricity supplier shall compensate a customer from whom the electricity supplier procures EDG (at the rate approved by the commission under section 17 of this chapter) through **a credit on the customer's *monthly* bill**…

(emphasis added). This provision identifies that EDG is being calculated and credited on a **monthly** bill basis, and not on an instantaneous basis.

Q. Has the Commission established regulations implementing changes to netting since the enactment of the DG Statutes in 2017?

A. No. In response to SEA 309, the Commission held collaborative meetings, issued Emergency Rulemaking 17-04, and General Administrative Orders 2017-2 and 2019-2. However, it did not issue formal regulations that would modify the measurement of EDG as currently prescribed under its net metering rules to a new netting policy or a "no netting" policy.

170 IAC 4-4.2-7 provides, in part, that under net metering,

> The investor-owned electric utility shall measure the difference between the amount of electricity delivered by the investor-owned electric utility to the net metering customer and the amount of electricity generated by the net metering customer and delivered to the investor-owned electric utility during the billing period, in accordance with normal metering practices.

Normal metering practice is monthly netting, not a new "no netting" metering.

D. Drawbacks of AES Indiana's "No Netting" Proposal

Q. Besides lacking support in the plain language of the DG Statutes, does AES Indiana's "no netting" proposal have any significant drawbacks?

A. Yes, absolutely. In sum, AES Indiana's proposal is insufficiently supported by its case-in-chief, creates perverse incentives rather than desirable price signals, substantially reduces the economic value of DG to customers thereby making it accessible primarily to higher income Hoosiers, produces a compensation rate that could be substantively worse than its Cogeneration & Small Power Production tariff, is a radical departure from the current Indiana DG policy and the best practices established in other states, and is not based on sound ratemaking or cost-of-service principles.

It is difficult to overstate the devastating effect AES Indiana's "no netting" proposal would have on Indiana's distributed solar market and solar industry, especially taken in context with the similar proposals filed by Indiana's other investor-owned utilities. It would significantly limit the ability of customers to benefit from more clean, local, on-site generation that supports the continued growth of Hoosier jobs. Similarly, it would reduce the ability of solar vendors and installers to do business in Indiana, leading to job losses and forgone economic development opportunities for the State. AES Indiana's "no netting" proposal produces unjust and unreasonable rates and should be rejected.

1) AES Indiana's "No Netting" Proposal Lacks Support

Q. Why do you say that AES Indiana's proposal is insufficiently supported?

A. AES Indiana's "no netting" proposal would result in a major policy change to how rooftop solar and other DG technologies will be compensated in the future compared to the monthly netting policy that has been in place for roughly the past 16 years in Indiana. Yet, its application and testimony are bereft of any meaningful analysis or justification to support this drastic change, meaning the Commission and parties have an extremely limited basis on which to consider the proposal and its intended and unintended impacts. The Company is proposing a major policy change without offering any meaningful analysis demonstrating its impacts. Net metering as it existed is ended by SEA 309. Imposing a "no netting" policy in addition to SEA 309's changes is unwarranted and very harmful.

AES Indiana's proposal is also not supported with a class cost of service study or any other evidence demonstrating that moving to a "no netting" framework would produce just and reasonable rates. Furthermore, it did not provide a DG benefit-cost analysis or a value of distributed solar study that would demonstrate on a forward-looking basis (as opposed to a backwards-looking snapshot in time that is typical of an embedded cost of service study) that its "no netting" proposal produces net benefits rather than costs, or reflects an overall fair policy for compensating DG customers for the benefits that they provide to both DG and non-DG customers. Furthermore, AES Indiana did not include any information on how its proposal will impact future DG growth, solar installation businesses, their employment levels, or related economic impacts in its service territory. Those ignored impacts will all be harmful to Indiana.

An important question related to determining whether a rate is just and reasonable is whether it reflects cost causation principles. By that, I mean AES Indiana's harmful "no netting" filing provides the Commission with no ability to conclude that the EDG Rider would produce rates that reflect or are designed to recover AES Indiana's cost to serve DG customers or are reflective of the value of the benefits DG customers provide. Importantly, AES Indiana has not made any showing demonstrating its proposed "no netting" policy would not recover *more than* its cost to serve DG customers. And even if one argues monthly netting is overly generous to DG customers at the expense of non-DG customers – a position I do not endorse and which no evidence has been offered by AES Indiana to substantiate – AES Indiana has failed to provide any reasonable basis on which the Commission can conclude its specific "no netting" approach is the best or even a reasonable one compared to many alternative policies.

On this basis alone, the Commission should reject AES Indiana's application, at least with respect to its "no netting" proposal, as insufficient and failing to demonstrate its resulting rates are just and reasonable.

Q. Does the "no netting" proposal in AES Indiana's EDG Rider align with the longstanding principles of just and reasonable rates?

A. In my opinion, it does not. The EDG Rider rate itself is calculated through an arbitrary, albeit legislative, 25% adjustment to the average wholesale market locational marginal price, and not an objective assessment on the actual value provided by EDG. Applying such an arbitrary calculation to determine the export credit rate for *all* kWh exported is not conducive of reaching a just and reasonable rate result. AES Indiana's proposal substantially worsens the impact of the statutorily prescribed credit rate by ignoring the statutorily prescribed "difference between" exports and imports in its measurement of EDG, resulting in an arbitrary rate untethered to any ratemaking principles and in a manner that will materially harm DG customers taking service under such a rate, as further analyzed below.

The negative impact of this combination will be worsened by the EDG rate changing every year, depriving an EDG customer of any certainty or stability in their rate and making it extremely difficult to reliably estimate the most basic financial metrics of purchasing a potential DG system, such as the savings potential and simple payback period of such a significant investment.

Finally, the negative impact AES Indiana's proposal will have on DG adoption rates will also harm *non-DG* customers by both limiting their ability to later adopt DG and by reducing the benefits non-DG customers can realize from having more clean, local, distributed generation on the grid.[21]

2) AES Indiana's "No Netting" Proposal Creates Perverse Incentives

Q. What do you mean when you say that AES Indiana's proposal creates perverse incentives?

A. Utility ratemaking typically aims to provide price signals to customers that align, to at least some degree, with how the utility incurs costs and in a manner that discourages waste and

[21] *E.g., see* Lawrence Berkeley National Laboratory, Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System, pp. 55-56, available at https://www.in.gov/iurc/files/2020-Report-to-the-21st-Century-Energy-Policy-Development-Task-Force.updated-min.pdf; *see generally* National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, 2020, available at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

promotes efficiency.[22] For example, AES Indiana's Off-Peak Energy Storage Separately Metered (Rate OES) tariff has an off-peak period of 10 p.m. to 6 a.m. weekdays, and its Cogeneration & Small Power Production (Rate CGS) tariff defines the peak period as 6 a.m. to 10 p.m. (April through September) and 7 a.m. to 11 p.m. (October through March) weekdays.[23] These price signals discourage discretionary electricity use and encourage energy conservation and generation exports during on-peak periods relative to off-peak periods. These price signals correspond to wholesale market prices. For example, the 2020 average LMP at the IPL.IPL load node for daylight hours (5 a.m. through 8 p.m.) was $24.65/MWh, whereas for nighttime hours (8 p.m. through 5 a.m.) the average 2020 LMP was only $18.57/MWh.[24]

In contrast, AES Indiana's "no netting" proposal would create a perverse incentive by doing the *opposite* of what the price signals in these rates are designed to incentivize: ***The "no netting" component of the EDG Rider would encourage DG customers to <u>increase</u> their consumption during AES Indiana's highest cost summer on-peak periods***. AES Indiana's summer on-peak hours align with the production of solar generation, which is the predominant form of DG technology on AES Indiana's grid now and anticipated into the future. A solar DG system designed to generate electricity in an amount equal to a customer's average annual electricity needs, as provided by the DG Statutes, will tend to produce more electricity during the daylight than the DG customer immediately consumes

[22] *See* James Bonbright's Principle 8 ("Efficiency of the rate classes and rate blocks in discouraging wasteful use of service…"). Bonbright principles are discussed further below.
[23] AES Indiana, Rates & Tariffs, available at https://www.aesindiana.com/rates-tariffs. Note that the referenced tariffs have additional specifications on the timing of the on-peak and off-peak rates.
[24] Based on data provided by AES Indiana, Workpaper MDF-1.

during daylight hours behind-the-meter. However, with "no netting" the DG customer no longer can net their exported electricity against their imported electricity over the billing period. That gives the DG customer a strong financial incentive to export as little electricity as possible.

To avoid the "penalty" of receiving this low EDG compensation rate, the economically rational DG customer would strive to shift all possible discretionary electricity consumption to hours when their DG system is generating more electricity than the customer is immediately consuming behind the meter (e.g., by cranking up their air conditioners on hot summer afternoons – during peak periods – to "pre-cool" their house for the nighttime hours; charging electric vehicles during the day instead of overnight; or washing and drying cloths and dishes during the daylight hours). Since this time period aligns with the utility's on-peak period, it means DG customers will be strongly incentivized to increase their gross consumption during on-peak periods and decrease gross consumption during off-peak periods.

This perverse incentive baked into the "no netting" EDG Rider proposal would harm *non-DG customers* because these non-DG customers would no longer be able to benefit from the EDG exports the DG customer would otherwise have provided during higher-cost peak hours. A key objective of demand-side management programs and on- and off-peak pricing are to reduce utility peaks. AES Indiana's "no netting" proposal would push in the opposite direction to the detriment of its customers.

3) AES Indiana's "No Netting" Proposal Compensates EDG Customers at a Rate that Could Be Below AES Indiana's Avoided Cost Rate

Q. Why do you claim that AES Indiana's "no netting" proposal could be substantively worse than AES Indiana's Cogeneration and Small Power Production tariff?

A. AES Indiana's Cogeneration & Small Power Production ("Rate CGS") tariff, available to eligible DG facilities, provides a compensation rate to DG customers that could, under certain circumstances or for certain customers, be higher than AES Indiana's EDG Rider.[25] Under Rate CGS, DG customers currently receive a payment of $0.0252/kWh for generation during peak periods[26] and $0.0226/kWh for generation during off-peak periods, plus a capacity payment of $5.66/kW per month. While the on-peak rate under Rate CGS is slightly below AES Indiana's proposed EDG credit rate, the additional capacity credit DG customers can earn under Rate CGS could be sufficient to result in a total compensation rate under Rate CGS that exceeds the total compensation rate under the EDG Rider.

Rider CGS represents AES Indiana's avoided cost rate under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and as such, reflects its incremental cost. Additionally, PURPA allows Qualifying Facilities to negotiate the length of the contract, whereas the DG Statutes provide for an annual change in the EDG rate. It would be an absurd result and illogical to assume the General Assembly intended for DG customers to be compensated at a rate that could be *below* AES Indiana's avoided cost rate while also potentially experiencing less certainty in pricing from year-to-year. DG customers

[25] AES Indiana, Cogeneration & Small Power Production, available at https://www.aesindiana.com/sites/default/files/2021-05/Rate-CGS-Effective-04-14-21.pdf.
[26] The peak period is 6 a.m. and 10 p.m. (April through September) or between 7 a.m. and 11 p.m. (October through March) on all days except Saturdays and Sundays.

generally provide substantial value that goes beyond that of centralized power generation facilities, such as by directly serving on-site load, proportionately avoiding line losses, proportionately avoiding wear and tear on transmission and distribution facilities, mitigating congestion on the grid, and providing enhanced resilience opportunities, among other benefits. Providing a compensation rate for *all* exported electricity that could be below AES Indiana's PURPA avoided cost rate would be unjust and unreasonable. It also conflicts with the statements made by the author of SEA 309 about the purpose of the legislation continuing to encourage DG and conferring a preference for DG technologies in statute, as described above in more detail.

If AES Indiana's EDG Rider is adopted as proposed, prospective DG customers that would be eligible for either the EDG Rider or Rate CGS would likely want to conduct an analysis and comparison (likely with the assistance of their DG provider) to identify the impacts of these two options and select service under the one that provides the better financial value to the customer. This analysis would require granular data about DG customers historical usage, reinforcing my concern I discussed earlier in my testimony about the lack of access many AES Indiana customers currently have to their own usage data at a granular level. One benefit of Rate CGS is that it does not contain provisions that would result in the utility taking excess generation from DG customers without providing compensation,[27] unlike the EDG Rider that confiscates customer EDG credits at the end of service, as I discuss later in my testimony. However, other terms and conditions of Rate CGS are unclear based on the filed tariff, such as how "contracted capacity" would be determined for small rooftop solar facilities, possible performance penalties (if any) that

[27] AES Indiana Response to IndianaDG Data Request 1-17.

could apply if the DG facility delivers less capacity in a given month, and possible additional metering or interconnection charges (if applicable).

If the Commission declines my recommendations and adopts AES Indiana's EDG Rider as proposed or with only modest revisions, I recommend the Commission also direct AES Indiana to ensure prospective DG customers are clearly presented with the option taking service under Rate CGS on an equal basis to the EDG Rider. For example, the Commission should direct AES Indiana to provide clear summary information on its Rate CGS option on its website side-by-side with any descriptions of its EDG Rider, in a location on its website that is easy to find, and that describes and compares the tariffs' terms and requirements in a manner that are easily understandable to a typical residential customer so that they are able to compare and contrast taking service under Rate CGS and the EDG Rider. In the past, this may not have been necessary since Rate CGS was primarily used by sophisticated independent power producers and not residential customers. But with the termination of net metering for new DG customers, Rate CGS may be utilized by many more types of customers than in the past. In addition, when existing net metering customers are no longer eligible to continue service under their net metering tariff, they should be presented with the option of which tariff they would like to take service under instead of being automatically defaulted onto the EDG Rider.

4) AES Indiana's "No Netting" Proposal Is a Dramatic Departure from DG Policies Adopted in Most Other States

Q. While not necessarily controlling on any issue, do you think it appropriate and beneficial to sound public policy and intelligent regulatory discretion that utility regulatory Commissions stay apprised of regulatory trends in other states?

A. Yes, I do. It has been my experience that utility regulatory commissions inquire about and watch with interest how evolving regulatory matters in other states raise new ideas, address emerging issues, and integrate new technologies. Such knowledge is beneficial to regulators when navigating evolving or new regulatory and technology matters and in applying their discretionary findings to reach an overall balanced outcome on issues consistent with the public interest. This is particularly so when a multifaceted issue like EDG can be broken down into its subcomponents and each subcomponent is subject to a regulatory finding, and potentially differing levels of regulatory discretion. Knowledge and understanding facilitate a balanced outcome in the formation of just and reasonable rates and sound regulatory public policy.

Q. Have other state utility regulators decided to retain monthly netting after conducting a review or investigation into DG policies?

A. Yes. In fact, maintaining monthly netting has frequently been the outcome of state proceedings that have addressed DG policies in recent years. In states with relatively modest customer net metering adoption rates, regulators have typically preserved monthly netting and only made modest changes that would not fundamentally alter the viability of solar DG, **even when the utility regulator is acting to implement new legislation authorizing changes to net metering**. I consider customer DG adoption in Indiana to be very modest.

Q. Can you provide specific examples of state utility regulators retaining monthly netting after legislation was enacted authoring changes to net metering?

A. Yes. The Arkansas Public Service Commission ("PSC") issued an Order on June 1, 2020, addressing implementation of Act 464 (2019). Even though Act 464 authorized the

Arkansas PSC to make changes to net metering, it elected to maintain monthly netting for the time being for residential and small commercial customers. It determined that:

> [b]ased upon the evidence currently showing very low levels of penetration of renewable distributed generation by solar facilities in Arkansas in the residential class and in any non-residential customers without a demand component, the Commission finds that the current 1:1 full retail credit for net excess generation should be retained for now as the default Net-Metering rate structure," (footnote omitted).[28]

The decision permits utilities to propose more substantive changes through filings submitted after December 31, 2022 but requires the utilities to justify such a proposal by using a "timely and properly designed cost-of-service study" that demonstrates the alternative DG policy is "in the public interest and will not result in an unreasonable allocation of or increase in costs to other utility customers.[29]

As I describe below, the Kentucky PSC also recently rejected changes to KPC's monthly netting policy, despite being granted discretion under Senate Bill 100 (2019) to make significant changes to DG policies.

Most states, including those with high DG adoption rates, have continued to offer monthly netting, while rejecting more significant changes or multiple changes that in combination could be detrimental to prospective net metering customers.

Q. Does AES Indiana's "no netting" proposal align with broader industry trends with respect to policy changes to net metering?

A. No. In fact, as I will describe below, although they both have approved different netting policies, <u>both the Kentucky PSC and Michigan PSC have established DG compensation rates for utilities in their respective states, that are roughly *three to four times* the EDG</u>

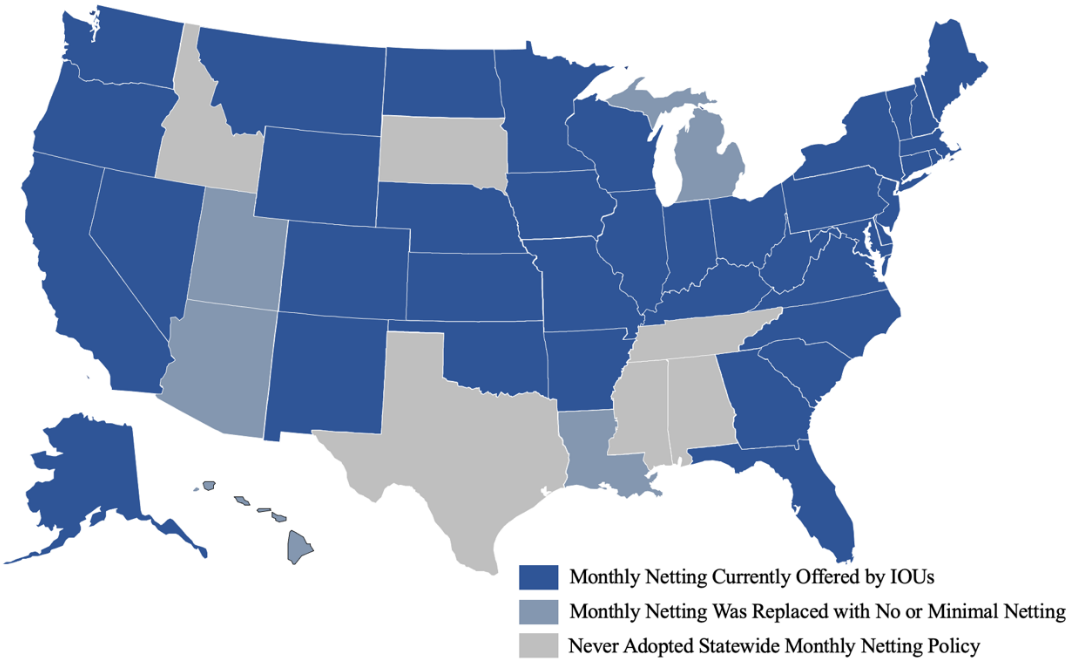
[28] Arkansas Public Service Commission, Docket No. 16-027-R, Order, June 1, 2020, p. 525.
[29] *Ibid*.

<u>Rider credit rate proposed by AES Indiana in this case</u> in conjunction with its "no netting" proposal. Furthermore, while many utilities have *proposed* significant changes to DG policies like net metering, few state regulatory commissions or state legislatures have adopted dramatic changes to existing policies in a manner that would significantly harm the future growth of DG, such as would be the case under AES Indiana's "no netting" proposal.

Q. How prevalent is monthly netting?

A. Monthly netting continues to be one of the most widespread and important components of DG compensation policies across U.S. states and utilities. At its peak, investor-owned utilities ("IOUs") in at least 43 states and the District of Columbia offered monthly netting to customers. Currently, most IOUs in 39 states and the District of Columbia offer monthly netting to new residential and small commercial customers, as identified in Figure 2. Only five states have transitioned from monthly netting to an "import/export" crediting scheme, characterized by no netting or a netting within only a short time interval (e.g., 15 minutes or one hour) and where exports are credited at a substantially lower rate than imports. In one state (Georgia), state regulators recently mandated a change *from* a "no netting" policy *to* monthly netting for Georgia Power, and two states (Nevada and Maine) that previously ended monthly netting subsequently restored it for residential customers through legislative changes.

Figure 2. Netting Policies for Residential and Small Commercial DG Customers of Investor-Owned Utilities



Q. Can you describe the types of DG policy changes that policymakers have approved?

A. States that moved from monthly netting to an alternative policy have, in most cases, established a compensation rate for exported electricity that is significantly higher than the EDG rate proposed by AES Indiana. For example:

- In **Michigan**, new DG customers receive an export credit rate based on the power supply rate excluding transmission. The credit rate for Indiana Michigan Power customers is based on the specific rate schedule's combined Capacity and Non-Capacity Power Supply rates plus the Power Supply Cost Recovery factor. For residential customers, these values are $0.0762/kWh, $0.02689/kWh, and ($0.00285)/kWh, which results in a total compensation rate for exports of $0.10024/kWh, which is roughly *four times* as much as AES Indiana's proposed compensation rate across the border in Indiana.[30] Similarly, the credit rate for Consumers Energy's residential customers is $0.119655/kWh for summer on-peak,

[30] Indiana Michigan Power Tariffs, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Michigan/IMMITBBk172021-06-21.pdf

$0.080485/kWh for summer off-peak, and $0.084785/kWh for all exports in non-summer months.[31]

- In **Arizona**, new residential DG customers of Arizona Public Service receive a specific export credit rate for a period of 10 years, with the amount depending on when the DG system is installed. A system installed October 1, 2021 through August 31, 2022 receives an export credit rate of $0.09405/kWh.[32]
- In **Utah**, new DG customers of Rocky Mountain Power receive summer and winter export credit rates of $0.05817/kWh and $0.05487/kWh, respectively.[33]

However, many state policymakers have rejected attempts to fundamentally alter the monthly netting framework when implementing other changes to a net metering policy. One notable recent example is the Kentucky PSC's rejection of a net metering replacement tariff proposed by Kentucky Power Company ("KPC"). In that case, KPC requested to move from monthly netting for all imports and exports to having two netting periods within the month that KPC alleged corresponded to on-peak and off-peak time periods. The Kentucky PSC's May 2021 Order ("KPC Order") rejected KPC's net metering tariff proposal and retained standard *monthly netting* while reducing the EDG *rate* for monthly rollover from the retail rate to $0.09746/kWh for residential customers and $0.09657/kWh for commercial customers, based on a bottom-up calculation of various categories of benefits provided by EDG.[34]

[31] Consumers Energy, Rate Book for Electric Service, Original Sheet No. C-64.30, available at https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.ashx?la=en&hash=3EC495A835F623EFFD51C5486014D83F
[32] Arizona Public Service, Rate Rider RCP, available at https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Renewable-Plans-and-Riders/rcp_RateSchedule.ashx?la=en
[33] Utah Public Service Commission, Order on Agency Rehearing, Docket No. 17-035-61, April 28, 2021, available at https://pscdocs.utah.gov/electric/17docs/1703561/3184591703561ooar4-28-2021.pdf
[34] Kentucky Public Service Commission, Order, Case No. 2020-00174, May 14, 2021, pp. 39-40, https://psc.ky.gov/pscscf/2020%20Cases/2020-00174//20210113_PSC_ORDER.pdf

Other examples of state utility regulators maintaining monthly netting policies include:

- In **South Carolina**, the PSC rejected a Dominion Energy proposal in May 2021 to replace monthly netting with netting on a 15-minute basis, where all exports would have been credited at time-based avoided cost rates, and charge DG customers additional surcharges. Instead, the PSC approved a tariff that has an annual netting period in which on-peak generation can offset on-peak usage on a 1:1 basis, and off-peak generation can offset off-peak generation on a 1:1 basis.[35] The PSC separately approved DG tariffs for Duke Energy customers that featured monthly netting within TOD periods.[36]
- In **New York**, the PSC has repeatedly decided to retain monthly netting for residential and small commercial customers, among others, even as it has moved other types of DG customers to its "Value of Distributed Energy Resources" tariff that differentially credits exported energy relative to imports.[37]
- In **Louisiana**, the PSC revised its net metering rules in December 2016 to maintain monthly netting while reducing the EDG credit rate to the applicable avoided cost rate after the utility reached its net metering cap.[38] Years later, in September 2019, it replaced the monthly netting policy with a no netting policy effective January 1, 2020.[39]
- In **California**, the Public Utilities Commission maintained monthly netting under its revised net metering policy that applied after a utility reached its net metering cap ("NEM 2.0"). NEM 2.0 customers were required to take service under a TOD rate and pay certain non-bypassable charges (e.g., related to funding public purpose programs), but otherwise were allowed to use monthly netting within the TOD period.[40]

Q. Have some utilities proposed additional charges on DG customers either in lieu of, or in addition to, changes to monthly netting?

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[35] South Carolina Public Service Commission, Docket No. 2020-229-E, Order No. 2021-391, May 29, 2021.
[36] South Carolina Public Service Commission, Docket Nos. 2020-264-E and 2020-265-E, Order No. 2021-390, May 30, 2021.
[37] New York Public Service Commission, Docket No. 15-E-0751, Order, July 16, 2020.
[38] Louisiana Public Service Commission, Docket No. R-33929, Phase I Order, December 8, 2016.
[39] Phase II Order, September 19, 2019.
[40] California Public Utilities Commission, Docket No. R.14-07-002, Decision No. 16-01-044, February 5, 2016.

A. Yes, but relatively few are adopted. Utilities across the country have proposed a variety of other changes to DG policies, including new surcharges or fees, either in combination with proposals to modify or end monthly netting or in lieu of these changes. These include proposals for new capacity-based charges based on the size of the DG system, mandatory demand charges, minimum bill amounts that exceed the amount charged to non-DG customers, and additional monthly fixed charges. While numerous, these utility proposals, like changes to monthly netting, are seldom adopted. Specifically, since November 2012, there have been at least 27 distinct examples of investor-owned utilities in the U.S. proposing extra surcharges on DG customers. In nearly every instance, those proposals were withdrawn by the proponent, denied by regulators, or overturned in court on appeal. I provide an overview of these examples in Attachment BDI-8.

While AES Indiana is not proposing a surcharge on DG customers in this case, its proposal to end monthly netting is analogous to utility proposals for DG surcharges insofar as both reduce the economic benefit to the customer of installing DG. These examples provide further evidence demonstrating that utility proposals of all types aimed at significantly undermining the growth of DG have broadly lacked policymaker support and failed to gain traction despite the substantial and numerous efforts by utilities to have them approved.

Q. How does AES Indiana's proposed "no netting" policy compare to modifications adopted in other jurisdictions to their DG policies?

A. Over the last decade, DG policies like net metering have been extensively studied and investigated in many jurisdictions across the country.[41] While I have not quantitatively analyzed the impact of every utility proposal, based on my professional experience, I can say that AES Indiana's proposed "no netting" policy in combination with its implementation of EDG Rider to replace net metering would be more far-reaching and likely more detrimental than the vast majority of the changes adopted to DG policies in other jurisdictions, including those with far greater deployment rates of DG.

More fundamentally, AES Indiana's proposal stands out when compared to most changes that have been adopted in other jurisdictions for its lack of underlying support and justification. Other jurisdictions, especially those that have higher penetration rates of DG, have undergone extensive investigation, study, and evaluation of DG policies over a period of several years *prior* to making significant modifications that were not expressly directed by legislation. Typically, state utility regulators have overseen investigations into net metering policies that include studies that quantify the costs and benefits of net metering or the value of distributed energy resources like solar prior to making significant changes to policies like monthly netting. The most common outcome of these proceedings is that the state utility commission adopts only limited and incremental changes to the overall design of the DG policy. Some states have gone through multiple iterations of this process, spanning multiple years, to collect evidence, gather input from a variety of parties, implement adjustments, monitor the results, and then restart the process in an iterative fashion to consider additional refinements.

[41] *See, e.g.,* ICF International, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar" (May 2018).

I have developed Attachment BDI-9 to highlight a selection of jurisdictions that have examined net metering policies. The table identifies examples of studies that have been conducted, key regulatory proceedings that have investigated these issues, and a summary of the outcomes for each jurisdiction examined. The table is meant to be illustrative, and not entirely comprehensive of every jurisdiction, study, and docket.

Q. What other observations do you have regarding state practices used when considering modifications to monthly netting based on your review of DG policies in other jurisdictions?

A. There are several commonalities among many jurisdictions in how they have considered modifications of DG policies like net metering. At a high level, some of the commonalities evident from the numerous state public utility commission proceedings evaluating modifications to DG policies are:

- **Quantitative analysis is key:** Cost of service studies, cost-benefit analyses, and value of solar (or distributed energy resources more broadly) studies, or a combination thereof, have been used to quantify the impacts of DG policies. These studies have been paramount in informing discussions of DG policy changes, although they are not necessarily dispositive of the ultimate outcome, as larger policy considerations have also played an important role in shaping discussions. They can also be helpful in identifying policy solutions that align DG customer incentives with broader grid benefits in a manner that does not unfairly discourage the adoption of DG.
- **Gradualism is an important ratemaking principle:** After gathering robust evidence on net metering implementation, public utility commissions that have determined that changes should be made to existing net metering policies have adhered to the ratemaking principle of Gradualism by implementing modest changes. For example, regulators in New Hampshire maintained monthly netting, excluding certain non-bypassable charges, when they implemented a reduced EDG credit rate for the rollover credit at the end of the month, while directing a multi-year study into DG to collect additional data. Most states that ultimately ended monthly netting, such as Arizona, Utah and Louisiana, only did so after many years, multiple investigations, and a transition period where a modified policy was in place that limited the immediate financial impacts on prospective DG customers.
- **Iterative process:** DG policy discussions are rarely resolved through one proceeding. Rather, the proliferation of rooftop solar has led many policymakers to study and

evaluate DG policies on an iterative basis, incorporating new information as additional experience is gained and data is collected.

