nationalgrid

Raquel J. Webster
Senior Counsel

September 12, 2014

BY HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4483 - National Grid's Proposal to Resolve the Issues in this Docket

Dear Ms. Massaro:

In lieu of filing a formal brief, National Grid[1] is filing this letter to set forth a proposal to resolve the disputes in this docket. Because the proposal contains conditions that would need formal approval by the Rhode Island Public Utilities Commission (PUC) for implementation, the Company is filing this proposal with the PUC.

In brief summary, Wind Energy Development LLC's and ACP Land LLC's (collectively, Petitioners) complaint raises two separate issues in connection with costs incurred in interconnecting two distributed generation projects to the Company's electric distribution system. The first issue is whether the Petitioners should be required to reimburse the Company for certain tax payments made by the Company to the Internal Revenue Service (IRS) in connection with the interconnection of the two projects to the Company's electric distribution system (referred to as the Tax Issue). The second issue is whether the Company should have provided a formal accounting of the costs incurred in constructing the interconnections to support the Company's final invoicing of costs to the Petitioners (referred to as the Invoicing Issue).

If these issues affected only the Petitioners in this case, it might call for a different resolution. However, the Rhode Island General Assembly has passed legislation that contemplates significant expansion of distributed generation in the State. See R.I.G.L. § 39-26.6 (Renewable Energy Growth Program) (Attachment A). Thus, the Company now expects these issues to arise repeatedly, unless a broader resolution can be implemented as a uniform policy across all applicable projects. As such, the Company offers the proposals contained in this letter.

With respect to the Tax Issue, the Company proposes to seek individual rulings from the IRS, followed by a further review and decision by the PUC. The details are complicated. Therefore, a more complete background and explanation is provided below, along with the

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

specifics of the resolution. With respect to the Invoicing Issue, the Company proposes to resolve the dispute by implementing a process change that would result in itemization of costs, as will be more fully set forth in this letter. While the two issues arose from the Petitioners' projects, they are unrelated in substance. Thus, they will be addressed separately, below.

The Company has discussed the proposals contained in this letter with the Division and the Petitioners. It is the Company's understanding that the Division supports the Company's proposals in this letter. Petitioners have indicated that they will file comments to the proposal as they deem necessary.

I. Resolution of the Tax Issue

The question of the tax liability of utilities for interconnections and line extensions has a long history. In simple terms, it is settled tax law that when a utility customer reimburses the utility for the cost of an interconnection, a line extension, and/or any associated equipment, the IRS views this contribution as taxable income to the utility and it requires the utility to pay federal taxes on the transaction. Such arrangements are referred to as "Contributions in Aid of Construction" or "CIAC." See Internal Revenue Code Section 118. (Attachment B). It is well settled across the industry that such a tax liability will generally occur when the utility receives such reimbursements.

There has been no legal ambiguity regarding tax liability for interconnections or line extensions for customers taking traditional utility service. Under Internal Revenue Code Section 118(b), payments made to utilities as reimbursement for the cost of constructing such interconnections are viewed as prepayments for future utility services and are taxed in the year received. See Attachment B (Section 118(b)). Nonetheless, the legislative history of Section 118(b) suggests that Congress recognized that there may be circumstances when payments are not related to utility services and should not be taxed.

In the late 1980s, the IRS provided guidance, which indicated that under specified circumstances, CIAC payments made by certain stand-alone generators identified as "Qualifying Facilities" under the Public Utilities Regulatory Act (PURPA) should not be subject to taxes because the utility is not using the interconnection to provide utility services to the Qualifying Facility. See IRS Notice 88-129 (Attachment C). Congress enacted an exception to the requirement for utilities to pay the CIAC tax for certain stand-alone generators identified as Qualifying Facilities under the PURPA. Among other requirements, the exemption applied if the generator was selling the power at wholesale under the terms of a long-term purchase power contract with the utility, using the interconnection to deliver this power to the utility's transmission grid, and not otherwise using the interconnection to take more than a *de minimis* amount of electricity from the utility's grid. At the time IRS issued Notice 88-129, it was typical for such generators to interconnect directly to the utility system at transmission voltage. Thus, IRS Notice 88-129 makes specific reference to interconnections to a "transmission network" through "transmission interties." The notice makes no reference to interconnections to distribution facilities.

Overtime, as vertically integrated utilities divested themselves of electric generating assets, it became common for non-utility generators who were not actually Qualifying Facilities under PURPA to seek interconnections. Therefore, the IRS eventually issued Notice 2001-82, which extended the exemption to these other generators (known as independent power producers). See Attachment D (Notice 2001-82). However, the IRS guidance continued to refer to "transmission interties." As such, utilities have been comfortable interpreting the IRS guidance as allowing exemptions when the generator's interconnection has been directly to transmission facilities. There has been no definitive pronouncement or notification given by the IRS that would indicate that utilities may extend this exemption to interconnections with distribution facilities.

Unfortunately, interpreting whether tax liability exists is complex and risky. Specifically, the IRS has limited what a taxpayer can rely upon in determining whether tax liability applies to a set of circumstances, which complicates matters. The IRS offers certainty through a process whereby the taxpayer may apply for a Private Letter Ruling (PLR) to determine whether a specific project interconnection is taxable. There is no process, however, for seeking a broad, general ruling that will be applicable to a class of projects. PLRs are effective only for the project described in the PLR application. Further, the IRS rules make clear that no taxpayer may rely upon another taxpayer's PLR or even another one of its *own* PLRs to avoid tax liability on a separate project, no matter how similar or identical the fact pattern. Moreover, the filing fee for a PLR is approximately $19,000, not including the administrative and other legal costs of preparing and addressing the ruling request. Given these constraints, a utility or project developer has no financial incentive to seek a PLR if the tax liability is less than the cost of obtaining a PLR.

Because most of the distributed generation interconnections being made today likely result in calculated tax liabilities that are less expensive than the cost of obtaining a PLR, it is the Company's practice to pay the calculated tax to the IRS and collect the cost of the tax as a part of the interconnection cost. If the Company did not do so, the tax liability would be properly included in rates and recovered from all other electric customers. The Company is always willing to file for a PLR if the developer pays the cost of the PLR. However, when the tax liability is less than the cost of obtaining a PLR, it makes no sense for either the utility or the developer to pursue a PLR.

When such interconnection requests were few in number, it made sense to continue this practice. However, in the last legislative session, the General Assembly passed a new law referred to as the Renewable Energy Growth Program, intending to expand the growth of distributed generation in the state, and expanded the potential for projects under the Company's Net Metering tariff. As such, it has become clear to the Company that the issue associated with distributed generation projects interconnecting to the Company's electric distribution facilities will repeat itself with many of the projects supported by these distributed generation incentive programs. Accordingly, it is the Company's view that it makes sense to obtain some clarity from the IRS on this matter by filing for one or more PLRs for some projects.

Given all these factors, the Company believes it has a resolution that fairly balances all these factors and risks. As such, the Company proposes to apply for one to four PLRs associated with projects that interconnect with the Company's electric distribution system and otherwise meet the remaining criteria required by the IRS for the tax exemption. The Company also proposes to share the PLR application content with the Division and the customer whose project is the subject of the PLR request prior to filing. Once the Company receives the IRS rulings, the Company would return to the PUC with a filing and recommendation based on the IRS responses. If the PLRs provide a reasonable basis to conclude that the tax exemption applies to projects interconnected to electric distribution facilities, the Company will recommend that it no longer pay taxes on future projects meeting the IRS criteria and, thus, no longer collect the tax from the eligible projects. If, however, the PLRs do not provide the necessary clarity, the Company will recommend that taxes continue to be paid and the cost collected from each project developer that interconnects a project to the Company's electric distribution system. In any event, placing the facts and the Company's recommendation before the PUC will allow the PUC to determine the right solution, based on the facts, the PLR language, and the circumstances. It also will allow other stakeholders to comment in the proceedings. In the meantime, all future project developers to whom this issue applies would place an amount in escrow with the Company equal to the potential tax liability, to be refunded if a decision is later made by the PUC that the taxes should not be paid.

However, if the PUC decision assumes no tax liability exists and, thus, the Company no longer pays the taxes, the Company would need further assurance from the PUC. That is, because the Company is not legally entitled to rely on the PLRs for broad-based application, the Company would be taking the risk that a future IRS would take a different view and require taxes to be paid for every project for which a PLR was not obtained. For that reason, the Company would want assurances from the PUC that, to the extent it does not pay taxes associated with projects interconnected to the Company's electric distribution system and the IRS later assesses taxes against the Company, the Company would be able to defer the costs and recover them in rates in an appropriate manner approved by the PUC after the taxes are assessed.

Because there is a cost associated with seeking PLRs, the Company also seeks approval from the PUC to defer the costs of seeking each PLR and recover such costs in rates in a future reconciliation to be determined. The Company agrees to cap the cost at no more than $25,000 per PLR.

Finally, if the decision is made that the Company should not be paying the tax, the Company would refund the tax reimbursement payments that were made by Petitioners and are at issue in this case. Petitioners paid approximately $20,593 for the two projects that are the subject of the disputes in this docket.[2] In turn, this cost would be deferred and included in the reconciliation for recovery by the Company from customers along with the PLR costs.

---

[2] NK Green LLC (WED) paid taxes totaling $15,467.00, and ACP Land, LLC paid taxes totaling $5,126.95. ACP Land, LLC originally paid taxes totaling $8,231.00, but the Company reimbursed it a total of $3,104.05 after conducting a final accounting.

This proposal is designed to address the Petitioners' complaint in this docket while at the same time providing an avenue for future policy that can be applied uniformly and fairly to all eligible projects in the future. Therefore, it would be imperative for the PUC to make clear in approving this proposal that it does not set a precedent for past or future projects. In other words, it does not mean that any project in the future may require a PLR at no cost, nor does it mean that projects in the past that reimbursed the Company for taxes paid in the past are entitled to any retroactive refund.

II. The Invoicing Issue

Resolution of the Invoicing Issue is far simpler and straightforward. Because there are two components, each will be explained separately.

(a) Impact Study Cost Itemization

Section 39-26.3-4(c) of the Rhode Island General Laws sets forth a process whereby developers may obtain either or both a feasibility study and cost impact study for a specified fee instead of the utility assessing the actual study costs which might vary from project to project and create cost uncertainty. For the PUC's convenience, the provisions of that section are included in Attachment E to this letter. However, it was recognized in the law that certain non-residential impact study costs may exceed the statutory fee. Accordingly, the law provides for recovery of any costs in excess of the fee, as quoted below:

> (c) To the extent that an impact study fee established under this section does not cover the reasonable cost of an impact study for a given non-residential project that commences operation, the balance of such costs shall be recovered from such applicant through billings after the project is online. The electric distribution company may, at its sole election, offset net metering credits or any standard contract payments until the full fee(s) is reimbursed, if it finds it administratively convenient to use that means of billing for the balance of the fee for a given project.

