Indiana Utility Regulatory Commission

2017 Technical Conference Addressing Questions
Re: Implementation of Net Metering Legislation
Indiana Code chapter 8-1-40

HANDOUT

Statute, Rules, and Comments

July 20, 2017
IURC Judicial Courtroom 222

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STATUTE – Distributed Generation

IC 8-1-40-1 “Commission”
As used in this chapter, “commission” refers to the Indiana utility regulatory commission created by IC 8-1-1-2.
As added by P.L.264-2017, SEC.6.

IC 8-1-40-2 “Customer”
As used in this chapter, “customer” means a person that receives retail electric service from an electricity supplier.
As added by P.L.264-2017, SEC.6.

IC 8-1-40-3 “Distributed generation”
(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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-4 “Electricity supplier”
(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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-5 “Excess distributed generation”
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.
As added by P.L.264-2017, SEC.6.

IC 8-1-40-6 “Marginal price of electricity”
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.
As added by P.L.264-2017, SEC.6.

IC 8-1-40-7 "Net metering tariff"

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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-8 "Premises"

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

As added by P.L.264-2017, SEC.6.

IC 8-1-40-9 "Regional transmission organization"

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

As added by P.L.264-2017, SEC.6.

IC 8-1-40-10 Availability of electricity supplier's net metering tariff; aggregate net metering facility nameplate capacity under tariff

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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-11 Changes to net metering tariffs prohibited before July 1, 2047; expiration of net metering tariffs after June 30, 2022

(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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-12 Amendment of commission's net metering rules and electricity suppliers' net metering tariffs; increase to aggregate net metering facility nameplate capacity; reservation of capacity for residential customers and organic waste biomass facilities

(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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-13 Installations of net metering facilities after December 31, 2017,and before expiration of tariff; continued service under tariff; successors in interest

(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

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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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-14 Installations of net metering facilities before January 1, 2018; continued service under tariff; successors in interest

(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 supplierthat 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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-15 Electricity supplier's duty to procure customers' excess distributed generation; amounts credited to customers to be recognized in fuel adjustment proceedings

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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-16 Electricity supplier's petition for rate for excess distributed generation; annual submission of updated rate

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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-17 Commission's review of rate petition; notice and hearing; approval of rate; calculation

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).

As added by P.L.264-2017, SEC.6.

IC 8-1-40-18 Credit on customer's monthly bill for excess distributed generation; excess credit carried forward

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. *As added by P.L.264-2017, SEC.6.*

IC 8-1-40-19 Electricity supplier's petition to commission for recovery of energy delivery costs attributable to distributed generation customers; approval; findings by commission

(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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-20 Electricity supplier to provide necessary metering equipment; recovery of costs

(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).

As added by P.L.264-2017, SEC.6.

IC 8-1-40-21 Commission's net metering and interconnection rules; application to distributed generation; permitted changes to rules

(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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-22 Distributed generation customer's duty to comply with standards

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.

As added by P.L.264-2017, SEC.6.

IC 8-1-40-23 Distributed generation equipment; customers' rights; attorney general to adopt rules

(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.

As added by P.L.264-2017, SEC.6.

RULES

Rule 4.2. Net Metering

170 IAC 4-4.2-1 Definitions
Authority: IC 8-1-1-3
Affected: IC 8-1-2-1; IC 8-1-37-4

(a) The definitions in this section apply throughout this rule.
(b) “Commission” means the Indiana utility regulatory commission.
(c) “Customer” means a person, firm, corporation, municipality, or other government agency that has agreed, orally or otherwise, to pay for electric service received from an investor-owned electric utility.
(d) “Eligible net metering energy resource” means the following:
(1) A renewable energy resource as defined in IC 8-1-37-4(a)(1) through IC 8-1-37-4(a)(8).
(2) Other emerging renewable energy technologies the commission determines appropriate.
(e) “In good standing” means a customer:
(1) whose account is not more than thirty (30) days in arrears; and
(2) who does not have legal orders outstanding pertaining to his or her investor-owned electric utility.
(f) “Interconnection” or “interconnected” means the physical, parallel connection of a net metering facility with a distribution facility of an investor-owned electric utility.
(g) “Investor-owned electric utility” means a utility:
(1) that is financed by the sale of securities; and
(2) whose business operations are overseen by a board representing their shareholders.
(h) “Name plate capacity” means the full-load continuous rating of a generator under specified conditions as designated by the manufacturer. For an inverter-based net metering facility, name plate capacity means the aggregate output rating of all inverters in the facility, measured in kW.
(i) “Net metering” means measurement of the difference between the electricity that is supplied by the investor-owned electric utility to a net metering customer and the electricity that is supplied back to the investor-owned electric utility by a net metering customer.
(j) “Net metering customer” means a customer in good standing that owns and operates an eligible net metering energy resource facility that:
(1) has a nameplate capacity less than or equal to one (1) megawatt (MW), or more at the investor-owned electric utility’s sole discretion;
(2) is located on the net metering customer’s premises; and
(3) is used primarily to offset all or part of the net metering customer’s own annual electricity requirements.
(k) “Net metering facility” means an arrangement of equipment for the production of electricity from an eligible net metering energy resource, that is owned and operated by a net metering customer.
(l) “Parallel” means the designed operation of the net metering facility, interconnection equipment, and the investor-owned electric utility’s system where the instantaneous flow of electrical energy may automatically occur in either direction across the interconnection point between the net metering facility and the investor-owned electric utility’s distribution system.
(m) “System emergency” means a condition on an investor-owned electric utility’s system reasonably likely to result in at least one (1) of the following:
(1) A significant disruption of service to a customer.
(2) A substantial deviation from a normal service standard.

(3) An endangerment to life or property.

(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-1; filed Oct 22, 2004, 11:00 a.m.: 28 IR 786; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; errata filed Aug 2, 2011, 2:16 p.m.: 20110817-IR-170100662ACA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.2-2 Applicability

Authority: IC 8-1-1-3

Affected: IC 8-1-2

These rules shall apply to an investor-owned electric utility, subject to the jurisdiction of the commission, that may now or hereafter be engaged in the production, transmission, sale, or distribution of electric service and all net metering facilities as defined in section 1 of this rule that are interconnected with the investor-owned electric utilities. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-2; filed Oct 22, 2004, 11:00 a.m.: 28 IR 786; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828- IR-170130227RFA)*

170 IAC 4-4.2-3 Exemption

Authority: IC 8-1-1-3

Affected: IC 8-1-2

Net metering facilities shall be exempt from revenue requirement and associated regulation under IC 8-1-2 as administered by the commission, but the commission shall have authority over rates charged by electric utilities to net metering facilities. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-3; filed Oct 22, 2004, 11:00 a.m.: 28 IR 786; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.2-4 Availability

Authority: IC 8-1-1-3

Affected: IC 8-1-2-34.5

An investor-owned electric utility shall offer net metering to a customer that installs a net metering facility. The investor-owned electric utility may limit the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one percent (1%) of the most recent summer peak load of the utility, with at least forty percent (40%) of the capacity reserved solely for participation by residential customers. However, the investor-owned electric utility may increase the limit on the aggregate amount of net metering facility nameplate capacity at the investor-owned electric utility's sole discretion. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-4; filed Oct 22, 2004, 11:00 a.m.: 28 IR 786; readopted filed Nov 12, 2010, 2:53p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; readopted filed Aug 2, 2013,2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.2-5 Interconnection

Authority: IC 8-1-1-3

Affected: IC 8-1-2-4

(a) A net metering interconnection agreement between the investor-owned electric utility and the net metering customer must be executed before the net metering facility may be interconnected with the investor-owned electric utility’s system.

(b) The net metering facility shall comply with the technical interconnection requirements approved by the commission as outlined in section 9(a) of this rule. Inverter based systems listed by Underwriters Laboratories (UL) to UL standard 1741, published May 7, 1999, as revised January 28, 2010 (UL 1741), shall be accepted by the investor-owned electric utility as meeting the technical interconnection requirements tested by UL 1741. The net metering facility shall comply with the applicable requirements of 170 IAC 4-4.3. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-5; filed Oct 22, 2004, 11:00 a.m.: 28 IR 787; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2169; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.2-6 Metering

Authority: IC 8-1-1-3

Affected: IC 8-1-2

(a) One (1) of the following metering options, if not already present, shall be installed on the net metering customer’s premises by the investor-owned electric utility to properly record the net kilowatt hours (kWh) of a net metering facility:

(1) One (1) main watt-hour meter capable of measuring net kWh.

(2) One (1) main watt-hour meter measuring kWh to the net metering customer and a second watt-hour meter measuring kWh to the investor-owned electric utility. The reading of the second meter will be subtracted from the reading of the main meter to obtain net kWh for billing.