- **<u>Insufficiently supported utility proposals are rejected:</u>** Numerous utility requests to modify DG policies or related rate design changes impacting DG customers have been rejected by regulators across the U.S. when they have not been adequately supported and justified by the utility. Regulators have been reluctant to make drastic changes to DG policies that are not clearly directed by statute that could undermine customer adoption of rooftop solar when the utility has not met its burden to demonstrate that its proposed changes result in just and reasonable rates and are in the public interest. In other words, regulatory determinations on DG policies have typically required utilities to meet the same burden of proof standard that applies more generally. Such a standard is critical for ensuring that adopted policies or rates are well vetted and not discriminatory.
- **<u>Monthly netting remains commonplace:</u>** Despite numerous proceedings and legislation addressing DG policies in states across the country, monthly netting remains one of the most widespread DG policies currently in place in the U.S.

Q. Why have some states adopted changes to their DG policies in recent years?

A. Based on my experience closely tracking this industry for more than seven years, I conclude that two factors are the primary drivers of this trend. First, rooftop solar deployment has increased in recent years, driven by equipment cost declines. Most state net metering policies specify an aggregate capacity limit for net metering programs ("net metering cap"). Often, state legislatures and utility regulators have responded to utilities nearing or exceeding the specified net metering cap as a result of the proliferation of DG solar by increasing the net metering cap and/or by adopting policies to modify net metering or establish a pathway for adopting a net metering successor policy, which is often preceded by a study or formal investigation.

Second, utilities, their trade associations, and other aligned interests have waged a long-running campaign against policies encouraging the adoption of rooftop solar, particularly net metering.[42] Net metering allows a customer to purchase less electricity from a utility, which can result in a decrease in a utility's revenue. In addition, electric utilities earn profit by making capital investments, on which they are permitted the opportunity to earn a return on equity. Investment in generation facilities such as solar DG by utility customers can therefore compete with a utility's generation investments, with a reduced need in new utility generation assets corresponding to a reduced profit opportunity for the utility. In states without retail choice, rooftop solar is one of the few examples of a utility facing a form of, albeit limited, competition, as utility customers otherwise need to be fully served by the electricity generated or procured by their monopoly utility.

Q. Have some state utility regulators expanded the availability of monthly netting after conducting a review or investigation into the policy?

A. Yes. For instance, the Iowa Utilities Board issued an Order in July 2016 maintaining monthly netting after investigating its net metering policy.[43] The Order created a three-year study process, while expanding the availability of net metering to all customer classes and increasing the maximum eligible system size from 500 kW to 1,000 kW.

More recently, the Georgia Public Service Commission modified the DG compensation policy in place for Georgia Power in December 2019 by moving from no netting to monthly netting.[44]

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[42] *See, e.g.,* Joby Warrick, "Utilities Wage Campaign Against Rooftop Solar," *Washington Post* (March 7, 2015); Hye-Jin Kim, Rachel J. Cross, and Bret Fanshaw, "Blocking the Sun: Utilities and Fossil Fuel Interests That Are Undermining American Solar Power," Frontier Group and Environment America Research & Policy Center (November 2, 2017); Gabe Elsner, "Edison Electric Institute Campaign Against Distributed Solar," Energy and Policy Institute (March 7, 2015); *See Generally,* Energy and Policy Institute, "Category: Net Metering," https://www.energyandpolicy.org/category/solar/net-metering/.

[43] Iowa Utilities Board, Docket No. NOI-2014-0001, Order, July 19, 2016.

[44] Georgia Public Service Commission, Docket No. 42516, Order, February 6, 2020.

Q. Why are other states' policy decisions on monthly netting or DG policy in general relevant to this proceeding?

A. All states and their Commissions value their autonomy. Their policy decisions are governed by their unique legal frameworks, policy priorities, and objectives. Knowledge about how other states regulatory commissions have approached new technologies and related ratemaking issues may provide useful insights for regulators reviewing similar matters. Despite inherent differences, it is significant that after substantial focus on DG policies in recent years, most states have elected to expand or maintain existing net metering policies, make only modest changes that retain monthly netting within a DG policy, or establish a future process for considering changes to DG policies while allowing customers to continue to use monthly netting in the interim.

5) AES Indiana's "No Netting" Proposal Is Inconsistent with Longstanding Ratemaking Principles

Q. What other factors do you think the Commission should consider when evaluating AES Indiana's "no netting" proposal?

A. In addition to the DG Statutes, the Commission should consider other relevant Indiana statutes and the same generally accepted ratemaking principles (*i.e.,* the Bonbright principles) that govern utility ratemaking. With respect to other relevant Indiana statutes, IC § 8-1-2-4 specifies that:

> Every public utility is required to furnish reasonably adequate service and facilities. The charge made by any public utility for any service rendered or to be rendered either directly or in connection therewith shall be reasonable and just, and every unjust or unreasonable charge for such service is prohibited and declared unlawful.

Q. Is AES Indiana's "no netting" proposal consistent with long-standing ratemaking principles?

A. No. In his seminal work that defined best practices in utility regulation, Professor James Bonbright enumerated a number of principles of utility ratemaking.[45] These principles have been foundational to determining rate structures that are just and reasonable. AES Indiana's "no netting" proposal fundamentally conflicts with several of these key principles.

First, asking the Commission to approve moving from the long-running monthly netting policy to a harmful "no netting" policy at the same time AES Indiana seeks to implement a statutorily prescribed reduction in the effective compensation rate does not comport with the ratemaking principle that is often described today as Gradualism.[46] It is an abrupt, far reaching, two-fold negative impact on prospective DG customers and the Indiana businesses that install solar. The DG Statutes made substantive changes to the treatment of DG customers, perhaps most significantly by reducing the compensation rate from an effective retail rate rollover credit to a credit at the EDG Rider rate. The principle of Gradualism would strongly caution against making additional dramatic changes, such as the "no netting" proposal, at the same time as making these changes to avoid the negative impacts of "rate shock" and to maintain some level of rate stability. As discussed earlier, I see no language in the DG Statutes that requires or calls for consideration of the end of the normal monthly netting policy in favor of "no netting" or that seeks to impose the resulting harsh impact on EDG customers and Indiana's solar industry.

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[45] James C. Bonbright, Principles of Public Utility Rates, Columbia Univ. Press (1961), p. 291.
[46] Bonbright, Principle 5 (stating "Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare 'The best tax is an old tax.')")

The Kentucky PSC's KPC Order, which retained *monthly netting* while reducing the EDG *rate* for monthly rollover, is instructive in this respect. It noted that:

> [c]ommitting to gradual compensation changes will provide customers and third parties with confidence to operate in Kentucky and, with improved integration, create significant benefits for all ratepayers.[47]

Second, moving to "no netting" violates the ratemaking principle of Simplicity, Understandability, Public Acceptability, and Feasibility of Application.[48] Monthly netting is understandable to, accepted by, and intuitive to customers. In contrast, AES Indiana's "no netting" proposal creates an impossibly complicated compensation scheme for DG customers, most of whom lack the capacity and capability to manage their moment-by-moment consumption relative to their generation.

Again, the KPC Order is illuminating on this point. In rejecting a move from monthly netting to two netting intervals within a billing month, the Kentucky PSC found that, "The proposed netting periods also significantly increase the complexity of the [net metering service] rate design, without clear indication of their benefit."[49] AES Indiana's "no netting" proposal is far more complicated than that proposed by KPC, and AES Indiana has asserted no benefit(s) that justifies this unnecessary complexity.

Third, the "no netting" proposal violates the principle that Professor Bonbright described as, "Fairness of the specific rates in the apportionment of total costs of service among the different consumers."[50] As I further describe below, AES Indiana has failed to offer any evidence demonstrating that its "no netting" proposal would recover the net costs

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[47] KPC Order, Case No. 2020-00174, May 14, 2021, p. 41.
[48] Bonbright, Principle 1.
[49] KPC Order, p. 24
[50] Bonbright, Principle 6.

to serve its DG customers and thereby is appropriately and fairly apportioning costs to DG customers relative to non-DG customers.

Again, the KPC Order is insightful on applying this principle in the context of DG policy. It found that KPC's class cost of service study for DG customers, which was not based on load research on its actual DG customers, was "unreliable and not useful for ratemaking," noting the "lack of appropriate and sufficient data" the utility had on its DG customers, concluding that "[w]ithout such data, claims regarding a subsidy or differentiated load profiles [between DG and non-DG customers] is moot."[51]

Q. Have other utilities used, or have state utility regulators required, that utilities conduct load research on their actual net metering customers to produce an accurate cost of service study prior to significantly modifying DG policies?

A. Yes. Table 1 identifies some examples where other state utility regulators rejected proposed changes to net metering based on cost of service studies that failed to use appropriate load profiles for net metering customers, or where the utility used or planned to use such data to support its proposal to make changes to net metering.

Table 1: Examples of Net Metering ("NEM") Customer Load Research Used or Required in Other Jurisdictions[52]

State	Utility	Summary	Key Excerpts
MT	NorthWestern Energy	In Northwestern Energy's 2018 rate case, its embedded cost of service study used NEM customer load data that intervenors described as artificial and derived through a convoluted series of assumptions and	"The Commission finds that NorthWestern should **develop load research sample data for NEM customers of comparable quality to that used for the broader residential class** for use in future cost of service studies."[53]

[51] KPC Order, pp. 20-21.
[52] Key portions of quoted excerpts have been bolded for emphasis. Footnotes from the excerpts have been omitted.
[53] Montana Public Service Commission, Docket No. 2018.02.012, Order, December 20, 2019, p. 63, available at http://psc.mt.gov/Portals/125/Documents/news/NWE%20Rate%20Case/2018212%20FO.pdf

State	Utility	Summary	Key Excerpts
		adjustments, rather than load research sample data for NEM customers like it did for all other residential customers in the study. Accordingly, the Montana Public Service Commission denied the utility's request to place NEM customers in a separate rate class and charge NEM customers a demand charge rate design.	
NV	NV Energy	The Public Utilities Commission of Nevada found that NEM ratepayers had unique service and cost characteristics based on the actual net metering class load shapes of NV Energy net metering customers.	"NV Energy states that the **NEM ratepayer class load shapes were developed using all active NEM ratepayers** as of March 31, 2015, for the entire study period of June 2014 through May 2015. Actual generation data was used when available. Missing hourly generation data was estimated using the average of those ratepayers that have at least 95 percent of the necessary 15-minute generation data. The compiled data was then compared to the National Renewable Energy Laboratory's averages for reasonableness."[54]
NH	Eversource Energy Liberty Utilities Unitil Energy Systems	In its Order adopting an alternative net metering tariff that will be in place "while further data is collected and analyzed, pilot programs are implemented, and a distributed energy resource (DER) valuation study is conducted," the New Hampshire Public Utilities Commission found that "there is little evidence of significant cost-shifting from DG customers to customers without DG," and that additional load research needed to be collected on DG customers.	"…[T]he **utilities should collect and make available load shape data** for individual distribution circuits, or at least for a selected sample of distribution circuits, **as well as customer load data on an hourly or shorter interval basis for at least a representative sample of customers**…Following completion of the value of DER study, and with the availability of the additional customer load and system planning and operations data, the Commission will open a new proceeding to determine whether and when further changes should be made to the net metering tariff structure."[55]
OK	Oklahoma Gas & Electric	The Oklahoma Corporation Commission rejected the proposed separate rate classes with three-part rates for DG customers. The utility's cost of service study using smart meter data on its actual DG customers showed DG customers were not subsidized by non-DG customers.	"In the event OG&E proposes, in the future, a demand charge or any other substantive change to a tariff applicable to customers with distributed generation that OG&E deems necessary to comply with 17 O.S. § 156, the Commission will require OG&E to include as part of its case cost effectiveness tests, such as those performed for the company's demand programs, and make available to the parties detailed cost and benefit data."[56]

[54] Public Utilities Commission of Nevada, Docket Nos. 15-07041 and 15-07042, Order, December 23, 2015, Paragraph 17, available at: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/8412.pdf
[55] New Hampshire Public Utilities Commission, Order, June 23, 2017, pp. 66 and 72-73, available at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/ORDERS/16-576_2017-06-23_ORDER_26029.PDF
[56] Oklahoma Corporation Commission, Docket No. PUD 201500273, Order No. 662059, p. 13, March 20, 2017, available at: http://imaging.occeweb.com/AP/Orders/occ5360859.pdf

State	Utility	Summary	Key Excerpts
SC	Duke Energy Carolinas (DEC) Duke Energy Progress (DEP)	DEC and DEP used actual metered solar production data on its NEM customers to define solar customer's contributions to their cost of service, the same data that they used to calculate costs and benefits. The utilities reached a settlement agreement, approved by the PSC, on its Solar Choice Net Metering tariff that will replace their existing net metering tariffs in the future.	**"[T]he Companies [Duke Energy Carolinas and Duke Energy Progress] utilized the same factors—including utilizing the same underlying data, such as production meter data—in performing a forward-looking evaluation** for the Companies' proposed Permanent Tariffs (as defined below). In this way, the Commission will be able to compare 'apples to apples' when evaluating the Companies' Permanent Tariffs against the Existing NEM Programs."[57]
TX	El Paso Electric (EPE)	EPE began load research studies on DG customers in 2013. The load research was used by the utility in its rate case application to support its proposed DG tariff. The DG tariff was ultimately resolved through an approved settlement agreement with intervenors.	"EPE performed a sample study for the Texas residential customers who have installed rooftop solar. **The study provides data about the different load characteristics of these residential DG customers compared to residential customers (non-DG)** ….As of the end of the Test Year, EPE had 57 customers in its residential DG load study for Texas."[58]
UT	Rocky Mountain Power (RMP)	RMP performed load research on net metering customers in 2015 prior to the Commission adopting a net metering transition program in 2017.	"The magnitude of this subsidy, if it exists, will not be readily apparent if the analysis does not 'drill down' another level and separately allocate costs to net metering customers based on their usage characteristics. Analyzing costs at the customer class level ensures the cost to serve the net metering customers is also recognized. PacifiCorp represents **'[u]sing data from the load research study that is currently underway**, [PacifiCorp] will be able to **create a class profile for residential NEM customers**, in the same manner done for other types of customer classes' and '[t]his will enable [PacifiCorp] to assign costs to the NEM customers based on how they use the utility system.'"[59]

[57] Public Service Commission of South Carolina, Docket No. 2020-265-E, Direct Testimony of Bradley Harris for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, November 2, 2020, p. 6, available at ; *See also* Public Service Commission of South Carolina, Docket No. 2019-182-E, Direct Testimony of Bradley Harris for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, October 8, 2020, p. 6, available at: https://dms.psc.sc.gov/Attachments/Matter/3670a579-5fe0-41c8-82ab-7a4af9f5019b

[58] Public Utilities Commission of Texas, Docket No. 46831, Direct Testimony of George Novela, February 13, 2017, pp. 921-922, available at: http://interchange.puc.texas.gov/Documents/46831_2_929022.PDF (Note: Testimony appears at PDF 4-87 of 100 of that file).

[59] Utah Public Service Commission, Docket No. 14-035-114, Order, November 10, 2015, p. 10, available at: https://pscdocs.utah.gov/electric/14docs/14035114/270449140351140.pdf

6) AES Indiana's "No Netting" Proposal Is Not Based on the Company's Cost to Serve DG Customers

Q. Is the "no netting" proposal consistent with AES Indiana's cost to serve a DG customer?

A. AES Indiana has provided no evidence that it is, nor has it asserted as much. In response to an IndianaDG request to provide the cost to serve DG customers, AES Indiana provided no information and said it "may have… information addressing the 'cost to serve' the customer class relevant to this proceeding," but "has not attempted to look for it."[60]

Q. How is a utility's cost to serve a specific set of customers typically determined?

A. To reliably identify the costs to serve a customer segment or class, a utility typically conducts load research and develops a class cost of service study based on that load research for the customer segment in question. In instances in which a utility operates in multiple jurisdictions, it will perform a jurisdictional cost of service study prior to its class cost of service study to determine its jurisdictional revenue requirement.

Q. Is it important that conclusions about cost of service for a customer segment be supported by a full class cost of service study of that specific group of customers?

A. Yes. There are several reasons why, but ultimately it amounts to a need for equity and fairness in ratemaking. It is unfair to use one standard of evidence, such as full cost of service study, for customers in general but permit a different standard to be applied to certain customer segments. Likewise, the results of a shoddy or incomplete evaluation could result in unfair rates that charge customers in excess of their cost of service. Nothing in the DG Statutes suggests that the Commission should depart from the typical standards

[60] AES Indiana Response to IndianaDG Data Request 1-1.

it applies for the establishment of just and reasonable rates, or generally accepted ratemaking principles.

Without a targeted cost of service evaluation, the Commission has no way of knowing at what level DG customers pay for service relative to their cost of service, and how that might vary within the class. Not only does that lack of information raise the potential for customers to be overcharged, but it also prevents a more informed evaluation of the options necessary to remedy any issues that are present. For example, the simple fact that a DG customer purchases less electricity from a utility than they would have had they not installed a DG system is insufficient evidence that they are being "subsidized" by other customers.

Q. Can you cite to any other examples illustrating this possibility?

A. Yes. In a 2015 general rate case, Oklahoma Gas and Electric ("OG&E") proposed to establish special demand rates for customers that install DG and eliminate *all* compensation for exported generation on the basis that the changes were necessary to eliminate an alleged "subsidy" to DG customers. As it turns out though, OG&E's class cost of service study, which evaluated residential DG customers as a separate class, showed that the residential DG class actually produced a considerably *higher* rate of return than the residential class as a whole (7.23% compared to 5.33%).[61] In other words, residential DG customers were subsidizing non-DG customers to a significant degree. Not surprisingly, the changes sought by OG&E were not adopted.[62]

[61] Oklahoma Corporation Commission, Docket No. PUD 201500273. Direct Testimony of Mark Garrett. March 31, 2016, p. 14, available at: http://imaging.occeweb.com/AP/CaseFiles/occ5272383.pdf

[62] Oklahoma Corporation Commission, Docket No. PUD 201500273. Order No. 662059. March 20, 2017, available at: http://imaging.occeweb.com/AP/Orders/occ5360859.pdf

Q. In what ways could DG affect AES Indiana's cost allocation in its cost of service study?

A. When properly factored into a cost of service study, DG customers can provide a number of benefits to non-DG customers in their class including, but not limited to, the following examples, which are based on how AES Indiana described its cost allocation in its last rate case:

- AES Indiana used a coincident peak demand method to allocate generation and transmission costs.[63] The coincident peaks during each of the twelve months of the test period ("12CP") were used by AES Indiana to allocate the demand- related costs associated with the transmission and production functions.[64] To the degree DG customers can aid in reducing their class's total coincident peak demands, either by generating electricity during those coincident peak hours with their DG systems or by themselves having a lower average demand during those hours than non-DG customers in their class, they will reduce costs allocated to their customer class.
- AES Indiana uses a non-coincident peak demand method to allocate demand-related distribution system costs.[65] To the degree DG customers can aid in reducing their class's total non-coincident peak demand, either by generating electricity during the non-coincident peak demand hours for their class or by themselves having a lower demand during those hours than non-DG customers in their class, they will reduce costs allocated to their customer class.
- AES Indiana allocates energy-related costs to rate classes based on the amount of energy used by each class.[66] All of the electricity generated by a DG facility reduces the amount of electricity that a utility needs to generate at its own facilities or through purchases. To the degree DG customers reduce kWh consumed as a result of self-consumption and reduced purchases from AES Indiana, they will reduce cost allocation to their customer class on a 1:1 basis. In other words, for costs allocated on the basis of energy, there can be no "subsidy" to DG customers.
- AES Indiana adjusts its cost allocation data for line losses in the transmission and distribution system.[67] System losses are greatest for customers that take service at the secondary voltage levels, so these customers are allocated a higher portion of the costs.[68] DG helps reduce line losses, and associated costs allocated to customers,

[63] Direct Testimony of J. Stephen Gaske, IURC Cause No. 45029, p. 20.
[64] *Id.*, p. 21.
[65] *Id.*, p. 20.
[66] *Id.*, p. 22.
[67] *Id.*, pp. 22-23.
[68] *Id.,* p. 23.

by both directly serving on-site loads and by providing EDG that is used by nearby customers in lieu of electricity that would have otherwise had to have been transmitted through the transmission and distribution systems.

Q. But you previously cited SEA 309's sponsor as saying he did not want complicated lengthy ratemaking proceeding. Is a cost of service study, or another type of analysis such as a cost-benefit analysis, actually needed in an EDG case?

A. In general, such studies are not required in an EDG case <u>when the utility is merely implementing a calculation of the EDG rate</u> in accordance with the statute. However, if the utility is *also* proposing additional, major policy changes not expressly directed in the statute that are a significant departure from important existing policies, such as AES Indiana's "no netting" proposal, then it is the utility's responsibility and burden to demonstrate these additional changes are just and reasonable as well as consistent with the DG Statutes. That has not occurred here.

<u>*7) AES Indiana's "No Netting" Proposal Would Undermine Solar Jobs and Economic Development in Indiana*</u>

Q. How would AES Indiana's "no netting" proposal impact the Indiana solar industry?

A. Based on my analysis of AES Indiana's proposal and my professional experience, I believe AES Indiana's proposal would significantly harm Indiana's residential and commercial sector solar industry, leading to job losses and reduced economic development benefits for local communities. For instance, abrupt changes to net metering policy at other utilities and states, including NV Energy in Nevada, Salt River Project in Arizona, Hawaiian Electric Company in Hawaii, and several smaller utilities in California, consistently demonstrate devasting impacts to DG deployment rates after drastic negative changes are implemented.[69]

Overall, the solar industry has created more than 3,300 solar jobs in Indiana, with solar jobs increasing by 114% since 2015.[70] AES Indiana's "no netting" proposal, and the similar proposals filed by other utilities in Indiana, would imperil many of these jobs through the abrupt and substantial decrease in the economic value of customer-sited solar. They would also create a substantial negative outlook and chilling effect for the State in terms of its ability to attract new residential and commercial sector-focused solar companies, and significantly diminish any additional job creation potential at existing companies operating in Indiana. AES Indiana's "no netting" policy will materially harm Indiana solar installation businesses by reducing demand for solar installations. The sum of the negative impacts will include loss of Indiana jobs, loss of economic development, and loss of state and local tax revenues from those companies and their employees, and the indirect ripple effects that will emanate from these direct impacts.

8) Monthly netting does not cause harm to AES Indiana and non-DG customers.

Q. Would retaining monthly netting harm AES Indiana or non-DG customers?

A. No. Whereas retaining monthly netting is of utmost importance for the nascent but growing Indiana distributed solar industry, and for Indiana residents that want financially viable on-

[69] Prepared Direct Testimony of Brad Heavner and Joshua Plaisted on Behalf of the California Solar and Storage Association [Third Amended Version dated August 2, 2021], California Public Utilities Commission Docket No. R.20-08-020.

[70] The Solar Foundation, National Jobs Census 2020, available at https://www.thesolarfoundation.org/national/

site solar options, there is little to no imperative to change this policy from AES Indiana's or its non-DG customers' perspective.

In fact, DG customers are likely providing substantial net benefits, as discussed further below, meaning the Commission should exercise its discretion in a manner that encourages the continued growth of DG in Indiana. For instance, the Lawrence Berkeley National Laboratory was commissioned by the Commission in response to a legislative request to provide a detailed analysis of emerging technologies and their impact on generation capacity, reliability, resilience, and rates ("LBNL DER Study"). It concluded that "[i]n general, scenarios with high adoption of rooftop solar PV result in system-wide savings," and "[r]ates tend to go down in the short term for the High PV scenarios."[71] These findings generally echo the results from studies commissioned on net metering or the value of solar in other states, some of which are discussed in more detail in the following section. The harmful impact of AES Indiana's "no netting" policy in conjunction with a very low EDG credit rate would hinder the State from realizing these substantial benefits.

Regardless of how the benefits of DG are quantified and considered, it is important to emphasize that the costs of DG are very modest on AES Indiana and non-DG customers. Through the end of 2020, AES Indiana had a meager 509 net metering customers out of more than 450,000 customers and 5.4 MW of installed net metering capacity – the lowest DG deployment levels on both metrics out of Indiana's five IOUs – compared to its peak

[71] Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System, pp. 55-56, available at https://www.in.gov/iurc/files/2020-Report-to-the-21st-Century-Energy-Policy-Development-Task-Force.updated-min.pdf

demand of 2,585 MW.[72] AES Indiana's annual revenue requirement is approximately $1.41 billion.[73] Even under conservative assumptions and assuming no value is provided by EDG, it would only amount to a *de minimis* "subsidy" or cost shift to non-DG customers that would not justify the major policy change being proposed by AES Indiana. But when the benefits are considered even that *de minimis* "subsidy" would not exist, or would be substantially reduced.[74]

Q. What if DG adoption continues to grow, causing the credit amount to also grow?

A. The revenue requirement for the EDG credit is so small that there would have to be unprecedented and abrupt growth in DG adoption rates for it to be a legitimate concern. Indiana's solar DG adoption rates are relatively modest to date, and there is no indication

[72] Indiana Utility Regulatory Commission, "2020 Year- End (2020YE) Net Metering Reporting Summary," March 2021, available at https://www.in.gov/iurc/files/2020-Year-End-Net-Metering-Required-Reporting-Summary.pdf; AES Indiana, FERC Form 1, Q4 2020.

[73] AES Indiana Response to IndianaDG Data Request 1-8.

[74] As of now in discovery AES Indiana has not provide some requested information that may be useful in demonstrating that any arguable subsidy between DG and non-DG customers is so small as to be *de minimis*. IndianaDG is attempting to resolve this matter with AES and obtain the information. I may need to correct my testimony for the missing information.

that such dramatic growth is likely. EDG customers are not major costs in the context of AES Indiana's $1.41 billion revenue requirement. Furthermore, focusing only on growth in the annual EDG credit fails to account for offsetting associated benefits customer-sited DG provides, and these benefits would need to be holistically and comprehensively analyzed on a forward-looking basis to fairly evaluate whether the existing policy is causing a net benefit or a net cost to Hoosier residents. Utilities are permitted to recover the costs of EDG credits under the plain language of Section 15 of the DG Statutes.

E. The Benefits of Retaining Monthly Netting

Q. What factors help explain why monthly netting policies have been popular and widely adopted in the U.S.?

A. Monthly netting offers a number of key advantages that have contributed to it becoming widely adopted, popular among customers, and effective at growing DG:

- **Understandable to customers.** Monthly netting makes sense to consumers. The simplicity of netting of kWh exports against kWh imports over the duration of a billing period is intuitive and understandable to customers, who are accustomed to the monthly character of typical billing.
- **Ability to estimate the financial benefit of a DG investment.** Monthly netting allows solar installers to provide reasonably accurate estimates of the financial viability of a distributed solar facility, whereas no netting policies add substantial complexity and uncertainty to these estimates. Monthly netting allows customers to make informed decisions about a potential solar investment that is sized to generate electricity sufficient to meet their expected annual electricity usage. Smaller systems (e.g., those designed to only offset a customer's minimum usage and never export electricity) typically have higher per-kW costs that can substantially erode the solar value proposition.
- **Technologically simple**. It does not take new or expensive metering equipment, such as advanced metering infrastructure, to implement monthly netting. Monthly netting can be implemented using existing metering equipment.
- **Fair compensation.** The full crediting of DG exports against imports from the grid over the duration of a billing period is generally perceived and accepted as a fair compensation rate by customers. In addition, numerous studies from across the country have shown this crediting rate is a reasonable approximation of the value

provided by rooftop solar during a month, particularly at low levels of rooftop solar deployment like in place in Indiana.

- **Benefits non-DG customers.** By facilitating DG growth, monthly netting produces greater systemwide DG benefits that flow to all grid users. The LBNL DER Study found that the estimated incremental economic impact on power system investment and operation in its High PV scenario relative to its Base case was $265.2 million in savings by 2025 and $549.2 million in savings by 2040.[75]
- **Bill certainty and stability.** Since compensation for excess generation takes the form of kWh credits, future changes to the utility's underlying kWh rates do not impact the economics of the system, as the customer continues to fully offset their electricity exports and imports during the month, giving a customer additional "peace of mind" about their financial investment.
- **Local and State economic development.** Monthly netting policies have proven effective at transforming nascent rooftop solar markets into significant job creators. Rooftop solar installer jobs are inherently local jobs and cannot be outsourced.

Q. Have states studied the costs and benefits of policies with monthly netting, or the value provided by DG solar net metering systems?

A. Yes, there have been numerous studies in recent years that have examined the costs and benefits of such policies or the value of solar DG or other distributed energy resources more broadly.