Today, such itemization occurs only if the customer requests one. Through this letter, the Company proposes to alter its process in cases where the cost exceeds the specified fee. In such cases, the Company would always provide a reasonable itemization of the costs to the extent it takes steps to collect costs in excess of the specified fee.

(b) Actual Interconnection Cost Itemization

Similarly, the Company has a process that is identified in its interconnection tariff where it reviews the actual interconnection costs after the construction of such system changes, and compares them to the estimated costs paid by the distributed generator before construction, which today occurs only at the request of the customer. The Company proposes to implement a new process where it supplies a reasonable itemization of the cost in every instance. Today, the tariff states that such itemization will occur only if the customer requests within a specified period of time. Instead, the itemization would occur as a matter of course. The Company will need some time to change its process and proposes to implement the new rule within sixty days of a PUC approval of the proposal.

In conclusion, the Company respectively requests that the PUC approve the proposals set forth in this letter. If approved, the Company believes that the disputes pending in this docket will be effectively mooted and no hearing would be necessary.

Sincerely,

Raquel J. Webster

Enclosures

cc: Docket 4483 Service List
Jon G. Hagopian, Esq.
Steve Scialabba, Division

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

Paper copies of this filing are being hand delivered to the RI Public Utilities Commission and to the RI Division of Public Utilities and Carriers.

___________________________________ September 12, 2014

Raquel J. Webster Date

Docket No. 4483 – Wind Energy Development LLC & ACP Land, LLC – Petition for Dispute Resolution Relating to Interconnection
Service List updated 7/29/14

Name/Address	E-mail Distribution List	Phone
Seth H. Handy, Esq. HANDY LAW, LLC 42 Weybosset St. Providence, RI 02903	seth@handylawllc.com	401-626-4839
John K. Habib, Esq. Keegan Werlin LLP 265 Franklin St. Boston, MA 02110-3113	jhabib@keeganwerlin.com	617-951-1400
Raquel Webster, Esq. National Grid 280 Melrose St. Providence, RI 02907	Raquel.webster@nationalgrid.com Thomas.teehan@nationalgrid.com Joanne.scanlon@nationalgrid.com Celia.obrien@nationalgrid.com	401-784-7667
Jon Hagopian, Esq. Division of Public Utilities & Carriers	Jhagopian@dpuc.ri.gov Acontente@dpuc.ri.gov Sscialabba@dpuc.ri.gov Jspirito@dpuc.ri.gov	401-784-4775
Original & 9 copies to be filed w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov Amy.dalessandro@puc.ri.gov Todd.Bianco@puc.ri.gov Alan.nault@puc.ri.gov	401-780-2107
Karen Lyons, Esq. Dept. of Attorney General	Klyons@riag.ri.gov jmunoz@riag.ri.gov dmacrae@riag.ri.gov	401-222-2424

2014 -- S 2690 SUBSTITUTE A AS AMENDED

========
LC004420/SUB A/3
========

STATE OF RHODE ISLAND

IN GENERAL ASSEMBLY

JANUARY SESSION, A.D. 2014

A N A C T

RELATING TO PUBLIC UTILITIES AND CARRIERS - THE CLEAN ENERGY JOBS PROGRAM

Introduced By: Senators Sosnowski, Walaska, Conley, Cool Rumsey, and Bates

Date Introduced: March 05, 2014

Referred To: Senate Environment & Agriculture

It is enacted by the General Assembly as follows:

SECTION 1. Title 39 of the General Laws entitled "PUBLIC UTILITIES AND CARRIERS" is hereby amended by adding thereto the following chapter:

CHAPTER 26.6

THE RENEWABLE ENERGY GROWTH PROGRAM

39-26.6-1. Purpose. -- The purpose of this chapter is to facilitate and promote installation of grid-connected generation of renewable energy; support and encourage development of distributed renewable-energy generation systems; reduce environmental impacts; reduce carbon emissions that contribute to climate change by encouraging the siting of renewable energy projects in the load zone of the electric-distribution company; diversify the energy generation sources within the load zone of the electric-distribution company; stimulate economic development; improve distribution system resilience and reliability within the load zone of the electric-distribution company; and reduce distribution system costs.

39-26.6-2. Renewable energy growth program established. -- To carry out these purposes, a tariff-based, renewable-energy distributed-generation financing program, hereinafter referred to as the renewable-energy growth program, is hereby established with the intention of continuing the development of renewable-energy distributed generation in the load zone of the electric-distribution company at reasonable cost. The program shall be designed to finance the development, construction, and operation of renewable-energy distributed-generation projects over five (5) years through a performance-based incentive system that is designed to achieve specified megawatt targets at reasonable cost through competitive processes. The renewable-energy growth program shall be implemented by the electric-distribution company, and guided by the distributed-generation board, in consultation with the office of energy resources, subject to the review and supervision of the commission.

39-26.6-3. Definitions. -- When used in this chapter, the following terms shall have the following meanings:

(1) "Commission" means the Rhode Island public utilities commission.

(2) "Board" shall mean the distributed-generation board as established pursuant to the provisions of § 39-26.2-10 under the title distributed generation standard contract board, but shall also fulfill the responsibilities set forth in this chapter.

(3) "Commercial-scale solar project" means a solar distributed generation project with the nameplate capacity specified in § 39-26.6-7.

(4) "Distributed generation facility" means an electrical generation facility located in the electric-distribution company's load zone with a nameplate capacity no greater than five megawatts (5 MW), using eligible renewable energy resources as defined by § 39-26-5, including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels, and connected to an electrical power system owned, controlled, or operated by the electric-distribution company. For purposes of this chapter, a distributed generation facility must be a new resource that:

(i) Has not begun operation;

(ii) Is not under construction, but excluding preparatory site work that is less than twenty-five percent (25%) of the estimated total project cost; and

(iii) Except for small-scale solar projects, does not have in place investment or lending agreements necessary to finance the construction of the facility prior to the submittal of an application or bid for which the payment of performance-based incentives are sought under this chapter except to the extent that such financing agreements are conditioned upon the project owner being awarded performance-based incentives under the provisions of this chapter. For purposes of this definition, pre-existing hydro generation shall be exempt from the provisions of subsection (i) of this section, regarding operation, if the hydro-generation facility will need a material investment to restore or maintain reliable and efficient operation and meet all regulatory, environmental, or operational requirements. For purposes of this provision, "material investment" shall mean investment necessary to allow the project to qualify as a new, renewable-energy resource under § 39-26-2(2). To be eligible for this exemption, the hydro-project developer at the time of submitting a bid in the applicable procurement must provide reasonable evidence with its bid application showing the level of investment needed, along with any other facts that support a finding that the investment is material, the determination of which shall be a part of the bid review process set forth in § 39-26.6-16 for the award of bids.

(5) "Distributed-generation project" means a distinct installation of a distributed-generation facility. An installation will be considered distinct if it does not violate the segmentation prohibition set forth in § 39-26.6-9.

(6) "Electric distribution company" means a company defined in § 39-1-2(12), supplying standard-offer service, last-resort service, or any successor service to end-use customers, but not including the Block Island Power Company or the Pascoag Utility District.

(7) "ISO-NE" means Independent System Operator-New England, the Regional Transmission Organization for New England designated by the Federal Energy Regulatory Commission.

(8) "Large distributed-generation project" means a distributed-generation project that has a nameplate capacity that exceeds the size of a small, distributed-generation project in a given year, but is no greater than five megawatts (5 MW) nameplate capacity.

(9) "Large-scale solar project" means a solar distributed-generation project with the nameplate capacity specified in § 39-26.6-7.

(10) "Medium-scale solar project" means a solar distributed-generation project with the nameplate capacity specified in § 39-26.6-7.

(11) "Office" means the Rhode Island office of energy resources.

(12) "Program year" means a year beginning April 1 and ending March 31, except for the first program year that may commence after April 1, 2015, subject to commission approval.

(13) "Renewable energy classes" means categories for different renewable-energy technologies using eligible renewable-energy resources as defined by § 39-26-5 , including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels specified in § 39-26-2(6). For each program year, in addition to the classes of solar distributed-generation specified in § 39-26.6-7, the board shall determine the renewable-energy classes as are reasonably feasible for use in meeting distributed-generation objectives from renewable-energy resources and are consistent with the goal of meeting the annual target for the program year. The board may make recommendations to the commission to add, eliminate, or adjust renewable-energy classes for each program year, provided that the solar classifications set forth in § 39-26.6-7 shall remain in effect for at least the first two (2) program years and no distributed-generation project may exceed five megawatts (5MW) of nameplate capacity.

(14) "Renewable-energy certificate" means a New England Generation Information System renewable energy certificate as defined in § 39-26-2(13).

(15) "Small-scale solar project" means a solar distributed generation project with the nameplate capacity specified in § 39-26.6-7.

(16) "Small distributed-generation project" means a distributed generation renewable energy project that has a nameplate capacity within the following: Wind: fifty kilowatts (50 KW) to one and one-half megawatts (1.5 MW); small-scale solar projects and medium-scale solar projects with the capacity limits as specified in § 39-26.6-7. For technologies other than solar and wind, the board shall set the nameplate capacity size limits, but such limits may not exceed one (1MW) megawatt.

(17) "Ceiling price" means the bidding price cap applicable to an enrollment for a given distributed-generation class that shall be approved annually for each renewable-energy class pursuant to the procedure established in this chapter. The ceiling price for each technology should be a price that would allow a private owner to invest in a given project at a reasonable rate of return, based on recently reported and forecast information on the cost of capital, and the cost of generation equipment. The calculation of the reasonable rate of return for a project shall include, where applicable, any state or federal incentives, including, but not limited to, tax incentives.

39-26.6-4. Continuation of Board. -- (a) The distributed generation standard contract board shall remain fully constituted and authorized as provided in chapter 26.2 of title 39 provided, however, that the name shall be changed to the "distributed-generation board." Additional purposes of the board shall be to:

(1) Evaluate and make recommendations to the commission regarding ceiling prices and annual targets, the make-up of renewable-energy classifications eligible under the distributed-generation growth program, the terms of the tariffs, and other duties as set forth in this chapter;

(2) Provide consistent, comprehensive, informed, and publicly accountable involvement by representatives of all interested stakeholders affected by, involved with, or knowledgeable about the development of distributed-generation projects that are eligible for performance-based incentives under the distributed generation growth program; and

(3) Monitor and evaluate the effectiveness of the distributed-generation growth program.