(b) An investor-owned electric utility shall not charge the net metering customer costs or fees for the following:

(1) Additional metering for single-phase configurations installed by the investor-owned electric utility.

(2) Net metering customer’s request to participate in net metering program.

(3) Initial net metering facility inspection.

(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-6; filed Oct 22, 2004, 11:00 a.m.: 28 IR 787; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.2-7 Billing

Authority: IC 8-1-1-3

Affected: IC 8-1-2-34.5; IC 8-1-2-38

An investor-owned electric utility shall determine a net metering customer’s monthly bill as follows:

(1) Bill charges, credits, rates, and adjustments shall be in accordance with the investor-owned electric utility’s tariff and administrative rules that would apply if the net metering customer did not participate in net metering.

(2) 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. If the kilowatt hours (kWh) delivered by the investor-owned electric utility to the net metering customer exceed the kWh delivered by the net metering customer to the investor-owned electric utility during the billing period, the net metering customer shall be billed for the kWh difference at the rate applicable to the net metering customer if it was not a net metering customer. If the kWh generated by the net metering customer and delivered to the investor-owned electric utility exceed

the kWh supplied by the investor-owned electric utility to the net metering customer during the billing period, the net metering customer shall be credited in the next billing cycle for the kWh difference.

(3) The credit shall roll over indefinitely for net metering customers, except that when the net metering customer elects to no longer participate in the net metering tariff, all unused credit shall revert to the investor-owned electric utility.

(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-7; filed Oct 22, 2004, 11:00 a.m.: 28 IR 787; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.2-8 Liability insurance and indemnity

Authority: IC 8-1-1-3

Affected: IC 8-1-2-33; IC 8-1-2-34

(a) A net metering customer operating a net metering facility shall maintain homeowners, commercial, or other insurance providing coverage in the amount of at least one hundred thousand dollars ($100,000) for the liability of the insured against loss arising out of the use of a net metering facility. Net metering customers shall not be required by the utility to obtain liability insurance with limits higher than that which is stated in this section, nor shall such net metering customers be required by the utility to purchase additional liability insurance, for example, insurance coverage that exceeds one hundred thousand dollars ($100,000) where the net metering customer’s existing insurance policy provides coverage against loss arising out of the use of a net metering facility by virtue of not explicitly excluding coverage for such loss.

(b) The utility and the net metering customer shall indemnify and hold the other party harmless from and against all claims, liability, damages, and expenses, including attorney’s fees, based on any injury to any person, including loss of life or damage to any property, including loss of use thereof, arising out of, resulting from, or connected with, or that may be alleged to have arisen out of, resulted from, or connected with an act or omission by such other party, its employees, agents, representatives, successors, or assigns in the construction, ownership, operation, or maintenance of such party’s facilities used in net metering. This indemnification provision is not applicable in the case of governmental net metering customers that are restricted from entering into indemnification provisions. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-8; filed Oct 22, 2004, 11:00 a.m.: 28 IR 788; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR- 170100662FRA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.2-9 Tariff and reporting requirements

Authority: IC 8-1-1-3

Affected: IC 8-1-2

(a) Within sixty (60) days of the effective date of this rule, investor-owned electric utilities shall submit for approval under the commission’s thirty (30) day filing process a net metering tariff. The net metering tariff shall:

(1) include the technical interconnection requirements of the investor-owned electric utility; and

(2) comply with the requirements of this rule.

(b) Within sixty (60) days of the effective date of this rule, investor-owned electric utilities shall submit for approval via the commission’s thirty (30) day filing process a generic interconnection agreement applicable to net metering facilities. An interconnection agreement shall include the following:

(1) The name of the net metering customer.

(2) The location of the proposed net metering facility.
(3) Type of the proposed net metering facility.
(4) Size or inverter power rating, or both, of the proposed net metering facility.
(5) Inverter manufacturer and model number.
(6) A description of the electrical installation of the inverter and associated electrical equipment.

(c) On or before March 1 of every year, the investor-owned electric utility shall file with the commission a net metering report. The net metering report shall contain the following:
(1) The total number of net metering customers and facilities.
(2) The number, size, and type of net metering facilities.
(3) The number of new net metering customers interconnected during the previous calendar year.
(4) The number of existing net metering customers that ceased participation in the net metering tariff during the previous calendar year.
(5) If available, data on the amount of electricity generated by net metering facilities.
(6) A list of system emergency disconnections that occurred and an explanation of the system emergency.

(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-9; filed Oct 22, 2004, 11:00 a.m.: 28 IR 788; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.2-10 Customer complaints
Authority: IC 8-1-1-3
Affected: IC 8-1-2-34.5

In the event an investor-owned electric utility and a net metering customer are unable to agree on matters relating to net metering, either party may raise a customer complaint to the commission in accordance with the commission’s consumer complaint rules. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.2-10; filed Oct 22, 2004, 11:00 a.m.: 28 IR 788; readopted filed Nov 12, 2010, 2:53 p.m.: 20101208-IR-170100605RFA; filed Jun 16, 2011, 8:44 a.m.: 20110713-IR-170100662FRA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

Rule 4.3. Customer-Generator Interconnection Standards

170 IAC 4-4.3-1 Definitions
Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2-1

(a) The definitions in this section apply throughout this rule.
(b) “Area network” means a type of electric distribution system served by multiple transformers interconnected in an electrical network circuit that is generally used in large metropolitan areas, which are densely populated, in order to provide high reliability of service.
(c) “Commission” means the Indiana utility regulatory commission.
(d) “Customer-generator facility” means an arrangement of equipment for the production of electricity that is owned and operated by:
(1) an eligible customer; or
(2) a third party at the eligible customer’s site.
(e) “Eligible customer” means any:

(1) person;
(2) firm;
(3) corporation;
(4) municipality; or
(5) other government agency;

that has agreed, orally or otherwise, to pay for electric service received from an investor-owned electric utility and is in good standing with that utility.

(f) "Equipment package" means a group of components connecting an electric generator with an electric distribution system and includes all interface equipment including any of the following:

(1) Switchgear.
(2) Inverters.
(3) Other interface devices.

The term includes an integrated generator or electric source.

(g) "Interconnection" or "interconnected" means the physical, parallel connection of a customer-generator facility with a distribution facility of an investor-owned electric utility.

(h) "Investor-owned electric utility" or "utility" means a public utility, as defined in IC 8-1-2-1:

(1) that provides electricity;
(2) that is financed by the sale of securities; and
(3) whose business operations are overseen by a board representing the utility's shareholders.

(i) "Nameplate capacity" means the full-load continuous rating of a generator under specified conditions as designated by the manufacturer.

(j) "Parallel" means the designed operation of the:

(1) customer-generator facility;
(2) interconnection equipment; and
(3) investor-owned electric utility's system;

where the instantaneous flow of electrical energy may automatically occur in either direction across the interconnection point between the customer-generator facility and the electrical utility's distribution system.

(k) "Spot network" means a type of electric distribution system that uses two (2) or more intertied transformers to supply an electrical network circuit. A spot network is generally used to supply power to a single customer or a small group of customers.

(l) "System emergency" means a condition on a utility's system reasonably likely to result in any of the following:

(1) A significant disruption of service to a customer.
(2) A substantial deviation from a normal service standard.
(3) An endangerment to life or property.

(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-1; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2170; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.3-2 Applicability

Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

This rule shall apply to any investor-owned electric utility, subject to the jurisdiction of the commission, that may now or hereafter be engaged in the:

(1) production;
(2) transmission;
(3) sale; or
(4) distribution;

of electric service and all customer-generator facilities that apply for interconnection with such utilities on or after the effective date of this rule. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-2; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2171; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR- 170130227RFA)*

170 IAC 4-4.3-3 Exemptions
Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

(a) Customer-generator facilities shall be exempt from revenue requirements and associated regulation under IC 8-1-2 as administered by the commission, except that the commission shall have authority over rates charged by electric utilities to customer-generator facilities.
(b) Upon agreement of an eligible customer and the utility, the customer-generator facility interconnection may be exempt from the requirements of this rule, except for the provisions of section 4(f) and 4(g) of this rule. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-3; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2171; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR- 170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.3-4 General interconnection provisions
Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

(a) Each investor-owned electric utility shall provide each of the following three (3) procedures for applications for interconnection of customer-generator facilities and use:
   (1) The Level 1 review procedure described in section 6 of this rule for applications to connect inverter-based customer- generator facilities that:
      (A) have a nameplate capacity of ten (10) kilowatts or less; and
      (B) meet the certification requirements of section 5 of this rule.
   (2) The Level 2 review procedure described in section 7 of this rule for applications to connect customer-generator facilities:
      (A) with a nameplate capacity of two (2) megawatts or less; and
      (B) that meet the certification requirements of section 5 of this rule.
   (3) The Level 3 review procedure described in section 8 of this rule for applications to connect customer-generator facilities to its distribution system that do not qualify for either Level 1 or Level 2 interconnection review procedures.
(b) Each utility shall designate a contact person or office from which an eligible customer can obtain basic application forms and information through an informal process.
(c) Each utility shall use commission-approved interconnection application and interconnection agreement forms.
(d) The utility may require the applicant to include a disconnect switch as a supplement to the equipment package.
(e) Application and interconnection review fees shall be set as follows:

(1) A utility shall not charge an application or other fee to an applicant that requests Level 1 interconnection review. However, if an application for Level 1 interconnection review is denied because the:
   (A) application does not meet the requirements for Level 1 interconnection review; and
   (B) applicant resubmits the application under another review procedure;
   the utility may impose a fee for the resubmitted application, consistent with this section.
(2) For a Level 2 interconnection review, the utility may charge fees up to fifty dollars ($50) plus one dollar ($1) per kilowatt of the customer-generator facility's nameplate capacity, plus the cost of any minor modifications to the electric distribution system or additional review, if required under section 7(q)(3) of this rule. Costs for minor modifications or additional review shall be:
   (A) based on utility estimates; and
   (B) subject to review by the commission or its designee.
   Costs for engineering work done as part of any additional review shall not exceed one hundred dollars ($100) per hour.
(3) For a Level 3 interconnection review, the utility may charge fees up to one hundred dollars ($100) plus two dollars ($2) per kilowatt of the customer-generator facility's nameplate capacity, as well as charges for actual time spent on any impact or facilities studies required under section 8 of this rule. Costs for engineering work done as part of any impact or facilities study shall not exceed one hundred dollars ($100) per hour. If the utility must install facilities in order to accommodate the interconnection of the customer-generator facility, the cost of such facilities shall be the responsibility of the applicant.

(f) The interconnection and operation of any customer-generator facility is secondary to and shall not interfere with the ability of the utility to meet its primary responsibility of furnishing reasonably adequate service to all customers.

(g) All the customer-generator facility electrical installations shall conform to the following:
   (1) The requirements of local ordinances and inspection authorities.
   (2) The applicable requirements of this rule.

(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-4; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2171; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.3-5 Certification of customer-generator facilities
Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

(a) In order to qualify for the Level 1 and the Level 2 interconnection review procedures described in sections 6 and 7 of this rule, a customer-generator facility must be certified as complying with the following standards, as applicable:
   (1) IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, as amended and supplemented, which is incorporated by reference herein. IEEE 1547 can be obtained through the IEEE at 445 Hoes Lane, P.O. Box 1331, Piscataway, New Jersey 08855-1331 or at www.ieee.org.
   (2) Underwriters Laboratories (UL) Standard 1741 on Inverters, Converters, and Controllers for Use in Independent Power Systems (January 2001), as amended and supplemented, which is incorporated by reference herein. UL Standards can be obtained through Underwriters Laboratories at 333 Pfingsten Road, Northbrook, Illinois 60062-2096 or at www.ul.com.

(b) An equipment package shall be considered certified for interconnection operation if it has been tested and listed by a nationally recognized testing and certification laboratory in compliance with subsection (a)(1).

(c) If the equipment package has been tested and listed in accordance with this section as an integrated package that includes a generator or other electric source, the:

(1) equipment package shall be deemed certified; and

(2) utility shall not require:

(A) further design review;

(B) testing; or

(C) additional certification;

of the listed equipment package.

(d) If the equipment package includes only the interface components, an interconnection applicant must show that the generator or other electric source being utilized with the equipment package is:

(1) compatible with the equipment package; and

(2) consistent with the testing and listing performed by the nationally recognized testing and certification laboratory.

If the generator or electric source being utilized with the equipment package is consistent with the testing and listing performed by the nationally recognized testing and certification laboratory, the equipment package shall be deemed certified, and the utility shall not require further design review, testing, or additional certification of the listed equipment package. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-5; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2172; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.3-6 Level 1 interconnection review

Authority: IC 8-1-1-3; IC 8-1-2.4

Affected: IC 8-1-2

(a) Each investor-owned electric utility shall adopt a Level 1 interconnection review procedure. The utility shall use the Level 1 review procedure for an application to interconnect a customer-generator facility that:

(1) is inverter-based;

(2) has a nameplate capacity of ten (10) kilowatts or less; and

(3) is certified in accordance with section 5 of this rule.

(b) For a customer-generator facility described in subsection (a), the utility shall approve interconnection under the Level 1 review if all of the applicable requirements in subsections (c) though (h) are met. A utility shall not impose additional requirements not specifically authorized under this section.

(c) If a customer-generator facility is to be connected to a radial distribution circuit, the aggregate generation nameplate capacity connected to the circuit, including the proposed nameplate capacity, shall not exceed five percent (5%) of the circuit annual peak load as most recently measured at the substation; the aggregate generation nameplate capacity connected to a line section, including the proposed nameplate capacity, shall not exceed ten percent (10%) of the line section annual peak load as most recently measured or estimated based on the most recently measured circuit load at the substation.

(d) The aggregate generation nameplate capacity on the distribution circuit to which the customer-generator facility will interconnect, including its nameplate capacity, shall not contribute more than ten percent (10%) to the circuit's maximum fault current at the point on which the primary level that is nearest the proposed point of common coupling.

(e) If a customer-generator facility is to be connected to a single-phase shared secondary, the aggregate generation nameplate capacity connected to the shared secondary, including the proposed nameplate capacity, shall not exceed the lesser of twenty (20) kVA or the nameplate rating of the service transformer.

(f) If a single-phase customer-generator facility is to be interconnected on a center tap neutral of a two hundred forty (240) volt service, the addition of the customer-generator facility shall not create an imbalance between the two (2) sides of the two hundred forty (240) volt service more than twenty percent (20%) of the nameplate rating of the service transformer.

(g) The customer-generator facility point of common coupling shall not be on:

(1) a transmission line;
(2) a spot network; or
(3) an area network.

(h) The customer-generator facility shall not violate any applicable provisions of IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, as identified by the utility.

(i) The utility shall notify the applicant within ten (10) business days after receiving an application for Level 1 interconnection review as to whether the application is complete. If the application is incomplete, the notification shall include a list detailing the information needed to complete the application.

(j) Within fifteen (15) business days after the utility notifies the applicant that the application is complete, the utility shall notify the applicant that the customer-generator facility:

(1) meets all of the criteria in subsections (c) through (h) that apply to the facility, and the interconnection will be finally approved upon completion of the process set forth in subsections (k) though (m); or
(2) has failed to meet one (1) or more of the applicable criteria in subsections (c) through (h), and the interconnection application is denied.

(k) If approved, the utility shall, within ten (10) business days after sending the notice of approval under subsection (j)(1), do the following:

(1) Notify the applicant if the utility will require inspection of the customer-generator facility for compliance with this rule before starting operation of the facility.
(2) Execute and send to the applicant a Level 1 interconnection agreement.

(l) An applicant that receives an interconnection agreement under subsection (k) shall do the following:

(1) Execute the agreement.
(2) Return the agreement to the utility at least ten (10) business days before starting operation of the customer-generator facility.
(3) Indicate the anticipated start date for operation of the customer-generator facility.

If the utility requires an inspection of the customer-generator facility, the applicant shall not begin operating the facility until completion of the inspection.

(m) Upon:

(1) receipt of the executed interconnection agreement; and
(2) satisfactory completion of any required inspection;

the utility shall approve the interconnection, conditioned on approval by the electric code officials with jurisdiction over the interconnection.

(n) If an application for Level 1 interconnection review is denied because it does not meet one (1) or more of the applicable requirements of this section, an applicant may resubmit the application under Level 2 or Level 3 interconnection review procedure as appropriate. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-6; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2172; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR- 170130227RFA)*

170 IAC 4-4.3-7 Level 2 interconnection review
Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

(a) Each investor-owned electric utility shall adopt a Level 2 interconnection review procedure. The utility shall use the Level 2 review procedure for an application to interconnect a customer-generator facility that:
(1) has a nameplate capacity of two (2) megawatts or less; and
(2) is certified in accordance with section 5 of this rule.

(b) For a customer-generator facility described in subsection (a), the utility shall approve interconnection under the Level 2 review if all of the applicable requirements in subsections (c) through (o) are met. A utility shall not impose additional requirements not specifically authorized under this section.

(c) If a customer-generator facility is to be connected to a radial distribution circuit, the aggregate generation nameplate capacity connected to the circuit, including the proposed nameplate capacity, shall not exceed fifteen percent (15%) of the line section annual peak load as most recently measured or estimated based on the most recently measured circuit load at the substation.

(d) The aggregate generation capacity on the distribution circuit to which the customer-generator facility will interconnect, including its capacity, shall not contribute more than ten percent (10%) to the circuit's maximum fault current at the point on which the primary level that is nearest the proposed point of common coupling.