Q. What have these studies found regarding the costs and benefits or the value of solar DG?

A. As shown in Figure 3 below, these studies have generally found that policies that employ monthly netting frameworks result in net benefits to all customers or only small net costs, prior to taking into consideration larger policy objectives and less directly quantifiable benefits (*e.g.,* societal benefits, local economic development benefits, etc.). Similarly, studies calculating the value of solar DG have often found the total value *exceeds* the

[75] Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System, pp. 55-56, available at https://www.in.gov/iurc/files/2020-Report-to-the-21st-Century-Energy-Policy-Development-Task-Force.updated-min.pdf

current retail rate. One recent review found that 14 out of 24 value of solar analyses conducted in 2012-2018 calculated that the value of solar was at or above the retail rate, and only one analysis calculated a value that was below 50% of the residential retail rate (Figure 4). For comparison, AES Indiana's EDG Rate is only 27.0% of AES Indiana's current total residential energy charges. Stated differently, **AES Indiana is proposing to reduce the effective compensation rate for all exported generation by a residential DG customer by 72.0% in this case**.[76]

There is considerable variation across these studies in the methodology used, the categories of costs and benefits or values included, and the entity performing the study, which can all significantly impact the conclusions reached. Therefore, it is important that the specific context of a utility or state be fully evaluated in a rigorous and transparent way by an independent or neutral entity to determine what the impacts of net metering are in a specific jurisdiction.

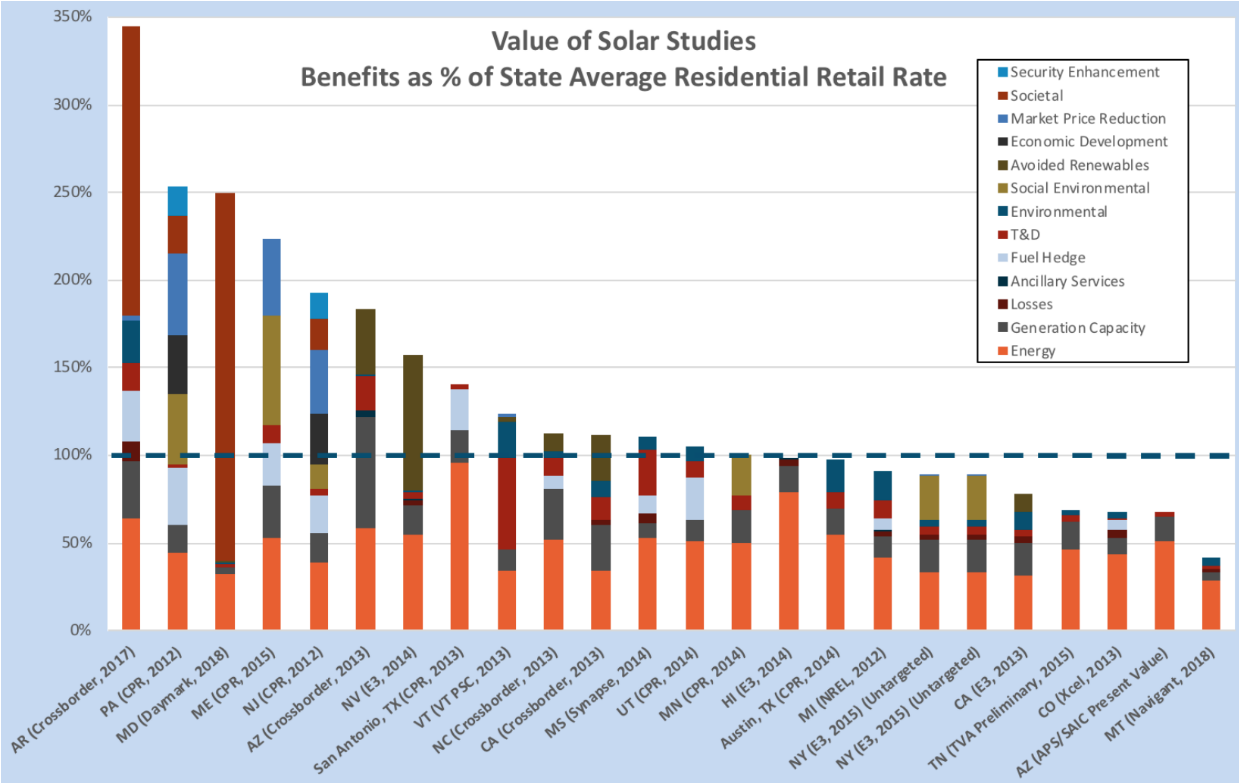
[76] The total energy charge was calculated by averaging the Residential Service base energy charges applicable to usage above and below 500 kWh and then adding the seven applicable rider adjustment charges (available at https://www.aesindiana.com/sites/default/files/2021-06/2021-Contract-Riders-Effective-05-28-2021.pdf). The percentage reduction in compensation was calculated by dividing the EDG Rate of $0.027960/kWh by the calculated total energy charge rate of $0.099918/kWh, and subtracting this value from 1 (one).

Figure 3. Summary of State Cost-Benefit Study Results[77]

State	Year	Prepared by	Principal Findings
NEM Cost-Benefit Analysis			
Arkansas	2017	Crossborder	Benefits of residential distributed generation (DG) exceed the costs; do not impose a burden on other ratepayers.
Nevada	2016	E3	Cost-shift amounts to a levelized cost of $0.08/kWh for existing installations.
Louisiana	2015	Acadian	Costs associated with solar NEM installations outweigh their benefits.
South Carolina	2015	E3	NEM-related cost-shifting was *de minimus* due to the low number of participants.
Mississippi	2014	Synapse	NEM provides net benefits under almost all of the scenarios and sensitivities analyzed.
Vermont	2014	PSD	NEM results in "close to zero" costs to non-participating ratepayers, and may be a net benefit.
VOS/NEM Successor			
District of Columbia	2017	Synapse	Utility system VOS is $132.66/MWh (2015$); cost-shifting remains relatively modest.
Georgia	2017	Southern Company	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Hawaii	2015	CPR	Provides a methodology for assessing costs and benefits. Preliminary results suggest a net benefit.
Maine	2015	CPR	Value of distributed PV is $0.337/kWh (levelized).
Oregon	2015	CPR	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Minnesota	2014	CPR	Provides a methodology for assessing VOS; no specific estimate is produced.
Utah	2014	CPR	VOS is $0.116/kWh levelized.
DER Value Frameworks			
California	2016	CPUC	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
New York	2016	NY DPS	Provides a methodology for assessing costs and benefits; no specific estimate is produced.

[77] Figure is from ICF International, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar," May 2018, available at: https://www.energy.gov/sites/default/files/2020/06/f75/ICF%20NEM%20Meta%20Analysis_Formatted%20FINAL_Revised%208-27-18.pdf

Figure 4. State Value of Solar Study Results[78]



1 **Q. What do you conclude based on your review of these studies?**

2 A. I conclude that monthly netting has been one of the key factors enabling the growth of DG
3 in the U.S., and that DG has been shown in numerous studies across the country to provide
4 substantial value that all customers benefit from. Approving AES Indiana's "no netting"
5 policy would harm the growth of DG, and the corresponding benefits it can provide to both
6 DG and non-DG customers alike.

[78] Figure is from Kush Patel, "Act 236: Version 2.0," Energy+Environmental Economics, August 7, 2018, available at http://energy.sc.gov/files/Act%20236%20Follow%20Up%20-%20Stakeholder%20Meeting%2008.07.18_Final.pdf

F. Other Netting Periods

Q. Has the Commission previously stated it has discretion in EDG proceedings to determine the appropriate netting period?

A. Yes, the Commission previously stated that it may "exercise its expertise and discretion in determining the reasonableness of a utility's proposed netting period for EDG."[79] As I will discuss further later, longer netting periods, including monthly netting, weekly or daily netting, rather than no netting or netting on a short time interval (e.g., 15-minute or hourly netting), are fairer to EDG customers. But again, I see no language in the DG Statutes that requires or invites a change from monthly netting.

Q. What netting period is most consistent with producing just and reasonable rates in this case?

A. As explained previously, monthly netting is most consistent with the plain language in the relevant provisions of the applicable statutes and long-standing ratemaking principles.

In addition, retaining monthly netting also represents a "no regrets" policy option for the Commission in this case. Adopting monthly netting for the time being would allow the Commission to monitor the impacts of the transition to the EDG Rider and avoid a hasty move to a "no netting" policy that would further compound the negative impacts of the EDG Rider rate on future DG growth. If the Commission believes it has discretion to adjust the netting period, then there is little or no risk from preserving monthly netting for the time being, while reserving the right to move away from monthly netting in the future, should a compelling case based on actual facts, data and analysis be made for that significant policy change.

[79] IURC Cause No. 45378, Final Order, April 7, 2021, p. 38.

A comparative analysis of the impacts of various netting methodologies is described in the following section.

Q. Is monthly netting a continuation of net metering?

A. No. Net metering closes to new customer participation after June 30, 2022 under the DG Statute. The DG Statutes implements a new EDG credit rate to apply to EDG for customers served under a utility's EDG tariff and made other changes to DG policy in Indiana. This is a significant reduction in the value of a DG system and a significant change from the past net metering policy. Maintaining monthly netting while implementing these legislative changes is consistent with the plain language of the DG Statutes and prudent policy.

G. Analysis of Impacts

Q. Did AES Indiana estimate the bill increase for a typical residential DG customer or for commercial DG customers under its "no netting" proposal compared to the current net metering policy or compared to monthly netting and the EDG credit rate?

A. No. AES has not offered any analysis whatsoever about the impacts of its "no netting" proposal.

Q. How would AES Indiana's "no netting" policy affect residential DG customer bill savings?

A. I estimate that AES Indiana's "no netting" policy would reduce residential customer bill savings by roughly 42.1% for a solar DG facility sized to produce an approximate 100% load offset on an annual basis (*i.e.,* 7.2 kW-dc) compared to monthly netting where EDG is credited at the EDG credit rate.

I arrived at this estimate through a multi-step process. First, I developed a typical residential solar production profile for a DG system located in Indianapolis, Indiana, using the default assumptions in, and the output from, the National Renewable Energy Laboratory's ("NREL") PVWatts Calculator, which is a public, freely available modeling tool.[80] AES Indiana used this tool as part of modeling it conducted as part of its 2019 Integrated Resource Plan.[81]

Second, I developed a representative hourly load profile for a typical residential customer in AES Indiana's service territory based on 2013-2017 residential service 8,760 hour load data provided by AES Indiana.[82]

Third, the default solar system size used in PVWatts is 4 kW-dc, so I scaled up the size of the DG facility to 7.2 kW-dc so its production offset approximately 100% of the AES Indiana residential customer's annual electricity consumption. Based on the resulting load profile and solar generation profile, I calculated the value diminishment and payback period of AES Indiana's proposal and several alternative policies.

Using *hourly* production and load figures as opposed to more granular data means that this analytical method will understate the actual amount of exported electricity (*i.e.,* my methodology is akin to using an *hourly* netting interval instead of the *no netting* measurement proposed). Therefore, the reduction in customer bill savings produced by this method is a conservative estimate, and the actual reduction to bill savings will be more drastic under AES Indiana's "no netting." To develop a rough estimate of the additional reduction in value from moving from an hourly netting to a "no netting" policy, I used the same reasonable deduction calculated in direct testimony by Joint Intervenors' witness William Kenworthy in Vectren's EDG case (IURC Cause No. 45378). Mr. Kenworthy

[80] https://pvwatts.nrel.gov/
[81] AES Indiana Response to IndianaDG Data Request 1-21, Attachment 1.
[82] AES Indiana Response to IndianaDG Data Request 1-4.

reasonably estimated that the annual bill for an average customer under the Dual-channel Billing methodology ("no netting") would be approximately 12% more than the average customer would pay under his Hourly Net Billing methodology.[83]

Finally, I also analyzed an alternative netting policy that would allow netting of imports against exports on a *daily* basis, which offers another alternative to AES Indiana's "no netting" proposal. The results of my analysis indicate daily netting is substantially less harmful to DG participants than either no netting or hourly netting. Specifically, no netting and hourly netting results in a 48.8% and 43.6%, respectively, value diminishment in the value of solar produced by a DG system relative to the current net metering policy, and a 42.1% and 36.1% value diminishment relative to monthly netting with EDG credited at the EDG Rider rate. Daily netting, on the other hand, results in only a 16.4% value diminishment of DG generation compared to the current net metering policy, and a 5.3% value diminishment relative to monthly netting with EDG credited at the EDG Rider rate. As shown in Table 2, the total value of DG generation (i.e., on-site consumption plus exported generation) in the first year after installing a solar DG facility is estimated to range from a high of $968.53 under net metering to a low of about $495.74 under AES Indiana's no netting proposal, with the other policy options analyzed reflecting a less significant reduction in total value. The results of this analysis are presented in Table 2.

Table 2. Annual Value Diminishment to Residential Solar Customer under Alternatives to Net Metering

Compensation Category	**No Netting**	**Hourly Netting**	**Daily Netting**	**Monthly Netting (EDG Credit)**	**Net Metering (Retail Rate)**
On-Site Value	*Unknown*	$382.53	$382.53	$382.53	$382.53

[83] IURC Cause No. 45378, Direct Testimony of William Kenworthy, p. 19.

Export Credits Value	*Unknown*	$163.98	$427.33	$473.01	$586.00
Total Value	$495.74	$546.51	$809.86	$855.54	$968.53
Value Diminishment Compared to Net Metering (Retail Rate)	**48.8%**	**43.6%**	**16.4%**	**11.7%**	--
Value Diminishment Compared to Monthly Netting (EDG Credit)	**42.1%**	**36.1%**	**5.3%**	--	--

While there will be a fair amount of variation between individual customers with respect to their hourly load profiles, my estimates are reasonable comparisons. Customers with lower daytime loads would produce a greater quantity of exports than those with higher daytime loads and, consequently, forfeit more value due to excess daytime generation being compensated at the low EDG Rider rate, instead of the volumetric retail rate compensation that the customer would receive under monthly netting. Second, system orientation and other site characteristics would influence the solar production shape and, correspondingly, the amount of hourly exports. However, I believe my estimate provides a useful and reliable illustration of the financial impacts of AES Indiana's proposal on a typical residential customer installing a solar DG system.

The daily netting results further demonstrate just how financially disastrous AES Indiana's no netting proposal would be on prospective solar DG customers compared to more reasonable alternatives. Even allowing solar customers to retain their export credits for a day yields a 11.7% diminishment in customer value compared to a 48.8% value diminishment from "no netting" relative to net metering.

Q. How would AES Indiana's "no netting" proposal affect residential DG customer payback periods?

A. I calculate that the payback period for a 7.2 kW system costing a residential customer \$3.05/watt,[84] or a total upfront cost of \$21,960, would be 30.3 years under AES Indiana's "no netting" proposal, compared to 15.9 years under the current net metering policy, or 17.9 years under monthly netting with EDG credited at the EDG Rider rate (Table 3). AES Indiana's proposals in the case would nearly double the payback period for a typical residential customer DG investment, to the point where it no longer would save a customer money over an assumed 25-year life of a rooftop solar facility.

Table 3. Payback Period of a 7.2 kW Residential Solar Facility in AES Indiana's Service Territory (With ITC)

DG Compensation Policy	Payback Period (Years)
Net Metering (Current)	15.9
Monthly Netting (EDG Credit for Excess Distributed Generation)	17.9
Daily Netting	18.9
Hourly Netting	27.6
No Netting	30.3

The payback periods above include the current 26% federal investment tax credit ("ITC"), discussed in more detail below. The payback period of a DG system will get worse in future years as the ITC phases out. For a residential DG system installed on or after the end of the ITC on January 1, 2024, the payback period would increase to 22.9 years under monthly netting and to nearly 38 years under AES Indiana's "no netting" proposal (Table 4).

[84] Energy Sage, https://www.energysage.com/local-data/solar-panel-cost/in/ (Showing that "[a]s of July 2021, the average solar panel cost in Indiana is \$3.05/W.")

Table 4. Payback Period of a 7.2 kW Residential Solar Facility in AES Indiana's Service Territory With (No ITC)

DG Compensation Policy	Payback Period (Years)
Net Metering (Current)	20.4
Monthly Netting (EDG Credit for Excess Distributed Generation)	22.9
Daily Netting	24.1
Hourly Netting	34.6
No Netting	37.9

Q. What is the impact of AES Indiana's "no netting" proposal relative to the application of the EDG credit rate?

A. As demonstrated in Tables 2 through 4, AES Indiana's "no netting" proposal is the primary driver of the reduced value of installing solar DG, and would result in a significantly longer payback period. In contrast, maintaining monthly netting and applying the EDG credit rate to all monthly net EDG produces a less drastic decrease in the value of installing solar DG and a smaller increase in the payback period relative to the current net metering policy.

Q. Would non-residential customers be similarly impacted?

A. Yes. Schools, churches, governments, and businesses would likely see a similar, negative impact on their potential bill savings from installing a DG system designed to meet their annual electricity usage under AES Indiana's proposed "no netting" policy. The specific magnitude of the impacts would depend on the customer's rate schedule, usage characteristics, and generation profile, among other factors.

Q. Will federal subsidies for DG technologies like solar make up for AES Indiana's dramatic reduction in compensation under its "no netting" proposal?

A. No. The federal ITC has been a factor in customer payback periods since it started, and it is factored into my payback period analysis described above. To say the existing ITC credit – even if it is extended by Congress – is a cure for or reduction to the financial harm that would be caused by AES Indiana's "no netting" proposal would be false. The ITC for solar is currently being phased out. The ITC currently provides a 26% tax credit for solar systems on residential (under Section 25D) and commercial (under Section 48) properties. In 2023, or only six months after AES Indiana's EDG Rider is scheduled to become effective for all new DG customers, the ITC will step down to a 22% tax credit. Beginning in 2024, the commercial ITC drops down to 10% in perpetuity, whereas the residential ITC will be *eliminated* for new systems.[85]

It is also important to note that entities without federal income tax liability like churches and municipal governments cannot directly benefit from current federal ITC. This means that solar sited at government buildings, public schools, and nonprofit organizations in Indiana are generally unable to benefit from the ITC.

Third-party power purchase agreements ("PPAs") are a financing mechanism that has been widely used in many other states, allowing entities without federal income tax liability to indirectly benefit from the federal ITC through the pass-through of the benefits realized by the third-party owner(s) to the customer purchasing the solar facility's output. However, this financing mechanism has not been explicitly authorized in Indiana, so its legal status is unclear here. As a result, Indiana taxpayers are paying for the ITC (to the extent all U.S. taxpayers bear the costs of federal tax credits) associated with solar PPAs

[85] Solar Energy Industries Association, "Solar Investment Tax Credit (ITC)," available at https://www.seia.org/initiatives/solar-investment-tax-credit-itc.

that other state regulators or policymakers have expressly allowed as part of their DG policies, meaning Hoosiers bear the costs but are not getting their fair share of the benefits of the ITC associated with solar PPA financing models.

Q. What would be the impact of the "no netting" proposal on the adoption rate of technologies like distributed solar and the type of customer that would be able to make such an investment in AES Indiana's service territory?

A. Simply put, as a result of the large reduction in potential savings for installing DG, AES Indiana's "no netting" proposal would have a devastating impact on the adoption rate of DG technologies like solar by preventing most customers from being able to install such a DG system based on the economics. For example, a rooftop solar system can have an upfront cost (prior to applying the federal ITC) of roughly $15,000 to $25,000, depending on system size and other factors.[86] If AES Indiana's "no netting" proposal is approved, solar companies will likely struggle to attract new customers and will be less likely to be able to offer financing arrangements like leasing, which can make rooftop solar economically viable for families that cannot afford the upfront costs of a solar system, because such leasing services are usually made available on the basis of demonstrating a net cost reduction to customers. Without a reasonable opportunity to save money from a solar investment, most customers are unlikely to install a system.

Only customers who are not sensitive to the economics of such a large investment would be able to make such an investment. Unfortunately, this leads me to conclude that

[86] The median price for residential solar in the U.S. in 2019 was $3.76/watt, according to Lawrence Berkeley National Laboratory's "Tracking the Sun" data, available at https://emp.lbl.gov/tracking-the-sun. More recent and regionally specific data suggest the price in Indiana is currently around $3.05/watt: https://www.energysage.com/solar-panels/in/.

AES Indiana's "no netting" proposal would likely mean that primarily high-income Hoosiers and perhaps some larger businesses would be able to afford investment in on-site DG technologies like rooftop solar, making solar out of reach for the average Hoosier household, small business, or school. In contrast, trends in rooftop solar adoption across the country show that the median household income for solar adopters is falling over time.[87]

AES Indiana's proposal is a step backwards in improving equity and access to the diverse benefits of DG solar.

Q. Could customers mitigate the adverse impacts of the "no netting" proposal by adding battery energy storage system to their DG facilities?

A. While battery energy storage is an extremely promising resource that can provide all customers, the utility, and the grid with many benefits, they are typically too expensive for individual customers to install, especially lower and moderate-income residential customers, and should not be *de facto* mandatory for participation in a DG program. For instance, one 5.8 kW / 13.5 kWh Tesla Powerwall costs $7,000, and that is before consideration of supporting hardware that can cost about $1,000, sales tax, plus installation costs that are site dependent and can run into thousands of dollars.[88] Most residential solar installations would need to be paired with multiple batteries for the customer to fully serve their entire load on an annual basis without importing or exporting any electricity.

Notably, AES Indiana offers no proposal to mitigate the upfront cost of customer investments in battery energy storage systems, or innovative proposals, akin to those I

[87] Lawrence Berkeley National Laboratory, "Residential Solar-Adopter Income and Demographic Trends: 2021 Update," available at https://eta-publications.lbl.gov/sites/default/files/solar-adopter_income_trends_final.pdf.
[88] Energy Sage, "The Tesla Powerwall home battery complete review," April 29, 2021, available at https://news.energysage.com/tesla-powerwall-battery-complete-review/

discuss later, that would help customers and the grid benefit from batteries' capacity located on the customer's premises. Instead, AES Indiana seeks to impose the most restrictive EDG paradigm possible, which will result in many customers not being able to install solar and the potential demise of solar installation business in Indiana. The DG Statutes' plain language does not require DG customers to install battery storage, and it would be unfair, unjustified, and unreasonable to impose a policy that would require such a financial burden on AES Indiana EDG customers.

Q. Couldn't DG customers limit their exported electricity through other means besides installing a battery energy storage system?

A. Only to a limited extent. DG customers do not generally have the ability or the capacity to monitor their instantaneous minute by minute electricity usage and generation and align the two, meaning customers are limited in their capability to respond to the "price signals" under "no netting." Similarly, residential customers of Indiana investor-owned utilities are not exposed to real-time wholesale market price fluctuations that would require closely monitoring and responding to sub-hourly price fluctuations, and are instead served under rate schedules that use flat energy rates, block rates, or TOD rates with a limited number of time periods.

Furthermore, only a portion of electricity usage is discretionary and can be shifted across time. Many customers will have limited ability to do so and maintain those behaviors, which further limits the customer's ability to avoid exporting generation by using the DG output behind the meter for on-site consumption. Some types of customers will be particularly constrained in their ability to shift usage during the day or across seasons (e.g., schools; residential customers with schedule constraints that prevent shifting when they cook dinner or do the laundry; etc.).

Finally, as discussed above, there is no reason customers should be discouraged from exporting EDG in the first place, particularly given that it will tend to overlap with AES Indiana's on-peak period in the summer and shave peak demand during these times.

Q. If a customer were to install battery storage, would a "no netting" policy provide a good price signal for maximizing the value that the battery can provide to the grid?

A. No. No netting or limited duration netting policies (e.g., hourly netting) prompt customers to use the battery to avoid exports, since those exports have a diminished value relative to electricity consumed on-site. This results in the battery charging during daylight hours, and discharging when solar production is not available at night. Discharge is limited to the customer's load at any given point in time.

By contrast, maximizing the value of a battery to the larger grid is achieved by maximizing discharge during the peak periods irrespective of on-site load. This characteristic is reflected in the "Bring Your Own Device" ("BYOD") battery storage grid services framework that is becoming increasingly common. For instance, in a recent proposal for a home battery program, Consumers Energy in Michigan proposed such a design for dispatch of enrolled batteries based on findings from a preliminary test deployment where it "learned that the usable battery energy was reduced when only offsetting customer home load – and it would be more efficient to maximize battery discharge beyond the customer home load during system peak conditions."[89] Likewise, in

[89] Michigan Public Service Commission, Docket No. U-20963, Direct Testimony of Priya D. Machi at 6:9-12, March 1, 2021.

Hawaii, Hawaiian Electric is now offering substantial financial incentives to incentivize residential and commercial customers to add a battery energy storage facility to an existing or new solar facility and use and/or export electricity stored in the battery between 6 p.m. to 8:30 p.m. daily in order to help contribute to resource adequacy during those times after an AES coal plant retires in September 2022.[90]

In other words, the greatest benefits to the grid accrue when exports, either from on-site solar alone or battery storage, are maximized during peak conditions. Devaluing exports during peak periods as AES Indiana proposes does exactly the opposite. It sends exactly the wrong signal to customers from the standpoint of maximizing the benefits of a DG system.

Q. Does monthly netting require the utility to serve as the EDG customer's battery?

A. No. The utility is neither acting as nor providing services comparable to a battery. Electricity exported by a DG customer flows onto the grid and is used by other customers. The utility charges those other customers the retail rate for that electricity and credits the DG customer for the electricity provided. The utility does not store the solar electricity generated by the DG customer and provide that electricity back to the customer when the DG customer needs it. Monthly netting is merely a compensation framework that provides fair compensation measurement to a DG customer for excess generation they provide to the utility and to the benefit of other customers.

[90] Hawaiian Electric, "New 'Battery Bonus' program to offer Oahu customers cash incentive to add energy storage to rooftop solar system," July 19, 2021, available at https://www.hawaiianelectric.com/new-battery-bonus-program-to-offer-oahu-customers-cash-incentive-to-add-energy-storage-to-rooftop-solar-system.

Battery storage provides distinguishable and separate services compared to the utility's grid, including as a back-up power source for when the utility experiences a grid outage, a method for a customer to manage their demand (e.g., to manage their demand charges or take advantage of time-of-use pricing), and a means for the customer of storing electricity generated on-site for future use. DG customers, like non-DG customers, can use electricity provided by the utility when they need it under the terms of their rate schedule and in line with the utility's obligation to serve all customers in its service territory. AES Indiana is neither an EDG customer's battery nor is acting as a battery under monthly or any other netting method.

III. EDG CREDITS AT END OF SERVICE

Q. Does AES Indiana's EDG Rider allow the full amount of EDG credits to be carried forward?

A. No. AES Indiana would confiscate any credits remaining when the customer discontinues service:

> Upon ending service as Customer at the premises, all unused credits shall be flowed through the FAC to the benefit of all Customers. EDG credit balances are not transferable to another account or service.[91]

This practice would deprive departing customers of earned EDG credits for energy already supplied to AES without any clear justification.

Q. Is this provision fair and consistent with the plain language of the DG Statutes?

[91] AES Indiana, Standard Contract Rider No. 16, Excess Distributed Generation (EDG) [Attachment MDF-1 to Supplemental Testimony of Matthew Fields].

A. No, I do not believe this is fair to EDG customers or consistent with the plain language of the DG Statutes. Section 18 of the DG Statutes provides that:

> An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

The language in the DG Statutes does not expressly specify how unused credits should be treated when a customer no longer receives retail electric service from the utility. It certainly does not direct a utility to confiscate the property of its DG customers and socialize the benefits across all of its customers by taking a DG customer's unused credits without compensation and applying the credits to its FAC.

Q. Do other jurisdictions allow DG customers to cash out unused credits?

A. Yes. In my experience, it is common for states to allow net metering customers to cash out unused net metering credits, such as on an annual basis for any credits that accrued over the year, or at the end of service. For instance, in 2016, Iowa regulators directed utilities to allow unused credits to be banked monthly and cashed out at the end of the year at the utility's avoided cost rate under net metering tariffs.[92]

I am not aware of any negative impacts that these customers have experienced as a result of such policies.

Q. What do you recommend?

A. I recommend that earned EDG credits be refundable to customers upon service termination. Those credits represent the approved value of electricity the customer generated and sent

[92] Iowa Utilities Board, Docket No. NOI-2014-0001, Order, July 19, 2016.

to AES Indiana. To not compensate DG customers for that valuable electricity is, in my view, to take the DG customer's property without compensation. Likewise, if the customer moves to a different premise, but remains an AES Indiana customer, they should receive their EDG credits on their subsequent AES Indiana bill. They earned it, it has value, and it should be theirs to keep.

An unused credit represents electricity a DG customer has generated through their investment in a DG system and provided to the utility to the benefit of its customers. The utility effectively sells EDG provided by a DG customer to other customers at the retail rate. Confiscating unused EDG credits takes the economic value of exported electricity provided by DG customers, but provides no compensation to the DG customer for that benefit.

IV. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission reject AES Indiana's EDG Rider to the extent it would implement a "no netting" methodology for measuring EDG. AES Indiana's proposal is inconsistent with the plain language of the DG Statutes.

AES Indiana's case in chief in my view has also failed to prove its case and has not demonstrated that this major policy change to "no netting" would produce rates that are just and reasonable. As my testimony demonstrates, there are many good reasons for the Commission to reject this radical departure from past methodologies and maintain the longstanding, widely adopted, and commonsense monthly netting framework for measuring EDG as it transitions away from net metering through implementation of the EDG Rider.

To the extent the Commission disagrees with my recommendation to maintain monthly netting under the EDG Rider, I recommend it consider less punitive alternatives to the “no netting” policy AES Indiana has proposed, such as daily netting.

If the Commission approves AES Indiana’s filing as proposed or with limited modifications, I recommend that the Commission direct AES Indiana to provide additional consumer information and education regarding its Cogeneration & Small Power Production tariff to ensure all eligible DG customers have access to and are fully informed of this rate option, which could provide a more favorable compensation rate than the EDG Rider as proposed for certain DG customers.