(b) The office, in consultation with the board, shall be authorized to hire, or to request the electric-distribution company to hire, the services of qualified consultants to perform ceiling price studies subject to commission approval that shall be granted or denied within sixty (60) days of receipt of such request from the office. The cost of such studies shall be recoverable through the rate reconciliation provisions of the electric-distribution company set forth in § 39-26.6-25, subject to commission approval. In addition, the office, in consultation with the board, may request the commission to approve other costs incurred by the board or the electric-distribution company to perform any other studies and reports, subject to the review and approval of the commission that shall be granted or denied within one hundred twenty (120) days of receipt of such request from the office and that shall be recoverable through the same reconciliation provisions.

39-26.6-5. Tariffs Proposed and Approved. -- (a) Each year, for a period of at least five (5) program years, the electric-distribution company shall file tariffs with the commission that are designed to provide a multi-year stream of performance-based incentives to eligible renewable-distributed-generation projects for a term of years, under terms and conditions set forth in the tariffs and approved by the commission. The tariffs shall set forth the rights and obligations of the owner of the distributed-generation project and the conditions upon which payment of performance-based incentives by the electric-distribution company will be paid. The tariffs shall include the non-price conditions set forth in §§ 39-26.2-7(2)(i) – (vii) for small distributed generation projects (other than small and medium scale solar) and large distributed-generation projects; provided, however, that the time periods for such projects to reach ninety percent (90%) of output shall be extended to twenty-four (24) months (other than eligible anaerobic-digestion projects, which shall be thirty-six (36) months, and eligible small-scale hydro, which shall be forty-eight (48) months). The non-price conditions in the tariffs for small-and medium-scale solar shall take into account the different circumstances for distributed-generation projects of the smaller sizes.

(b) In addition to the tariff(s), the filing shall include the rules governing the solicitation and enrollment process. The solicitation rules will be designed to ensure the orderly functioning of the distributed-generation growth program and shall be consistent with the legislative purposes of this chapter.

(c) In proposing the tariff(s) and solicitation rules applicable to each year, the tariff(s) and rules shall be developed by the electric-distribution company and will be reviewed by the office and the board before being sent to the commission for its approval. The proposed tariffs shall include the ceiling prices and term lengths for each tariff that are recommended by the board. The term lengths shall be from fifteen (15) to twenty (20) years, provided, however, that the board may recommend shorter terms for small-scale solar projects. Whatever term lengths between fifteen (15) and twenty (20) years are chosen for any given tariff, the evaluation of the bids for that tariff shall be done on a consistent basis such that the same term lengths for competing bids are used to determine the winning bids.

(d) The board shall use the same standards for setting ceiling prices as set forth in § 39-26.2-5. In setting the ceiling prices, the board may specifically consider:

(1) Transactions for newly developed renewable energy resources, by technology and size, in the ISO-NE control area and the northeast corridor;

(2) Pricing from bids received during the previous program year;

(3) Environmental benefits, including, but not limited to, reducing carbon emissions;

(4) System benefits; and

(5) Cost effectiveness.

(e) At least forty-five (45) days before filing the tariff(s) and solicitation rules, the electric-distribution company shall provide the tariff(s) and rules in draft form to the board for review. The commission shall have the authority to determine the final terms and conditions in the tariff and rules. Once approved, the commission shall retain exclusive jurisdiction over the performance-based incentive payments, terms, conditions, rights, enforcement, and implementation of the tariffs and rules, subject to appeals pursuant to chapter 5 of title 39.

39-26.6-6. Permanence of Tariff Terms Once Set. -- It is the intention of the general assembly in enacting this chapter that the developers, owners, investors, customers, and lenders of the distributed-generation projects receiving performance-based incentives under the tariffs be able to rely on the tariffs for the entire term of the applicable tariff for purposes of obtaining financing. Consistent with that intention and expectation, the terms under the tariffs for a given program year, once approved by the commission, shall not be altered in any way that would undermine such reliance on those tariffs during the applicable terms of the tariffs; and in no circumstance will the performance-based incentive rate paid to a renewable energy project developer or owner be reduced during the term of the tariff once a renewable energy project has qualified to receive a tariff under the terms of this chapter.

39-26.6-7. Solar Project Size Categories. – (a) Tariff(s) shall be proposed for each of the following solar distributed generation classes:

(1) Small-scale solar projects;

(2) Medium-scale solar projects;

(3) Commercial-scale solar projects; and

(4) Large-scale solar projects.

(b) Such classes of solar distributed-generation projects shall be established based on nameplate megawatt size as follows:

(1) Large scale: solar projects from one megawatt (1 MW), up to and including, five megawatts (5MW) nameplate capacity;

(2) Commercial scale: solar projects greater than two hundred fifty kilowatts (250 kW), but less than one megawatt (1 MW) nameplate capacity;

(3) Medium scale: solar projects greater than twenty-five kilowatts (25 kW), up to and including, two hundred fifty kilowatts (250 kW) nameplate capacity; and

(4) Small scale: solar projects, up to and including, twenty-five kilowatts (25 kW) nameplate capacity.

(c) Other classifications of solar projects may also be proposed by the board, subject to the approval of the commission. After the second program year, the board may make recommendations to the commission to adjust the size categories of the solar classes, provided that the medium-scale solar projects may not exceed two hundred fifty kilowatts (250 kW).

39-26.6-8. Renewable Technologies Other Than Solar. -- Tariffs also shall be proposed for on-shore wind and any other distributed-generation technologies permissible under this chapter that the board, in its discretion, recommends; provided, however, that no project shall exceed five megawatts (5 MW) nameplate capacity. The electric-distribution company shall file tariffs for each technology and size categories recommended by the board pursuant to the procedures set forth in this chapter.

39-26.6-9. Project Segmentation Prohibition. -- In no case may a project developer be allowed to segment a distributed-generation project on the same parcel or contiguous parcels into smaller-sized projects in order to fall under a smaller-size project classification. Notwithstanding this prohibition, a project developer may designate a generation unit on the same parcel or contiguous parcel for net metering or other means of participating in electricity markets, provided that such unit, or portion of such unit, designated for net metering or other market participation is not receiving performance-based incentives under this chapter; is capable of being segregated electrically; is configured with such electrical segregation; and is separately metered. Further, a project shall not be considered to have been segmented if:

(1) There is a lapse of at least twenty-four (24) months between: (i) The commencement of construction of new distributed-generation units on a parcel that is the same as, or is contiguous with, a parcel upon which a distributed-generation project has already been constructed; and (ii) The operation date of the pre-existing project; or

(2) The new project is a different renewable technology.

39-26.6-10. Timing and Schedule of Tariff Filings. -- (a) The electric-distribution company shall file with the commission the first set of tariffs and solicitation rules pursuant to this chapter no later than November 15, 2014. Thereafter, the electric-distribution company shall make annual tariff and solicitation rules filings with the commission no later than November 15 prior to the beginning of the applicable program year, which tariffs and rules shall be applicable for the next program year.

(b) Upon receiving the filing from the electric-distribution company, the commission shall open a docket to consider the filing. The commission shall issue an order approving the proposed tariffs and solicitation rules; provided, however, that the commission may make any modifications that it deems appropriate consistent with the legislative purposes of this chapter as set forth herein.

(c) For the first program year, the commission shall issue its order approving tariff(s) and solicitation rules by no later than March 31, 2015. Thereafter, the commission shall approve them by February 15 of each succeeding year.

(d) During the course of any program year, the electric-distribution company may, at any time, in consultation with the office and the board, propose tariff or solicitation rules modifications. The commission shall consider such proposed modifications through an already open or new docket, and shall issue its order within one hundred five (105) days of the filing of the proposed modification. If approved, the proposed modification shall take effect for the next enrollment event following the issuance of the commission's order.

39-26.6-11. Power Purchase Agreements Not Required. -- The distributed generation growth program shall be implemented and administered exclusively through the tariff structure and procedures set forth in this chapter, and the electric-distribution company shall not be required to execute power purchase agreements for the procurement of the renewable energy distributed-generation capacity requirements set forth in this chapter.

39-26.6-12. Annual Bidding and Enrollments. -- (a) With the exception of the first program year (2015), the electric-distribution company, in consultation with the board and office, shall conduct at least three (3) tariff enrollments for each distributed-generation class each program year. For the first program year, the board may recommend that either two (2) or three (3) enrollments be conducted.

(b) During each program year, the tariff enrollments shall have both an annual targeted amount of nameplate megawatts ("annual MW target") and a nameplate megawatt target for each separate enrollment event ("enrollment MW target"). The enrollment MW target shall comprise the specific portion of the annual MW target sought to be obtained in that enrollment. The enrollment MW targets shall be recommended by the board each year, subject to commission approval. The board shall also recommend a megawatt target for each class ("class MW target") that comprises a specified portion of the enrollment MW target, subject to commission approval. If the electric-distribution company, the office, and the board mutually agree, they may reallocate megawatts during an enrollment from one class to another without commission approval if there is an over subscription in one class and an under subscription in another, provided that the annual MW Target is not being exceeded, except as provided in § 39-26.6-7.

(c) The annual MW targets shall be established as follows; provided, however, that at least three megawatts (3 MW) of nameplate capacity shall be carved out exclusively for small-scale solar projects in each of the first four (4) program years:

(1) For the first program year (2015), the annual MW target shall be twenty-five (25) nameplate megawatts;

(2) For the second program year, the annual targets shall be forty (40) nameplate megawatts;

(3) For the third and fourth program years, the annual target shall be forty (40) nameplate megawatts, subject to the conditions set forth in § 39-26.6-12(f) having been met for the applicable prior program year as determined in the manner specified in § 39-26.6-12(g); and

(4) For the fifth program year, the annual target shall be set to obtain the balance of capacity needed to achieve one hundred sixty (160) nameplate megawatts within the five-year (5) distributed-generation growth program, subject to § 39-26.6-12(e) and the conditions set forth in § 39-26.6-12(f) having been met for the fourth program year as determined in the manner specified in § 39-26.6-12(g).