(e) If a customer-generator facility is to be connected to a single-phase shared secondary, the aggregate generation capacity connected to the shared secondary, including the proposed capacity, shall not exceed the lesser of twenty(20) kVA or the nameplate rating of the service transformer.

(f) If a single-phase customer-generator facility is to be interconnected on a center tap neutral of a two hundred forty (240) volt service, its addition will not create an imbalance between the two (2) sides of the two hundred forty (240) volt service more than twenty percent (20%) of the nameplate rating of the service transformer.

(g) The aggregate generation capacity on the distribution circuit to which the customer-generator facility will interconnect, including its capacity, shall not cause any:
(1) distribution protective equipment; or
(2) customer equipment on the distribution system;
to exceed ninety percent (90%) of the short circuit interrupting capability of the equipment. In addition, a customer-generator facility shall not be connected to a circuit that already exceeds ninety percent (90%) of the short circuit interrupting capability.

(h) If there are known or posted transient stability limits to generating units located in the general electrical vicinity of the proposed point of common coupling, for example, three (3) or four (4) transmission voltage level busses, the aggregate generation capacity, including the proposed facility, connected to the distribution low voltage side of the substation transformer feeding the distribution circuit containing the point of common coupling shall not exceed ten (10) megawatts.

(i) If a customer-generator facility is to be connected to three-phase, three (3) wire primary utility distribution lines, a three- phase or single-phase generator shall be connected phase to phase.

(j) If a customer-generator facility is to be connected to three-phase, four (4) wire primary utility distribution lines, the generator shall appear to the primary utility distribution line as an effectively grounded source.

(k) The customer-generator facility point of common coupling shall not be on a transmission line.

(l) If a customer-generator facility is to be connected to the load side of spot network protectors, the proposed facility shall:
(1) utilize an inverter-based equipment package; and

(2) together with the aggregated other inverter-based generation, not exceed the smaller of five percent (5%) of a spot network's maximum load or fifty (50) kilowatts.

(m) If a customer-generator facility is to be connected to any network, the proposed facility must utilize a protective scheme that will ensure that its current flow will not affect the network protective devices including reverse power relays or a comparable function. Synchronous customer-generator facilities shall not be interconnected to a secondary network.

(n) If a customer-generator facility that:

(1) is an induction generator; or

(2) utilizes inverter-based protective functions;

both of which include reverse power relays functions, the proposed facility, in aggregate with other generation interconnected on the load side of the network protective devices, will not exceed the lesser of ten percent (10%) of the minimum load on the network or fifty (50) kilowatts.

(o) The customer-generator facility shall not violate any applicable provisions of IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, as identified by the utility.

(p) The utility shall notify the applicant within ten (10) business days after receiving an application for Level 2 interconnection review as to whether the application is complete. If the application is incomplete, the notification shall include a list detailing all of the information needed to complete the application.

(q) Within fifteen (15) business days after the utility notifies the applicant that the application is complete, the investor- owned electric utility shall perform an initial review to determine if the applicable requirements of subsections (c) through (o) are met. During the initial review the utility may, at its own expense, conduct any studies or tests it deems necessary to evaluate the proposed interconnection. The initial review shall result in one (1) of the following determinations:

(1) The customer-generator facility meets the applicable requirements in subsections (c) through (o). In this case, the utility shall:

(A) notify the applicant that the interconnection will be finally approved upon completion of the process set forth in subsections (r) through (t); and

(B) within ten (10) business days after this notice, provide the applicant with an executable interconnection agreement.

(2) The customer-generator facility has failed to meet one (1) or more of the applicable requirements in subsections (c) through (o); however, the utility has determined that the customer-generator facility can be interconnected consistent with safety, reliability, and power quality. In this case, the utility shall:

(A) notify the applicant that the interconnection will be finally approved upon completion of the process set forth in subsections (r) through (t); and

(B) within ten (10) business days after this notice, provide the applicant with an executable interconnection agreement.

(3) The customer-generator facility has failed to meet one (1) or more of the applicable requirements in subsections (c) through (o); however, the initial review indicates that additional review may enable the utility to determine that the customer- generator facility can be interconnected consistent with safety, reliability, and power quality. In such a case, the utility shall:

(A) offer to perform additional review to determine whether minor modifications to the electrical distribution system would enable the interconnection to be made consistent with safety, reliability, and power quality;

(B) provide to the applicant a nonbinding, good faith estimate of the costs of the additional review or the minor modifications, or both; and

(C) undertake the additional review or modifications in accordance with subsection (u).

(4) The customer-generator facility has failed to meet one (1) or more of the applicable requirements of subsections (c) through (o), and the initial review indicates that additional review would not enable the utility to determine that the customer-generator facility can be interconnected consistent with safety, reliability, and power quality. In such a case, the utility shall:

(A) notify the applicant that the interconnection application has been denied; and

(B) provide an explanation of the reason or reasons for the denial, including a list of additional information or modifications, or both, to the customer-generator's facility that would be required in order to obtain an approval under Level 2 interconnection procedures.

(r) An applicant that receives an interconnection agreement under subsection (q)(1) or (q)(2) shall do the following:

(1) Execute the agreement.

(2) Return the agreement to the utility at least ten (10) business days before starting operation of the customer-generator facility.

(3) Indicate to the utility the anticipated start date for operation of the customer-generator facility.

(s) The utility may:

(1) require an inspection of a customer-generator facility for compliance with this section before operation; and

(2) require and arrange for witness of commissioning tests as set forth in IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems.

The utility shall schedule any inspections or tests under this section promptly and within a reasonable time after submittal of the application. The applicant shall not begin operating the customer-generator facility until after the inspection and testing is completed.

(t) For an applicant that receives an interconnection agreement under subsection (q)(1) or (q)(2), approval of interconnected operation of the customer-generator facility shall be conditioned on all of the following:

(1) The interconnection has been approved by the electrical code official with jurisdiction over the interconnection.

(2) Any utility inspection or witnessing of commissioning tests arranged under subsection (s) are successfully completed.

(3) The planned start date provided by the applicant under subsection (r)(3) has passed.

(u) For an applicant that pays for additional review under subsection (q)(3), within ten (10) business days from the receipt of payment, the utility shall perform any additional review and notify the applicant of the results. If the additional review determines that the customer-generator facility can be interconnected without adversely affecting safety, reliability, and power quality upon the completion of utility system modifications, the utility shall provide a cost estimate of the modifications with the results. Within twenty (20) business days after receipt of the cost estimate, the applicant will either:

(1) send payment to the utility for the estimated cost; or

(2) notify the utility in writing that it does not wish to proceed with the project.

Upon receipt of payment, the utility shall proceed to schedule and complete the required modifications or new construction. Within five (5) business days after the completion *[sic., of]* the modifications or new construction, the utility shall provide the applicant with an executable interconnection agreement and notification that the interconnection will finally be approved upon completion of the process set forth in subsections (r) through (t).

(v) If an application for Level 2 interconnection review is denied because it does not meet one (1) or more of the applicable requirements in this section, an applicant may resubmit the application under the Level 3 interconnection review procedure as appropriate. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-7; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2173; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-*

170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.3-8 Level 3 interconnection review
Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

(a) Each investor-owned electric utility shall adopt a Level 3 interconnection review procedure. The utility shall use the Level 3 review procedure for an application to interconnect a customer-generator facility that:
 (1) is connected to its distribution system; and
 (2) does not meet the requirements of section 6 or 7 of this rule.

(b) The utility shall do the following:
 (1) Conduct an initial review of the application.
 (2) Offer the applicant the opportunity to meet with utility staff to discuss the application.

(c) The utility shall provide an impact study agreement to the applicant, which shall include a good faith estimate of the cost for an impact study to be performed by the utility.

(d) If the proposed interconnection may affect electric transmission or delivery systems other than those controlled by the utility, operators of these systems may require additional studies to determine the impact of the interconnection on these systems. The utility shall coordinate the studies of other operators, but shall not be responsible for their timing. The applicant shall be responsible for the costs of any such additional studies required by other affected system operators. The studies shall be conducted only after the applicant has provided written authorization.

(e) After the applicant has executed the impact study agreement and has paid the utility the amount of the good faith estimate required under subsection (c), the utility shall conduct the impact study and notify the applicant of the results as follows:
 (1) If the impact study indicates that only insubstantial modifications to the utility's electric distribution system are necessary to accommodate the proposed interconnection, the utility shall send the applicant an interconnection agreement that details the following:
  (A) The scope of the necessary modifications.
  (B) An estimate of their cost.
 (2) If the impact study indicates that substantial modifications to the utility's electric distribution system are necessary to accommodate the proposed interconnection, the utility shall do the following:
  (A) Provide a good faith estimate of the cost of the modifications.
  (B) Offer to conduct a facilities study at the applicant's expense, which will identify the types and cost of equipment needed to safely interconnect the applicant's customer-generator facility.