I also recommend that the Commission direct AES Indiana to modify its calculation methodology for the EDG Rider credit rate as described in my testimony to recognize the fact that solar is producing and exporting generation only during daylight hours and should be compensated accordingly.

I also recommend the Commission to ensure that all DG customers are provided fair terms and conditions under net metering and the EDG Rider. Specifically, I recommend the Commission reject AES Indiana’s taking without just compensation of EDG credits remaining at the end of a customer’s service, as described above. These terms are unjustified and would further harm EDG customers by imposing additional, unnecessary costs or take away benefits to which DG customers are entitled without providing fair compensation.

Q. Does this conclude your testimony?

A. Yes, at this time. I may need to supplement this testimony in the future. There are data responses that have yet to be received from AES Indiana.

VERIFICATION

I, Benjamin Inskeep, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

______________________________ August 17, 2021

Benjamin Inskeep

ATTACHMENT BDI-1

***Curriculum Vitae* of Benjamin D. Inskeep**

Benjamin D. Inskeep

binskeep@eq-research.com

EDUCATION

School of Public and Environmental Affairs (SPEA), Indiana University, Bloomington, IN
M.S. in Environmental Science, 2012, Top GPA Award
Master of Public Affairs, 2012, Top GPA Award, Concentration: Environmental Policy

"IU at Oxford," University of Oxford, Oxford, United Kingdom
Six-week graduate school program on climate change governance and environmental regulation, 2011

Indiana University, Bloomington, IN
B.S., Psychology, 2009, with *Highest Distinction*, Honors Notation, and Phi Beta Kappa honors
Certificate, Liberal Arts and Management Program (honors-level interdisciplinary business program)

EXPERIENCE

Principal Energy Policy Analyst, February 2020 – Present
Senior Energy Policy Analyst, January 2019 - Present
Energy Analyst, May 2018 – December 2018
Independent Contractor, July 2017-April 2018
Research Analyst, March 2016 – June 2017
EQ Research LLC, Cary, North Carolina

- Lead EQ Research's CCA services focused on regulatory monitoring, compliance reporting, and customized research and analysis.
- Develop expert witness testimony, clean energy legislation, policy memos, regulatory public comments, policy reports, and market analyses with an emphasis on clean energy policy.
- Research, track, and analyze renewable energy legislation, regulatory proceedings, and stakeholder opportunities to participate in policymaking for client-facing policy tracking services.
- Manage EQ Research's services on U.S. electric utility rate cases including reviewing and summarizing all rate cases, researching and tracking anticipated rate cases and providing bi-weekly updates to clients on utility rate developments.
- Support and collaborate with a diverse regulatory team, including attorneys, policy analysts, businesses and environmental advocates, in ongoing regulatory proceedings.

Researcher, August 2017 – January 2018
Earth Island Institute, Indianapolis, Indiana

- Developed more than 100 wiki pages on existing and planned coal, LNG terminals and oil and gas pipelines for the CoalSwarm and FrackSwarm projects, which provide clearinghouses addressing the impacts of coal and fracking and moving to cleaner sources of energy.

Policy Analyst, June 2014 – March 2016
North Carolina Clean Energy Technology Center, N.C. State University, Raleigh, North Carolina

- Co-creator, lead author, and editor for *The 50 States of Solar*, a quarterly report series that comprehensively tracks state regulatory and legislative distributed solar policy developments.
- Created an internal database for tracking distributed solar regulatory and legislative policy proposals, and queried and analyzed the data to answer policy questions, identify trends, and develop reports.

- Tracked and updated summaries of more than 500 utility, local, state, and federal policies and incentives for the *Database of State Incentives for Renewables and Efficiency* (DSIRE).
- Led solar workshops and provided technical assistance to local governments, including solar financial and policy analysis, reports, case studies, fact sheets, and customer-facing solar guides as part of the U.S. Department of Energy SunShot Solar Outreach Partnership.

Doctoral Research Assistant, August 2012 – December 2013
SPEA, Indiana University, Bloomington, Indiana

- Completed three semesters of Ph.D. coursework, attaining a 4.0/4.0 GPA.
- Collaborated with Professor Shahzeen Attari in academic research projects on the psychology of energy and water use and conservation.
- Lead-authored peer-reviewed research on the most effective actions households can take to curb water use.

Climate Corps Fellow, June 2012 – August 2012
Environmental Defense Fund, Cary, North Carolina

- Quantitatively benchmarked the energy efficiency of 90+ North Carolina fire stations and authored case studies highlighting the most effective local fire station energy efficiency initiatives.
- Evaluated the cost-effectiveness of various local government energy efficiency measures to demonstrate the financial value of sustainability.

Sustainability Intern, October 2011 – April 2012
Office of Sustainability, Indiana University, Bloomington, Indiana

- Analyzed data on Indiana University's energy use to determine greenhouse gas emission trends.
- Collected and analyzed quantitative and qualitative sustainability metrics for sustainability ratings.
- Benchmarked the university's sustainability relative to peer institutions.

Research Intern, February 2010 – May 2010
The Nature Conservancy, Indianapolis, Indiana

- Synthesized research on the economic benefits of community green space as part of a white paper.

PUBLICATIONS

- Inskeep, B. **Pollinator-Friendly Solar in Indiana.** May 2020. Published by EQ Research.
- Inskeep, B. **Four Flavors of Grid Modernization in the Midwest.** April 12, 2019. Published by EQ Research.
- Inskeep, B. **States Charting Paths to 100% Targets.** March 15, 2019. Published by EQ Research.
- Makhyoun, M. and B. Inskeep, **Ten Things to Know about CCAs in California.** February 13, 2019. Published by EQ Research.
- Inskeep, B. **EQ Research's Q4 2018 GRC [General Rate Case] Update.** January 15, 2019. Published by EQ Research.
- Inskeep, B. **EQ Research's Q3 2018 GRC Update.** October 16, 2018. Published by EQ Research.

- Argetsinger, B. and B. Inskeep. **Standards and Requirements for Solar Equipment, Installation, and Licensing and Certification.** January 2017. Published by the Clean Energy States Alliance.
- Barnes, C., J. Barnes, B. Elder, and B. Inskeep. **Comparing Utility Interconnection Timelines for Small-Scale Solar PV, 2nd Edition.** October 2016. Published by EQ Research.
- Barnes, J., B. Inskeep, and C. Barnes [with Synapse Energy Economics]. **Envisioning Pennsylvania's Energy Future.** October 2016. Published by the Delaware Riverkeeper Network.
- Inskeep, B., et al. **The 50 States of Solar.** February 2015, April 2015, August 2015, November 2015, February 2016. Lead author & editor for five quarterly editions. Published by the NC Clean Energy Technology Center.
- Inskeep, B., et al. **Utility Ownership of Rooftop Solar PV.** November 2015. Published by U.S. DOE SunShot Solar Outreach Partnership.
- Inskeep, B., and A. Proudlove. **Renewable Cities: Case Studies.** Published by U.S. DOE SunShot Solar Outreach Partnership, October 2015.
- Inskeep, B., K. Daniel, and A. Proudlove. **Delaware Goes Solar: A Guide for Residential Customers.** June 2015. Published by U.S. DOE SunShot Solar Outreach Partnership.
- Inskeep, B., and A. Proudlove. **Homeowner's Guide to the Federal Investment Tax Credit for Solar PV.** Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Inskeep, B., and A. Proudlove. **Commercial Guide to the Federal Investment Tax Credit for Solar PV**. Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Daniel, K., B. Inskeep, and A. Proudlove. **Understanding Sales Tax Incentives for Solar Energy Systems.** Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Inskeep, B. and A. Shrestha. **Comparing Subsidies for Conventional and Renewable Energy.** Published by NC Clean Energy Technology Center, March 2015.
- Inskeep, B., K. Daniel, and A. Proudlove. **Solar on Multi-Unit Buildings: Policy and Financing Options to Address Split Incentives.** Published by U.S. DOE SunShot Solar Outreach Partnership, February 2015.
- Daniel, K., B. Inskeep, et al. **In-State RPS Requirements**. Published by NC Clean Energy Technology Center, November 2014.
- Inskeep, B. and S. Attari. **The Water Short List: The Most Effective Actions U.S. Households Can Take to Curb Water Use.** *Environment: Science and Policy for Sustainable Development* 56, No. 4, 2014: 4-15.

PARTICIPATION AT PUBLIC UTILITY COMMISSIONS

- **Kentucky Public Service Commission**, *March 2021*, Provided direct testimony on behalf of Kentucky Solar Energy Industries on Louisville Gas & Electric's net metering proposal, Case No. 2020-00350.
- **Kentucky Public Service Commission**, *March 2021*, Provided direct testimony on behalf of Kentucky Solar Energy Industries on Kentucky Utilities's net metering proposal, Case No. 2020-00349.

- **Kentucky Public Service Commission**, *October 2020, February 2021*, *March 2021,* Provided direct, supplemental, and rebuttal testimony on behalf of Kentucky Solar Energy Industries on Kentucky Power Company's net metering proposal, Case No. 2020-00174.
- **Kentucky Public Service Commission,** *November 2019*, Provided comments on behalf of Kentucky Solar Energy Industries on the implementation of the Net Metering Act, Case No. 2019-00256.
- **Indiana Utility Regulatory Commission,** *September 2019*, Provided public comments as a ratepayer at Public Hearing against Indianapolis Power and Light's (IPL) proposed $1.2 billion grid modernization plan that would raise customer bills by $10.50.
- **Indiana Utility Regulatory Commission,** *May 2018,* Provided public comments as a ratepayer at Public Hearing against IPL's proposal in its rate case to increase it fixed customer charge from $17 to $27, which would have been the highest fixed charge among investor-owned utilities in the nation.

PRESENTATIONS

- **Indiana's Energy Transition**, November 2020
  Presentation at Hoosier Environmental Council's "Greening the Statehouse"
- **Energy Storage in Integrated Resource Planning**, September 2020
  Panelist on webinar hosted by the Energy Storage Association
- **DERs [Distributed Energy Resources] in the Midwest**
  Moderated panel at Solar and Storage Midwest, November 2019
- **Planning for the Solar Revolution**
  Poster presentation at Solar Power International, Salt Lake City, Utah, September 2019
- **Policy Considerations for Accelerating the U.S. Clean Energy Transition**
  Invited by Prof. Sanya Carley to give lecture to graduate energy economics class at Indiana University School of Public and Environmental Affairs, Bloomington, Indiana, March 2019.
- **Solar Equipment, Installation, and Licensing & Certification: A Guide for States and Municipalities**
  Webinar presentation on report findings sponsored by the Clean Energy States Alliance, February 2017.
- **Distributed Solar PV Trends in Net Metering and Rate Design**
  Invited to give presentation at Solar Asset Management Conference, San Francisco, California, March 2016.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at Kerr-Tar Councils of Government, Henderson, North Carolina, November 20, 2015.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at NC Clean Energy Technology Center, Raleigh, North Carolina, November 19, 2015.
- **North Carolina in Context: Regional and National Trends**.
  Panel presentation at University of North Carolina Clean Energy Forum, Chapel Hill, North Carolina, September 2015.
- **Net Metering Updates**.

Panel presentation at Solar Power International, Anaheim, California, September 2015.

- **The 50 States of Solar: Trends in Net Metering Policies and Rate Design.**
  Poster presentation at Solar Power International, Anaheim, California, September 2015.
- **Net Metering and Rate Design Trends**.
  Panel presentation at Intersolar North America, San Francisco, California, July 2015.
- **Distributed Disruption: The Economics and Policy Behind the Distributed Solar PV Boom**.
  Invited by Prof. Sanya Carley to give lecture to graduate energy economics class at Indiana University School of Public and Environmental Affairs, Bloomington, Indiana, April 2015.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at Grand Valley State University's Michigan Alternative and Renewable Energy Center, Muskegon, Michigan, May 5, 2015.
- **The Water Short List: The Most Effective Actions to Reduce Household Water Consumption**
  Poster presentation at the International School on Energy Systems, Seeon, Germany, September 2014.
- **More Than a Drop in the Bucket: How U.S. Households Can Reduce Water Consumption by 70%**
  Presentation at the 13th Annual Association for SPEA Ph.D. Students Conference, Bloomington, IN, March, 2013.

AWARDS & HONORS

- 2012 Top GPA Award, M.S. in Environmental Science
- 2012 Top GPA Award, Masters in Public Affairs
- 2011 SPEA Merit Award
- 2005-2009 Indiana University Honors Recognition Scholarship

VOLUNTEER SERVICE

Citizens Action Coalition, Indiana, February 2019 – present
Board Member

Solar Power International, 2014 – 2016
Education Committee Member for the largest solar conference in America

SPEA, Prof. Evan Ringquist Research Team, Bloomington, Indiana, 2011
Volunteer Researcher on Environmental Justice Research Project

ATTACHMENT BDI-2

SENATE BILL No. 309

DIGEST OF INTRODUCED BILL

Citations Affected: IC 8-1.

Synopsis: Distributed generation. Requires: (1) the utility regulatory commission (IURC) to post a summary of the results of the IURC's most recent periodic review of the basic rates and charges of an electricity supplier on the IURC's Internet web site; and (2) the electricity supplier subject to the review to provide a link on the electricity supplier's Internet web site to the IURC's posted summary. Amends the statute concerning alternate energy production, cogeneration, and small hydro facilities to: (1) include in the definition of a "private generation project" certain cogeneration facilities that: (A) are located on the same site as the host operation; or (B) are located on or contiguous to the site of the host operation and are directly integrated with the host operation; and (2) define an "eligible facility" for purposes of the statute. Specifies that an electric utility or a steam utility is not required to distribute, transmit, deliver, or wheel electricity from a private generation project. Requires the IURC to: (1) review the rates charged by electric utilities for backup power to eligible facilities and for purchases of power from eligible facilities; (2) identify the extent to which the rates meet specified criteria; and (3) report the IURC's findings to the interim study committee on energy, utilities, and telecommunications; not later than November 1, 2018. Provides that a public utility that: (1) installs a wind or solar project with a nameplate capacity of not more than 50,000 kilowatts; and (2) uses for the project a contractor that is: (A) subject to Indiana unemployment taxes; and (B) selected by the public utility through a competitive procurement process; is not required to obtain a certificate of public convenience and necessity for the project from the IURC. Provides that a net

(Continued next page)

Effective: July 1, 2017.

Hershman

January 9, 2017, read first time and referred to Committee on Utilities.

45504-- IndianaDG Exhibit 1 Attachment BDI-2

metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the first calendar year after the aggregate amount of net metering facility nameplate capacity under the tariff equals at least 1% of the electricity supplier's most recent summer peak load. Provides that after June 30, 2027: (1) an electricity supplier may not make a net metering tariff available to customers; and (2) the terms and conditions of any net metering tariff offered by an electricity supplier before July 1, 2027, expire and are unenforceable. Provides that not later than March 1, 2026, an electricity supplier shall file with the IURC a petition requesting a rate for the electricity supplier's purchase of distributed generation from customers. Provides that the IURC shall approve a rate submitted by an electricity supplier if the rate equals either: (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; or (2) the direct costs of generating or purchasing electricity that the electricity supplier will avoid by purchasing distributed generation. Establishes protections for customers producing distributed generation.

Introduced

First Regular Session 120th General Assembly (2017)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in **this style type**, and deletions will appear in ~~this style type.~~

Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in **this style type**. Also, the word **NEW** will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.

Conflict reconciliation: Text in a statute in *this style type* or ~~*this style type*~~ reconciles conflicts between statutes enacted by the 2016 Regular Session of the General Assembly.

SENATE BILL No. 309

A BILL FOR AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 8-1-2-42.5 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 42.5. **(a)** The commission shall by rule or order, consistent with the resources of the commission and the office of the utility consumer counselor, require that the basic rates and charges of all public, municipally owned, and cooperatively owned utilities (except those utilities described in ~~IC 8-1-2-61.5)~~ **section 61.5 of this chapter)** are subject to a regularly scheduled periodic review and revision by the commission. However, the commission shall conduct the periodic review at least once every four (4) years and may not authorize a filing for an increase in basic rates and charges more frequently than is permitted by operation of section 42(a) of this chapter.

(b) The commission shall make the results of the commission's most recent periodic review of the basic rates and charges of an electricity supplier (as defined in IC 8-1-2.3-2(b)) available for

public inspection by posting a summary of the results on the commission's Internet web site. An electricity supplier whose basic rates and charges are reviewed under this section shall provide a link on the electricity supplier's Internet web site to the summary of the results posted on the commission's Internet web site.

SECTION 2. IC 8-1-2.4-2, AS AMENDED BY P.L.222-2014, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 2. (a) The definitions in this section apply throughout this chapter.

(b) "Alternate energy production facility" means:

(1) a solar, wind turbine, waste management, resource recovery, refuse-derived fuel, or wood burning facility;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(c) "Cogeneration facility" means:

(1) a facility that:

(A) simultaneously generates electricity and useful thermal energy; and

(B) meets the energy efficiency standards established for cogeneration facilities by the Federal Energy Regulatory Commission under 16 U.S.C. 824a-3;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(d) "Electric utility" means any public utility or municipally owned utility that owns, operates, or manages any electric plant.

(e) "Small hydro facility" means:

(1) a hydroelectric facility at a dam;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(f) "Steam utility" means any public utility or municipally owned utility that owns, operates, or manages a steam plant.

(g) "Private generation project" means a cogeneration facility that has an electric generating capacity of eighty (80) megawatts or more and is:

(1) primarily used by its owner for the owner's industrial, commercial, heating, or cooling purposes; or

(2) a qualifying facility for purposes of the Public Utility Regulatory Policies Act of 1978 that ~~(A) is in existence on July 1, 2014; and (B)~~ produces electricity and useful thermal energy that is primarily used by a **single** host operation for industrial, commercial, heating, or cooling purposes **and is:**

(A) located on the same site as the host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

(h) "Eligible facility" means an alternate energy production facility, a cogeneration facility, or a small hydro facility that is:

(1) described in section 5 of this chapter; and

(2) either:

(A) located on the same site as a single host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

The term includes the consuming elements of a host operation using the associated energy output for industrial, commercial, heating, or cooling purposes.

SECTION 3. IC 8-1-2.4-4 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 4. (a) Subject to section 5 of this chapter, the commission shall require electric utilities and steam utilities to enter into long term contracts to:

(1) purchase or wheel electricity or useful thermal energy from ~~alternate energy production facilities, cogeneration facilities, or small hydro~~ **eligible** facilities located in the utility's service territory, under the terms and conditions that the commission finds:

(A) are just and economically reasonable to the corporation's ratepayers;

(B) are nondiscriminatory to alternate energy producers, cogenerators, and small hydro producers; and

(C) will further the policy stated in section 1 of this chapter; and

(2) provide for the availability of supplemental or backup power to ~~alternate energy production facilities, cogeneration facilities, or small hydro~~ **eligible** facilities on a nondiscriminatory basis and at just and reasonable rates.

(b) Upon application by the owner or operator of any ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility or any interested party, the commission shall establish for the affected utility just and economically reasonable rates for electricity purchased under subsection (a)(1). The rates shall be established at levels sufficient to stimulate the development of ~~alternate energy production, cogeneration, and small hydro~~ **eligible** facilities in Indiana, and to encourage the continuation of existing capacity from those facilities.

(c) The commission shall base the rates for new facilities or new capacity from existing facilities on the following factors:

(1) The estimated capital cost of the next generating plant, including related transmission facilities, to be placed in service by the utility.

(2) The term of the contract between the utility and the seller.

(3) A levelized annual carrying charge based upon the term of the contract and determined in a manner consistent with both the methods and the current interest or return requirements associated with the utility's new construction program.

(4) The utility's annual energy costs, including current fuel costs, related operation and maintenance costs, and any other energy-related costs considered appropriate by the commission.

~~Until July 1, 1986, the rate for a new facility may not exceed eight cents ($.08) per kilowatt hour.~~

(d) The commission shall base the rates for existing facilities on the factors listed in subsection (c). However, the commission shall also consider the original cost less depreciation of existing facilities and may establish a rate for existing facilities that is less than the rate established for new facilities.

(e) In the case of a utility that purchases all or substantially all of its electricity requirements, the rates established under this section must be equal to the current cost to the utility of similar types and quantities of electrical service.

(f) In lieu of the other procedures provided by this section, a utility and an owner or operator of an ~~alternate energy production facility,~~

~~cogeneration facility, or small hydro~~ **eligible** facility may enter into a long term contract in accordance with subsection (a) and may agree to rates for purchase and sale transactions. A contract entered into under this subsection must be filed with the commission in the manner provided by IC 8-1-2-42.

(g) This section does not require an electric utility or steam utility to:

(1) construct any additional facilities unless those facilities are paid for by the owner or operator of the affected ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility; **or**

(2) distribute, transmit, deliver, or wheel electricity from a private generation project.

(h) The commission shall do the following not later than November 1, 2018:

(1) Review the rates charged by electric utilities under subsections (a)(2) and (e).

(2) Identify the extent to which the rates offered by electric utilities under subsections (a)(2) and (e):

(A) are cost based;

(B) are nondiscriminatory; and

(C) do not result in the subsidization of costs within or among customer classes.

(3) Report the commission's findings under subdivisions (1) and (2) to the interim study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

This subsection expires November 2, 2018.

SECTION 4. IC 8-1-8.5-7, AS AMENDED BY P.L.168-2013, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 7. The certification requirements of this chapter do not apply to ~~persons who:~~ **a person that:**

(1) ~~construct~~ **constructs** an electric generating facility primarily for that person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation;

(2) ~~construct~~ **constructs** an ~~alternate energy production facility, cogeneration facility, or a small hydro~~ **eligible** facility that complies with the limitations set forth in IC 8-1-2.4-5; ~~or~~

(3) ~~are~~ **is** a municipal utility, including a joint agency created under IC 8-1-2.2-8, and ~~install~~ **installs** an electric generating facility that has a capacity of ten thousand (10,000) kilowatts or less; **or**

(4) is a public utility and:

(A) installs a clean energy project described in IC 8-1-8.8-2(2) that is approved by the commission and that:

(i) uses a clean energy resource described in IC 8-1-37-4(a)(1) or IC 8-1-37-4(a)(2); and

(ii) has a nameplate capacity of not more than fifty thousand (50,000) kilowatts; and

(B) uses a contractor that:

(i) is subject to Indiana unemployment taxes; and

(ii) is selected by the public utility through bids solicited in a competitive procurement process;

in the engineering, procurement, or construction of the project.

However, ~~those persons~~ **a person described in this section** shall, nevertheless, be required to report to the commission the proposed construction of such a facility before beginning construction of the facility.

SECTION 5. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of energy on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency purposes.

(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k))

operating under a net metering tariff.

Sec. 4. As used in this chapter, "electricity supplier" has the meaning set forth in IC 8-1-2.3-2(b).

Sec. 5. As used in this chapter, "marginal price of electricity" means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 6. As used in this chapter, "net metering tariff" means a tariff that:

(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and

(2) is in effect on January 1, 2017.

Sec. 7. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 8. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 9. Subject to section 10 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one percent (1%) of the most recent summer peak load of the electricity supplier. If, at any point in a calendar year, an electricity supplier reasonably anticipates that the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one percent (1%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 12 of this chapter, petition the commission for approval of a rate for the purchase of distributed generation.

Sec. 10. (a) Before July 1, 2027:

(1) an electricity supplier may not seek to change the terms and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) After June 30, 2027:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2027, expire and are

unenforceable.

Sec. 11. An electricity supplier shall purchase the distributed generation produced by a customer at a rate approved by the commission under section 13 of this chapter. Amounts paid by an electricity supplier for distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 12. Not later than March 1, 2026, an electricity supplier shall file with the commission a petition requesting a rate for the purchase of distributed generation by the electricity supplier. After an electricity supplier's initial rate for distributed generation is approved by the commission under section 13 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate for distributed generation in accordance with the methodology set forth in section 13 of this chapter.

Sec. 13. The commission shall review a petition filed under section 12 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be paid by the electricity supplier for distributed generation. The rate to be paid by the electricity supplier must equal one (1) of the following, as submitted by the electricity supplier in the electricity supplier's petition, and as approved by the commission:

(1) The average marginal price of electricity paid by the electricity supplier during the most recent calendar year.

(2) The direct costs of generating or purchasing electricity that the electricity supplier will avoid by purchasing distributed generation.

Sec. 14. An electricity supplier shall compensate a customer from whom the electricity supplier purchases distributed generation (at the rate approved by the commission under section 13 of this chapter) through either of the following means:

(1) A credit on the customer's monthly bill.

(2) A direct payment to the customer for the amount owed.

If the electricity supplier elects to provide a credit on the customer's monthly bill as described in subdivision (1), any credit that exceeds the amount that is billed to the customer in accordance with section 15 of this chapter shall be carried forward and credited against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 15. To ensure that a customer is properly charged for the

costs of the electricity delivery system through which an electricity supplier provides retail electric service to the customer:

(1) all distributed generation produced by the customer shall be purchased by the electricity supplier at the rate approved by the commission under section 13 of this chapter; and

(2) all electricity consumed by the customer at the premises shall be considered electricity supplied by the electricity supplier and is subject to the applicable retail rate schedule.

Sec. 16. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the purchase of distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 17. (a) Subject to subsection (b) and sections 9 and 10 of this chapter, after June 30, 2017, the commission's rules and standards:

(1) concerning interconnection; and

(2) set forth in 170 IAC 4-4.2 (concerning net metering) and 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 18. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.
(4) The National Electrical Safety Code.
(5) The Institute of Electrical and Electronics Engineers.
(6) Underwriters Laboratories.
(7) The Federal Energy Regulatory Commission.
(8) Local regulatory authorities.

Sec. 19. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.
(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.
(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.
(4) The right to know the value of all federal, state, or local tax credits, electricity supplier rate credits, or other incentives or rebates that the customer may receive.
(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to an electricity supplier.
(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.
(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an

emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.

ATTACHMENT BDI-3

February 21, 2017

SENATE BILL No. 309

DIGEST OF SB 309 (Updated February 16, 2017 1:22 pm - DI 101)

Citations Affected: IC 8-1.

Synopsis: Distributed generation. Requires: (1) the utility regulatory commission (IURC) to post a summary of the results of the IURC's most recent periodic review of the basic rates and charges of an electricity supplier on the IURC's Internet web site; and (2) the electricity supplier subject to the review to provide a link on the electricity supplier's Internet web site to the IURC's posted summary. Amends the statute concerning alternate energy production, cogeneration, and small hydro facilities to: (1) include in the definition of a "private generation project" certain cogeneration facilities that: (A) are located on the same site as the host operation; or (B) are located on or contiguous to the site of the host operation and are directly integrated with the host operation; (2) define an "eligible facility" for purposes of the statute; and (3) include organic waste biomass facilities within the definition of an "alternative energy production facility". Specifies that an electric utility or a steam utility is not required to distribute, transmit, deliver, or wheel electricity from a private generation project. Requires the IURC to: (1) review the rates charged by electric utilities for backup power to eligible facilities and for purchases of power from eligible facilities; (2) identify the extent to which the rates meet specified criteria; and (3) report the IURC's findings to the interim study committee on energy, utilities, and telecommunications; not later than November 1, 2018.
(Continued next page)

Effective: July 1, 2017.

Hershman

January 9, 2017, read first time and referred to Committee on Utilities.
February 20, 2017, amended, reported favorably — Do Pass.

45504-- IndianaDG Exhibit 1 Attachment BDI-3

Provides that before granting a certificate of public convenience and necessity for the construction of an electric facility with a generating capacity of more than 80 megawatts, the utility regulatory commission (IURC) must find that the applicant allowed third parties to submit firm and binding bids for the construction of the proposed facility. Provides that a public utility that: (1) installs a wind, a solar, or an organic waste biomass project with a nameplate capacity of not more than 50,000 kilowatts; and (2) uses for the project a contractor that is: (A) subject to Indiana unemployment taxes; and (B) selected by the public utility through a competitive procurement process; is not required to obtain a certificate of public convenience and necessity for the project from the IURC. Provides that a net metering tariff of an electricity supplier (other than a municipally owned utility or a rural electric membership corporation) must remain available to the electricity supplier's customers until: (1) the aggregate amount of net metering facility nameplate capacity under the tariff equals at least 1.5% of the electricity supplier's most recent summer peak load; or (2) July 1, 2022; whichever occurs earlier. Requires the IURC to amend its net metering rule, and an electricity supplier to amend its net metering tariff, to: (1) increase the limit on the aggregate amount of net metering capacity under the tariff to 1.5% of the electricity supplier's most recent summer peak load; and (2) reserve 40% of the capacity under the tariff for residential customers and 15% of the capacity for customers that install an organic waste biomass facility. Provides that a customer that installs a net metering facility on the customer's premises after June 30, 2017, and before the date on which the net metering tariff of the customer's electricity supplier terminates under the bill, shall continue to be served under the net metering tariff until: (1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility is located; or (2) July 1, 2032; whichever occurs earlier. Provides that a customer that installs a net metering facility on the customer's premises before July 1, 2017, and that is participating in an electricity supplier's net metering tariff on July 1, 2017, shall continue to be served under the terms and conditions of the net metering tariff until: (1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility is located; or (2) July 1, 2047; whichever occurs earlier. Provides that an electricity supplier shall procure only the excess distributed generation produced by a customer. Provides that the rate for excess distributed generation procured by an electricity supplier must equal the product of: (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by (2) 1.25. Provides that: (1) an electricity supplier may request that the rate for excess distributed generation be set by the IURC at a rate equal to the average marginal price of electricity during the most recent calendar year; and (2) the IURC shall approve such a rate if the IURC determines that the breakeven cost of distributed generation effectively competes with the cost of generation produced by the electricity supplier. Provides that an electricity supplier shall compensate a customer for excess distributed generation through a credit on the customer's monthly bill. Provides that the IURC may approve an electricity supplier's request to recover energy delivery costs from customers producing distributed generation if the IURC finds that the request: (1) is reasonable; and (2) does not result in a double recovery of energy delivery costs from customers producing distributed generation.