(d) During the fifth year of the distributed-generation growth program, the board may recommend to the commission an extension of time in the event that additional time is required to achieve the full one hundred sixty (160) nameplate megawatt target of the program. The commission shall approve the recommendation of the board; provided, however, that the commission may make any modifications to the board's recommendation that the commission deems appropriate, consistent with the legislative purposes of this chapter as set forth herein.

(e) To the extent there was a shortfall of capacity procured under chapter 26.2 of title 39 from distributed generation procurements in 2014, such shortfall amount may be added to the one hundred sixty megawatt (160MW) target for acquisition in the fifth program year under this chapter. In no event shall the electric-distribution company be required to exceed the aggregate amount of one hundred sixty (160) nameplate capacity plus any such shortfall amount over the five (5) years, but may do so voluntarily, in consultation with the board and subject to commission approval.

(f) The conditions specified in subsections (c)(3) and (c)(4) of this section are as follows: (1) That it is reasonable to conclude that the bid prices submitted in the procurements for the large-scale solar and commercial-scale solar classes were reasonably competitive in the immediately preceding program year; (2) That it is reasonable to conclude that the annual MW target specified for the next program year is reasonably achievable; and (3) That the electric-distribution company was able to, or with reasonably prudent efforts should have been able to, perform the studies and system upgrades on a timely basis necessary to accommodate the number of applications associated with the targets without materially adversely affecting other electric-distribution construction projects needed to provide reliable and safe electric-distribution service. To the extent the board or the commission concludes that any of these conditions have not been met for the applicable program year, the board may recommend, and/or the commission may adopt, a new annual MW target, based on the factors set forth in § 39-26.6-12(h).

(g) Before the third, fourth, and fifth program years, each year the board shall review the conditions specified in § 39-26.6-12(f) and make a recommendation to the commission for findings as to whether they have been met for the applicable year. The recommendation shall be filed with the commission, with copies to the office and the electric-distribution company, and any person who has made a written request to the commission to be included in such notification, such list which may be obtained from the commission clerk, and a notice of such filing shall be posted by the commission on its website. If no party files an objection to the recommended findings within ten (10) business days of the posting, the commission may accept them without hearings. If an objection is filed with a reasonable explanation for its basis, the commission shall hold hearings and make the factual determination of whether the conditions have been met.

(h) In the event that the conditions in § 39-26.6-12(f) have not been met for any program year, then the board and the commission shall take into account the factors set forth below in setting the annual MW target for the following year. In addition, for every program year the board and the commission shall take into account these factors in setting the class MW targets, and the enrollment MW targets for the following year: (1) That the new annual, class, and enrollment levels reasonably assure that competition among projects for the applicable bidding classifications remains robust and likely to yield reasonable and competitive program costs; (2) That, assuming prudent management of the program, the electric-distribution company should be able to perform the studies and system upgrades on a timely basis necessary to accommodate the number of applications associated with the targets without materially adversely affecting other electric-distribution construction projects needed to provide reliable and safe electric-distribution service; and (3) Any other reasonable factors that are consistent with the legislative purpose of this chapter as set forth herein, including the program purpose to facilitate the development of renewable distributed generation in the load zone of the electric-distribution company at reasonable cost.

(i) The renewable energy growth program is intended to achieve at least an aggregate amount of one hundred sixty (160) nameplate megawatts over five (5) years, plus any shortfall amount added in pursuant to § 39-26.6-12(e). However, after the second program year the board may, based on market data and other information available to it, including pricing received during previous program years, recommend changes to the annual target for any program year above or below the specified targets in § 39-26.6-12(c) if the board concludes that market conditions are likely to produce favorably low or unfavorably high target pricing during the upcoming program year, provided that the recommendation may not result in the five (5)-year one hundred sixty megawatt (160MW) nameplate target, plus any shortfall added pursuant to § 39-26.6-12(e), being exceeded. Any megawatt reduction in an annual target shall be added to the target in the fifth year of the program (and any subsequent years if necessary) such that the overall program target of one hundred sixty megawatt (160MW) nameplate capacity, plus any shortfall added pursuant to § 39-26.6-12(e), is achieved. In considering such issues, the board and the commission may take into account the reasonableness of current pricing and its impact on all electric-distribution customers and the legislative purpose of this chapter as set forth herein, including the program purpose to facilitate the development of renewable distributed generation in the load zone of the electric-distribution company at reasonable cost.

(j) The provisions of § 39-26.1-4 shall apply to the annual value of performance based incentives (actual payments plus the value of net metering credits, as applicable) provided by the electric-distribution company to all the distributed generation projects under this chapter, subject to the following conditions:

(1) The targets set for the applicable program year for the applicable project classifications were met or, if not met, such failure was due to factors beyond the reasonable control of the electric-distribution company;

(2) The electric-distribution company has processed applications for service and completed interconnections in a timely and prudent manner for the projects under this chapter, taking into account factors within the electric-distribution company's reasonable control. The commission is authorized to establish more specific performance standards to implement the provisions of this chapter; and

(3) The incentive shall be one and three-quarters percent (1.75%) of the annual value of performance-based incentives. The commission is authorized to establish more specific performance standards to implement the provisions of this paragraph.

39-26.6-13. Cost reconciliation. -- To the extent the electric-distribution company incurs incremental costs to meet the program objectives or make billing system improvements that are required to facilitate payments of performance-based incentives and administering net metering, the electric-distribution company may elect to recover those incremental costs through the annual charge set forth in § 39-26.6-25, subject to commission review and approval that assures such costs were properly and prudently incurred.

39-26.6-14. Existing powers of agencies and advocacy rights of parties unchanged. -- Nothing in this chapter shall be construed to derogate from the statutory authority of the commission or the division of public utilities and carriers, including, but not limited to, the authority to protect ratepayers from unreasonable rates. Nothing in this chapter shall be construed to preclude any party from advocating a position in commission proceedings that differs from the recommendations made by the board to the commission or in any filing with the commission relating to this chapter, including without limitation (1) Individual or organizational members of the board; (2) Participants in board deliberations; (3) The office; and (4) The electric-distribution company, unless such party has consented by vote to the execution or executed a settlement agreement agreeing to the terms, policy proposals, or any other matter proposed to the commission.

39-26.6-15. Bidding and Incentive Award Processes for Solar DG Projects. -- (a) Large scale and commercial scale solar projects and distributed generation projects for other eligible technologies shall bid a price per kilowatt-hour for the entire output of the facility (net of any station service), which price shall not exceed the applicable ceiling price. Small-scale and medium-scale solar projects will submit an enrollment application to receive a standard performance-based incentive for the period of years in the applicable tariff, which shall be a price per kilowatt-hour for the entire output of the facility. Except for megawatts that may be allocated to the energy efficiency program pursuant to § 39-26.6-19, small and medium scale projects shall be selected on a first come, first served basis, or by means of a commission-approved lottery system, or such other method as may be recommended by the board and approved by the commission.

(b) Except for the first program year, the board shall determine, subject to commission approval, the standard performance based incentive for small and medium sized solar projects from the average bid price from the last two (2) procurement enrollments conducted in the commercial scale and/or large scale solar projects class. For the first program year, the board may derive the standard performance incentive for small and medium sized solar projects from the bidding data obtained from the distributed generation program in effect in 2014 under the provisions of chapter 26.2 of title 39, until there is bidding data from the first procurement under the new program which shall then be used to set a new standard performance incentive. The standard performance incentive may be set at a higher rate than payments for commercial scale and large scale solar projects in order to take into account the potentially higher per-unit cost of smaller projects. The standard performance incentive also shall be adjusted upward or downward, as needed, in order to take into account the term length over which the incentive shall be paid for the small and medium scale solar projects if such terms are different than the terms applicable to the classes from which the standard performance incentive was derived.

(c) For each program year, the board shall recommend to the commission a standard performance incentive for each of the small scale and medium scale solar project classifications. Upon receiving the recommendations from the board, the commission shall open a docket to consider the recommendations or address the recommendations in its approval process for the program year in a consolidated docket, as provided in § 39-26.6-10. The commission shall issue its order approving the recommendations no later than concurrently with approval of the entire program and tariffs applicable to the program year; provided, however, that the commission may make modifications or changes to the board's recommendations consistent with the legislative purposes of this chapter.

(d) If after the first program year the applications for the medium scale solar projects are significantly over-subscribed, then the board and the electric-distribution company, in consultation with the office, may propose to the commission a bidding process for medium scale projects or a subset of the medium scale projects under which project selections would be made based on the lowest bids rather than first come first served or such other method previously approved by the commission. The commission shall approve the proposal from the board and electric company within ninety (90) days; provided, however, that the commission may make changes to the proposal consistent with the legislative purposes of this chapter.

(e) The commission shall approve the bidding process for medium scale solar projects recommended by the board only if the commission finds that such bidding process is in a sufficiently simple form that is not administratively burdensome to bidders, and will not have the effect of discouraging participation in the distributed generation growth program by developers of medium scale solar projects who may be unrepresented by counsel.

39-26.6-16. Enrollment Program. -- (a) Each enrollment shall be open for a two (2) week period during which the electric-distribution company is required to receive standard short-form applications. The standard short-form application shall require the applicant to provide the following information: the project owner's identity; the location of the proposed project; the nameplate capacity of the proposed project; and renewable energy class of the proposed project. The standard short-form application shall allow project owners to provide additional information relative to the permitting, financial feasibility, ability to build, and timing for deployment of the proposed projects. The applicant must submit an affidavit with the standard short-form application confirming that the project is not in violation of the rules that prohibit project segmentation, as set forth in § 39-26.6-9.

(b) For large distributed generation projects only, the standard short-form application shall also require the applicant to bid a bundled price that applies to the energy, renewable energy certificates, and all other environmental attributes and market products that are available or may become available from the distributed generation facility, on a per kilowatt-hour basis measured from the output of the project. At the election of the electric-distribution company, and subject to the approval of the commission, the bid may be required to include the sale of capacity.

(c) For (i) Small distributed generation projects other than small scale and medium scale solar projects; and (ii) Large distributed generation projects, the electric-distribution company shall select projects based on the lowest proposed prices received that do not exceed the ceiling price from the distributed generation projects which meet the requirements of all applicable tariffs and regulations, and meet the criteria of the renewable energy class in effect, until the class target is met. Performance based incentives shall be awarded to the winning bidders based on their bids submitted.

(d) For small scale and medium scale solar projects, awards shall be made in the manner set forth in §§ 39-26.6-15 and 39-26.6-19.