(f) If the applicant requests a facilities study under subsection (e)(2), the utility shall provide a facilities study agreement. The facilities studyagreement shall describe the work to be undertaken in the facilities studyand shall include a good faith estimate of the cost to the applicant for completion of the study. Upon execution by the applicant of the facilities study agreement, the utility shall conduct a facilities study, which shall identify the following:
 (1) The facilities necessary to safely interconnect the customer-generator facility with the utility's electric distribution system.
 (2) The cost of those facilities.
 (3) The time required to build and install those facilities.

(g) Upon completion of the facilities study, the utility shall provide the applicant with the results of the study

and an executable interconnection agreement. The agreement shall list the following:
(1) The conditions and facilities necessary to safely interconnect the customer-generator facility with the utility's electric distribution system.
(2) The cost of those facilities.
(3) The time required to build and install those facilities.

(h) If the applicant wishes to interconnect, the applicant shall do the following:
(1) Execute the interconnection agreement.
(2) Provide a deposit of the cost of the facilities identified in the facilities study.
(3) Complete installation of the customer-generator facility.
(4) Agree to pay the utility the amount required for the facilities needed to interconnect as identified in the facilities study.

(i) Within fifteen (15) business days after notice from the applicant that the customer-generator facility has been installed, the utility shall do the following:
(1) Inspect the customer-generator facility.
(2) Arrange to witness any commissioning tests required under IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems.

The utility and the applicant shall select a date by mutual agreement for the utility to witness commissioning tests.

(j) Provided the customer-generator facility passes any required commissioning tests satisfactorily, the utility shall notify the applicant in writing, within five (5) business days after the tests, of one (1) of the following:
(1) The interconnection is approved and the customer-generator facility may begin operation.
(2) The facilities study identified necessary construction that has not been completed, the date upon which the construction will be completed, and the date when the customer-generator facility may begin operation.

(k) If the commissioning tests are not satisfactory, the customer-generator shall repair or replace the unsatisfactory equipment and reschedule a commissioning test under subsection (i). *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-8; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2175; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.3-9 Requirements for ongoing operation of customer-generator facilities

Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

(a) The investor-owned electric utility may perform reasonable on-site inspections to verify the proper installation and continuing safe operation of the customer-generator facility and interconnection facilities:
(1) at reasonable times; and
(2) upon reasonable advance notice to the customer.

The cost of the inspection or inspections shall be at the utility's expense; however, the utility shall not be responsible for any other cost the customer may incur as a result of the inspection or inspections.

(b) The customer shall install, operate, and maintain the customer-generator facility in accordance with the manufacturer's suggested practices for safe, efficient, and reliable operation in parallel to the utility's system.

(c) The utility may isolate any customer-generator facility if the utility believes continued interconnection with the customer- generator facility creates or contributes to a system emergency. System emergencies causing discontinuance of interconnection shall be subject to verification by the commission upon a complaint made by the customer in accordance with the commission's consumer complaint rules.

(d) If the utility finds that the customer-generator's facility is not in compliance with the requirements of this rule, and the noncompliance adversely affects the safety, reliability, or power quality of the electric distribution system, the utility may require the customer-generator to disconnect the customer-generator facility until compliance is achieved. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-9; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2176; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.3-10 Liability insurance and indemnity

Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2-33; IC 8-1-2-34

(a) The liability insurance and indemnification requirements of a customer-generator facility that is also a net metering facility, as defined at 170 IAC 4-4.2-1, shall be in accordance with 170 IAC 4-4.2-8.

(b) The liability insurance and indemnification requirements of a customer-generator facility that is not also a net metering facility, as defined at 170 IAC 4-4.2-1, shall be as follows:

(1) Insurance provisions shall require a party to obtain only reasonable amounts of insurance against risks for which there is a reasonable likelihood of occurrence.

(2) The utility and the customer shall indemnifyand hold each other harmless from and against all claims, liability, damages, and expenses, including attorney's fees, based on any injury to any person, including loss of life or damage to any property, including loss of use thereof, arising out of, resulting from, or connected with, or that may be alleged to have arisen out of, resulted from, or connected with an act or omission by the other party or its:

(A) employees;
(B) agents;
(C) representatives;
(D) successors; or
(E) assigns;

in the construction, ownership, operation, or maintenance of the party's facilities.
(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-10; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2177; readopted filed Jul 12,2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

170 IAC 4-4.3-11 Tariff and reporting requirements

Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2

(a) Within sixty (60) days of the effective date of this rule, all investor-owned electric utilities shall submit for approval via the commission's thirty (30) day filing process generic interconnection application and interconnection agreement forms for each of the three (3) levels of review.

(b) To assist the commission in monitoring the effectiveness of this rule over time, each investor-owned utility shall file a report with the commission's electricity division before March 2 of each year following the effective date of this rule. The report shall contain the number, size, and type of the following:

(1) Customer-generator facilities detailed in all applications received during the pervious *[sic.]* calendar year and the resolution, for example, granted, denied, withdrawn, of the applications. The

report shall include the following:

(A) The application procedure (Level 1, 2, or 3) for all applications.

(B) The reason or reasons for any denied application or applications.

(2) The number, size, and type of customer-generator facilities interconnected, pursuant to Rule 4.3 as of December 31 of the previous calendar year. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-11; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2177; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

170 IAC 4-4.3-12 Customer complaints

Authority: IC 8-1-1-3; IC 8-1-2.4
Affected: IC 8-1-2-34.5

In the event an investor-owned electric utility and an eligible customer are unable to agree on matters relating to customer-generator facility interconnection, either party may raise a customer complaint to the commission in accordance with the commission's consumer complaint rules. *(Indiana Utility Regulatory Commission; 170 IAC 4-4.3-12; filed Mar 6, 2006, 9:45 a.m.: 29 IR 2177; readopted filed Jul 12, 2012, 2:12 p.m.: 20120808-IR-170120114RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)*

COMMENTS

Bose McKinney & Evans

Dear Mrs. Heline:

We commend the Indiana Utility Regulatory Commission ("IURC" or "Commission") for hosting a Technical Conference as a forum to address questions and concerns regarding the implementation of the newly-enacted IC § 8-1-40, also known as Senate Enrolled Act 309 ("SEA 309") on net metering and distributed generation. We are hopeful that this Technical Conference will result in clarification to the public and interested parties regarding how SEA 309 will be implemented. Bose McKinney & Evans LLP represents several clients that are affected by SEA 309, including the following types of customers with existing or planned distributed generation: industrial companies, solar installers, financing entities, schools, churches and municipalities. As utility practitioners, we appreciate the opportunity to provide comments in advance of the Technical Conference, so that we may provide sound advice to our clients about the bill's impact. As we watched the legislative process surrounding SEA 309 unfold and have reviewed the bill in its final form, we raise the following issues and questions for the Commission's consideration:

1. It appears as though the customer must "install" a net metering facility and be "participating in the electricity supplier's metering tariff" by December 31, 2017 to meet the deadline for the 30-year "grandfathering" of the current net metering rules (*see* SEA 309, Section 13(a) and (b)). There does not appear to be any clear definition of what qualifies as an "install," nor are we clear on the timing and steps required to ensure customers are "participating" in the net metering tariff. Must an interconnection agreement be in place? What happens if a customer's project is in the "pipeline" (e.g., the interconnection application is in process and/or has been approved), but the project is not yet fully "installed" by December 31? If a customer executes a net metering agreement during the December billing period, would it take effect immediately, or would the utilities claim the customer didn't "participate" until the January 2018 billing period (therefore after December 31, 2017 deadline)? What if the utility caused additional delay that was not the fault of the customer? Such a delay might not be intentional, but rather might simply be caused by the sheer volume of interconnection requests the utility may receive in advance of the deadline. From a practical standpoint, it would be very helpful for the Commission to provide the specific requirements necessary to meet this December 31, 2017 deadline.

2. What, if any, changes does the Commission anticipate will be necessary to the Customer- Generator Interconnection Rules (170 IAC 4-4.3) as a result of SEA 309? For example, a new definition of "distributed generation" was created in SEA 309, Section 3(a)(2), which requires that the generation device on the customer's premises be owned by the customer. However, 170 IAC 4-4.3 -1(d) provides that a customer-generator facility includes equipment for the production of electricity owned by a third party at the customer's site (thus, customer-generator facilities can be, but are not required to be, owned by the customer). How would Section 3(a)(2) in SEA 309 impact customer- generation projects financed or owned by third parties?