February 21, 2017

First Regular Session 120th General Assembly (2017)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in **this style type**, and deletions will appear in ~~this style type.~~

Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in **this style type**. Also, the word **NEW** will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.

Conflict reconciliation: Text in a statute in *this style type* or ~~*this style type*~~ reconciles conflicts between statutes enacted by the 2016 Regular Session of the General Assembly.

SENATE BILL No. 309

A BILL FOR AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 8-1-2-42.5 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 42.5. **(a)** The commission shall by rule or order, consistent with the resources of the commission and the office of the utility consumer counselor, require that the basic rates and charges of all public, municipally owned, and cooperatively owned utilities (except those utilities described in ~~IC 8-1-2-61.5)~~ **section 61.5 of this chapter)** are subject to a regularly scheduled periodic review and revision by the commission. However, the commission shall conduct the periodic review at least once every four (4) years and may not authorize a filing for an increase in basic rates and charges more frequently than is permitted by operation of section 42(a) of this chapter.

(b) The commission shall make the results of the commission's most recent periodic review of the basic rates and charges of an electricity supplier (as defined in IC 8-1-2.3-2(b)) available for

public inspection by posting a summary of the results on the commission's Internet web site. If an electricity supplier whose basic rates and charges are reviewed under this section maintains a publicly accessible Internet web site, the electricity supplier shall provide a link on the electricity supplier's Internet web site to the summary of the results posted on the commission's Internet web site.

SECTION 2. IC 8-1-2.4-2, AS AMENDED BY P.L.222-2014, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 2. (a) The definitions in this section apply throughout this chapter.

(b) "Alternate energy production facility" means:

(1) ~~a~~ **any** solar, wind turbine, waste management, resource recovery, refuse-derived fuel, **organic waste biomass,** or wood burning facility;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(c) "Cogeneration facility" means:

(1) a facility that:

(A) simultaneously generates electricity and useful thermal energy; and

(B) meets the energy efficiency standards established for cogeneration facilities by the Federal Energy Regulatory Commission under 16 U.S.C. 824a-3;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(d) "Electric utility" means any public utility or municipally owned utility that owns, operates, or manages any electric plant.

(e) "Small hydro facility" means:

(1) a hydroelectric facility at a dam;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct

the energy produced by the facility to users located at or near the project site.

(f) "Steam utility" means any public utility or municipally owned utility that owns, operates, or manages a steam plant.

(g) "Private generation project" means a cogeneration facility that has an electric generating capacity of eighty (80) megawatts or more and is:

(1) primarily used by its owner for the owner's industrial, commercial, heating, or cooling purposes; or

(2) a qualifying facility for purposes of the Public Utility Regulatory Policies Act of 1978 that ~~(A) is in existence on July 1, 2014; and (B)~~ produces electricity and useful thermal energy that is primarily used by a **single** host operation for industrial, commercial, heating, or cooling purposes **and is:**

(A) located on the same site as the host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

(h) "Eligible facility" means an alternate energy production facility, a cogeneration facility, or a small hydro facility that is:

(1) described in section 5 of this chapter; and

(2) either:

(A) located on the same site as a single host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

The term includes the consuming elements of a host operation using the associated energy output for industrial, commercial, heating, or cooling purposes.

SECTION 3. IC 8-1-2.4-4 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 4. (a) Subject to section 5 of this chapter, the commission shall require electric utilities and steam utilities to enter into long term contracts to:

(1) purchase or wheel electricity or useful thermal energy from ~~alternate energy production facilities, cogeneration facilities, or small hydro~~ **eligible** facilities located in the utility's service territory, under the terms and conditions that the commission finds:

(A) are just and economically reasonable to the corporation's ratepayers;

(B) are nondiscriminatory to alternate energy producers, cogenerators, and small hydro producers; and

(C) will further the policy stated in section 1 of this chapter; and

(2) provide for the availability of supplemental or backup power to ~~alternate energy production facilities, cogeneration facilities, or small hydro~~ **eligible** facilities on a nondiscriminatory basis and at just and reasonable rates.

(b) Upon application by the owner or operator of any ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility or any interested party, the commission shall establish for the affected utility just and economically reasonable rates for electricity purchased under subsection (a)(1). The rates shall be established at levels sufficient to stimulate the development of ~~alternate energy production, cogeneration, and small hydro~~ **eligible** facilities in Indiana, and to encourage the continuation of existing capacity from those facilities.

(c) The commission shall base the rates for new facilities or new capacity from existing facilities on the following factors:

(1) The estimated capital cost of the next generating plant, including related transmission facilities, to be placed in service by the utility.

(2) The term of the contract between the utility and the seller.

(3) A levelized annual carrying charge based upon the term of the contract and determined in a manner consistent with both the methods and the current interest or return requirements associated with the utility's new construction program.

(4) The utility's annual energy costs, including current fuel costs, related operation and maintenance costs, and any other energy-related costs considered appropriate by the commission.

~~Until July 1, 1986, the rate for a new facility may not exceed eight cents ($.08) per kilowatt hour.~~

(d) The commission shall base the rates for existing facilities on the factors listed in subsection (c). However, the commission shall also consider the original cost less depreciation of existing facilities and may establish a rate for existing facilities that is less than the rate established for new facilities.

(e) In the case of a utility that purchases all or substantially all of its electricity requirements, the rates established under this section must be equal to the current cost to the utility of similar types and quantities of electrical service.

(f) In lieu of the other procedures provided by this section, a utility and an owner or operator of an ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility may enter into a long term contract in accordance with subsection (a) and may agree to rates for purchase and sale transactions. A contract entered into under this subsection must be filed with the commission in the manner provided by IC 8-1-2-42.

(g) This section does not require an electric utility or steam utility to:

(1) construct any additional facilities unless those facilities are paid for by the owner or operator of the affected ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility; **or**

(2) distribute, transmit, deliver, or wheel electricity from a private generation project.

(h) The commission shall do the following not later than November 1, 2018:

(1) Review the rates charged by electric utilities under subsection (a)(2) and section 6(e) of this chapter.

(2) Identify the extent to which the rates offered by electric utilities under subsection (a)(2) and section 6(e) of this chapter:

(A) are cost based;

(B) are nondiscriminatory; and

(C) do not result in the subsidization of costs within or among customer classes.

(3) Report the commission's findings under subdivisions (1) and (2) to the interim study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

This subsection expires November 2, 2018.

SECTION 4. IC 8-1-8.5-5, AS AMENDED BY P.L.246-2015, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 5. (a) As a condition for receiving the certificate required under section 2 of this chapter, the applicant shall file an estimate of construction, purchase, or lease costs in such detail as the commission may require.

(b) The commission shall hold a public hearing on each such application. The commission may consider all relevant information related to construction, purchase, or lease costs. A certificate shall be granted only if the commission has:

(1) made a finding as to the best estimate of construction,

purchase, or lease costs based on the evidence of record;

(2) made a finding that either:

(A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or

(B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). However, if the commission has developed, in whole or in part, an analysis for the expansion of electric generating capacity and the applicant has filed and the commission has approved under subsection (d) a utility specific proposal submitted under section 3(e)(1) of this chapter, the commission shall make a finding under this clause that the construction, purchase, or lease is consistent with the commission's analysis, to the extent developed, and that the construction, purchase, or lease is consistent with the applicant's plan under section 3(e)(1) of this chapter, to the extent the plan was approved by the commission;

(3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility;

(4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal; and

(5) made the findings under subsection (e), if applicable.

(c) If:

(1) the commission grants a certificate under this chapter based upon a finding under subsection (b)(2) that the construction, purchase, or lease of a generating facility is consistent with the commission's analysis for the expansion of electric generating capacity; and

(2) a court finally determines that the commission analysis is invalid;

the certificate shall remain in full force and effect if the certificate was also based upon a finding under subsection (b)(2) that the construction, purchase, or lease of the facility was consistent with a utility specific plan submitted under section 3(e)(1) of this chapter and approved under subsection (d).

(d) The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

(e) This subsection applies if an applicant proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. Before granting a certificate to the applicant, the commission:

(1) must, in addition to the findings required under subsection (b), find that:

(A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) the applicant allowed third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:

(A) Reliability.

(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

SECTION 5. IC 8-1-8.5-7, AS AMENDED BY P.L.168-2013, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 7. The certification requirements of this chapter do not apply to ~~persons who:~~ **a person that:**

(1) ~~construct~~ **constructs** an electric generating facility primarily for that person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation;

(2) ~~construct~~ **constructs** an ~~alternate energy production facility, cogeneration facility, or a small hydro~~ **eligible** facility that complies with the limitations set forth in IC 8-1-2.4-5; ~~or~~

(3) ~~are~~ **is** a municipal utility, including a joint agency created under IC 8-1-2.2-8, and ~~install~~ **installs** an electric generating facility that has a capacity of ten thousand (10,000) kilowatts or

less; **or**

(4) is a public utility and:

(A) installs a clean energy project described in IC 8-1-8.8-2(2) that is approved by the commission and that:

(i) uses a clean energy resource described in IC 8-1-37-4(a)(1), IC 8-1-37-4(a)(2), or IC 8-1-37-4(a)(5); and

(ii) has a nameplate capacity of not more than fifty thousand (50,000) kilowatts; and

(B) uses a contractor that:

(i) is subject to Indiana unemployment taxes; and

(ii) is selected by the public utility through bids solicited in a competitive procurement process;

in the engineering, procurement, or construction of the project.

However, ~~those~~ ~~persons~~ **a person described in this section** shall, nevertheless, be required to report to the commission the proposed construction of such a facility before beginning construction of the facility.

SECTION 6. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of electricity on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency

purposes.
(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff.

Sec. 4. (a) As used in this chapter, "electricity supplier" means a public utility (as defined in IC 8-1-2-1) that furnishes retail electric service to customers in Indiana.

(b) The term does not include a utility that is:
(1) a municipally owned utility (as defined in IC 8-1-2-1(h));
(2) a corporation organized under IC 8-1-13; or
(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

Sec. 5. As used in this chapter, "excess distributed generation" means the difference between:
(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and
(2) the electricity that is supplied back to the electricity supplier by the customer.

Sec. 6. As used in this chapter, "marginal price of electricity" means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 7. As used in this chapter, "net metering tariff" means a tariff that:
(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and
(2) is in effect on January 1, 2017.

Sec. 8. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 9. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:
(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) July 1, 2022.

Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 11. (a) Except as provided in sections 12 and 21(b) of this chapter, before July 1, 2047:

(1) an electricity supplier may not seek to change the terms and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) Except as provided in sections 13 and 14 of this chapter, after June 30, 2022:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2022, expire and are unenforceable.

Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:

(1) Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:

(A) forty percent (40%) of the capacity for participation by residential customers; and

(B) fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

(b) In amending 170 IAC 4-4.2-4, as required by subsection (a), the commission may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an

emergency rule adopted by the commission under this section and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:

(1) after June 30, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2032;

whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before July 1, 2017.

(b) A customer that is participating in an electricity supplier's net metering tariff on July 1, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2047;

whichever occurs earlier.

Sec. 15. An electricity supplier shall procure the excess distributed generation produced by a customer at a rate approved by the commission under section 17 of this chapter. Amounts credited to a customer by an electricity supplier for excess distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess

distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Sec. 17. (a) Subject to subsection (b), the commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:

(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by

(2) one and twenty-five hundredths (1.25).

(b) In a petition filed under section 16 of this chapter, an electricity supplier may request that the rate to be credited to a customer for excess distributed generation be set by the commission at a rate equal to the average marginal price of electricity during the most recent calendar year. The commission shall approve a rate requested under this subsection if the commission determines that the break even cost of excess distributed generation effectively competes with the cost of generation produced by the electricity supplier.

Sec. 18. An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 19. (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:

(1) provides retail electric service to those customers; and

(2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery

submitted by an electricity supplier under subsection (a) if the commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

Sec. 20. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the procurement of excess distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 21. (a) Subject to subsection (b) and sections 10 and 11 of this chapter, after June 30, 2017, the commission's rules and standards set forth in:

(1) 170 IAC 4-4.2 (concerning net metering); and

(2) 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 22. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.

(4) The National Electrical Safety Code.

(5) The Institute of Electrical and Electronics Engineers.

(6) Underwriters Laboratories.

(7) The Federal Energy Regulatory Commission.

(8) Local regulatory authorities.

Sec. 23. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.

(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.

(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.

(4) The right to know the value of all federal, state, or local tax credits or other incentives or rebates that the customer may receive.

(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to a public utility (as defined in IC 8-1-2-1).

(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.

(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation equipment to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires

on the date on which a rule that supersedes the emergency rule is adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.

COMMITTEE REPORT

Madam President: The Senate Committee on Utilities, to which was referred Senate Bill No. 309, has had the same under consideration and begs leave to report the same back to the Senate with the recommendation that said bill be AMENDED as follows:

Page 2, line 2, delete "An" and insert "**If an**".

Page 2, line 3, after "section" insert "**maintains a publicly accessible Internet web site, the electricity supplier**".

Page 2, line 11, strike "a" and insert "**any**".

Page 2, line 12, after "fuel," insert "**organic waste biomass,**".

Page 5, line 17, delete "subsections (a)(2) and (e)." and insert "**subsection (a)(2) and section 6(e) of this chapter.**".

Page 5, line 19, delete "subsections (a)(2) and (e):" and insert "**subsection (a)(2) and section 6(e) of this chapter:**".

Page 5, between lines 27 and 28, begin a new paragraph and insert:

"SECTION 4. IC 8-1-8.5-5, AS AMENDED BY P.L.246-2015, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 5. (a) As a condition for receiving the certificate required under section 2 of this chapter, the applicant shall file an estimate of construction, purchase, or lease costs in such detail as the commission may require.

(b) The commission shall hold a public hearing on each such application. The commission may consider all relevant information related to construction, purchase, or lease costs. A certificate shall be granted only if the commission has:

(1) made a finding as to the best estimate of construction, purchase, or lease costs based on the evidence of record;

(2) made a finding that either:

(A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or

(B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). However, if the commission has developed, in whole or in part, an analysis for the expansion of electric generating capacity and the applicant has filed and the commission has approved under subsection (d) a utility specific proposal submitted under section 3(e)(1) of this chapter, the commission shall make a finding under this clause that the construction, purchase, or lease is consistent

with the commission's analysis, to the extent developed, and that the construction, purchase, or lease is consistent with the applicant's plan under section 3(e)(1) of this chapter, to the extent the plan was approved by the commission;

(3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility;

(4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal; and

(5) made the findings under subsection (e), if applicable.

(c) If:

(1) the commission grants a certificate under this chapter based upon a finding under subsection (b)(2) that the construction, purchase, or lease of a generating facility is consistent with the commission's analysis for the expansion of electric generating capacity; and

(2) a court finally determines that the commission analysis is invalid;

the certificate shall remain in full force and effect if the certificate was also based upon a finding under subsection (b)(2) that the construction, purchase, or lease of the facility was consistent with a utility specific plan submitted under section 3(e)(1) of this chapter and approved under subsection (d).

(d) The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

(e) This subsection applies if an applicant proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. Before granting a certificate to the applicant, the commission:

(1) must, in addition to the findings required under subsection (b), find that:

(A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) the applicant allowed third parties to submit firm and binding bids for the construction of the proposed facility

on behalf of the applicant that met all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:

(A) Reliability.

(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.".

Page 6, line 6, delete "IC 8-1-37-4(a)(1) or IC 8-1-37-4(a)(2);" and insert "**IC 8-1-37-4(a)(1), IC 8-1-37-4(a)(2), or IC 8-1-37-4(a)(5);**".

Page 6, delete lines 19 through 42, begin a new paragraph and insert:

"SECTION 6. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of electricity on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency purposes.

(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff.

Sec. 4. (a) As used in this chapter, "electricity supplier" means a public utility (as defined in IC 8-1-2-1) that furnishes retail electric service to customers in Indiana.

(b) The term does not include a utility that is:

(1) a municipally owned utility (as defined in IC 8-1-2-1(h));

(2) a corporation organized under IC 8-1-13; or

(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

Sec. 5. As used in this chapter, "excess distributed generation" means the difference between:

(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and

(2) the electricity that is supplied back to the electricity supplier by the customer.

Sec. 6. As used in this chapter, "marginal price of electricity" means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 7. As used in this chapter, "net metering tariff" means a tariff that:

(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and

(2) is in effect on January 1, 2017.

Sec. 8. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 9. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) July 1, 2022.

Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate

amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 11. (a) Except as provided in sections 12 and 21(b) of this chapter, before July 1, 2047:

(1) an electricity supplier may not seek to change the terms and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) Except as provided in sections 13 and 14 of this chapter, after June 30, 2022:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2022, expire and are unenforceable.

Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:

(1) Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:

(A) forty percent (40%) of the capacity for participation by residential customers; and

(B) fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

(b) In amending 170 IAC 4-4.2-4, as required by subsection (a), the commission may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this section and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the

commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:

(1) after June 30, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2032;

whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before July 1, 2017.

(b) A customer that is participating in an electricity supplier's net metering tariff on July 1, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2047;

whichever occurs earlier.

Sec. 15. An electricity supplier shall procure the excess distributed generation produced by a customer at a rate approved by the commission under section 17 of this chapter. Amounts credited to a customer by an electricity supplier for excess distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate

for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Sec. 17. (a) Subject to subsection (b), the commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:

(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by

(2) one and twenty-five hundredths (1.25).

(b) In a petition filed under section 16 of this chapter, an electricity supplier may request that the rate to be credited to a customer for excess distributed generation be set by the commission at a rate equal to the average marginal price of electricity during the most recent calendar year. The commission shall approve a rate requested under this subsection if the commission determines that the break even cost of excess distributed generation effectively competes with the cost of generation produced by the electricity supplier.

Sec. 18. An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 19. (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:

(1) provides retail electric service to those customers; and

(2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery submitted by an electricity supplier under subsection (a) if the commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

Sec. 20. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the procurement of excess distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 21. (a) Subject to subsection (b) and sections 10 and 11 of this chapter, after June 30, 2017, the commission's rules and standards set forth in:

(1) 170 IAC 4-4.2 (concerning net metering); and

(2) 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 22. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.

(4) The National Electrical Safety Code.

(5) The Institute of Electrical and Electronics Engineers.

(6) Underwriters Laboratories.

(7) The Federal Energy Regulatory Commission.

(8) Local regulatory authorities.

Sec. 23. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.

(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.

(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.

(4) The right to know the value of all federal, state, or local tax credits or other incentives or rebates that the customer may receive.

(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to a public utility (as defined in IC 8-1-2-1).

(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.

(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation equipment to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.".

Delete pages 7 through 11.
Renumber all SECTIONS consecutively.

and when so amended that said bill do pass.

(Reference is to SB 309 as introduced.)

MERRITT, Chairperson

Committee Vote: Yeas 8, Nays 2.

ATTACHMENT BDI-4

Reprinted
February 24, 2017

SENATE BILL No. 309

DIGEST OF SB 309 (Updated February 23, 2017 3:25 pm - DI 101)

Citations Affected: IC 8-1.

Synopsis: Distributed generation. Requires: (1) the utility regulatory commission (IURC) to post a summary of the results of the IURC's most recent periodic review of the basic rates and charges of an electricity supplier on the IURC's Internet web site; and (2) the electricity supplier subject to the review to provide a link on the electricity supplier's Internet web site to the IURC's posted summary. Amends the statute concerning alternate energy production, cogeneration, and small hydro facilities to: (1) include in the definition of a "private generation project" certain cogeneration facilities that: (A) are located on the same site as the host operation; or (B) are located on or contiguous to the site of the host operation and are directly integrated with the host operation; (2) define an "eligible facility" for purposes of the statute; and (3) include organic waste biomass facilities within the definition of an "alternative energy production facility".
(Continued next page)

Effective: July 1, 2017.

Hershman

January 9, 2017, read first time and referred to Committee on Utilities.
February 20, 2017, amended, reported favorably — Do Pass.
February 23, 2017, read second time, amended, ordered engrossed.

45504-- IndianaDG Exhibit 1 Attachment BDI-4

Specifies that an electric utility or a steam utility is not required to distribute, transmit, deliver, or wheel electricity from a private generation project. Requires the IURC to: (1) review the rates charged by electric utilities for backup power to eligible facilities and for purchases of power from eligible facilities; (2) identify the extent to which the rates meet specified criteria; and (3) report the IURC's findings to the interim study committee on energy, utilities, and telecommunications; not later than November 1, 2018. Provides that before granting a certificate of public convenience and necessity for the construction of an electric facility with a generating capacity of more than 80 megawatts, the utility regulatory commission (IURC) must find that the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility. Provides that a public utility that: (1) installs a wind, a solar, or an organic waste biomass project with a nameplate capacity of not more than 50,000 kilowatts; and (2) uses for the project a contractor that is: (A) subject to Indiana unemployment taxes; and (B) selected by the public utility through a competitive procurement process; is not required to obtain a certificate of public convenience and necessity for the project from the IURC. Provides that a net metering tariff of an electricity supplier (other than a municipally owned utility or a rural electric membership corporation) must remain available to the electricity supplier's customers until: (1) the aggregate amount of net metering facility nameplate capacity under the tariff equals at least 1.5% of the electricity supplier's most recent summer peak load; or (2) July 1, 2022; whichever occurs earlier. Requires the IURC to amend its net metering rule, and an electricity supplier to amend its net metering tariff, to: (1) increase the limit on the aggregate amount of net metering capacity under the tariff to 1.5% of the electricity supplier's most recent summer peak load; and (2) reserve 40% of the capacity under the tariff for residential customers and 15% of the capacity for customers that install an organic waste biomass facility. Provides that a customer that installs a net metering facility on the customer's premises after June 30, 2017, and before the date on which the net metering tariff of the customer's electricity supplier terminates under the bill, shall continue to be served under the net metering tariff until: (1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility is located; or (2) July 1, 2032; whichever occurs earlier. Provides that a customer that installs a net metering facility on the customer's premises before July 1, 2017, and that is participating in an electricity supplier's net metering tariff on July 1, 2017, shall continue to be served under the terms and conditions of the net metering tariff until: (1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility is located; or (2) July 1, 2047; whichever occurs earlier. Provides that an electricity supplier shall procure only the excess distributed generation produced by a customer. Provides that the rate for excess distributed generation procured by an electricity supplier must equal the product of: (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by (2) 1.25. Provides that: (1) an electricity supplier may request that the rate for excess distributed generation be set by the IURC at a rate equal to the average marginal price of electricity during the most recent calendar year; and (2) the IURC shall approve such a rate if the IURC determines that the breakeven cost of distributed generation effectively competes with the cost of generation produced by the electricity supplier. Provides that an electricity supplier shall compensate a customer for excess distributed generation through a credit on the customer's monthly bill. Provides that the IURC may approve an electricity supplier's request to recover energy delivery costs from customers producing distributed generation if the IURC finds that the request: (1) is reasonable; and (2) does not result in a double recovery of energy delivery costs from customers producing distributed generation.

Reprinted
February 24, 2017

First Regular Session 120th General Assembly (2017)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in **this style type**, and deletions will appear in ~~this style type.~~

Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in **this style type**. Also, the word **NEW** will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.

Conflict reconciliation: Text in a statute in *this style type* or ~~*this style type*~~ reconciles conflicts between statutes enacted by the 2016 Regular Session of the General Assembly.

SENATE BILL No. 309

A BILL FOR AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 8-1-2-42.5 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 42.5. **(a)** The commission shall by rule or order, consistent with the resources of the commission and the office of the utility consumer counselor, require that the basic rates and charges of all public, municipally owned, and cooperatively owned utilities (except those utilities described in ~~IC 8-1-2-61.5)~~ **section 61.5 of this chapter)** are subject to a regularly scheduled periodic review and revision by the commission. However, the commission shall conduct the periodic review at least once every four (4) years and may not authorize a filing for an increase in basic rates and charges more frequently than is permitted by operation of section 42(a) of this chapter.

(b) The commission shall make the results of the commission's most recent periodic review of the basic rates and charges of an electricity supplier (as defined in IC 8-1-2.3-2(b)) available for

public inspection by posting a summary of the results on the commission's Internet web site. If an electricity supplier whose basic rates and charges are reviewed under this section maintains a publicly accessible Internet web site, the electricity supplier shall provide a link on the electricity supplier's Internet web site to the summary of the results posted on the commission's Internet web site.

SECTION 2. IC 8-1-2.4-2, AS AMENDED BY P.L.222-2014, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 2. (a) The definitions in this section apply throughout this chapter.

(b) "Alternate energy production facility" means:

(1) ~~a~~ **any** solar, wind turbine, waste management, resource recovery, refuse-derived fuel, **organic waste biomass,** or wood burning facility;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(c) "Cogeneration facility" means:

(1) a facility that:

(A) simultaneously generates electricity and useful thermal energy; and

(B) meets the energy efficiency standards established for cogeneration facilities by the Federal Energy Regulatory Commission under 16 U.S.C. 824a-3;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(d) "Electric utility" means any public utility or municipally owned utility that owns, operates, or manages any electric plant.

(e) "Small hydro facility" means:

(1) a hydroelectric facility at a dam;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct

the energy produced by the facility to users located at or near the project site.

(f) "Steam utility" means any public utility or municipally owned utility that owns, operates, or manages a steam plant.

(g) "Private generation project" means a cogeneration facility that has an electric generating capacity of eighty (80) megawatts or more and is:

(1) primarily used by its owner for the owner's industrial, commercial, heating, or cooling purposes; or

(2) a qualifying facility for purposes of the Public Utility Regulatory Policies Act of 1978 that ~~(A) is in existence on July 1, 2014; and (B)~~ produces electricity and useful thermal energy that is primarily used by a **single** host operation for industrial, commercial, heating, or cooling purposes **and is:**

(A) located on the same site as the host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

(h) "Eligible facility" means an alternate energy production facility, a cogeneration facility, or a small hydro facility that is:

(1) described in section 5 of this chapter; and

(2) either:

(A) located on the same site as a single host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

The term includes the consuming elements of a host operation using the associated energy output for industrial, commercial, heating, or cooling purposes.

SECTION 3. IC 8-1-2.4-4 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 4. (a) Subject to section 5 of this chapter, the commission shall require electric utilities and steam utilities to enter into long term contracts to:

(1) purchase or wheel electricity or useful thermal energy from ~~alternate energy production facilities, cogeneration facilities, or small hydro~~ **eligible** facilities located in the utility's service territory, under the terms and conditions that the commission finds:

(A) are just and economically reasonable to the corporation's ratepayers;

(B) are nondiscriminatory to alternate energy producers, cogenerators, and small hydro producers; and

(C) will further the policy stated in section 1 of this chapter; and

(2) provide for the availability of supplemental or backup power to ~~alternate energy production facilities, cogeneration facilities, or small hydro~~ **eligible** facilities on a nondiscriminatory basis and at just and reasonable rates.

(b) Upon application by the owner or operator of any ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility or any interested party, the commission shall establish for the affected utility just and economically reasonable rates for electricity purchased under subsection (a)(1). The rates shall be established at levels sufficient to stimulate the development of ~~alternate energy production, cogeneration, and small hydro~~ **eligible** facilities in Indiana, and to encourage the continuation of existing capacity from those facilities.

(c) The commission shall base the rates for new facilities or new capacity from existing facilities on the following factors:

(1) The estimated capital cost of the next generating plant, including related transmission facilities, to be placed in service by the utility.

(2) The term of the contract between the utility and the seller.

(3) A levelized annual carrying charge based upon the term of the contract and determined in a manner consistent with both the methods and the current interest or return requirements associated with the utility's new construction program.

(4) The utility's annual energy costs, including current fuel costs, related operation and maintenance costs, and any other energy-related costs considered appropriate by the commission.

~~Until July 1, 1986, the rate for a new facility may not exceed eight cents ($.08) per kilowatt hour.~~

(d) The commission shall base the rates for existing facilities on the factors listed in subsection (c). However, the commission shall also consider the original cost less depreciation of existing facilities and may establish a rate for existing facilities that is less than the rate established for new facilities.

(e) In the case of a utility that purchases all or substantially all of its electricity requirements, the rates established under this section must be equal to the current cost to the utility of similar types and quantities of electrical service.

(f) In lieu of the other procedures provided by this section, a utility and an owner or operator of an ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility may enter into a long term contract in accordance with subsection (a) and may agree to rates for purchase and sale transactions. A contract entered into under this subsection must be filed with the commission in the manner provided by IC 8-1-2-42.

(g) This section does not require an electric utility or steam utility to:

(1) construct any additional facilities unless those facilities are paid for by the owner or operator of the affected ~~alternate energy production facility, cogeneration facility, or small hydro~~ **eligible** facility; **or**

(2) distribute, transmit, deliver, or wheel electricity from a private generation project.