(e) If there are more projects bidding at the same price than the capacity that is specified for a class target, the electric-distribution company shall, in consultation with the board and the office, select first those projects that appear to be the furthest along in development and that are most likely to be deployed. Those projects that are likely to be deployed at the earliest time shall be selected first. To the extent the electric-distribution company is unable to make a clear distinction on this basis, the electric-distribution company shall report its findings to the board and not award bids for those projects that are tied on pricing. In such case, the board may take such action as it deems appropriate for the selection of projects, including seeking more information from the projects.

(f) Should the electric-distribution company determine that it has made sufficient awards to achieve a program-year class target, it shall immediately report this fact to the board, the office, and the commission, and may cease making awards for that renewable energy class for the remainder of the program year. In any event, the electric-distribution company may exceed the renewable energy class target if the last award may cause the total purchased to exceed the target.

(g) The board, the office, and the electric-distribution company shall enter into a memorandum of understanding regarding the sharing of the information and data related to the renewable energy growth program, including, without limitation, information on bids received, details regarding project ownership, and pricing. At the request of the board, the office, or the electric-distribution company, the commission shall have the authority to protect from public disclosure individual bid information for any projects that have not been awarded performance based incentives.

(h) The electric-distribution company is authorized to award bids up to the applicable ceiling price. As long as the terms of the tariff are met and the pricing is no higher than the applicable ceiling price, such awards shall be deemed prudent and approved by the commission for purposes of recovering the costs in rates.

(i) With respect to any procurement that includes bids from pre-existing hydro-electric generation, the electric-distribution company, in consultation with the office, shall have the authority to accept the applicant's representation that its investment is material, within the meaning of § 39-26.6-3(4). However, if the electric-distribution company or the office questions whether the material investment standard has been met or the application is otherwise rejected, the application shall be submitted to the board for review and the board shall draw its own conclusion and make a recommendation to the commission at the time the commission is approving awards from the procurement to which the application pertains. The commission shall have the final authority to make the determination as to whether the material investment standard has been met. Nothing in this paragraph shall preclude a project developer from seeking a preliminary confirmation of eligibility for the material investment exemption from the electric-distribution company, the office, and the board prior to the submittal of a bid. In such case, if there is any disagreement, the final determination shall be submitted to the commission.

39-26.6-17. Excess enrollment not required. -- The electric-distribution company shall not be required to award bids in excess of the annual target for the applicable program year and shall not be required to procure projects in excess of any limit set by the board and approved by the commission for a given enrollment. However, the electric-distribution company, in consultation with the board and the office, may voluntarily exceed an enrollment period limit as long as it does not exceed an annual target for the applicable program year. At its election, the electric-distribution company may exceed an annual target for the applicable program year after review by the board and approval by the commission.

39-26.6-18. Utility Right to Separately Meter. -- Owners of medium scale, commercial scale, and large scale solar projects and other distributed generation technologies shall be required to provide at their cost a revenue quality meter to standards approved by the division of public utilities and carriers and provide access to the information from the meter to the electric-distribution company to measure the output of the generation. The electric-distribution company shall have the discretion to install the second meter in a parallel configuration to the retail meter or behind the meter, provided that a parallel installation shall have no effect on the right of the customer to net meter using the net of the two meters. The electric-distribution company also shall have the right to install its own revenue quality meter for small scale solar projects if not being supplied by the owner. The electric-distribution company shall recover the installation and capital cost of the separate meters it installs for small scale solar projects in the annual reconciliation of solar costs under § 39-26.6-25.

39-26.6-19. Coordination with Energy Efficiency Programs. -- (a) In consultation with the office, the electric-distribution company may make a request to the commission that up to half of the megawatts for the small and medium scale solar project enrollments be allocated by the commission for selection through a process coordinated with the energy efficiency program in order that specified solar incentives may be tied with energy efficiency program incentives in order to allow the electric-distribution company to implement a coordinated energy efficiency and solar program offering. In such case, the electric-distribution company will propose criteria for eligibility for performance based incentives for solar that requires certain energy efficiency standards be met at the customer location in order to be eligible for performance based incentives for a small scale and/or medium scale solar installation.

(b) The electric-distribution company must also include program parameters that do not disrupt competition among small-scale and/or medium-scale solar developers, including, without limitation, safeguards against any one or subset of developers in this market being given exclusive rights or other market advantages over competitors. In approving the proposal, the commission must find that there is no such small and medium solar-market disruption.

(c) The commission shall approve the request of the distribution company within ninety (90) days, making such modifications as it deems reasonable, provided such modifications are consistent with the legislative purposes of this chapter and the state's energy efficiency goals.

(d) The allocation of megawatts is for implementation purposes only and shall not authorize funds to be shifted from the distributed generation growth program to energy efficiency programs, nor will implementation of the electric distribution company's request cause a reduction of the annual or cumulative capacity goals established for the distributed generation growth program. To the extent that the megawatts allocated to the energy efficiency program pursuant to this section are not committed during a program year, such uncommitted megawatts shall be allocated back to the distributed generation growth program in the following year or such year the board recommends to the commission. Funding for the energy efficiency measures that are tied to the solar installations must be obtained separately from the energy efficiency program budget funded through applicable energy efficiency charges.

(e) Should the small-scale and medium-scale project classes in the renewable energy growth program be oversubscribed in two (2) consecutive enrollments and there are megawatts that have not been committed through the process coordinated with the energy efficiency program after the second enrollment, the board, after consultation with the office and the electric distribution company, shall have the authority to move all or a portion of the uncommitted megawatts out of the coordinated program back to the renewable energy growth program to meet the demand of the oversubscription, subject to commission approval. If, in such case, the board does not exercise the authority, any party may file a petition to the commission requesting action to be taken

39-26.6-20. Issuance of certificates and right to incentive payments. -- (a) For small scale and medium scale solar projects, the electric distribution company shall provide certificates of eligibility to the selected projects without commission confirmation of approval ("distribution company awarded certificates"), subject to the review and consent of the office. The electric distribution company shall file with the commission a list of all such distribution company awarded certificates.

(b) For commercial-scale and large-scale solar and all other distributed generation projects, the electric distribution company shall file with the commission a list of the distributed generation projects selected together with the corresponding pricing information. Within sixty (60) days of receipt of the list, the commission shall issue an order awarding certificates of eligibility to the distributed generation projects ("PUC awarded certificates").

(c) Upon receipt of a PUC awarded certificate or a distribution company certificate, a distributed generation project shall be entitled to receive, and the electric distribution company shall pay and/or credit (as applicable), the performance-based incentives for the specified term and under the terms and conditions of the applicable tariff in the manner set forth below.

(d) The performance based incentive shall be the price per kilowatt-hour that was bid and awarded or established as a standard incentive, as applicable. The performance-based incentive shall be applied as a price per kilowatt-hour for all kilowatt-hours actually produced from the distributed generation (net of station service, if any) for the term of years specified in the applicable tariff, less the value of any kilowatt-hour charges that were offset by any net metering (if applicable) for the host customer associated with the distributed generation for the billing month; provided, however, if the value of kilowatt-hour charges that otherwise would be offset by net metering in a given month exceeds the total value of the performance-based incentive for the month, the customer shall not be subject to any additional charge nor receive any additional net metering credit for the difference between the performance-based incentive value and net metering value for the month.

(e) Except as provided herein for residential small-scale solar projects, in every case where a distributed generation project can be configured for net metering, it shall be the election of the owner of such generation to choose one of two (2) separate methods through which the owner will be compensated for the performance based incentive:

(1) The owner is compensated solely through direct payments under the performance-based incentive provisions of this chapter for the life of the tariff term with no net metering implemented; or

(2) The owner is compensated through a combination of direct payments and the bill credit value of net metering for the life of the term of the tariff under the provisions of this chapter.

In the case of residential small-scale solar projects, only option (2) shall be available.

In either option, the total value of the performance incentive per kilowatt-hour is the same. An owner shall have a one-time right to switch the compensation methods after the generation commences operation, provided that at least sixty (60) days notice is given to the electric distribution company. Thereafter, any further compensation method switches shall be at the sole discretion of the electric distribution company if requested again by the owner.

(f) Every owner who elects the compensation method shall:

(1) Receive compensation solely in the form of a check from the electric distribution company or such other payment method that is mutually agreed between the electric distribution company and the owner; and

(2) Shall receive compensation in the form of offsets against its electricity bill from the electric distribution company from net metering and the balance in the form of a check from the electric distribution company or such other payment method that is mutually agreed upon between the electric distribution company and the owner; provided, however, that no owner of a distributed generation project may be compensated twice for the same kilowatt hour of electricity, and that every self-generator shall receive the full pecuniary benefit of its election to participate in the performance-based incentive program.

(g) Every owner of a distributed generation project that can be configured for net metering that elects the first option for compensation under the provisions of § 39-26.6-20(e) shall become eligible to net meter its output in conformity with the provisions of existing law upon the completion of the full term of the applicable tariff. Nothing in this section shall preclude a customer from electing not to participate in the performance based program and electing simply to net meter under the provisions of existing law; provided, however, once an election is made to participate, the customer will remain subject to the performance based tariff conditions and may not terminate the arrangement without the consent of the electric distribution company.

(h) As provided in § 39-26.6-9, any project developer may designate a generation unit on the same parcel or contiguous parcel for net metering, provided that such unit or portion of such unit designated for net metering is not receiving performance-based incentives under this chapter, is capable of being segregated electrically, is configured with such electrical segregation, and is separately metered.

(i) All distributed generation projects accepting certificates shall be obligated to abide by all the terms and conditions of the approved applicable tariff.

39-26.6-21. Ownership of output, other attributes, and renewable energy certificates. -- (a) Except as provided herein for residential small-scale solar projects, distributed generation projects participating in the renewable energy growth program shall transfer to the electric distribution company the rights and title to:

(1) Those renewable energy certificates generated by the project during the term of the applicable performance-based incentive tariff;

(2) All energy produced by the generation that is not otherwise consumed on site under a net metering arrangement; and

(3) Rights to any other environmental attributes or market products that are created or produced by the project; provided, however, that it shall be the election of the electric distribution company whether it chooses to acquire the capacity of the distributed generation projects under the tariffs set forth in this chapter and no ceiling prices recommended by the board and approved by the commission will be adjusted downward in light of the electric distribution company's election. The electric distribution company shall sell any products acquired and credit them to the reconciliation account specified in § 39-26.6-25. When a generator reverts to net metering after the end of the tariff term under the renewable energy growth program, the net metering generator shall retain title to the renewable energy certificates generated by the project. In the case of residential small-scale projects, title to all energy and capacity produced from the solar generation shall remain with the residential customer, shall not be transferred to the electric distribution company, and shall be deemed consumed by the residential customer on-site during the applicable distribution service billing period with no sale or purchase between the residential customer and the electric distribution company.