3. Section 3 of the bill also requires that the nameplate capacity be the lesser of 1 MW or the customer's average annual consumption of electricity. As a threshold issue, this comparison is problematic because it compares MW (instantaneous power) to MWh (energy production over a period of time). We have interpreted this to mean that the nameplate capacity must be the lesser of 1 MW or the system size (in kW or MW) that is expected to generate electricity over the course of a year that is not greater than the

customer's average annual consumption of electricity. We would appreciate guidance from the Commission about whether this is the right approach, particularly given the number of assumptions that can be made regarding how much power a system is expected to produce. Given that consumption can vary widely with the weather, over what period of time should this average annual consumption be calculated? What happens if a solar photovoltaic ("PV") system is installed according to these guidelines, and then in the future, the customer subsequently improves the efficiency of the building such that the solar PV system would generate considerably more power than the customer's average annual consumption?

4. After 2022, the price a customer will receive for excess distributed generation is the average annual market price for electricity (meaning the hourly market price established in the wholesale market, *see* SEA 309, Sections 6 and 17). Since regional transmission organization pricing varies from hub to hub, how will a customer know which price is applicable? How will customers and solar installers be able to forecast the price they will receive for excess generation (particularly in regard to meeting the right to know provisions noted below, related to the price of electricity they will be credited under SEA 309, Section 23(a)(5))?

5. The total amount of net metering nameplate capacity was raised from 1% to 1.5% (see SEA 309, Section 9). Is nameplate capacity in alternating current (AC) or direct current (DC)? Forty percent of that nameplate capacity is now reserved for residential customers, and 15% is reserved for biomass. That leaves 45% (or 0.675% of the total 1.5%) reserved for all other types of customers, including schools. The IURC's March 2017 Net Metering Report indicates that Indiana is already 1/10 of the way to that point, with approximately 0.08% of the existing nameplate capacity currently serving non-residential customers. Will the Commission require reporting for biomass nameplate capacity? Particularly given these percentages are based on the most recent summer peak, which can vary widely from year-to-year due to weather, will the Commission require more frequent reporting than annually (particularly after the summer peaking season), so that customers whose projects are being contemplated or who are not yet complete will have advanced notice that these caps are close to being met?

6. Customers producing distributed generation will receive a new delivery charge which is intended to capture costs the utility incurs from serving those customers (*see* SEA 309, Section 18). Since these rates have not yet been filed or approved by the IURC, it is difficult to determine what financial impact this new delivery charge will have, but it most certainly will at least partially offset any credit the customer receives at the wholesale rate for excess generation. What process does the Commission anticipate that utilities will use to establish delivery charges?

7. There are also several new customer "right-to-know" provisions, including the amount of electricity produced, tax implications of the project, rate for excess generation, insurance and responsibilities for installation and removal of equipment. While we support transparency, we ponder how installers of distributed generation will meet these right-to- know requirements, particularly given the unknowns we have identified regarding what rates customers will receive for excess generation and be charged for delivery costs? If an installer cannot own the equipment under the net metering rule, how does it make representations regarding insurance, removal of equipment, etc. for facilities it does not own?

8. The Attorney General is authorized to enforce the new distributed generation law, including by receiving

customer complaints regarding installation and ownership of distributed generation equipment. Does the Commission's Consumer Affairs Division intend to continue to take consumer complaints regarding net metering, particularly with regard to any disputes about whether a customer has met the December 31, 2017 deadline for grandfathering?

9. Does the Commission plan to evaluate in the impacts of SEA 309 and present the results of the Technical Conference to the Summer Interim Study Committee that is to consider issues related to self-generation by schools?

Should you or the Commission staff have any questions or require any clarification of our comments in advance of the Technical Conference, please don't hesitate to contact us.

Sincerely,
Kristina Kern Wheeler
Nikki Gray Shoultz

Carmel Green Initiative, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Indiana Distributed Energy Alliance and Sierra Club— Hoosier Chapter

Per the request of the Indiana Utility Regulatory Commission (IURC) in preparation for the Technical Conference to be held on July 20th, please find below questions, concerns, and comments related to the implementation of Senate Enrolled Act (SEA) 309 and net metering generally from Carmel Green Initiative, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Indiana Distributed Energy Alliance (IndianaDG), and Sierra Club— Hoosier Chapter. We respectfully reserve our right to supplement this list of questions and comments, especially since we limited this submission to our immediate concerns about the implementation of SEA 309 and provisions related to net metering. We would anticipate a much more involved process for provisions related to cogeneration or what happens after the expiration of net metering, for example.

1) SECTIONS 13 & 14: There is a high degree of uncertainty regarding certain provisions contained within Sections 13 and 14 of SEA 309.

i) Both sections apply to "a customer that installs a net metering facility (as defined in 170 IAC 4-4.2-1(k))". However, the word "installs" is not defined in SEA309, nor is it defined in the 170 IAC 4-4.2-1(k). What does "installs" mean?

ii) We would note that the definition provided in 170 IAC 4-4.2-1(k) states that a "net metering facility means an arrangement of equipment for the production of electricity from an eligible net metering resource, that is owned and operated by a net metering customer." This definition is vague and may need clarification.

iii) Both sections apply to "a customer that is participating in an electricity supplier's net metering tariff". However, the word "participating" is unclear and undefined. When is a customer "participating"? Is it when the interconnection agreement is filed with the utility, when the interconnection agreement is approved by the utility, when the meter is dropped, when the final inspection is complete, etc.? If the definition is interpreted to mean any time after the interconnection agreement is filed with the utility by the customer, then we have a host of concerns:

a. There are multiple Solarize[1] campaigns across the State, as well as an overall sense of urgency to have panels installed prior to the December 31, 2017 deadline contained within SEA 309. This is creating concern that electricity suppliers may slow-walk new installations, creating a bottle-neck of applications, similar to the issues addressed in IURC Cause No. 44344. What can the IURC do to alleviate the concerns of the public and ensure customers of their ability and their right to get in under the extremely tight deadlines the legislation imposes without impediments from the utility, including a utility requiring unnecessary equipment like an external disconnect switch for small inverter-based systems or taking advantage of the complex and multiple rounds of paperwork and hand-offs in the interconnection process? These issues were addressed in Cause No. 44344.[2]

iv) Both sections state that a customer "shall continue to be served under the terms and conditions of the net metering tariff until" the tariff expires or "when the customer removes from the customer's premises or replaces the net metering facility". However, this is ambiguous and should be clarified. For example:

a. Does this mean that a customer loses their net metering status if they replace a PV module, inverter, or any other component of the net metering facility due to storm damage, equipment failure, or any Force Majeure event which is not the fault of the customer?

b. Many customers install a few panels due to financial resources or other constraints, with the intent of adding to the system in the future. Will customers lose their net metering status if PV modules are added to their existing net metering facility? Will customers lose their net metering status if the addition of PV modules requires a new inverter, which may require a new interconnection agreement?

c. What if the roof needs to be replaced or there is an issue with a homeowner's association requiring the facility to be removed and replaced with the same facility or a new facility?

d. Will customers maintain their net metering status if they upgrade their PV modules or any other component of the net metering facility to increase the efficiency or energy production of their system? A recent example which has been brought to our attention is the new Tesla solar roof. So, what would happen to a customer's net metering status if she replaces her existing net metering facility with a Tesla solar roof?

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[1] *See, e.g.*, this resource for an explanation of Solarizing a community: http://www.nrel.gov/docs/fy12osti/54738.pdf.

[2] Please see CAC's post-hearing brief, available here, for more information: https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/d6c95baf-7784-e611-8107-1458d04eabe0/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44344_7_18_20149-16-34pm.pdf.

e. Will customers maintain their net metering status if they add a battery storage system to their existing net metering facility?

f. Will customers maintain their net metering status if they move panels due to re-roofing, remodeling, or other reasons?

v) Both sections state that the net metering status can be transferred to 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))". However, successor in interest is not defined in SEA 309.

a. Would a successor in interest include a renter who assumed responsibility for the electric bill, but ownership of the property was not transferred?

b. Is there a limit to the number of successors in interest who could participate in the net metering tariff?

c. Will the electricity supplier provide documentation clearly stating the eligibility of the net metering facility which could be provided to any potential successors in interest? Should the interconnection agreement follow the property rather than the customer?

2) **<u>SECTION 12:</u>** SEA 309 at Section 12(a)(2)(B) directs the IURC to modify the net metering rule "to require the reservation of…15% of 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)." This would be in addition to the existing required reservation of 40% of capacity for residential customers per Section 12(a)(2)(A). These required reservations raise the following questions:

a. Will non-residential installations and installations not utilizing organic waste biomass be cut off prior to the electricity supplier reaching 1.5% of summer peak because of those reservations? Meaning, does the IURC consider those "set- asides"? To the best of our knowledge, no net metering facility utilizing organic waste biomass has requested to participate in net metering since the adoption of the current rule in 2011. We believe it is likely that there will be no applications for these technologies going forward. Therefore, and if the IURC does consider that 15% reservation a "set-aside", will the IURC reallocate this 15% capacity to other eligible technologies at a certain point in time? At what point would the reservation of this 15% capacity for certain customer classes or technologies be cut-off?

b. Who will track the remaining capacity available to those specific customer classes and fuel sources, and will that information be public and reported in a real time or timely fashion?