(h) The commission shall do the following not later than November 1, 2018:

(1) Review the rates charged by electric utilities under subsection (a)(2) and section 6(e) of this chapter.

(2) Identify the extent to which the rates offered by electric utilities under subsection (a)(2) and section 6(e) of this chapter:

(A) are cost based;

(B) are nondiscriminatory; and

(C) do not result in the subsidization of costs within or among customer classes.

(3) Report the commission's findings under subdivisions (1) and (2) to the interim study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

This subsection expires November 2, 2018.

SECTION 4. IC 8-1-8.5-5, AS AMENDED BY P.L.246-2015, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 5. (a) As a condition for receiving the certificate required under section 2 of this chapter, the applicant shall file an estimate of construction, purchase, or lease costs in such detail as the commission may require.

(b) The commission shall hold a public hearing on each such application. The commission may consider all relevant information related to construction, purchase, or lease costs. A certificate shall be granted only if the commission has:

(1) made a finding as to the best estimate of construction,

purchase, or lease costs based on the evidence of record;

(2) made a finding that either:

(A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or

(B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). However, if the commission has developed, in whole or in part, an analysis for the expansion of electric generating capacity and the applicant has filed and the commission has approved under subsection (d) a utility specific proposal submitted under section 3(e)(1) of this chapter, the commission shall make a finding under this clause that the construction, purchase, or lease is consistent with the commission's analysis, to the extent developed, and that the construction, purchase, or lease is consistent with the applicant's plan under section 3(e)(1) of this chapter, to the extent the plan was approved by the commission;

(3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility;

(4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal; and

(5) made the findings under subsection (e), if applicable.

(c) If:

(1) the commission grants a certificate under this chapter based upon a finding under subsection (b)(2) that the construction, purchase, or lease of a generating facility is consistent with the commission's analysis for the expansion of electric generating capacity; and

(2) a court finally determines that the commission analysis is invalid;

the certificate shall remain in full force and effect if the certificate was also based upon a finding under subsection (b)(2) that the construction, purchase, or lease of the facility was consistent with a utility specific plan submitted under section 3(e)(1) of this chapter and approved under subsection (d).

(d) The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

(e) This subsection applies if an applicant proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. Before granting a certificate to the applicant, the commission:

(1) must, in addition to the findings required under subsection (b), find that:

(A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:

(A) Reliability.

(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

SECTION 5. IC 8-1-8.5-7, AS AMENDED BY P.L.168-2013, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 7. The certification requirements of this chapter do not apply to ~~persons who:~~ **a person that:**

(1) ~~construct~~ **constructs** an electric generating facility primarily for that person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation;

(2) ~~construct~~ **constructs** an ~~alternate energy production facility, cogeneration facility, or a small hydro~~ **eligible** facility that complies with the limitations set forth in IC 8-1-2.4-5; ~~or~~

(3) ~~are~~ **is** a municipal utility, including a joint agency created under IC 8-1-2.2-8, and ~~install~~ **installs** an electric generating facility that has a capacity of ten thousand (10,000) kilowatts or

less; **or**

(4) is a public utility and:

(A) installs a clean energy project described in IC 8-1-8.8-2(2) that is approved by the commission and that:

(i) uses a clean energy resource described in IC 8-1-37-4(a)(1), IC 8-1-37-4(a)(2), or IC 8-1-37-4(a)(5); and

(ii) has a nameplate capacity of not more than fifty thousand (50,000) kilowatts; and

(B) uses a contractor that:

(i) is subject to Indiana unemployment taxes; and

(ii) is selected by the public utility through bids solicited in a competitive procurement process;

in the engineering, procurement, or construction of the project.

However, ~~those~~ ~~persons~~ **a person described in this section** shall, nevertheless, be required to report to the commission the proposed construction of such a facility before beginning construction of the facility.

SECTION 6. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of electricity on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency

purposes.

(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff.

Sec. 4. (a) As used in this chapter, "electricity supplier" means a public utility (as defined in IC 8-1-2-1) that furnishes retail electric service to customers in Indiana.

(b) The term does not include a utility that is:

(1) a municipally owned utility (as defined in IC 8-1-2-1(h));

(2) a corporation organized under IC 8-1-13; or

(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

Sec. 5. As used in this chapter, "excess distributed generation" means the difference between:

(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and

(2) the electricity that is supplied back to the electricity supplier by the customer.

Sec. 6. As used in this chapter, "marginal price of electricity" means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 7. As used in this chapter, "net metering tariff" means a tariff that:

(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and

(2) is in effect on January 1, 2017.

Sec. 8. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 9. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) July 1, 2022.

Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 11. (a) Except as provided in sections 12 and 21(b) of this chapter, before July 1, 2047:

(1) an electricity supplier may not seek to change the terms and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) Except as provided in sections 13 and 14 of this chapter, after June 30, 2022:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2022, expire and are unenforceable.

Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:

(1) Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:

(A) forty percent (40%) of the capacity for participation by residential customers; and

(B) fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

(b) In amending 170 IAC 4-4.2-4, as required by subsection (a), the commission may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an

emergency rule adopted by the commission under this section and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:

(1) after June 30, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2032;

whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before July 1, 2017.

(b) A customer that is participating in an electricity supplier's net metering tariff on July 1, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2047;

whichever occurs earlier.

Sec. 15. An electricity supplier shall procure the excess distributed generation produced by a customer at a rate approved by the commission under section 17 of this chapter. Amounts credited to a customer by an electricity supplier for excess distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess

distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Sec. 17. (a) Subject to subsection (b), the commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:

(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by

(2) one and twenty-five hundredths (1.25).

(b) In a petition filed under section 16 of this chapter, an electricity supplier may request that the rate to be credited to a customer for excess distributed generation be set by the commission at a rate equal to the average marginal price of electricity during the most recent calendar year. The commission shall approve a rate requested under this subsection if the commission determines that the break even cost of excess distributed generation effectively competes with the cost of generation produced by the electricity supplier.

Sec. 18. An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 19. (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:

(1) provides retail electric service to those customers; and

(2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery

submitted by an electricity supplier under subsection (a) if the commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

Sec. 20. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the procurement of excess distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 21. (a) Subject to subsection (b) and sections 10 and 11 of this chapter, after June 30, 2017, the commission's rules and standards set forth in:

(1) 170 IAC 4-4.2 (concerning net metering); and

(2) 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 22. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.

(4) The National Electrical Safety Code.

(5) The Institute of Electrical and Electronics Engineers.

(6) Underwriters Laboratories.

(7) The Federal Energy Regulatory Commission.

(8) Local regulatory authorities.

Sec. 23. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.

(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.

(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.

(4) The right to know the value of all federal, state, or local tax credits or other incentives or rebates that the customer may receive.

(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to a public utility (as defined in IC 8-1-2-1).

(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.

(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation equipment to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires

on the date on which a rule that supersedes the emergency rule is adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.

COMMITTEE REPORT

Madam President: The Senate Committee on Utilities, to which was referred Senate Bill No. 309, has had the same under consideration and begs leave to report the same back to the Senate with the recommendation that said bill be AMENDED as follows:

Page 2, line 2, delete "An" and insert "**If an**".

Page 2, line 3, after "section" insert "**maintains a publicly accessible Internet web site, the electricity supplier**".

Page 2, line 11, strike "a" and insert "**any**".

Page 2, line 12, after "fuel," insert "**organic waste biomass,**".

Page 5, line 17, delete "subsections (a)(2) and (e)." and insert "**subsection (a)(2) and section 6(e) of this chapter.**".

Page 5, line 19, delete "subsections (a)(2) and (e):" and insert "**subsection (a)(2) and section 6(e) of this chapter:**".

Page 5, between lines 27 and 28, begin a new paragraph and insert:

"SECTION 4. IC 8-1-8.5-5, AS AMENDED BY P.L.246-2015, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 5. (a) As a condition for receiving the certificate required under section 2 of this chapter, the applicant shall file an estimate of construction, purchase, or lease costs in such detail as the commission may require.

(b) The commission shall hold a public hearing on each such application. The commission may consider all relevant information related to construction, purchase, or lease costs. A certificate shall be granted only if the commission has:

(1) made a finding as to the best estimate of construction, purchase, or lease costs based on the evidence of record;

(2) made a finding that either:

(A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or

(B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). However, if the commission has developed, in whole or in part, an analysis for the expansion of electric generating capacity and the applicant has filed and the commission has approved under subsection (d) a utility specific proposal submitted under section 3(e)(1) of this chapter, the commission shall make a finding under this clause that the construction, purchase, or lease is consistent

with the commission's analysis, to the extent developed, and that the construction, purchase, or lease is consistent with the applicant's plan under section 3(e)(1) of this chapter, to the extent the plan was approved by the commission;

(3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility;

(4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal; and

(5) made the findings under subsection (e), if applicable.

(c) If:

(1) the commission grants a certificate under this chapter based upon a finding under subsection (b)(2) that the construction, purchase, or lease of a generating facility is consistent with the commission's analysis for the expansion of electric generating capacity; and

(2) a court finally determines that the commission analysis is invalid;

the certificate shall remain in full force and effect if the certificate was also based upon a finding under subsection (b)(2) that the construction, purchase, or lease of the facility was consistent with a utility specific plan submitted under section 3(e)(1) of this chapter and approved under subsection (d).

(d) The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

(e) This subsection applies if an applicant proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. Before granting a certificate to the applicant, the commission:

(1) must, in addition to the findings required under subsection (b), find that:

(A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) the applicant allowed third parties to submit firm and binding bids for the construction of the proposed facility

on behalf of the applicant that met all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:

(A) Reliability.

(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.".

Page 6, line 6, delete "IC 8-1-37-4(a)(1) or IC 8-1-37-4(a)(2);" and insert "**IC 8-1-37-4(a)(1), IC 8-1-37-4(a)(2), or IC 8-1-37-4(a)(5);**".

Page 6, delete lines 19 through 42, begin a new paragraph and insert:

"SECTION 6. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of electricity on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency purposes.

(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff.

Sec. 4. (a) As used in this chapter, "electricity supplier" means a public utility (as defined in IC 8-1-2-1) that furnishes retail electric service to customers in Indiana.

(b) The term does not include a utility that is:

(1) a municipally owned utility (as defined in IC 8-1-2-1(h));

(2) a corporation organized under IC 8-1-13; or

(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

Sec. 5. As used in this chapter, "excess distributed generation" means the difference between:

(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and

(2) the electricity that is supplied back to the electricity supplier by the customer.

Sec. 6. As used in this chapter, "marginal price of electricity" means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 7. As used in this chapter, "net metering tariff" means a tariff that:

(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and

(2) is in effect on January 1, 2017.

Sec. 8. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 9. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) July 1, 2022.

Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate

amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 11. (a) Except as provided in sections 12 and 21(b) of this chapter, before July 1, 2047:

(1) an electricity supplier may not seek to change the terms and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) Except as provided in sections 13 and 14 of this chapter, after June 30, 2022:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2022, expire and are unenforceable.

Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:

(1) Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:

(A) forty percent (40%) of the capacity for participation by residential customers; and

(B) fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

(b) In amending 170 IAC 4-4.2-4, as required by subsection (a), the commission may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this section and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the

commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:

(1) after June 30, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2032;

whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before July 1, 2017.

(b) A customer that is participating in an electricity supplier's net metering tariff on July 1, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2047;

whichever occurs earlier.

Sec. 15. An electricity supplier shall procure the excess distributed generation produced by a customer at a rate approved by the commission under section 17 of this chapter. Amounts credited to a customer by an electricity supplier for excess distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate

for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Sec. 17. (a) Subject to subsection (b), the commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:

(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by

(2) one and twenty-five hundredths (1.25).

(b) In a petition filed under section 16 of this chapter, an electricity supplier may request that the rate to be credited to a customer for excess distributed generation be set by the commission at a rate equal to the average marginal price of electricity during the most recent calendar year. The commission shall approve a rate requested under this subsection if the commission determines that the break even cost of excess distributed generation effectively competes with the cost of generation produced by the electricity supplier.

Sec. 18. An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 19. (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:

(1) provides retail electric service to those customers; and

(2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery submitted by an electricity supplier under subsection (a) if the commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

Sec. 20. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the procurement of excess distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 21. (a) Subject to subsection (b) and sections 10 and 11 of this chapter, after June 30, 2017, the commission's rules and standards set forth in:

(1) 170 IAC 4-4.2 (concerning net metering); and

(2) 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 22. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.

(4) The National Electrical Safety Code.

(5) The Institute of Electrical and Electronics Engineers.

(6) Underwriters Laboratories.

(7) The Federal Energy Regulatory Commission.

(8) Local regulatory authorities.

Sec. 23. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.

(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.

(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.

(4) The right to know the value of all federal, state, or local tax credits or other incentives or rebates that the customer may receive.

(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to a public utility (as defined in IC 8-1-2-1).

(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.

(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation equipment to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.".

Delete pages 7 through 11.
Renumber all SECTIONS consecutively.

and when so amended that said bill do pass.

(Reference is to SB 309 as introduced.)

MERRITT, Chairperson

Committee Vote: Yeas 8, Nays 2.

SENATE MOTION

Madam President: I move that Senate Bill 309 be amended to read as follows:
Page 7, line 14, after "allowed" insert "**or will allow**".
Page 7, line 16, after "met" insert "**or meet**".

(Reference is to SB 309 as printed February 21, 2017.)

HERSHMAN

ATTACHMENT BDI-5

March 31, 2017

ENGROSSED SENATE BILL No. 309

DIGEST OF SB 309 (Updated March 30, 2017 1:16 pm - DI 101)

Citations Affected: IC 8-1; noncode.

Synopsis: Distributed generation. Requires: (1) the utility regulatory commission (IURC) to post a summary of the results of the IURC's most recent periodic review of the basic rates and charges of an electricity supplier on the IURC's Internet web site; and (2) the electricity supplier subject to the review to provide a link on the electricity supplier's Internet web site to the IURC's posted summary. Amends the statute concerning alternate energy production, cogeneration, and small hydro facilities to: (1) include in the definition of a "private generation project" certain cogeneration facilities that: (A) are located on the same site as the host operation; or (B) are located on or contiguous to the site of the host operation and are directly
(Continued next page)

Effective: July 1, 2017.

Hershman, Merritt

(HOUSE SPONSORS — OBER, SOLIDAY)

January 9, 2017, read first time and referred to Committee on Utilities.
February 20, 2017, amended, reported favorably — Do Pass.
February 23, 2017, read second time, amended, ordered engrossed.
February 24, 2017, engrossed.
February 27, 2017, read third time, passed. Yeas 39, nays 9.

HOUSE ACTION

March 6, 2017, read first time and referred to Committee on Utilities, Energy and Telecommunications.
March 30, 2017, amended, reported — Do Pass.

integrated with the host operation; and (2) include organic waste biomass facilities within the definition of an "alternative energy production facility". Specifies that an electric utility or a steam utility is not required to distribute, transmit, deliver, or wheel electricity from a private generation project. Requires the IURC to: (1) review the rates charged by electric utilities for backup power to eligible facilities and for purchases of power from eligible facilities; (2) identify the extent to which the rates meet specified criteria; and (3) report the IURC's findings to the interim study committee on energy, utilities, and telecommunications; not later than November 1, 2018. Provides that before granting to an electricity supplier that is a public utility a certificate of public convenience and necessity for the construction of an electric facility with a generating capacity of more than 80 megawatts, the utility regulatory commission (IURC) must find that the electricity supplier allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility. Provides that a public utility that: (1) installs a wind, a solar, or an organic waste biomass project with a nameplate capacity of not more than 50,000 kilowatts; and (2) uses for the project a contractor that is: (A) subject to Indiana unemployment taxes; and (B) selected by the public utility through a competitive procurement process; is not required to obtain a certificate of public convenience and necessity for the project from the IURC. Provides that a net metering tariff of an electricity supplier (other than a municipally owned utility or a rural electric membership corporation) must remain available to the electricity supplier's customers until: (1) the aggregate amount of net metering facility nameplate capacity under the tariff equals at least 1.5% of the electricity supplier's most recent summer peak load; or (2) July 1, 2022; whichever occurs earlier. Requires the IURC to amend its net metering rule, and an electricity supplier to amend its net metering tariff, to: (1) increase the limit on the aggregate amount of net metering capacity under the tariff to 1.5% of the electricity supplier's most recent summer peak load; and (2) reserve 40% of the capacity under the tariff for residential customers and 15% of the capacity for customers that install an organic waste biomass facility. Provides that a customer that installs a net metering facility on the customer's premises after December 31, 2017, and before the date on which the net metering tariff of the customer's electricity supplier terminates under the bill, shall continue to be served under the net metering tariff until: (1) the customer removes from the customer's premises or replaces the net metering facility; or (2) July 1, 2032; whichever occurs earlier. Provides that a successor in interest to the premises on which a net metering facility was installed during the applicable period may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier serving the premises until: (1) the net metering facility is removed from the premises or is replaced; or (2) July 1, 2032; whichever occurs earlier. Provides that a customer that installs a net metering facility on the customer's premises before January 1, 2018, and that is participating in an electricity supplier's net metering tariff on December 31, 2017, shall continue to be served under the terms and conditions of the net metering tariff until: (1) the customer removes from the customer's premises or replaces the net metering facility; or (2) July 1, 2047; whichever occurs earlier. Provides that a successor in interest to the premises on which a net metering facility was installed before January 1, 2018, may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier serving the premises until: (1) the net metering facility is removed from the premises or is replaced; or (2) July 1, 2047; whichever occurs earlier. Provides that an electricity supplier shall procure only the excess distributed generation produced by a customer. Provides that the rate for excess distributed generation procured by an electricity supplier must equal

(Continued next page)

45504-- IndianaDG Exhibit 1 Attachment BDI-5

the product of: (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by (2) 1.25. Provides that an electricity supplier shall compensate a customer for excess distributed generation through a credit on the customer's monthly bill. Provides that the IURC may approve an electricity supplier's request to recover energy delivery costs from customers producing distributed generation if the IURC finds that the request: (1) is reasonable; and (2) does not result in a double recovery of energy delivery costs from customers producing distributed generation. Urges the legislative council to assign to the interim study committee on energy, utilities, and telecommunications the topic of self-generation of electricity by school corporations.

March 31, 2017

First Regular Session 120th General Assembly (2017)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in **this style type**, and deletions will appear in ~~this style type.~~
Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in **this style type**. Also, the word **NEW** will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.
Conflict reconciliation: Text in a statute in *this style type* or ~~*this style type*~~ reconciles conflicts between statutes enacted by the 2016 Regular Session of the General Assembly.

ENGROSSED
SENATE BILL No. 309

A BILL FOR AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 8-1-2-42.5 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 42.5. **(a)** The commission shall by rule or order, consistent with the resources of the commission and the office of the utility consumer counselor, require that the basic rates and charges of all public, municipally owned, and cooperatively owned utilities (except those utilities described in ~~IC 8-1-2-61.5)~~ **section 61.5 of this chapter)** are subject to a regularly scheduled periodic review and revision by the commission. However, the commission shall conduct the periodic review at least once every four (4) years and may not authorize a filing for an increase in basic rates and charges more frequently than is permitted by operation of section 42(a) of this chapter.

(b) The commission shall make the results of the commission's most recent periodic review of the basic rates and charges of an electricity supplier (as defined in IC 8-1-2.3-2(b)) available for

public inspection by posting a summary of the results on the commission's Internet web site. If an electricity supplier whose basic rates and charges are reviewed under this section maintains a publicly accessible Internet web site, the electricity supplier shall provide a link on the electricity supplier's Internet web site to the summary of the results posted on the commission's Internet web site.

SECTION 2. IC 8-1-2.4-2, AS AMENDED BY P.L.222-2014, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 2. (a) The definitions in this section apply throughout this chapter.

(b) "Alternate energy production facility" means:

(1) ~~a~~ **any** solar, wind turbine, waste management, resource recovery, refuse-derived fuel, **organic waste biomass,** or wood burning facility;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(c) "Cogeneration facility" means:

(1) a facility that:

(A) simultaneously generates electricity and useful thermal energy; and

(B) meets the energy efficiency standards established for cogeneration facilities by the Federal Energy Regulatory Commission under 16 U.S.C. 824a-3;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(d) "Electric utility" means any public utility or municipally owned utility that owns, operates, or manages any electric plant.

(e) "Small hydro facility" means:

(1) a hydroelectric facility at a dam;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct

the energy produced by the facility to users located at or near the project site.

(f) "Steam utility" means any public utility or municipally owned utility that owns, operates, or manages a steam plant.

(g) "Private generation project" means a cogeneration facility that has an electric generating capacity of eighty (80) megawatts or more and is:

(1) primarily used by its owner for the owner's industrial, commercial, heating, or cooling purposes; or

(2) a qualifying facility for purposes of the Public Utility Regulatory Policies Act of 1978 that ~~(A) is in existence on July 1, 2014; and (B)~~ produces electricity and useful thermal energy that is primarily used by a **single** host operation for industrial, commercial, heating, or cooling purposes **and is:**

(A) located on the same site as the host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

SECTION 3. IC 8-1-2.4-4 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 4. (a) Subject to section 5 of this chapter, the commission shall require electric utilities and steam utilities to enter into long term contracts to:

(1) purchase or wheel electricity or useful thermal energy from alternate energy production facilities, cogeneration facilities, or small hydro facilities located in the utility's service territory, under the terms and conditions that the commission finds:

(A) are just and economically reasonable to the corporation's ratepayers;

(B) are nondiscriminatory to alternate energy producers, cogenerators, and small hydro producers; and

(C) will further the policy stated in section 1 of this chapter; and

(2) provide for the availability of supplemental or backup power to alternate energy production facilities, cogeneration facilities, or small hydro facilities on a nondiscriminatory basis and at just and reasonable rates.

(b) Upon application by the owner or operator of any alternate energy production facility, cogeneration facility, or small hydro facility or any interested party, the commission shall establish for the affected utility just and economically reasonable rates for electricity purchased under subsection (a)(1). The rates shall be established at levels sufficient to stimulate the development of alternate energy production, cogeneration, and small hydro facilities in Indiana, and to encourage the continuation of existing capacity from those facilities.

(c) The commission shall base the rates for new facilities or new capacity from existing facilities on the following factors:

(1) The estimated capital cost of the next generating plant, including related transmission facilities, to be placed in service by the utility.

(2) The term of the contract between the utility and the seller.

(3) A levelized annual carrying charge based upon the term of the contract and determined in a manner consistent with both the methods and the current interest or return requirements associated with the utility's new construction program.

(4) The utility's annual energy costs, including current fuel costs, related operation and maintenance costs, and any other energy-related costs considered appropriate by the commission.

~~Until July 1, 1986, the rate for a new facility may not exceed eight cents ($.08) per kilowatt hour.~~

(d) The commission shall base the rates for existing facilities on the factors listed in subsection (c). However, the commission shall also consider the original cost less depreciation of existing facilities and may establish a rate for existing facilities that is less than the rate established for new facilities.

(e) In the case of a utility that purchases all or substantially all of its electricity requirements, the rates established under this section must be equal to the current cost to the utility of similar types and quantities of electrical service.

(f) In lieu of the other procedures provided by this section, a utility and an owner or operator of an alternate energy production facility, cogeneration facility, or small hydro facility may enter into a long term contract in accordance with subsection (a) and may agree to rates for purchase and sale transactions. A contract entered into under this subsection must be filed with the commission in the manner provided by IC 8-1-2-42.

(g) This section does not require an electric utility or steam utility to:

(1) construct any additional facilities unless those facilities are paid for by the owner or operator of the affected alternate energy production facility, cogeneration facility, or small hydro facility; **or**

(2) distribute, transmit, deliver, or wheel electricity from a

private generation project.

(h) The commission shall do the following not later than November 1, 2018:

(1) Review the rates charged by electric utilities under subsection (a)(2) and section 6(e) of this chapter.

(2) Identify the extent to which the rates offered by electric utilities under subsection (a)(2) and section 6(e) of this chapter:

(A) are cost based;

(B) are nondiscriminatory; and

(C) do not result in the subsidization of costs within or among customer classes.

(3) Report the commission's findings under subdivisions (1) and (2) to the interim study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

This subsection expires November 2, 2018.

SECTION 4. IC 8-1-8.5-5, AS AMENDED BY P.L.246-2015, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 5. (a) As a condition for receiving the certificate required under section 2 of this chapter, the applicant shall file an estimate of construction, purchase, or lease costs in such detail as the commission may require.

(b) The commission shall hold a public hearing on each such application. The commission may consider all relevant information related to construction, purchase, or lease costs. A certificate shall be granted only if the commission has:

(1) made a finding as to the best estimate of construction, purchase, or lease costs based on the evidence of record;

(2) made a finding that either:

(A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or

(B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). However, if the commission has developed, in whole or in part, an analysis for the expansion of electric generating capacity and the applicant has filed and the commission has approved under subsection (d) a utility specific proposal submitted under section 3(e)(1) of this chapter, the commission shall make a finding under this clause that the construction, purchase, or lease is consistent

with the commission's analysis, to the extent developed, and that the construction, purchase, or lease is consistent with the applicant's plan under section 3(e)(1) of this chapter, to the extent the plan was approved by the commission;

(3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility;

(4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal; and

(5) made the findings under subsection (e), if applicable.

(c) If:

(1) the commission grants a certificate under this chapter based upon a finding under subsection (b)(2) that the construction, purchase, or lease of a generating facility is consistent with the commission's analysis for the expansion of electric generating capacity; and

(2) a court finally determines that the commission analysis is invalid;

the certificate shall remain in full force and effect if the certificate was also based upon a finding under subsection (b)(2) that the construction, purchase, or lease of the facility was consistent with a utility specific plan submitted under section 3(e)(1) of this chapter and approved under subsection (d).

(d) The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

(e) This subsection applies if an applicant proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. Before granting a certificate to the applicant, the commission:

(1) must, in addition to the findings required under subsection (b), find that:

(A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third

parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:

(A) Reliability.

(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

SECTION 5. IC 8-1-8.5-7, AS AMENDED BY P.L.168-2013, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 7. The certification requirements of this chapter do not apply to ~~persons who:~~ **a person that:**

(1) ~~construct~~ **constructs** an electric generating facility primarily for that person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation;

(2) ~~construct~~ **constructs** an alternate energy production facility, cogeneration facility, or a small hydro facility that complies with the limitations set forth in IC 8-1-2.4-5; ~~or~~

(3) ~~are~~ **is** a municipal utility, including a joint agency created under IC 8-1-2.2-8, and ~~install~~ **installs** an electric generating facility that has a capacity of ten thousand (10,000) kilowatts or less; **or**

(4) is a public utility and:

(A) installs a clean energy project described in IC 8-1-8.8-2(2) that is approved by the commission and that:

(i) uses a clean energy resource described in IC 8-1-37-4(a)(1), IC 8-1-37-4(a)(2), or IC 8-1-37-4(a)(5); and

(ii) has a nameplate capacity of not more than fifty thousand (50,000) kilowatts; and

(B) uses a contractor that:

(i) is subject to Indiana unemployment taxes; and

(ii) is selected by the public utility through bids solicited

in a competitive procurement process;

in the engineering, procurement, or construction of the project.

However, ~~those~~ ~~persons~~ **a person described in this section** shall, nevertheless, be required to report to the commission the proposed construction of such a facility before beginning construction of the facility.

SECTION 6. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of electricity on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency purposes.

(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff.

Sec. 4. (a) As used in this chapter, "electricity supplier" means a public utility (as defined in IC 8-1-2-1) that furnishes retail electric service to customers in Indiana.

(b) The term does not include a utility that is:

(1) a municipally owned utility (as defined in IC 8-1-2-1(h));

(2) a corporation organized under IC 8-1-13; or

(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

Sec. 5. As used in this chapter, "excess distributed generation"

means the difference between:

(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and

(2) the electricity that is supplied back to the electricity supplier by the customer.

Sec. 6. As used in this chapter, "marginal price of electricity" means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 7. As used in this chapter, "net metering tariff" means a tariff that:

(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and

(2) is in effect on January 1, 2017.

Sec. 8. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 9. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) July 1, 2022.

Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 11. (a) Except as provided in sections 12 and 21(b) of this chapter, before July 1, 2047:

(1) an electricity supplier may not seek to change the terms

and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) Except as provided in sections 13 and 14 of this chapter, after June 30, 2022:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2022, expire and are unenforceable.

Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:

(1) Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:

(A) forty percent (40%) of the capacity for participation by residential customers; and

(B) fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

(b) In amending 170 IAC 4-4.2-4, as required by subsection (a), the commission may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this section and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:

(1) after December 31, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's

net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer removes from the customer's premises or replaces the net metering facility (as defined in 170 IAC 4-4.2-1(k)); or

(2) July 1, 2032;

whichever occurs earlier.

(c) A successor in interest to a customer's premises on which a net metering facility (as defined in 170 IAC 4-4.2-1(k)) that was installed during the period described in subsection (a) is located may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier that provides retail electric service at the premises until:

(1) the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is removed from the premises or is replaced; or

(2) July 1, 2032;

whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before January 1, 2018.

(b) A customer that is participating in an electricity supplier's net metering tariff on December 31, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer removes from the customer's premises or replaces the net metering facility (as defined in 170 IAC 4-4.2-1(k)); or

(2) July 1, 2047;

whichever occurs earlier.