(b) For the accounting purposes of the electric distribution company in treating the performance-based incentives, the cost of the energy that is procured shall be the real time market price of energy and the balance of the performance-based incentive shall be attributable to the purchase of environmental and any other attributes acquired. This accounting shall have no effect on the total bundled performance-based incentive to which the distributed generation project is entitled under the provisions of this chapter.

39-26.6-22. Zonal and other incentive payments. -- In order to provide the electric distribution company with the flexibility to encourage distributed generation projects to be located in designated geographical areas within its load zone where there is an identifiable system benefit, reliability benefit, or cost savings to the distribution system in that geographical area, the electric distribution company, in consultation with board and office, may propose to include an incentive payment adder to the bid price of any winning bidder that proposes a distributed generation project in the desired geographical area. The electric distribution company also may propose other incentive payments to achieve other technical or public policy objectives that provide identifiable benefits to customers. Any incentive payment adders must be approved by the commission, and shall not be counted as part of the bid price when the bids are selected at an enrollment event.

39-26.6-23. Intersection of distributed generation and net metering. -- (a) Net metering credits for excess generation shall not be credited during the term of the tariff when the distributed generation project is receiving performance-based incentive payments under the tariff. After the end of the term of the performance-based incentive tariff applicable to a distributed generation project, net metering credits for excess generation in any given month shall be credited to the net metered account at the applicable rate allowed under the law.

(b) All distributed generation projects that had begun development prior to the date the commission approves the first set of ceiling price recommendations from the board and that are in operation by no later than July 1, 2016, shall be eligible to continue operation under the net metering rules that would have been applicable to that self-generation project absent the change in law set forth in this section, provided that such project does not otherwise participate in the performance based incentive program set forth in this chapter.

39-26.6-24. Rate design review by the commission. -- (a) On or after July 1, 2015, the commission shall open a docket to consider rate design and distribution cost allocation among rate classes in light of net metering and the changing distribution system that is expected to include more distributed energy resources, including, but not limited to, distributed generation. The commission will determine the appropriate cost responsibility and contributions to the operation, maintenance, and investment in the distribution system that is relied upon by all customers, including, without limitation, non-net metered and net metered customers. In that docket, the commission shall require the electric distribution company to file a revenue-neutral allocated cost of service study for all rate classes and a proposal for new rates for all customers in each rate class. The electric distribution company shall use the distribution revenue requirement upon which the then-current distribution rates were set. The electric distribution company may use the allocated cost of service that was filed with the compliance filing from the rate case when the then current distribution rates were set. The commission may also address the rate design for the equitable recovery of costs associated with energy efficiency and any renewable energy programs that are recovered in rates.

(b) In establishing any new rates the commission may deem appropriate, the commission shall take into account and balance the following factors:

(1) The benefits of distributed energy resources;

(2) The distribution services being provided to net metered customers when the distributed generation is not producing electricity;

(3) Simplicity, understandability and transparency of rates to all customers, including non-net metered and net-metered customers;

(4) Equitable ratemaking principles regarding the allocation of the costs of the distribution system;

(5) Cost causation principles;

(6) The general assembly's legislative purposes in creating the distributed generation growth program; and

(7) Any other factors the commission deems relevant and appropriate in establishing a fair rate structure. The rates shall be designed for each proposed rate class in accordance with industry-standard cost allocation principles. The commission may consider any reasonable rate design options, including without limitation, fixed charges, minimum monthly charges, demand charges, volumetric charges, or any combination thereof, with the purpose of assuring recovery of costs fairly across all rate classes.

(c) The commission shall issue an order in the docket by no later than December 1, 2015. Any new rates shall take effect for usage on and after January 1, 2016; provided, however, that the electric distribution company may seek an extension if necessary to make the billing system changes necessary to implement a new rate structure. After new revenue-neutral rates are set in the docket specified above, the commission may approve changes to the rate design in any future distribution base rate cases when a fully allocated embedded cost of service study is being reviewed in the rate case, subject to the principles set forth in subsection (b) of this section.

39-26.6-25. Forecasted rate and reconciliation. -- (a) Three (3) months prior to the beginning of the first program year, the electric distribution company shall file a forecast of the total amount of payments that is likely to be paid out to distributed generation projects in the coming program year within the electric distribution company's load zone, along with any costs permitted for recovery pursuant to §§ 39-26.6-4, 39-26.6-13 and 39-26.6-18. The total of all forecasted payments and costs shall be aggregated, net of forecasted revenues from the sale of the energy, renewable energy certificates, and any other market products from the distributed generation projects participating in the performance based incentive program. The forecasted net aggregate amount shall be used to design a fixed monthly charge per customer to recover the net forecast in rates charged to all distribution customers during the prospective calendar year, which fixed charge may be different by rate class in order to reasonably and equitably spread the program costs across all customer classes. The fixed rate shall stay in effect until changed after the first reconciliation filing set forth below and the rate reconciliation process shall be repeated annually, as set forth below. The commission, in its discretion, may move the reconciliation of costs and credits under § 39-26.1-5(f) into this reconciliation in order to have one reconciliation of all program costs and credits from the long-term contracting standard, distributed generation standard contracting, and renewable energy growth program.

(b) Within three (3) months after the end of each program year, the electric distribution company shall reconcile the total amount recovered from distribution customers against the total of net payments and costs for the program year. The electric distribution company shall file the reconciliation with a report along with a new forecast of payments to be made for the next twelve (12) month period, net of forecasted revenues for the resale of energy, renewable energy certificates, or any other market attributes sold by the electric distribution company. The forecast shall be used to set a new rate in the same manner as set forth above and the new rate shall remain in effect until rates are reset in the next annual reconciliation and the reconciliation balance shall be reflected in the new rate.

SECTION 2. Section 39-26.1-3 of the General Laws in Chapter 39-26.1 entitled "Long-Term Contracting Standard for Renewable Energy" is hereby amended to read as follows:

39-26.1-3. Long-term contract standard. -- (a) Beginning on or before July 1, 2010, each electric distribution company shall be required to annually solicit proposals from renewable energy developers and, provided commercially reasonable proposals have been received, enter into long-term contracts with terms of up to fifteen (15) years for the purchase of capacity, energy and attributes from newly developed renewable energy resources. Subject to commission approval, the electric distribution company may enter into contracts for term lengths longer than fifteen (15) years. Notwithstanding any other provisions of this chapter, on or before August 15, 2009, the electric distribution company shall solicit proposals for one newly developed renewable energy resources project as required in ~~section~~ § 39-26.1-7. Proposals for the sale of output from an offshore wind project received under the provisions of this section shall be diligently and fully considered without prejudice, regardless of the status of any proceedings under ~~sections~~ §§ 39-26.1-7 or 39-26.1-8.

(b) The timetable and method for solicitation and execution of such contracts shall be proposed by the electric distribution company, and shall be subject to review and approval by the commission prior to issuance by the company~~; provided that the timetable is reasonably designed to result in the electric distribution company having the minimum long-term contract capacity under contract within four (4) years of the date of the first solicitation; it is not necessary that the projects associated with these contracts be operational within these four (4) years, as the operational dates shall be specified in the contract~~. The electric distribution company shall, subject to review and approval of the commission, select a reasonable method of soliciting proposals from renewable energy developers, which shall include, at a minimum, an annual public solicitation, but may also include individual negotiations. The solicitation process shall permit a reasonable amount of negotiating discretion for the parties to engage in commercially reasonable arms-length negotiations over final contract terms. Each long-term contract entered into pursuant to this section shall contain a condition that it shall not be effective without commission review and approval. The electric distribution company shall file such contract, along with a justification for its decision, within a reasonable time after it has executed the contract following a solicitation or negotiation. The commission shall hold public hearings to review the contract within forty-five (45) days of the filing and issue a written order approving or rejecting the contract within sixty (60) days of the filing; in rejecting a contract the commission may advise the parties of the reason for the contract being rejected and direct the parties to attempt to address the reasons for rejection in a revised contract within a specified period not to exceed ninety (90) days. The commission shall approve the contract if it determines that: (1) the contract is commercially reasonable; (2) the requirements for the annual solicitation have been met; and (3) the contract is consistent with the purposes of this chapter. A report on each solicitation shall be filed with the commission each year within a reasonable time after decisions are made by the electric distribution company regarding the solicitation results, even if no contracts are executed following the solicitation.

(c) (1) No electric distribution company shall be obligated to enter into long-term contracts for newly developed renewable energy resources on terms which the electric distribution company reasonably believes to be commercially unreasonable; provided, however, if there is a dispute about whether these terms are commercially unreasonable, the commission shall make the final determination after an evidentiary hearing. The electric distribution company shall not be obligated to enter into long-term contracts pursuant to this section that would, in the aggregate, exceed the minimum long-term contract capacity, but may do so voluntarily subject to commission approval. As long as the electric distribution company has entered into long-term contracts in compliance with this section, the electric distribution company shall not be required by regulation or order to enter into power purchase contracts with renewable generation projects for power, renewable energy certificates, or any other attributes with terms of more than three (3) years in meeting its applicable annual renewable portfolio standard requirements set forth in section 39-26-4 or pursuant to any other provision of the law.

(2) Except as provided in section 39-26.1-7 and 39-26.1-8, an electric distribution company shall not be required to enter into long-term contracts for newly developed renewable energy resources that exceed the following five (5) year phased schedule:

By December 30, 2010: Twenty-five percent (25%) of the minimum long-term contract capacity;

By December 30, 2011: Fifty percent (50%) of the minimum long-term contract capacity;

By December 30, 2012: Seventy-five percent (75%) of the minimum long-term contract capacity;

~~By~~ After December 30, ~~2014~~ 2013: One hundred percent (100%) of the minimum long-term contract capacity~~; but may do so earlier voluntarily, subject to commission approval~~ subject to subsection (f) of this section.

(d) Compliance with the long-term contract standard shall be demonstrated through procurement pursuant to the provisions of a long-term contract of energy, capacity and attributes reflected in NE-GIS certificates relating to generating units certified by the commission as using newly developed renewable energy resources, as evidenced by reports issued by the NE-GIS administrator and the terms of the contract; provided, however, that the NE-GIS certificates were procured pursuant to the provisions of a long-term contract. The electric distribution company also may purchase other attributes from the generator as part of the long-term contract.