3) **<u>SECTION 23:</u>** There are many concerns and questions related to Section 23 of SEA 309, which include, but are not limited to, items such as when a rulemaking related to Section 23 will begin; what is required for and who will provide the payback charts to customers; what is required for and who will provide the projection of electricity prices; and, what is required for and who will provide the projection of Solar Renewable Energy Credit (SREC) prices. However, it is important to note that it is not clear if Section 23 even applies to net metering facilities. Section 23 is applicable to a "customer that produces distributed generation". The definition of distributed generation contained within Section 3 of Chapter 40 of SEA 309 "does not include electricity produced by…A net metering facility (as defined in 170 IAC 4-4.2-1(k)) operating under a net metering tariff." Does the IURC believe that Section 23 applies to net metering facilities? If the answer is yes, we would reserve our right to provide the IURC with specific questions related to Section 23 at a later date and would request further discussion on this since it appears that this would require a separate effort and coordination with the attorney general.

4) **SECTION 11:** Section 11(a) of SEA 309 states that the IURC "may not approve changes to an electricity supplier's net metering tariff…Except as provided in sections 12 and 21(b) of this chapter"(emphasis added).

   a. We already discussed the referenced Section 12 above in #2.

   b. However, the referenced Section 21(b) authorizes the IURC to adopt changes to both the net metering rule and the interconnection rule "only as necessary to: (a) update fees or charges; (b) adopt revisions necessitated by new technologies; or
   (c) reflect changes in safety, performance, or reliability standards." Does the IURC envision adopting changes beyond the prescribed changes in Section 12 to the existing rules, which may include potential new fees, charges or standards that may impose additional costs or requirements to net metering customers on top of what is imposed elsewhere in SEA 309? If so, would that not conflict with the grandfathering provisions, or at a minimum the "spirit" of the grandfathering provisions, contained within Sections 13 and 14?

5) **SECTION 3:** Under Section 3(a)(3)(A) of Chapter 40 in SEA 309, distributed generation means "electricity produced by a generator or other device that is….sized at a nameplate capacity of the lesser of not more than one (1) megawatt…" There is a difference of opinion regarding how to interpret the 1MW cap for net metering facilities. Is the 1MW cap based on a per meter basis, or is the 1MW cap based on a per customer basis?

6) **OTHER CONCERNS:** There are things occurring in the field with installers and their prospective net metering customers which have not, to our knowledge, arisen in the past before the passage of SEA 309, besides the issues investigated by the Commission in Cause No. 44344 and mentioned in CAC's post-hearing brief in Cause No. 44344.[3] We feel it necessary to share with the IURC some examples of those experiences, which include:

   a. **Changing Policies with regard to Requiring an External Disconnect Switch**. Duke Energy Indiana (DEI) has recently insisted that an external disconnect switch be installed for a Level One installation, which is a change to their current practice. This was not the case for DEI prior to the enactment of SEA 309. Furthermore, there is no publicly available document from DEI reflecting this requirement and change in policy. What can the IURC to do to prevent these types of changes from occurring, and to ensure that changes such as this are communicated to the public in a timely

[3] https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/d6c95baf-7784-e611-8107-1458d04eabe0/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44344_7_18_20149-16-34pm.pdf

and transparent manner? Similarly, we understand that NIPSCO and I&M still require an external disconnect switch for a Level One installation. Yet in Cause No. 44344, Vectren changed its policy to cease requiring external disconnect switches for Level 1 interconnections and entered into the following Stipulation of Facts with Complainant Morton Solar and Wind, LLC (see Joint Exhibit 1 in that Cause):

i. Section 170 IAC 4-4.3-4(d) provides that a utility may require a customer generation facility to provide a disconnect switch as a supplement to the equipment package.
ii. This is optional at the discretion of the utility; Vectren South requires an external disconnect switch, including a switch for Level 1 and Level 2 systems.
iii. Brad Morton estimates that the cost of an external disconnect switch is $500 or more.
iv. Customer-owned generation facilities must comply with Underwriters Laboratories Standard 1741 and IEEE Standard 1547 to qualify for a Level 1 or Level 2 interconnection review.
v. These standards require inverters to automatically cease to energize the circuit to which it is connected.
vi. Indiana Net metering reporting filed with the Commission for calendar years 2009-2012 identify no emergency disconnects for Indiana investor owned utilities. The 2012 report indicates that 388 customers are participating in net metering in Indiana among Indiana's investor-owned electric utilities.
vii. Vectren South will not require customer owned generation facilities that otherwise qualify as a Level 1 interconnection to include an external disconnect switch.

This raises several concerns about the lack of consistency between utilities with regard to the imposition of certain requirements, the discretion provided to utilities to require said equipment, and how this will delay the process for individuals wishing to get in under the December 31, 2017 deadline in SEA 309 or to make other deadlines contemplated in SEA 309.

b. **Mandatory Meter Changes**. Another recent net metering and interconnection issue with DEI concerns mandatory meter changes for net metering customers which seeks to add an additional 14 business days to the Interconnection Process which is not addressed in the current Interconnection Rule. What can the IURC do by way of coordinating and speeding up the IOU practice of meter change after a completed installation? If "installs" is interpreted to mean before this would occur, then this issue could be moot.

c. **Delays with Interconnection Process.** Currently, for a Level 1 interconnection review, the utility must notify the applicant as to whether the application is complete within 10 business days of receiving the application. 170 IAC 4-4.3- 6(i). Within 15 business days of notification of a complete application, the utility must inform the applicant as to whether the application is approved, pending completion of the review process. 170 IAC 4-4.3-6(j).Within 10 business days of sending the approval notice, the utility must execute and send to the applicant a Level 1 interconnection agreement, which the applicant must then execute and return to the utility at least 10 business days before starting operation of the customer-generator facility. 170 IAC 4-4.3-6(k)(2), .3-6(l). The durations required for utility approvals (pre-project interconnection applications and post-project meter change/system approval) have become more variable, and generally longer. In some cases, it has been pronounced. Interconnection approval processes vary in detailed requirements and time to execute, sometimes taking much longer than the timeline outlined above, even with no technical review required. In some cases, the utility does not copy the installer, only its own customer, which causes confusion and limits the installers' ability to track the schedule. But this also varies between utilities. These types of situations were major issues addressed in Cause No. 44344[4] and is now of critical importance as the Commission interprets what the statute means with regard to when "a customer that installs a net metering facility" and when "a customer that is participating in an electricity supplier's net metering tariff" especially for purposes of the December 31, 2017 deadline. What can the IURC do to ensure consistency and fairness across the State with respect the process?

d. **Eligibility of Emerging Renewable Energy Technologies.** A solar installer was recently asked about net metering for an Indianapolis Power and Light (IPL) customer who wants to install a battery back-up system. IPL responded that such a solar customer with a battery backup would not be eligible for net metering. IPL indicated that the current definition of eligible technologies as per 170 IAC 4-4.2- 1 and IC 8-1-37-4 "Clean energy resource" does not require IPL to net meter "energy storage facilities or technologies". This is a new development as customers have been permitted to install solar systems with energy storage and participate in net metering. We would request that the IURC clarify this issue. We would note that the existing net metering rule defines "eligible net metering energy resource" to include "***Other emerging renewable energy technologies the commission determines appropriate.***" 170 IAC 4-4.2-1(d)(2).

Indiana Energy Association (Duke Energy, Indiana Michigan Power, Indianapolis Power & Light, Northern Indiana Public Service Co., and Vectren Energy Delivery of Indiana, Inc.)

Dear Ms. Heline:

On behalf of the electric utility members of the Indiana Energy Association (Duke Energy, Indiana Michigan Power, Indianapolis Power & Light, Northern Indiana Public Service Co., and Vectren Energy Delivery of Indiana, Inc.), the IEA is hereby submitting the enclosed comments in response to the request from the Indiana Utility Regulatory Commission for questions, concerns, and examples regarding the Implementation of Net Metering Legislation (SEA 309) and the Technical Conference scheduled for July 20, 2017.

Thank you for considering our comments. If you have any questions or comments, please do not hesitate to contact me at (317) 607-7791 or trushenberg@indianaencrgy.org.