(c) A successor in interest to a customer's premises on which is located a net metering facility (as defined in 170 IAC 4-4.2-1(k)) that was installed before January 1, 2018, may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier that provides retail electric service at the premises until:

(1) the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is removed from the premises or is replaced; or

(2) July 1, 2047;

whichever occurs earlier.

Sec. 15. An electricity supplier shall procure the excess distributed generation produced by a customer at a rate approved

by the commission under section 17 of this chapter. Amounts credited to a customer by an electricity supplier for excess distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Sec. 17. The commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:

(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by

(2) one and twenty-five hundredths (1.25).

Sec. 18. An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 19. (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:

(1) provides retail electric service to those customers; and

(2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery submitted by an electricity supplier under subsection (a) if the

commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

Sec. 20. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the procurement of excess distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 21. (a) Subject to subsection (b) and sections 10 and 11 of this chapter, after June 30, 2017, the commission's rules and standards set forth in:

(1) 170 IAC 4-4.2 (concerning net metering); and

(2) 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 22. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.

(4) The National Electrical Safety Code.

(5) The Institute of Electrical and Electronics Engineers.

(6) Underwriters Laboratories.

(7) The Federal Energy Regulatory Commission.

(8) Local regulatory authorities.

Sec. 23. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.

(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.

(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.

(4) The right to know the value of all federal, state, or local tax credits or other incentives or rebates that the customer may receive.

(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to a public utility (as defined in IC 8-1-2-1).

(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.

(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation equipment to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is

adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.

SECTION 7. [EFFECTIVE JULY 1, 2017] **(a) As used in this SECTION, "legislative council" refers to the legislative council established by IC 2-5-1.1-1.**

(b) As used in this SECTION, "committee" refers to the interim study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

(c) The legislative council is urged to assign to the committee during the 2017 legislative interim the topic of self-generation of electricity by school corporations.

(d) If the topic described in subsection (c) is assigned to the committee, the committee may:

(1) consider, as part of its study:

(A) use of self-generation of electricity by school corporations;

(B) funding of self-generation of electricity by school corporations; and

(C) any other matter concerning self-generation of electricity by school corporations that the committee considers appropriate; and

(2) request information from:

(A) the Indiana utility regulatory commission;

(B) school corporations; and

(C) any experts, stakeholders, or other interested parties;

concerning the issues set forth in subdivision (1).

(e) If the topic described in subsection (c) is assigned to the committee, the committee shall issue a final report to the legislative council containing the committee's findings and recommendations, including any recommended legislation concerning the topic described in subsection (c) or the specific issues described in subsection (d)(1), in an electronic format under IC 5-14-6 not later than November 1, 2017.

(f) This SECTION expires December 31, 2017.

COMMITTEE REPORT

Madam President: The Senate Committee on Utilities, to which was referred Senate Bill No. 309, has had the same under consideration and begs leave to report the same back to the Senate with the recommendation that said bill be AMENDED as follows:

Page 2, line 2, delete "An" and insert "**If an**".

Page 2, line 3, after "section" insert "**maintains a publicly accessible Internet web site, the electricity supplier**".

Page 2, line 11, strike "a" and insert "**any**".

Page 2, line 12, after "fuel," insert "**organic waste biomass,**".

Page 5, line 17, delete "subsections (a)(2) and (e)." and insert "**subsection (a)(2) and section 6(e) of this chapter.**".

Page 5, line 19, delete "subsections (a)(2) and (e):" and insert "**subsection (a)(2) and section 6(e) of this chapter:**".

Page 5, between lines 27 and 28, begin a new paragraph and insert:

"SECTION 4. IC 8-1-8.5-5, AS AMENDED BY P.L.246-2015, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 5. (a) As a condition for receiving the certificate required under section 2 of this chapter, the applicant shall file an estimate of construction, purchase, or lease costs in such detail as the commission may require.

(b) The commission shall hold a public hearing on each such application. The commission may consider all relevant information related to construction, purchase, or lease costs. A certificate shall be granted only if the commission has:

(1) made a finding as to the best estimate of construction, purchase, or lease costs based on the evidence of record;

(2) made a finding that either:

(A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or

(B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). However, if the commission has developed, in whole or in part, an analysis for the expansion of electric generating capacity and the applicant has filed and the commission has approved under subsection (d) a utility specific proposal submitted under section 3(e)(1) of this chapter, the commission shall make a finding under this clause that the construction, purchase, or lease is consistent

with the commission's analysis, to the extent developed, and that the construction, purchase, or lease is consistent with the applicant's plan under section 3(e)(1) of this chapter, to the extent the plan was approved by the commission;

(3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility;

(4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal; and

(5) made the findings under subsection (e), if applicable.

(c) If:

(1) the commission grants a certificate under this chapter based upon a finding under subsection (b)(2) that the construction, purchase, or lease of a generating facility is consistent with the commission's analysis for the expansion of electric generating capacity; and

(2) a court finally determines that the commission analysis is invalid;

the certificate shall remain in full force and effect if the certificate was also based upon a finding under subsection (b)(2) that the construction, purchase, or lease of the facility was consistent with a utility specific plan submitted under section 3(e)(1) of this chapter and approved under subsection (d).

(d) The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

(e) This subsection applies if an applicant proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. Before granting a certificate to the applicant, the commission:

(1) must, in addition to the findings required under subsection (b), find that:

(A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) the applicant allowed third parties to submit firm and binding bids for the construction of the proposed facility

on behalf of the applicant that met all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:

(A) Reliability.

(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.".

Page 6, line 6, delete "IC 8-1-37-4(a)(1) or IC 8-1-37-4(a)(2);" and insert "**IC 8-1-37-4(a)(1), IC 8-1-37-4(a)(2), or IC 8-1-37-4(a)(5);**".

Page 6, delete lines 19 through 42, begin a new paragraph and insert:

"SECTION 6. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of electricity on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency purposes.

(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff.

Sec. 4. (a) As used in this chapter, "electricity supplier" means a public utility (as defined in IC 8-1-2-1) that furnishes retail electric service to customers in Indiana.

(b) The term does not include a utility that is:

(1) a municipally owned utility (as defined in IC 8-1-2-1(h));

(2) a corporation organized under IC 8-1-13; or

(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

Sec. 5. As used in this chapter, "excess distributed generation" means the difference between:

(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and

(2) the electricity that is supplied back to the electricity supplier by the customer.

Sec. 6. As used in this chapter, "marginal price of electricity" means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 7. As used in this chapter, "net metering tariff" means a tariff that:

(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and

(2) is in effect on January 1, 2017.

Sec. 8. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 9. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) July 1, 2022.

Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate

amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 11. (a) Except as provided in sections 12 and 21(b) of this chapter, before July 1, 2047:

(1) an electricity supplier may not seek to change the terms and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) Except as provided in sections 13 and 14 of this chapter, after June 30, 2022:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2022, expire and are unenforceable.

Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:

(1) Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:

(A) forty percent (40%) of the capacity for participation by residential customers; and

(B) fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

(b) In amending 170 IAC 4-4.2-4, as required by subsection (a), the commission may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this section and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the

commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:

(1) after June 30, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2032;

whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before July 1, 2017.

(b) A customer that is participating in an electricity supplier's net metering tariff on July 1, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer no longer owns, occupies, or resides at the premises on which the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is located; or

(2) July 1, 2047;

whichever occurs earlier.

Sec. 15. An electricity supplier shall procure the excess distributed generation produced by a customer at a rate approved by the commission under section 17 of this chapter. Amounts credited to a customer by an electricity supplier for excess distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate

for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Sec. 17. (a) Subject to subsection (b), the commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:

(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by

(2) one and twenty-five hundredths (1.25).

(b) In a petition filed under section 16 of this chapter, an electricity supplier may request that the rate to be credited to a customer for excess distributed generation be set by the commission at a rate equal to the average marginal price of electricity during the most recent calendar year. The commission shall approve a rate requested under this subsection if the commission determines that the break even cost of excess distributed generation effectively competes with the cost of generation produced by the electricity supplier.

Sec. 18. An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 19. (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:

(1) provides retail electric service to those customers; and

(2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery submitted by an electricity supplier under subsection (a) if the commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

Sec. 20. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the procurement of excess distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 21. (a) Subject to subsection (b) and sections 10 and 11 of this chapter, after June 30, 2017, the commission's rules and standards set forth in:

(1) 170 IAC 4-4.2 (concerning net metering); and

(2) 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 22. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.

(4) The National Electrical Safety Code.

(5) The Institute of Electrical and Electronics Engineers.

(6) Underwriters Laboratories.

(7) The Federal Energy Regulatory Commission.

(8) Local regulatory authorities.

Sec. 23. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.

(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.

(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.

(4) The right to know the value of all federal, state, or local tax credits or other incentives or rebates that the customer may receive.

(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to a public utility (as defined in IC 8-1-2-1).

(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.

(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation equipment to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.".

Delete pages 7 through 11.
Renumber all SECTIONS consecutively.

and when so amended that said bill do pass.

(Reference is to SB 309 as introduced.)

MERRITT, Chairperson

Committee Vote: Yeas 8, Nays 2.

SENATE MOTION

Madam President: I move that Senate Bill 309 be amended to read as follows:
Page 7, line 14, after "allowed" insert "**or will allow**".
Page 7, line 16, after "met" insert "**or meet**".

(Reference is to SB 309 as printed February 21, 2017.)

HERSHMAN

COMMITTEE REPORT

Mr. Speaker: Your Committee on Utilities, Energy and Telecommunications, to which was referred Senate Bill 309, has had the same under consideration and begs leave to report the same back to the House with the recommendation that said bill be amended as follows:
Page 3, delete lines 21 through 33.
Page 3, reset in roman line 39.
Page 3, line 40, reset in roman "small hydro".
Page 3, line 40, delete "eligible".
Page 4, line 8, reset in roman "alternate energy production facilities, cogeneration facilities, or".
Page 4, line 9, reset in roman "small hydro".
Page 4, line 9, delete "eligible".
Page 4, line 11, reset in roman "alternate".
Page 4, line 12, reset in roman "energy production facility, cogeneration facility, or small hydro".
Page 4, line 12, delete "eligible".
Page 4, line 16, reset in roman "alternate energy".

Page 4, line 17, reset in roman "production, cogeneration, and small hydro".

Page 4, line 17, delete "eligible".

Page 5, line 3, reset in roman "alternate energy production facility,".

Page 5, line 4, reset in roman "cogeneration facility, or small hydro".

Page 5, line 4, delete "eligible".

Page 5, line 12, reset in roman "alternate energy".

Page 5, line 13, reset in roman "production facility, cogeneration facility, or small hydro".

Page 5, line 13, delete "eligible".

Page 7, line 14, after "(B)" insert "**if the applicant is an electricity supplier (as defined in IC 8-1-37-6),**".

Page 7, line 37, reset in roman "alternate energy production facility,".

Page 7, line 38, reset in roman "cogeneration facility, or a small hydro".

Page 7, line 38, delete "eligible".

Page 11, delete lines 5 through 32, begin a new paragraph and insert the following:

"**Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:**

(1) after December 31, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer removes from the customer's premises or replaces the net metering facility (as defined in 170 IAC 4-4.2-1(k)); or

(2) July 1, 2032;

whichever occurs earlier.

(c) A successor in interest to a customer's premises on which a net metering facility (as defined in 170 IAC 4-4.2-1(k)) that was installed during the period described in subsection (a) is located may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier that provides retail electric service at the premises until:

(1) the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is removed from the premises or is replaced; or
(2) July 1, 2032;

whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before January 1, 2018.

(b) A customer that is participating in an electricity supplier's net metering tariff on December 31, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer removes from the customer's premises or replaces the net metering facility (as defined in 170 IAC 4-4.2-1(k)); or
(2) July 1, 2047;

whichever occurs earlier.

(c) A successor in interest to a customer's premises on which is located a net metering facility (as defined in 170 IAC 4-4.2-1(k)) that was installed before January 1, 2018, may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier that provides retail electric service at the premises until:

(1) the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is removed from the premises or is replaced; or
(2) July 1, 2047;

whichever occurs earlier.".

Page 12, line 6, delete "(a) Subject to subsection (b), the" and insert "**The**".

Page 12, delete lines 17 through 25.

Page 15, after line 3, begin a new paragraph and insert:

"SECTION 7. [EFFECTIVE JULY 1, 2017] **(a) As used in this SECTION, "legislative council" refers to the legislative council established by IC 2-5-1.1-1.**

(b) As used in this SECTION, "committee" refers to the interim study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

(c) The legislative council is urged to assign to the committee during the 2017 legislative interim the topic of self-generation of electricity by school corporations.

(d) If the topic described in subsection (c) is assigned to the committee, the committee may:

(1) consider, as part of its study:

(A) use of self-generation of electricity by school corporations;
(B) funding of self-generation of electricity by school corporations; and
(C) any other matter concerning self-generation of electricity by school corporations that the committee considers appropriate; and
(2) request information from:
(A) the Indiana utility regulatory commission;
(B) school corporations; and
(C) any experts, stakeholders, or other interested parties;
concerning the issues set forth in subdivision (1).

(e) If the topic described in subsection (c) is assigned to the committee, the committee shall issue a final report to the legislative council containing the committee's findings and recommendations, including any recommended legislation concerning the topic described in subsection (c) or the specific issues described in subsection (d)(1), in an electronic format under IC 5-14-6 not later than November 1, 2017.

(f) This SECTION expires December 31, 2017.".

Renumber all SECTIONS consecutively.

and when so amended that said bill do pass.

(Reference is to SB 309 as reprinted February 24, 2017.)

OBER

Committee Vote: yeas 8, nays 5.

ATTACHMENT BDI-6

First Regular Session 120th General Assembly (2017)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in **this style type**, and deletions will appear in ~~this style type.~~

Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in **this style type**. Also, the word **NEW** will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.

Conflict reconciliation: Text in a statute in *this style type* or ~~*this style type*~~ reconciles conflicts between statutes enacted by the 2016 Regular Session of the General Assembly.

SENATE ENROLLED ACT No. 309

AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 8-1-2-42.5 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 42.5. **(a)** The commission shall by rule or order, consistent with the resources of the commission and the office of the utility consumer counselor, require that the basic rates and charges of all public, municipally owned, and cooperatively owned utilities (except those utilities described in ~~IC 8-1-2-61.5)~~ **section 61.5 of this chapter)** are subject to a regularly scheduled periodic review and revision by the commission. However, the commission shall conduct the periodic review at least once every four (4) years and may not authorize a filing for an increase in basic rates and charges more frequently than is permitted by operation of section 42(a) of this chapter.

(b) The commission shall make the results of the commission's most recent periodic review of the basic rates and charges of an electricity supplier (as defined in IC 8-1-2.3-2(b)) available for public inspection by posting a summary of the results on the commission's Internet web site. If an electricity supplier whose basic rates and charges are reviewed under this section maintains a publicly accessible Internet web site, the electricity supplier shall provide a link on the electricity supplier's Internet web site to the summary of the results posted on the commission's Internet web

site.

SECTION 2. IC 8-1-2.4-2, AS AMENDED BY P.L.222-2014, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 2. (a) The definitions in this section apply throughout this chapter.

(b) "Alternate energy production facility" means:

(1) ~~a~~ **any** solar, wind turbine, waste management, resource recovery, refuse-derived fuel, **organic waste biomass,** or wood burning facility;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(c) "Cogeneration facility" means:

(1) a facility that:

(A) simultaneously generates electricity and useful thermal energy; and

(B) meets the energy efficiency standards established for cogeneration facilities by the Federal Energy Regulatory Commission under 16 U.S.C. 824a-3;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(d) "Electric utility" means any public utility or municipally owned utility that owns, operates, or manages any electric plant.

(e) "Small hydro facility" means:

(1) a hydroelectric facility at a dam;

(2) any land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; and

(3) the transmission or distribution facilities necessary to conduct the energy produced by the facility to users located at or near the project site.

(f) "Steam utility" means any public utility or municipally owned utility that owns, operates, or manages a steam plant.

(g) "Private generation project" means a cogeneration facility that has an electric generating capacity of eighty (80) megawatts or more and is:

(1) primarily used by its owner for the owner's industrial, commercial, heating, or cooling purposes; or

(2) a qualifying facility for purposes of the Public Utility Regulatory Policies Act of 1978 that ~~(A) is in existence on July 1, 2014; and (B)~~ produces electricity and useful thermal energy that is primarily used by a **single** host operation for industrial, commercial, heating, or cooling purposes **and is:**

(A) located on the same site as the host operation; or

(B) determined by the commission to be a facility that:

(i) satisfies the requirements of this chapter;

(ii) is located on or contiguous to the property on which the host operation is sited; and

(iii) is directly integrated with the host operation.

SECTION 3. IC 8-1-2.4-4 IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 4. (a) Subject to section 5 of this chapter, the commission shall require electric utilities and steam utilities to enter into long term contracts to:

(1) purchase or wheel electricity or useful thermal energy from alternate energy production facilities, cogeneration facilities, or small hydro facilities located in the utility's service territory, under the terms and conditions that the commission finds:

(A) are just and economically reasonable to the corporation's ratepayers;

(B) are nondiscriminatory to alternate energy producers, cogenerators, and small hydro producers; and

(C) will further the policy stated in section 1 of this chapter; and

(2) provide for the availability of supplemental or backup power to alternate energy production facilities, cogeneration facilities, or small hydro facilities on a nondiscriminatory basis and at just and reasonable rates.

(b) Upon application by the owner or operator of any alternate energy production facility, cogeneration facility, or small hydro facility or any interested party, the commission shall establish for the affected utility just and economically reasonable rates for electricity purchased under subsection (a)(1). The rates shall be established at levels sufficient to stimulate the development of alternate energy production, cogeneration, and small hydro facilities in Indiana, and to encourage the continuation of existing capacity from those facilities.

(c) The commission shall base the rates for new facilities or new capacity from existing facilities on the following factors:

(1) The estimated capital cost of the next generating plant, including related transmission facilities, to be placed in service by the utility.

(2) The term of the contract between the utility and the seller.

(3) A levelized annual carrying charge based upon the term of the contract and determined in a manner consistent with both the methods and the current interest or return requirements associated with the utility's new construction program.

(4) The utility's annual energy costs, including current fuel costs, related operation and maintenance costs, and any other energy-related costs considered appropriate by the commission.

~~Until July 1, 1986, the rate for a new facility may not exceed eight cents ($.08) per kilowatt hour.~~

(d) The commission shall base the rates for existing facilities on the factors listed in subsection (c). However, the commission shall also consider the original cost less depreciation of existing facilities and may establish a rate for existing facilities that is less than the rate established for new facilities.

(e) In the case of a utility that purchases all or substantially all of its electricity requirements, the rates established under this section must be equal to the current cost to the utility of similar types and quantities of electrical service.

(f) In lieu of the other procedures provided by this section, a utility and an owner or operator of an alternate energy production facility, cogeneration facility, or small hydro facility may enter into a long term contract in accordance with subsection (a) and may agree to rates for purchase and sale transactions. A contract entered into under this subsection must be filed with the commission in the manner provided by IC 8-1-2-42.

(g) This section does not require an electric utility or steam utility to:

(1) construct any additional facilities unless those facilities are paid for by the owner or operator of the affected alternate energy production facility, cogeneration facility, or small hydro facility; **or**

(2) distribute, transmit, deliver, or wheel electricity from a private generation project.

(h) The commission shall do the following not later than November 1, 2018:

(1) Review the rates charged by electric utilities under subsection (a)(2) and section 6(e) of this chapter.

(2) Identify the extent to which the rates offered by electric

utilities under subsection (a)(2) and section 6(e) of this chapter:

(A) are cost based;

(B) are nondiscriminatory; and

(C) do not result in the subsidization of costs within or among customer classes.

(3) Report the commission's findings under subdivisions (1) and (2) to the interim study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

This subsection expires November 2, 2018.

SECTION 4. IC 8-1-8.5-5, AS AMENDED BY P.L.246-2015, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 5. (a) As a condition for receiving the certificate required under section 2 of this chapter, the applicant shall file an estimate of construction, purchase, or lease costs in such detail as the commission may require.

(b) The commission shall hold a public hearing on each such application. The commission may consider all relevant information related to construction, purchase, or lease costs. A certificate shall be granted only if the commission has:

(1) made a finding as to the best estimate of construction, purchase, or lease costs based on the evidence of record;

(2) made a finding that either:

(A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or

(B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). However, if the commission has developed, in whole or in part, an analysis for the expansion of electric generating capacity and the applicant has filed and the commission has approved under subsection (d) a utility specific proposal submitted under section 3(e)(1) of this chapter, the commission shall make a finding under this clause that the construction, purchase, or lease is consistent with the commission's analysis, to the extent developed, and that the construction, purchase, or lease is consistent with the applicant's plan under section 3(e)(1) of this chapter, to the extent the plan was approved by the commission;

(3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the

facility;

(4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal; and

(5) made the findings under subsection (e), if applicable.

(c) If:

(1) the commission grants a certificate under this chapter based upon a finding under subsection (b)(2) that the construction, purchase, or lease of a generating facility is consistent with the commission's analysis for the expansion of electric generating capacity; and

(2) a court finally determines that the commission analysis is invalid;

the certificate shall remain in full force and effect if the certificate was also based upon a finding under subsection (b)(2) that the construction, purchase, or lease of the facility was consistent with a utility specific plan submitted under section 3(e)(1) of this chapter and approved under subsection (d).

(d) The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

(e) This subsection applies if an applicant proposes to construct a facility with a generating capacity of more than eighty (80) megawatts. Before granting a certificate to the applicant, the commission:

(1) must, in addition to the findings required under subsection (b), find that:

(A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on

which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:

(A) Reliability.

(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

SECTION 5. IC 8-1-8.5-7, AS AMENDED BY P.L.168-2013, SECTION 2, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]: Sec. 7. The certification requirements of this chapter do not apply to ~~persons who:~~ **a person that:**

(1) ~~construct~~ **constructs** an electric generating facility primarily for that person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation;

(2) ~~construct~~ **constructs** an alternate energy production facility, cogeneration facility, or a small hydro facility that complies with the limitations set forth in IC 8-1-2.4-5; ~~or~~

(3) ~~are~~ **is** a municipal utility, including a joint agency created under IC 8-1-2.2-8, and ~~install~~ **installs** an electric generating facility that has a capacity of ten thousand (10,000) kilowatts or less; **or**

(4) is a public utility and:

(A) installs a clean energy project described in IC 8-1-8.8-2(2) that is approved by the commission and that:

(i) uses a clean energy resource described in IC 8-1-37-4(a)(1), IC 8-1-37-4(a)(2), or IC 8-1-37-4(a)(5); and

(ii) has a nameplate capacity of not more than fifty thousand (50,000) kilowatts; and

(B) uses a contractor that:

(i) is subject to Indiana unemployment taxes; and

(ii) is selected by the public utility through bids solicited in a competitive procurement process;

in the engineering, procurement, or construction of the project.

However, ~~those persons~~ **a person described in this section** shall, nevertheless, be required to report to the commission the proposed construction of such a facility before beginning construction of the facility.

SECTION 6. IC 8-1-40 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2017]:

Chapter 40. Distributed Generation

Sec. 1. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 2. As used in this chapter, "customer" means a person that receives retail electric service from an electricity supplier.

Sec. 3. (a) As used in this chapter, "distributed generation" means electricity produced by a generator or other device that is:

(1) located on the customer's premises;

(2) owned by the customer;

(3) sized at a nameplate capacity of the lesser of:

(A) not more than one (1) megawatt; or

(B) the customer's average annual consumption of electricity on the premises; and

(4) interconnected and operated in parallel with the electricity supplier's facilities in accordance with the commission's approved interconnection standards.

(b) The term does not include electricity produced by the following:

(1) An electric generator used exclusively for emergency purposes.

(2) A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff.

Sec. 4. (a) As used in this chapter, "electricity supplier" means a public utility (as defined in IC 8-1-2-1) that furnishes retail electric service to customers in Indiana.

(b) The term does not include a utility that is:

(1) a municipally owned utility (as defined in IC 8-1-2-1(h));

(2) a corporation organized under IC 8-1-13; or

(3) a corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13.

Sec. 5. As used in this chapter, "excess distributed generation" means the difference between:

(1) the electricity that is supplied by an electricity supplier to a customer that produces distributed generation; and

(2) the electricity that is supplied back to the electricity supplier by the customer.

Sec. 6. As used in this chapter, "marginal price of electricity"

means the hourly market price for electricity as determined by a regional transmission organization of which the electricity supplier serving a customer is a member.

Sec. 7. As used in this chapter, "net metering tariff" means a tariff that:

(1) an electricity supplier offers for net metering under 170 IAC 4-4.2; and

(2) is in effect on January 1, 2017.

Sec. 8. As used in this chapter, "premises" means a single tract of land on which a customer consumes electricity for residential, business, or other purposes.

Sec. 9. As used in this chapter, "regional transmission organization" has the meaning set forth in IC 8-1-37-9.

Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) July 1, 2022.

Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 11. (a) Except as provided in sections 12 and 21(b) of this chapter, before July 1, 2047:

(1) an electricity supplier may not seek to change the terms and conditions of the electricity supplier's net metering tariff; and

(2) the commission may not approve changes to an electricity supplier's net metering tariff.

(b) Except as provided in sections 13 and 14 of this chapter, after June 30, 2022:

(1) an electricity supplier may not make a net metering tariff available to customers; and

(2) the terms and conditions of a net metering tariff offered by an electricity supplier before July 1, 2022, expire and are unenforceable.

Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:

(1) Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

(2) Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:

(A) forty percent (40%) of the capacity for participation by residential customers; and

(B) fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

(b) In amending 170 IAC 4-4.2-4, as required by subsection (a), the commission may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this section and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 13. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises:

(1) after December 31, 2017; and

(2) before the date on which the net metering tariff of the customer's electricity supplier terminates under section 10(1) or 10(2) of this chapter.

(b) A customer that is participating in an electricity supplier's net metering tariff on the date on which the electricity supplier's net metering tariff terminates under section 10(1) or 10(2) of this chapter shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer removes from the customer's premises or replaces the net metering facility (as defined in 170 IAC 4-4.2-1(k)); or

(2) July 1, 2032;
whichever occurs earlier.

(c) A successor in interest to a customer's premises on which a net metering facility (as defined in 170 IAC 4-4.2-1(k)) that was installed during the period described in subsection (a) is located may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier that provides retail electric service at the premises until:

(1) the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is removed from the premises or is replaced; or
(2) July 1, 2032;
whichever occurs earlier.

Sec. 14. (a) This section applies to a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k)) on the customer's premises before January 1, 2018.

(b) A customer that is participating in an electricity supplier's net metering tariff on December 31, 2017, shall continue to be served under the terms and conditions of the net metering tariff until:

(1) the customer removes from the customer's premises or replaces the net metering facility (as defined in 170 IAC 4-4.2-1(k)); or
(2) July 1, 2047;
whichever occurs earlier.

(c) A successor in interest to a customer's premises on which is located a net metering facility (as defined in 170 IAC 4-4.2-1(k)) that was installed before January 1, 2018, may, if the successor in interest chooses, be served under the terms and conditions of the net metering tariff of the electricity supplier that provides retail electric service at the premises until:

(1) the net metering facility (as defined in 170 IAC 4-4.2-1(k)) is removed from the premises or is replaced; or
(2) July 1, 2047;
whichever occurs earlier.

Sec. 15. An electricity supplier shall procure the excess distributed generation produced by a customer at a rate approved by the commission under section 17 of this chapter. Amounts credited to a customer by an electricity supplier for excess distributed generation shall be recognized in the electricity supplier's fuel adjustment proceedings under IC 8-1-2-42.

Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the

procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Sec. 17. The commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:

(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by

(2) one and twenty-five hundredths (1.25).

Sec. 18. An electricity supplier shall compensate a customer from whom the electricity supplier procures excess distributed generation (at the rate approved by the commission under section 17 of this chapter) through a credit on the customer's monthly bill. Any excess credit shall be carried forward and applied against future charges to the customer for as long as the customer receives retail electric service from the electricity supplier at the premises.

Sec. 19. (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:

(1) provides retail electric service to those customers; and

(2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery submitted by an electricity supplier under subsection (a) if the commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

Sec. 20. (a) An electricity supplier shall provide and maintain the metering equipment necessary to carry out the procurement of

excess distributed generation from customers in accordance with this chapter.

(b) The commission shall recognize in the electricity supplier's basic rates and charges an electricity supplier's reasonable costs for the metering equipment required under subsection (a).

Sec. 21. (a) Subject to subsection (b) and sections 10 and 11 of this chapter, after June 30, 2017, the commission's rules and standards set forth in:

(1) 170 IAC 4-4.2 (concerning net metering); and

(2) 170 IAC 4-4.3 (concerning interconnection);

remain in effect and apply to net metering under an electricity supplier's net metering tariff and to distributed generation under this chapter.

(b) After June 30, 2017, the commission may adopt changes under IC 4-22-2, including emergency rules in the manner provided by IC 4-22-2-37.1, to the rules and standards described in subsection (a) only as necessary to:

(1) update fees or charges;

(2) adopt revisions necessitated by new technologies; or

(3) reflect changes in safety, performance, or reliability standards.

Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the commission under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the commission under IC 4-22-2-24 through IC 4-22-2-36.

Sec. 22. A customer that produces distributed generation shall comply with applicable safety, performance, and reliability standards established by the following:

(1) The commission.

(2) An electricity supplier, subject to approval by the commission.

(3) The National Electric Code.

(4) The National Electrical Safety Code.