(e) After the adoption of the rules and regulations promulgated by the commission pursuant to this chapter, an electric distribution company may, at its sole election, immediately and from time to time, procure additional commercially reasonable long-term contracts for newly developed renewable energy resources on an earlier timetable or above the minimum long-term contract capacity, subject to commission approval.

(f) At least once per year beginning in 2014, the electric distribution company shall conduct solicitations until one hundred percent (100%) of the minimum long-term contract capacity is met; provided, however, that no contracts shall be awarded unless the pricing under such contract(s) is below the forecasted market price of energy and renewable energy certificates over the term of the proposed contract, using industry standard forecasting methodologies as have been used to evaluate pricing in the past solicitation processes reviewed by the commission under this section. In such solicitations, the electric distribution company may elect not to acquire capacity, but shall acquire all environmental attributes and energy.

SECTION 3. Section 39-26.4-3 of the General Laws in Chapter 39-26.4 entitled "Net Metering" is hereby amended to read as follows:

39-26.4-3. Net metering. -- (a) The following policies regarding net metering of electricity from eligible net metering systems and regarding any person that is a renewable self-generator shall apply:

(1) The maximum allowable capacity for eligible net metering systems, based on nameplate capacity, shall be five megawatts (5 mw).

~~(2) The aggregate amount of net metering in Rhode Island shall not exceed three percent (3%) of peak load, provided that at least two megawatts (2 mw) are reserved for projects of less than fifty kilowatts (50 kw).~~ The aggregate amount of net metering in the Block Island Power Company and the Pascoag Utility District shall not exceed three percent (3%) of peak load for each utility district.

~~(3)~~(2) For ease of administering net metered accounts and stabilizing net metered account bills, the electric distribution company may elect (but is not required) to estimate for any twelve (12) month period:

(i) The production from the eligible net metering system; and

(ii) Aggregate consumption of the net metered accounts at the eligible net metering system site and establish a monthly billing plan that reflects the expected credits that would be applied to the net metered accounts over twelve (12) months. The billing plan would be designed to even out monthly billings over twelve (12) months, regardless of actual production and usage. If such election is made by the electric distribution company, the electric distribution company would reconcile payments and credits under the billing plan to actual production and consumption at the end of the twelve (12) month period and apply any credits or charges to the net metered accounts for any positive or negative difference, as applicable. Should there be a material change in circumstances at the eligible net metering system site or associated accounts during the twelve (12) month period, the estimates and credits may be adjusted by the electric distribution company during the reconciliation period. The electric distribution company also may elect (but is not required) to issue checks to any net metering customer in lieu of billing credits or carry forward credits or charges to the next billing period. For residential eligible net metering systems twenty-five kilowatts (25 kw) or smaller, the electric distribution company, at its option, may administer renewable net metering credits month to month allowing unused credits to carry forward into following billing period.

~~(4)~~(3) If the electricity generated by an eligible net metering system during a billing period is equal to or less than the net metering customer's usage during the billing period for electric distribution company customer accounts at the eligible net metering system site, the customer shall receive renewable net metering credits, which shall be applied to offset the net metering customer's usage on accounts at the eligible net metering system site.

~~(5)~~(4) If the electricity generated by an eligible net metering system during a billing period is greater than the net metering customer's usage on accounts at the eligible net metering system site during the billing period, the customer shall be paid by excess renewable net metering credits for the excess electricity generated beyond the net metering customer's usage at the eligible net metering system site up to an additional twenty-five percent (25%) of the renewable self-generator's consumption during the billing period; unless the electric distribution company and net metering customer have agreed to a billing plan pursuant to subdivision (3).

~~(6)~~(5) The rates applicable to any net metered account shall be the same as those that apply to the rate classification that would be applicable to such account in the absence of net metering including customer and demand charges and no other charges may be imposed to offset net metering credits.

(b) The commission shall exempt electric distribution company customer accounts associated with an eligible net metering system from back-up or standby rates commensurate with the size of the eligible net metering system, provided that any revenue shortfall caused by any such exemption shall be fully recovered by the electric distribution company through rates.

(c) Any prudent and reasonable costs incurred by the electric distribution company pursuant to achieving compliance with subsection (a) and the annual amount of the distribution component of any renewable net metering credits or excess renewable net metering credits provided to accounts associated with eligible net metering systems, shall be aggregated by the distribution company and billed to all distribution customers on an annual basis through a uniform per kilowatt-hour (kwh) surcharge embedded in the distribution component of the rates reflected on customer bills.

~~(7)~~(6) The billing process set out in this section shall be applicable to electric distribution companies thirty (30) days after the enactment of this chapter.

SECTION 4. Section 39-26.2-7 of the General Laws in Chapter 39-26.2 entitled "Distributed Generation Standard Contracts" is hereby amended to read as follows:

39-26.2-7. Standard contract -- Form and provisions. -- The following process shall be implemented to establish the non-price terms and conditions of the standard contract:

(1) A working group ("contract working group") shall be established and supervised by the board, consisting of the following members:

(i) The director of the office of energy resources;

(ii) A designee from the division of public utilities and carriers;

(iii) Two (2) designees of the electric distribution company;

(iv) Two (2) individuals designated by the office of energy resources who are experienced developers of renewable generation projects;

(v) One individual designated by the office of energy resources who represents a customer of the electric distribution company; and (vi) A lawyer designated by the office of energy resources who has at least three (3) years of experience in negotiating and/or developing power purchase agreements. With respect to the lawyer designated in (vi) above, the electric distribution company shall enter into a cost reimbursement agreement with such lawyer, to compensate the lawyer for the time spent serving in the contract working group at the reasonable hourly rate negotiated by the office of energy resources. The costs incurred by the electric distribution company under the reimbursement agreement shall be recovered in rates by the electric distribution company in the year incurred or the year following incurrence through an appropriate filing with the commission. The contract working group shall be an advisory group that is not to be considered to be an agency for purposes of the administrative procedures act or any other laws pertaining to public bodies.

(2) The contract working group shall work in good faith to develop standard contracts that would be applicable for various technologies for both small and large distributed generation projects. The standard contracts should balance the need for the project to obtain financing against the need for the distribution company to protect itself and its distribution customers against unreasonable risks. The standard contract should be developed from contracting terms typically utilized in the wholesale power industry, taking into account the size of each project and the technology. The standard contracts shall provide for the purchase of energy, capacity, renewable energy certificates, and all other environmental attributes and market products that are

available or may become available from the distributed generation facility. However, the electric distribution company shall retain the right to separate out pricing for each market product under the contracts for administrative and accounting purposes to avoid any detrimental accounting effects or for administrative convenience, provided that such accounting as specified in the contract does not affect the price and financial benefits to the seller as a seller of a bundled product. The standard contract also shall:

(i) Hold the distributed generation facility owner liable for the cost of interconnection from the distributed generation facility to the interconnect point with the distribution system, and for any upgrades to the existing distributed generation system that may be required by the electric distribution company. However, a distributed generation facility owner may appeal to the commission to reduce any required system upgrade costs to the extent such upgrades can be shown to benefit other customers of the electric distribution company and the balance of such costs shall be included in rates by the electric distribution company for recovery in the year incurred or the year following incurrence;

(ii) Require the distributed generation facility owner to make a performance guarantee deposit to the electric distribution company of fifteen dollars ($15.00) for small distributed generation projects or twenty-five dollars ($25.00) for large distributed generation projects for every renewable energy certificate estimated to be generated per year under the contract, but at least five hundred dollars ($500) and not more than seventy-five thousand dollars ($75,000), paid at the time of contract execution;

(iii) Require the electric distribution company to refund the performance guarantee deposit on a pro-rated basis of renewable energy credits actually delivered by the distributed generation facility over the course of the first year of the project's operation, paid quarterly;

(iv) Provide that if the distributed generation facility has not generated ninety percent (90%) of the output proposed in its enrollment application within eighteen (18) months after execution of the contract, the contract shall be terminated and the performance guarantee shall be forfeited. An eligible small-scale hydropower distributed generation facility that has not generated ninety percent (90%) of the output proposed in its enrollment application within forty-eight (48) months after execution of the contract shall result in the contract being terminated and the performance guarantee being forfeited. An eligible anaerobic digestion distributed generation facility that has not generated ninety percent (90%) of the output proposed in its enrollment application within thirty-six (36) months after execution of the contract shall result in the contract being terminated and the performance guarantee being forfeited. Any forfeited performance guarantee deposits shall be credited to all distribution customers in rates and not retained by the electric distribution company;

(v) Provide for flexible payment schedules that may be negotiated between the buyer and seller, but shall be no longer than quarterly if an agreement cannot be reached;

(vi) Require that an electric meter which conforms with standard industry norms be installed to measure the electrical energy output of the distributed generation facility, and require a system or procedure by which the distributed generation facility owner shall demonstrate creation of renewable energy credits, in a manner recognized and accounted for by the GIS; such demonstration of renewable energy credit creation to be at the distributed generation facility owner's expense. The electric distribution company may, at its discretion, offer to provide such a renewable energy credit measurement and accounting system or procedure to the distributed generation facility owner, and the distributed generation facility owner may, at its discretion, use the electric distribution company's program, or use that of an independent third party, approved by the commission, and the costs of such measurement and accounting are paid for by the distributed generation facility owner.

(vii) All distributed generation projects that have executed contracts will be required to submit quarterly reports on the progress of the project to the distribution company and the office of energy resources. Failure to submit these quarterly progress reports may result in the termination of the contract.

(3) If the contract working group reaches agreement on the terms of standard contracts, the board shall file the contracts with the commission for approval. If there are any disagreements, they shall be identified to the commission. The commission shall review the standard contracts for conformance with the standards set forth in subsection (2). Should there be any disputes, the commission shall issue an order resolving them. To the extent the commission needs expert assistance to resolve any disagreements noted in the filing, the commission is authorized to hire a consultant to assist it in the proceedings, the costs of which shall be recovered from electric distribution customers pursuant to a uniform factor established by the commission in rates for recovery by the electric distribution company in the year incurred or the year following incurrence, as requested through a filing by the electric distribution company. The commission shall issue an order approving standard forms of contract within sixty (60) days of the filing.

SECTION 5. This act shall take effect upon passage.

========
LC004420/SUB A/3
========

EXPLANATION

BY THE LEGISLATIVE COUNCIL

OF

A N A C T

RELATING TO PUBLIC UTILITIES AND CARRIERS - THE CLEAN ENERGY JOBS PROGRAM

***

This act would create a tariff-based renewable energy distributed generation financing program, or "Renewable Energy Growth Program", to provide for the continuation of the development of the renewable energy growth program in the load zone of the electric distribution company at a reasonable cost.