Very Respectfully,

Timothy J. Rushenberg
Vice President

[4] https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/d6c95baf-7784-e611-8107-1458d04eabe0/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44344_7_18_20149-16-34pm.pdf

IEA Electric Utilities' Proposed Guidelines for Implementation of SEA 309's Grandfathering Provisions Relating to Net Metering

(<u>for Level 1[5] and Level 2[6] Interconnections</u>)

If a Customer has installed or installs a net metering facility, as defined in 170 IAC 4-4.2-1(k), before January 1, 2018, and is participating in a Utility's net metering tariff on December 31, 2017, that Customer may continue to participate in the net metering tariff *(i.e.,* may receive a full retail rate credit for excess generation exported to the Utility) until the earlier of (1) a removal or replacement of the Customer's net metering facility, [7] or (2) July 1, 2047. *See* new Ind. Code § 8-1-40-14.[8]

Accordingly, to qualify for "grandfathering," **the Customer must achieve two key milestones <u>by December 31, 2017</u>:**

(1) **The Customer must have its net metering equipment installed**. The Oxford English Dictionary defines installed as "to place in position or connect for service or use." As used in SEA 309, the Customer's net metering equipment must be in place and ready to be operated - and such installation must be consistent with an interconnection application submitted to and approved by the Utility pursuant to the IURC's interconnection rules (170 IAC 4-4.3), as well as consistent with SEA 309, the IURC's net metering rules (170 IAC 4-4.2) and the Utility's net metering tariff; and

(2) **The Customer must be participating in its Utility's net metering program and tariff**. Sec. 21(a) of SEA 309 states "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

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[5] Per IAC 170 4-4.3-6(a), a Level 1 interconnection involves customer/generators with distributed generation facilities that are inverter-based having nameplate capacity of 10 kilowatts or less and are certified in accordance with 170 IAC 4-4.3-5 .

[6] Per IAC 170 4-4.3-6(a), a Level 2 interconnection involves customer/generators with distributed generation facilities that have nameplate capacity of 2 megawatts or less and are certified in accordance with 170 IAC 4-4.3-5. (But note that per 170 IAC 4-4.2-l(j), a net metering facility may not exceed 1 megawatt.)

[7] The replacement of some or all of the components of a Customer's net metering facility - for example due to damage or normal wear and tear - will be considered to be a repair, rather than a replacement that would terminate grandfathering, so long as the facility retains the same nameplate capacity. An increase in the facility's nameplate capacity will not be eligible for net metering service and will be assumed to be the source of the base amount of excess generation.

[8] SEA 309 creates a second grandfathering opportunity and these guidelines will also apply for this second grandfathering opportunity: *If a Customer installs a net metering facility, as defined in 170 IAC 4-4.2-l(k), after December 31, 2017 but before the date the Utility's net metering tariff terminates pursuant to SEA 309 (i.e., the earlier of July 1, 2022, or the date the Utility's aggregate net metering nameplate capacity reaches 1.5% of its most recent peak summer load), that Customer may continue to participate in the net metering tariff (i.e., may receive a full retail rate credit for excess generation exported to the Utility) until the earlier of: (1) a removal or replacement of the Customer's net metering facility; or (2) July 1, 2032. See new Ind. Code § 8-1-40-13.*

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." Therefore, a Customer will be participating in the net metering program **if**, consistent with the IURC's interconnection rules (170 IAC 4-4.3), the Customer has (a) submitted to the Utility a complete application for interconnection, (b) received from the Utility notice that its application is complete, [9] (c) received notice from the Utility that the application meets the required interconnection criteria outlined in 170 IAC 4-4.3-6(c) through (h)(for Level 1 interconnections) or in 170 IAC 4-4.3-7(c) through (o)(for Level 2 interconnections), [10] (d) received from the Utility an executable interconnection agreement, [11] and (e) returned to the Utility an executed interconnection agreement. Note that under the Commission's interconnection rules, these requirements will require a minimum of 35 business days (more if the Customer's application is incomplete or denied and must be re-submitted).

Grandfathering is contingent upon the Customer meeting all applicable requirements of SEA 309, the IURC's net metering and interconnection rules, and the Utility's net metering tariff, in addition to achieving the above two key milestones by December 31, 2017. Such requirements include, but are not limited to, the following:

- The net metering facility must be a renewable facility, as defined by Ind. Code 8-1-37(a)(1) thru (a)(8)[12] (such as wind, solar, photovoltaic, biomass);
- The Customer must be in good standing with the Utility, as defined by 170 IAC 4-4.2-1(e);
- The Customer's net metering facility must be sized so as to be used primarily to offset all or a part of the Customer's own annual electricity requirements, and in any event may not exceed 1 megawatt;
- The net metering facility must be located on the Customer's premises;
- The net metering facility must be owned and operated by the Customer;
- The Customer must have liability insurance and must indemnify the Utility, consistent with 170 IAC 4-4.2-8; and
- The Customer must comply with the Customer-Generator Interconnection Standards and deadlines set out in 170 IAC 4-4.3 (and any applicable Utility tariff requirements).

The Utilities will work to meet the timeframes set out in the Commission's interconnection rules as expeditiously as possible. **In the event that the Customer achieves the two key milestones discussed above, and the Utility is unable to complete its inspections and upgrades prior to January 1, 2018, the Customer will be**

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[9] The IURC's Level 1 and Level 2 interconnection rules require that a Utility must notify a Customer whether an application is complete within 10 business days of receiving the Customer's application. *See* 170 IAC 4-4.3-6(i).

[10] The IURC's interconnection rules require that a Utility must notify a Customer whether the Customer's application meets the required interconnection criteria outlined in the IURC's interconnection rules within 15 business days after the Utility notified the Customer whether the application was complete. *See* 170 IAC 4-4.3-6(j) and 170 IAC 4-4.3-7(q).

[11] The IURC's interconnection rules require that a Utility send an executable interconnection agreement to a Customer within 10 business days after the Utility notified the Customer that its application meets the required interconnection criteria. *See* 170 IAC 4-4.3-6(k) and 170 IAC 4-4.3-7(q).

[12] Or other emerging renewable technologies approved by the IURC.

“grandfathered” -- subject to the Customer meeting all other requirements.

All local zoning, permitting, homeowners’ association, or similar approvals are the sole responsibility of the Customer.

Johnson-Melloh Companies

Good Morning, the following are questions re: the implementation of Net Metering Legislation (SEA 309):

Many of the concerns/questions we field relate to a completed project or installed project and specifically how that is defined. Per the language contained in SEA 309, ***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,*** the consensus is that if the customer has an interconnection agreement and an installed project they will continue to be served as stated above, thru July 1, 2047. Please confirm in detail.

- What constitutes the <u>installation</u> of a net metering facility, and more specifically, when is the project recognized as it relates to starting the Net Metering timeframe?
    - i.e., if customer receives interconnection and installs the net metering project in 2017, but IOU does not set their meter or inspect the project is the project deemed incomplete and therefore not recognized for Net Metering Tariff thru July 1, 2047?
- Define Installs as it pertains to a net metering project. Our customers want to know what constitutes an installation.
- What is the timeframe that an IOU has to approve interconnection?
- What is the timeframe that an IOU has to respond to setting the meter and performing a site inspection?
- What prevents IOU’s from dragging their feet and delaying a project past January 1, 2018?
- One IOU stated that if our customer has an interconnection agreement in place by 12/31/2017 and the project is under construction by that date they will honor the tariff thru July 1, 2047. Is that true?
- Another IOU stated that the customer must have the interconnection, the project built, the meter set and the site inspection completed by IOU before installation qualifies for tariff.
    - Again, what if IOU’s drag their feet?
- Can the IURC help IOU’s define ‘install’? It would be fair if the project had interconnection and was under construction by 12.31.2017, as that mitigates customer risk and exposure to IOU delays.

We have 6 customers that are working thru interconnection right now with 3 different IOU’s. Each IOU seems to have a different interpretation regarding the tariff and what an installation is. This is causing undue risk and concern that can be mitigated with a fair definition of an installation. The IOU’s got SEA 309 approved, it seems only fair that we eliminate the gray.

Bob McKinney
President
Johnson-Melloh Companies

Rectify Solar

Hello Beth,

In light of the passing of SEA 309 and recent talks with IPL, I wish the commission would clarify the introduction of battery systems with solar applications and it’s ability to be net metered.

IC 8-1-37-4 “Clean energy resource mentions that solar is included as an approved item for net metering. Later it says that battery systems are not approved.

There is a section that says

Other emerging renewable energy technologies the commission determines appropriate.

I would understand if the commission deems that batteries if installed without a solar system would not qualify for net metering. However with the batteries being installed as part of a solar system, I believe that grid tie solar + storage should be the included for net metering for both DC and AC coupled solar systems. If you could clarify that during the technical conference, I would much appreciate it.

Please let me know if you need any clarification or other questions. I’d be happy to come to the event as well if needed to talk about various types of battery systems if you felt the need.

Talk to you soon,

Phil Teague