(5) The Institute of Electrical and Electronics Engineers.

(6) Underwriters Laboratories.

(7) The Federal Energy Regulatory Commission.

(8) Local regulatory authorities.

Sec. 23. (a) A customer that produces distributed generation has the following rights regarding the installation and ownership of distributed generation equipment:

(1) The right to know that the attorney general is authorized

to enforce this section, including by receiving complaints concerning the installation and ownership of distributed generation equipment.

(2) The right to know the expected amount of electricity that will be produced by the distributed generation equipment that the customer is purchasing.

(3) The right to know all costs associated with installing distributed generation equipment, including any taxes for which the customer is liable.

(4) The right to know the value of all federal, state, or local tax credits or other incentives or rebates that the customer may receive.

(5) The right to know the rate at which the customer will be credited for electricity produced by the customer's distributed generation equipment and delivered to a public utility (as defined in IC 8-1-2-1).

(6) The right to know if a provider of distributed generation equipment insures the distributed generation equipment against damage or loss and, if applicable, any circumstances under which the provider does not insure against or otherwise cover damage to or loss of the distributed generation equipment.

(7) The right to know the responsibilities of a provider of distributed generation equipment with respect to installing or removing distributed generation equipment.

(b) The attorney general, in consultation with the commission, shall adopt rules under IC 4-22-2 that the attorney general considers necessary to implement and enforce this section, including a rule requiring written disclosure of the rights set forth in subsection (a) by a provider of distributed generation equipment to a customer. In adopting the rules required by this subsection, the attorney general may adopt emergency rules in the manner provided by IC 4-22-2-37.1. Notwithstanding IC 4-22-2-37.1(g), an emergency rule adopted by the attorney general under this subsection and in the manner provided by IC 4-22-2-37.1 expires on the date on which a rule that supersedes the emergency rule is adopted by the attorney general under IC 4-22-2-24 through IC 4-22-2-36.

SECTION 7. [EFFECTIVE JULY 1, 2017] **(a) As used in this SECTION, "legislative council" refers to the legislative council established by IC 2-5-1.1-1.**

(b) As used in this SECTION, "committee" refers to the interim

study committee on energy, utilities, and telecommunications established by IC 2-5-1.3-4(8).

(c) The legislative council is urged to assign to the committee during the 2017 legislative interim the topic of self-generation of electricity by school corporations.

(d) If the topic described in subsection (c) is assigned to the committee, the committee may:

(1) consider, as part of its study:

(A) use of self-generation of electricity by school corporations;

(B) funding of self-generation of electricity by school corporations; and

(C) any other matter concerning self-generation of electricity by school corporations that the committee considers appropriate; and

(2) request information from:

(A) the Indiana utility regulatory commission;

(B) school corporations; and

(C) any experts, stakeholders, or other interested parties;

concerning the issues set forth in subdivision (1).

(e) If the topic described in subsection (c) is assigned to the committee, the committee shall issue a final report to the legislative council containing the committee's findings and recommendations, including any recommended legislation concerning the topic described in subsection (c) or the specific issues described in subsection (d)(1), in an electronic format under IC 5-14-6 not later than November 1, 2017.

(f) This SECTION expires December 31, 2017.

President of the Senate

President Pro Tempore

Speaker of the House of Representatives

Governor of the State of Indiana

Date: ____________________ Time: ____________________

ATTACHMENT BDI-7

Star Press.

OPINION | **Opinion** *This piece expresses the views of its author(s), separate from those of this publication.*

Utility fairness for Hoosier customers

State Sen. Brandt Hershman

Published 4:50 p.m. ET Feb. 23, 2017 | **Updated 12:22 p.m. ET Mar. 7, 2017**

This session, I've authored a measure to encourage renewable energy generation while bringing more fairness and market sensibility to the way privately owned solar panels and wind turbines are subsidized by other customers.

Let me first say that I support renewable energy and authored the original legislation to create solar tax incentives in Indiana.

Some critics are mischaracterizing Senate Bill 309 and focusing on earlier versions, but the proposal has already been amended to address many of these concerns.

The proposed bill would address "net metering," the practice of requiring electric utilities to purchase energy that is consumer-generated at full retail rates, which are approximately two to three times the actual value of the energy on the market. This practice was established years ago as an incentive to encourage investment in consumer-generated power, including solar and wind at a time when costs were much higher than they are today.

The federal government decided to phase down its incentives for residential renewables as the products become more affordable. Now, Indiana must also evaluate whether to allow the market to determine the appropriate incentives for self-generation.

SB 309 offers a long-range, common-sense approach. Anyone who owns net metering self-generation equipment or installs it by July 1 of this year would be grandfathered under the existing net metering rules for 30 years until 2047, and anyone who installs it in the next five years will be eligible for current rules until 2032.

Further, SB 309 does not stop anyone from self-generating in the future. Hoosiers could still sell the excess they produce back to the grid, receiving a credit based on the value of that same generation on the market, plus 25 percent.

For the first time, the proposal would establish the equivalent of a Bill of Rights for Hoosiers who want to generate energy using renewable power. One of the specific protections that would be written into law includes the right to know all costs associated with installing self-generation equipment, including solar panels and wind turbines. Consumers would also have the right to be informed of the responsibilities of the person or company installing or removing the equipment and to know the rate at which the customer will be credited for electricity delivered to an electricity supplier.

Hoosiers would also have the ability to file complaints about their self-generation equipment with the Indiana attorney general, who would have the authority to enforce the protections.

Finally, SB 309 recognizes the importance in our state not only of residential and industrial self-generation, but also includes, for the first time, a clear recognition for agriculture-derived renewable generation like biomass.

SB 309 passed out of the Senate Committee on Utilities with a bipartisan vote of 8 to 2. Like all bills going through the legislature, it is subject to change at several more steps in the process. However, in its current form, the bill offers protections for those who generate energy they sell to the electric utility as well as more fairness for all of the utility's customers who are paying for the incentives of Hoosiers who net meter today.

State Sen. Brandt Hershman, is a Republican from Buck Creek.

ATTACHMENT BDI-8

Exhibit BDI-8

Rejected, Withdrawn, and Approved Investor-Owned Utility Fixed Fees on Solar DG Customers

No.	State	Utility	Proposal	Outcome	Docket Number	Decision Date
1	Arizona	Arizona Public Service	Mandatory demand rate for DG customers	Settlement: Mandatory TOU service; $0.93/kW capacity charge for DG customers not taking demand rate service	E-01345A-16-0036	8/18/17
2	Arizona	Tucson Electric Power	Mandatory demand rate for DG customers	Rejected. Mandatory TOU rates adopted	E-01933A-15-0322	9/20/18
3	Arizona	Unisource Energy Services	Mandatory demand rate for DG customers	Rejected. Mandatory TOU rates adopted	E-04204A-15-0142	9/20/18
4	Kansas	Westar	Mandatory demand rate for DG customers	Adopted but later vacated by courts	18-WSEE-328-RTS	9/27/18 & 2/25/21
5	Idaho	Idaho Power Company	Higher fixed charge; mandatory demand rate for DG customers	Rejected	IPC-E-12-27	7/3/13
6	Georgia	Georgia Power	Mandatory demand rate for DG customers	Withdrawn	36989	12/23/13
7	Massachusetts	Eversource	Mandatory demand rate for DG customers	Adopted but later nullified by Legislature (producing a DPU suspension order)	17-05	01/05/2018 & 8/29/2018
8	Maine	Central Maine Power	Mandatory standby/demand rate for DG customers	Withdrawn	2013-00168	8/25/14
9	Michigan	Detroit Edison	System capacity charge on DG customers	Rejected	U-20162	5/8/20

No.	State	Utility	Proposal	Outcome	Docket Number	Decision Date
10	Michigan	Upper Peninsula Power Company	System capacity charge on DG customers	Withdrawn	U-20276	5/23/19
11	Montana	Montana-Dakota Utilities	Mandatory demand rate for DG customers	Withdrawn	2016.06.051	3/11/16
12	Montana	Northwestern Energy	Mandatory demand rate for DG customers	Rejected	2018.02.012	12/20/19
13	Nevada	NV Power Company	Mandatory demand rate for DG customers	Rejected. Higher fixed charge and reduced export credit adopted, but later nullified by Legislature	15-07041	12/23/15
14	New Hampshire	Eversource; Unitil	Mandatory demand rate for DG customers	Withdrawn	DE 16-576	6/23/17
15	New Mexico	Southwest Public Service	Existing standby charge ($/kWh) of all system production for non-demand DG customers	Rejected. Existing standby charge eliminated	17-00255-UT	9/5/18
16	Oklahoma	Oklahoma Gas & Electric	Mandatory demand rate for DG customers	Rejected, but consideration transferred to rate case (PUD 201500273)	PUD 201500274	4/12/16
17	Oklahoma	Oklahoma Gas & Electric	Mandatory demand rate for DG customers	Withdrawn	PUD 201500273	3/20/17
18	Oklahoma	Public Service Oklahoma	Mandatory demand rate for DG customers	Withdrawn	PUD 201500478	12/29/16

No.	State	Utility	Proposal	Outcome	Docket Number	Decision Date
19	South Carolina	Dominion South Carolina	Increased fixed charge & system capacity charge on non-demand DG customers	Rejected. Mandatory TOU rates adopted	2020-229-E	4/28/21
20	South Dakota	Black Hills Power	Mandatory demand rate for DG customers	Withdrawn	EL14-026	4/17/15
21	Texas	Oncor	Additional minimum bill for DG customers based on historic demand or energy use	Withdrawn	46957	10/13/17
22	Texas	El Paso Electric	Higher fixed charge; mandatory demand rate for DG customers	Withdrawn	44941	8/25/16
23	Texas	El Paso Electric	Higher fixed charge; mandatory demand rate for DG customers	Settlement: $30/month minimum bill for flat rate service and $26.50/month minimum bill for energy-only TOU service	46831	12/18/17
24	Tennessee	Kingsport Power	Mandatory demand rate for DG customers	Withdrawn	1600001	10/19/16
25	Utah	Rocky Mountain Power	Higher fixed charge; mandatory demand rate for DG customers	Settlement: Reduced export rate.	14-035-114	9/29/17
26	Wisconsin	We Energies	System capacity charge on non-demand DG customers	Withdrawn	5-UR-109	12/19/19

No.	State	Utility	Proposal	Outcome	Docket Number	Decision Date
27	Wisconsin	We Energies	Higher fixed charge; system capacity charge on non-demand DG customers	Adopted but later vacated by courts	5-UR-107 (Dane County Circuit Court Case 2015CV000153)	12/23/14 & 10/30/15

ATTACHMENT BDI-9

Exhibit BDI-9

Key Examples of Jurisdictions Studying and Investigating Net Metering ("NEM")

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Arizona (Arizona Public Service)	Distributed Renewable Energy Operating Impacts and Valuation Study (2009)[1] The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2013[2], 2016[3])	E-01345A-13-0248 (2013 APS Lost Fixed Cost Recovery Charge) E-00000J-14-0023 (2014 Investigation into the Value of DG) E-01345A-16-0036 (2016 APS Rate Case) RE-00000A-17-0260 (2017 NEM Rulemaking)	Monthly netting retained, with a small monthly fee on APS NEM customers, through 2017. The Arizona Corporation Commission adopted an export credit rate policy for APS beginning in 2017.
California	The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California (2010)[4] Evaluating the Benefits and Costs of Net Energy Metering in California (2013)[5] Net-Energy Metering 2.0 Look-Back Study (2021)[6]	R.14-07-002 (2014 NEM "2.0" rulemaking) R.20-08-020 (2020 NEM successor tariff rulemaking)	Monthly netting (NEM 1.0) retained through 2017. NEM 2.0 in effect from 2017-2022 (est.). NEM 2.0 includes mandatory service under a TOD rate and monthly netting (minus non-bypassable charges). A new NEM Successor Tariff is now being developed in R.20-08-020 to take effect in 2022 (est.).

[1] https://appsrv.pace.edu/VOSCOE/?do=DownloadFile&res=J8PAM033116121012
[2] https://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf
[3] https://images.edocket.azcc.gov/docketpdf/0000168554.pdf
[4] https://emp.lbl.gov/publications/impact-rate-design-and-net-metering
[5] https://www.growsolar.org/wp-content/uploads/2012/06/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf
[6] https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467448

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Colorado	Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System (2013)[7]	14M-0235E (2014 DG Cost Benefit Investigation) 16AL-0048E, 16A-0139E, 16A-0055E (2016 Cases Resulting in NEM Settlement) 18AL-0097E (2018 Roll-over Provisions to Xcel's NEM Agreed to in Rate Case) 19R-0096E (2019 Electric Rule Changes)	Monthly netting retained. A 2016 proposal by Xcel Energy to implement a Grid Usage Charge of up to $44.79 on residential customers was withdrawn as part of a settlement, resulting in NEM customers retaining monthly netting.
Connecticut	Value of Distributed Energy Resources (2020, Draft)[8]	15-09-03 (2015 Investigation into NEM kWh Banking) 18-06-15 (2018 DG Tariff Development re Public Act 18-50) 19-06-29 (2019 Value of Distributed Energy Resources Study) 20-07-01 (2020 Development of Tariffs for Residential Renewable Energy re Public Act 19-35)	Retail rate NEM retained after multiple proceedings and despite legislation allowing for NEM changes. A 2018 law would have ended NEM but was revoked through a 2019 law. In February 2021, the Public Utilities Regulatory Authority ("PURA") retained retail rate net metering under a new "Netting Tariff" option. (A Buy-All, Sell-All option was also created.) PURA determined monthly netting was appropriate, even though Public Act 19-35 granted PURA discretion to impose other intervals, including instantaneous netting.

7 https://bit.ly/2ZIhfet.
8 https://bit.ly/3aQTbMS

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Iowa	PV Valuation Methodology (2016)[9]	NOI-2014-0001 (2014 DG investigation) TF-2016-0321, TF-2016-0323 (2016 Alliant and MidAmerican NEM pilots) TF-2020-0235, TF-2020-0237 (2020 Alliant and MidAmerican DG Tariffs)	A 2014 DG investigation retained and expanded monthly netting, establishing utility NEM "pilots" for IOUs to study impacts of retail rate NEM over several years. SF 583 (2020) maintained monthly netting through 2027, after which a value of solar methodology will be used to determine compensation for exports.
Maryland	Value of Solar Report (2017)[10] Benefits and Cost of Utility Scale and Behind the Meter Solar Resources in Maryland (2018)[11]	RM 41 (2011 NEM Rulemaking) PC 40 (2015 Public Conference on Small DG Deployment) PC 44 (2016 Transforming Maryland's Distribution Systems) PC 48 (2017 Investigation re Costs and Benefits of DG for Electric Cooperatives)	Monthly netting retained after multiple proceedings and studies. 2018 Study found NEM benefits exceed costs.

9 https://www.growsolar.org/wp-content/uploads/2016/03/PV-Valuation-in-Iowa.pdf
10 https://bit.ly/3aJXsS8
11 https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Massachusetts	Value of Distributed Generation: Solar PV in Massachusetts (2015)[12] Massachusetts Net Metering and Solar Task Force Final Report to the Legislature (2015)[13]	16-64 (2016 Transition to "Market Rate" NEM and a Minimum Monthly Reliability Contribution ("MMRC") 16-151 (2016 IOUs' Petition re Revised Model NEM Tariff) 17-105; 17-146 (2017 Storage NEM Eligibility) 18-150 (2018 National Grid Rate Case Proposing MMRC) 19-24 (2019 IOUs' Revised Model NEM Tariff)	Near-retail rate monthly crediting retained for residential customers. A reduced credit rate applies to certain other categories of customers. IOU proposals to implement a demand-charge or fixed-charge based MMRC have been denied by regulators or overruled through subsequent legislative changes. (2016 legislation allowed utilities to propose an MMRC, and 2018 legislation amended those provisions.)
New Hampshire	Value of Distributed Energy Resources Study (Anticipated Q1 2022)[14]	DE 16-576 (2016 Investigation on Alternative NEM Tariff Development) DE 16-873, DE 16-864 (2016 Liberty Utilities Large NEM Methodology) DE 18-029 (2018 Unitil Alternative NEM Tariff) DRM 19-158 (2019 NEM Rulemaking) DE 20-136 (2020 Eversource NEM Cost Recovery)	Monthly netting retained for customers <100 kW, with reduction to the credit rate for monthly excess distributed generation. Non-bypassable charges assessed on gross grid consumption during a month and excluded from the monthly credit. Value of DER Study is ongoing and will provide detailed information regarding costs avoided by NEM under general conditions, as well as at specific times and at particular locations.

12 https://acadiacenter.org/resource/value-of-solar-massachusetts/

13 https://www.mass.gov/doc/final-net-metering-and-solar-task-force-report/download

14 *See* New Hampshire Public Utilities Commission, Docket No. DE 16-576.

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
New York	An Analysis of the Benefits and Costs of Increasing Generation From Photovoltaic Devices in New York (2012)[15]	14-M-0101 (2014 Reforming the Energy Vision) 15-E-0703 (2015 NEM Cost-Benefit Study) 15-E-0751 (2015 NEM Successor and Value of DER Phase I) 15-E-0751 (2017 NEM Successor and Value of DER Phase II) 17-01276 (2017 VDER Phase 2 Value Stack Working Group) 17-01277 (2017 VDER Phase 2 Rate Design Working Group)	Monthly netting retained for residential, small commercial, and behind-the-meter systems. In 2022, a $0.69/kW to $1.09/kW customer benefit contribution charge will apply as a means of ensuring funding for public benefit programs, but monthly netting will continue. Value of DER (VDER) implemented for other customers. Gross exports accrue as a monetary credit at a utility-specific VDER rates composed of energy, generation capacity, distribution capacity (including possible local adder) and environmental value. System distribution capacity locked in for 3 years, local distribution capacity for 10 years, and environmental value for 25 years.

15 https://www.nyserda.ny.gov/About/Publications/Solar-Study

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Utah	Value of Solar in Utah (2014)[16]	14-035-114 (2014 RMP Net Metering Cost-Benefit Investigation) 16-035-T14 (2016 RMP Temporary NEM Tariff) 17-035-61 (2017 Credit Rate for DG Customer Energy Exports)	In 2015, the Utah Public Service Commission rejected Rocky Mountain Power's (RMP) proposal that net metering customers be converted into a separate customer class but directed RMP to file a cost-of-service study on net metering customers in its next rate case. In September 2017, the PSC adopted a NEM "Transition Program" as a result of a settlement agreement. DG customers were compensated at fixed rates, which varied by rate schedule, and were equal to 90% of the average energy rate for residential customers and 92.5% for other customers, for any net kWh exports at the end of 15-minute increments, capped at 170 MW for residential customers and 70 MW for other customers. In October 2020, the PSC approved RMP's request to lower the export credit rate.

16 https://pscdocs.utah.gov/electric/13docs/13035184/255147ExAWrightTest5-22-2014.pdf

ATTACHMENT BDI-10

Data Request Indiana DG DR 1 **-** 4

Please provide an executable version (i.e., Excel format) of AES Indiana's 8760-hour representative load profile for its Residential customer class and for each additional customer class for which AES Indiana currently has one or more net metering customers taking service.

Objection:

AES Indiana objects to the Request because it seeks information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. The issue in this case is very narrow: the EDG rate and the statutory methodology for calculating EDG. The information sought by this Request is not relevant to either issue. AES Indiana further objects to the Request on the grounds and to the extent it is overly broad and unduly burdensome in that it is not narrowly tailored to any particular projects. Subject to and without waiver of the foregoing objections, AES Indiana responds as follows.

Response:

See Indiana DG DR 1-4 Attachment 1, which was provided in the Company's response to OUCC DR 5-4 in Cause No. 45029.

Data Request Indiana DG DR 1 **-** 8

Please identify the amount of AES Indiana's approved annual revenue requirement.

Objection:

AES Indiana objects to the Request because it seeks information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. The issue in this case is very narrow: the EDG rate and the statutory methodology for calculating EDG. The information sought by this Request is not relevant to either issue. Given that fact it also imposes on AES Indiana an undue burden that is not commensurate with the needs of this case. Subject to and without waiver of the foregoing objections, AES Indiana responds as follows.

Response:

See finding 2 on p. 34 of the Commission's 10/31/2018 Order in CN 45029 which identifies an approved annual revenue requirement of $1,413.182 million.

Data Request Indiana DG DR 1 **-** 13

Please refer to Fields Direct Testimony, p. 6, lines 2-6, stating in pertinent part that "Vectren proposed that EDG be calculated "instantaneously". The Consumer parties in the Vectren case proposed that EDG be calculated monthly, just like net metering. AES Indiana believes there may be additional methods for calculating EDG that comply with Ind. Code § 8-1-40-5, that do not mimic net metering's methodology, and that mitigate certain of the adverse incentives net metering creates."

a. Confirm that AES Indiana's proposal in this case is for EDG to be calculated "instantaneously."
b. Confirm or refute that AES Indiana's use of 15-minute intervals to calculate excess distributed generation would result in the same monthly bill for DG customers should AES Indiana reprogram its meters to use "instantaneous" intervals (e.g., intervals of 1 second or less). If your answer is anything other than an unqualified confirmation, please explain why this description is not accurate.
c. Confirm or refute that under AES Indiana's proposal, kWh amounts recorded under Channel 1 are never netted against kWh amounts recorded under Channel 2.
d. Confirm or refute that Channel 1 of a DG customer's meter measures gross kWh, and not net kWh, that AES Indiana supplies a DG customer. If this is inaccurate, please detail the components of the netting calculation that AES Indiana believes is occurring (i.e., identify which values are being used in the netting calculation, including the kWh that are being netted against the gross kWh delivered by AES Indiana, and explain how AES Indiana will measure all of these values).
e. Confirm or refute that Channel 2 of a DG customer's meter measures gross kWh, and not net kWh, that is supplied back to the AES Indiana by the DG customer. If this is inaccurate, please detail the components of the netting calculation that AES Indiana believes is occurring (i.e., identify which values are being used in the netting calculation, including the kWh that are being netted against the gross kWh delivered to AES Indiana, and explain how AES Indiana will measure all of these values).
f. Please list and explain all "additional methods for calculating EDG that comply with Ind. Code § 8-1-40-5" in AES Indiana's opinion.

Objection:

The term "instantaneous" in the context of determining EDG is undefined and ambiguous. It is not a term AES Indiana has used in describing its methodology for determining EDG. AES Indiana thus cannot answer questions about its meaning or application. AES Indiana's filed testimony describes it proposed methodology for determining EDG. AES Indiana objects to the Request on the grounds and to the extent the request seeks a compilation, analysis, or study that AES Indiana has not performed and to which AES Indiana objects to performing. Subject to and without waiver of the foregoing objections, AES Indiana responds as follows.

Response:

a) AES Indiana does not know what is meant by "instantaneous." AES Indiana's testimony describes the methodology by which it proposes to determine EDG.

b) Confirmed.
c) Confirmed.
d) Channel 1 on the meter records kWh that AES Indiana supplies a DG customer, as indicated on lines 2 and 3 of p. 5 of Witness Fields's supplemental testimony. There are a few, customer-specific metering arrangements that exist on the AES Indiana system that allow for AES Indiana to measure the total amount of electricity delivered to the customer. Such arrangements were made at the customer's request and cost.
e) Channel 2 on the meter records kWh that the DG customer supplies back to AES Indiana, as detailed on lines 6 through 8 on p. 5 of Witness Fields's supplemental testimony. There are a few, customer-specific metering arrangements that exist on the AES Indiana system that allow for AES Indiana to measure the total amount of electricity produced by a DG facility. Such arrangements were made at the customer's request and cost.
f) AES Indiana has not attempted to identify all hypothetical methodologies that might comply with the referenced statute. AES Indiana's testimony merely referred to the fact that the statute is silent on the netting period used to calculate Excess DG, therefore it would be possible to net on 1-minute, 2-minute, 5-minute, 10-minute and other intervals.

Data Request Indiana DG DR 1 **-** 17

Please refer to tariffs Renewable Energy Production ("Rate REP") and Cogeneration and Small Power Production ("Rate CGS").
a. Please confirm or refute that customers taking service under Rate REP and Rate CGS are paid for all electricity provided to AES Indiana and that AES Indiana does not take any energy from such customers without compensating them for the energy. If your response is anything other than an unqualified confirmation, please explain.
b. Please confirm or refute that both residential and non-residential DG customers would be eligible to take service under Rate REP or Rate CGS in the alternative to taking service under Rider EDG beginning July 1, 2022.
c. Please identify the amount of remaining capacity available under Rate REP to the extent the tariff remains open to new DG customers (i.e., new capacity under this tariff).
d. Please explain why Rate REP is currently limited to facilities sized no less than 50 kW (20 kW for solar) and provide the supporting justification for limiting smaller renewable facilities from being eligible under this option.
e. Please identify the term (i.e., number of years) customers would be able to execute a contract for under Rate REP and Rate CGS. Please explain whether the compensation rate(s) would be fixed for the term of such a contract.

Objection:

AES Indiana objects to the Request because it seeks information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. The issue in this case is very narrow: the EDG rate and the statutory methodology for calculating EDG. The information sought by this Request is not relevant to either issue. Indiana further objects to the Request on the grounds and to the extent the request seeks a compilation, analysis, or study that AES Indiana has not performed and to which AES Indiana objects to performing. AES Indiana further objects to the request on the grounds and to the extent it is overly broad and unduly burdensome in that it is not narrowly tailored to any particular projects. Subject to and without waiver of the foregoing objections, AES Indiana responds as follows.

Response:

a) Confirmed.
b) Rate REP is fully subscribed. Customers would be eligible for Rate CGS but would still need to meet the stated tariff requirements. Customers could not participate in Rate REP and Rate CGS, or Rate REP and Rider 16, or Rate CGS and Rider 16 contemporaneously.
c) Rate REP is fully subscribed. See the following link: https://www.aesindiana.com/renewable-energy-production-rep
d) See objection.
e) Rate REP is fully subscribed. Rate CGS does not have a term and is not set at a fixed rate. Rather, Rate CGS is updated annually via 30-day filing.

Data Request Indiana DG DR 1 **-** 20

Confirm or refute with explanation that all AES Indiana customers are currently able to access through an online portal, or through other means provided by AES Indiana, information on what the customer's instantaneous electricity usage, including what the customer's instantaneous purchases are from AES Indiana. If accessing such customer data is provided at a cost or charge(s) assessed on the customer, please identify the charge(s). If all AES Indiana customers do not have this capability, please explain how a customer installing distributed generation would be able to maximize self-consumption to avoid purchases from AES Indiana to avoid or minimize excess generation that would be credited at a substantially lower rate than the customer's retail rate under the Company's EDG tariff proposal.

Objection:

AES Indiana objects to the Request because it seeks information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. The issue in this case is very narrow: the EDG rate and the statutory methodology for calculating EDG. The information sought by this Request is not relevant to either issue. AES Indiana objects to the term "instantaneous." It is undefined and has been used in multiple ways in this proceeding such that AES Indiana is unsure of its use and meaning in this Request. AES Indiana further objects to the request on the grounds and to the extent it is overly broad and unduly burdensome in that it is not narrowly tailored to any particular projects or limited to the customers relevant to this proceeding. Subject to and without waiver of the foregoing objections, AES Indiana responds as follows.

Response:

Yes, the Company's customers with AMI meters have the ability to access detailed consumption information through the portal at no additional cost to the customer. The deployment of AMI meters for residential and small commercial customers is well underway, in accordance with the Company's Commission approved TDSIC Plan. As of August 1, 2021, 69% of the Company's meters are AMI meters.

Data Request Indiana DG DR 1 **-** 21

a. Please provide the Company's forecast for distributed generation adoption in its Indiana service territory over the next 20 years including number of customers by class and their class DG kWh output, to the extent the Company has such a forecast for any or all of these years, in an executable format with formulae intact, and all variables clearly explained.
b. Please explain how the forecast was created, the data sources used, the modeling method used, and the extent to which the Company's EDG tariff proposal is incorporated into its forecast.
c. If the Company's EDG tariff proposal has not been incorporated into its distributed generation forecast, please describe how the EDG tariff would impact the Company's forecast if it were updated to include the EDG tariff.

Objection:

AES Indiana objects to the Request because it seeks information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. The issue in this case is very narrow: the EDG rate and the statutory methodology for calculating EDG. The information sought by this Request is not relevant to either issue. AES Indiana further objects to the Request on the grounds and to the extent the request seeks a compilation, analysis, or study that AES Indiana has not performed and to which AES Indiana objects to performing. AES Indiana further objects to the request on the grounds and to the extent it seeks a massive amount of information that is not commensurate with the needs of this case, especially given the sought information's irrelevance. It is overly broad and unduly burdensome in that it is not narrowly tailored to any particular projects. Subject to and without waiver of the foregoing objections, AES Indiana responds as follows.

Response:

a. Indiana DG DR 1-21 Attachment 1 includes the 8760 load profiles for the 20-year solar forecast that was included in AES Indiana's 2019 IRP. The forecast was created at the residential sector and C&I sector level and not by class. For additional detail regarding how this forecast was created see Section 4.4 p. 44 of AES Indiana's 2019 Integrated Resource Plan (IRP) Volume 1.
b. See Section 4.4 p. 44 of AES Indiana's 2019 Integrated Resource Plan (IRP) Volume 1. AES Indiana did not include an assumption of the EDG tariff in its solar forecast in the 2019 IRP.
c. AES Indiana did not include an assumption of the EDG tariff in its solar forecast in the 2019 IRP. See objection above.