This act would take effect upon passage.

========
LC004420/SUB A/3
========

§ 118. Contributions to the capital of a corporation.

(a) General rule. In the case of a corporation, gross income does not include any contribution to the capital of the taxpayer.

(b) Contributions in aid of construction, etc. For purposes of subsection (a), except as provided in subsection (c), the term "contribution to the capital of the taxpayer" does not include any contribution in aid of construction or any other contribution as a customer or potential customer.

(c) Special rules for water and sewerage disposal utilities.

(1) General rule. For purposes of this section, the term "contribution to the capital of the taxpayer" includes any amount of money or other property received from any person (whether or not a shareholder) by a regulated public utility which provides water or sewerage disposal services if--

(A) such amount is a contribution in aid of construction,

(B) in the case of contribution of property other than water or sewerage disposal facilities, such amount meets the requirements of the expenditure rule of paragraph (2), and

(C) such amount (or any property acquired or constructed with such amount) is not included in the taxpayer's rate base for ratemaking purposes.

(2) Expenditure rule. An amount meets the requirements of this paragraph if--

(A) an amount equal to such amount is expended for the acquisition or construction of tangible property described in section 1231(b) [26 USCS § 1231(b)] --

(i) which is the property for which the contribution was made or is of the same type as such property, and

(ii) which is used predominantly in the trade or business of furnishing water or sewerage disposal services,

(B) the expenditure referred to in subparagraph (A) occurs before the end of the second taxable year after the year in which such amount was received, and

(C) accurate records are kept of the amounts contributed and expenditures made, the expenditures to which contributions are allocated, and the year in which the contributions and expenditures are received and made.

(3) Definitions. For purposes of this subsection--

(A) Contribution in aid of construction. The term "contribution in aid of construction" shall be defined by regulations prescribed by the Secretary, except that such term shall not include amounts paid as service charges for starting or stopping services.

(B) Predominantly. The term "predominantly" means 80 percent or more.

(C) Regulated public utility. The term "regulated public utility" has the meaning given such term by section 7701(a)(33) [26 USCS § 7701(a)(33)], except that such term shall not include any utility which is not required to provide water or sewerage disposal services to members of the general public in its service area.

(4) Disallowance of deductions and credits; adjusted basis. Notwithstanding any other provision of this

Page 2 of 2

subtitle [26 USCS §§ 1 et seq.], no deduction or credit shall be allowed for, or by reason of, any expenditure which constitutes a contribution in aid of construction to which this subsection applies. The adjusted basis of any property acquired with contributions in aid of construction to which this subsection applies shall be zero.

(d) Statute of limitations. If the taxpayer for any taxable year treats an amount as a contribution to the capital of the taxpayer described in subsection (c), then--

(1) the statutory period for the assessment of any deficiency attributable to any part of such amount shall not expire before the expiration of 3 years from the date the Secretary is notified by the taxpayer (in such manner as the Secretary may prescribe) of--

(A) the amount of the expenditure referred to in subparagraph (A) of subsection (c)(2),

(B) the taxpayer's intention not to make the expenditures referred to in such subparagraph, or

(C) a failure to make such expenditure within the period described in subparagraph (B) of subsection (c)(2), and

(2) such deficiency may be assessed before the expiration of such 3-year period notwithstanding the provisions of any other law or rule of law which would otherwise prevent such assessment.

(e) Cross references.

(1) For basis of property acquired by a corporation through a contribution to its capital, see section 362.

(2) For special rules in the case of contributions of indebtedness, see section 108(e)(6).

History

(Aug. 16, 1954, ch 736, 68A Stat. 39; Oct. 4, 1976, P.L. 94-455, Title XXI, § 2120(a), 90 Stat. 1912; *Nov. 6, 1978,* P.L. 95-600, Title III, § 364(a), 92 Stat. 2854; *Dec. 24, 1980,* P.L. 96-589, *§ 2(e)(2),* 94 Stat. 3396; *July 18, 1984,* P.L. 98-369, *Div A, Title I, § 163(a),* 98 Stat. 697; *Oct. 22, 1986,* P.L. 99-514, *Title VIII, § 824(a),* 100 Stat. 2374; *Aug. 20, 1996,* P.L. 104-188, Title I, § 1613(a)(1), (2), 110 Stat. 1848*-1850.)*

UNITED STATES CODE SERVICE

FTC

Notice 88-129, 1988-2 CB 541, IRC Sec(s). 118

Headnote:

Notice 88-129, 1988-2 CB 541[CAUTION: This Notice has been amplified and modified by Notice 90-60, 1990-2 CB 345 and Notice 2001-82, 2001-2 CB 619.]

Reference(s): Code Sec. 118;

Full Text:

Transfers of Property to Regulated Public Utilities by "Qualifying Facilities."

This notice provides guidance with respect to certain payments or transfers of property to regulated public utilities ("utilities") by qualifying small power producers and qualifying cogenerators (collectively "Qualifying Facilities"), as defined in section 3 of the Federal Power Act, as amended by section 201 of the Public Utilities Regulatory Policies Act of 1978 ("PURPA").

BACKGROUND

Notice 87-82, 1987-2 C.B. 389, addressed the Federal tax treatment of contributions in aid of construction ("CIACS") in light of the amendments made to section 118 of the Internal Revenue Code ("Code") by section 824 of the Tax Reform Act of 1986 (the "1986 Act"). Notice 87-82 reserved for separate guidance the treatment of payments or transfers of property made by Qualifying Facilities to utilities in connection with sales of power under PURPA. The Internal Revenue Service has received many inquiries concerning whether, as a result of the 1986 Act, such transfers result in income to utilities. This notice provides guidance with respect to certain types of transfers from Qualifying Facilities to utilities. No inference is intended with respect to other types of transfers.

1. Transfers Exclusively in Connection With the Sale of Electricity by a Qualifying Facility.

PURPA and its implementing rules and regulations require that a utility interconnect with a Qualifying Facility for the purpose of allowing the sale of power produced by the Qualifying Facility. A Qualifying Facility must bear the cost of the purchase and installation of any equipment required for the interconnection. This equipment, referred to herein as an "intertie," may include new connecting and transmission facilities, or modifications, upgrades or relocations of a utility's existing transmission network. Generally, the utility takes legal title to the intertie, which becomes part of the utility's transmission network. Under standard cost-based rate regulation, utilities may neither earn a profit on sales of power purchased from Qualifying Facilities nor include the cost of interties in rate base.**<Page 542>**

The amendment of Code section 118(b) by the 1986 Act was intended to require utilities to include in income the value of any contribution in aid of construction made to encourage the provision of services by a utility to a customer. See H.R. Rep. No. 841, 99th Cong., 2d Sess. 324 (1986) (Conference Report). In a CIAC transaction the purpose of the contribution of property to the utility is to facilitate the sale of power by the utility to a customer. In contrast, the purpose of the contribution by a Qualifying Facility to a utility is to permit the sale of power by the Qualifying Facility to the utility. Accordingly, the fact that the 1986 amendments to Code section 118(b) render CIAC transactions taxable to the utility does not require a similar conclusion with respect to transfers from Qualifying Facilities to utilities.

Qualifying Facilities generally sell electricity to utilities pursuant to long-term power purchase contracts. Some contracts require the Qualifying Facility to construct and install the intertie, and subsequently transfer the intertie to the utility. With respect to transfers of property made by a Qualifying Facility to a utility exclusively in connection with the sale of electricity by the Qualifying Facility to the utility, a utility will not realize income upon transfer of an intertie by a Qualifying Facility. These nontaxable transfers are referred to herein as "QF transfers." The possibility that an intertie may be used to transmit power to a utility that will in turn transmit the power across its transmission network for sale by the Qualifying Facility to another utility (i.e., "wheeling") shall not cause the contribution to be treated as a CIAC. A utility takes no basis in property transferred in a QF transfer, thus, for example, a utility shall not be allowed any depreciation (or amortization) deductions with respect to the property transferred in a QF transfer.

Under some power purchase contracts, the utility agrees to construct and install the intertie on behalf of the Qualifying Facility, with the Qualifying Facility agreeing to reimburse or finance the construction and installation costs. A utility that constructs an intertie in exchange for a cash payment from a Qualifying Facility pursuant to a PURPA contract will be deemed to construct the property for the Qualifying Facility under contract and will recognize income from the construction in the same manner as any other taxpayer constructing similar property under contract. See, e.g., Code section 460. Subsequent to the construction of the property, the Qualifying Facility will be deemed to transfer the property to the utility in a QF transfer that will be treated in exactly the same manner as an in-kind QF transfer.

2. Other QF Transfers.

In some situations the transfer of property by a Qualifying Facility to a utility may not be exclusively in connection with the sale of power from the Qualifying Facility to the utility. In addition to transmitting power from the Qualifying Facility to the utility, the intertie may be used to transmit power from the utility for sale to the Qualifying Facility (a "dual-use intertie"). A dual-use intertie may be employed where a Qualifying Facility relies on the utility as a "backup" or supplemental power source, either sporadically or on a regular basis. The transfer of a dual-use intertie may be treated as a QF transfer, as provided in the following paragraph; however, the transfer of an asset necessary only for sale of power by the utility to the Qualifying Facility is not a QF transfer and constitutes a CIAC, even if the asset is used in part in connection with the transmission of power to the utility. Thus, for example, if at the time of a QF transfer a Qualifying Facility transfers an asset necessary only for the sale of power to the Qualifying Facility, the transfer of that asset is not a QF transfer.

The contribution of a dual-use intertie to a utility will be treated as a QF transfer (and, therefore, nontaxable) if, in light of all information available to the utility at the time of transfer, it is reasonably projected that during the first ten taxable years of the utility, beginning with the year in which the transferred property is placed in service, no more than 5% of the projected total power flows over the intertie will flow to the Qualifying Facility (the "5% test"). Such a projection shall, if practicable, be supported by a report from an independent engineer. Total power flows means power flows to or from the Qualifying Facility over the intertie. For purposes of this notice, power flows to a Qualifying Facility include power flows to a related party of the Qualifying Facility, if the transmission of power to the related party has been facilitated by the transfer of the intertie. Thus, for example, in the case of a modification or relocation of a utility's existing transmission line, power flows to an unrelated third party are ignored. For purposes of the 5% test, power flows in the taxable year in which the transferred property is placed in service may, at the option of the utility, be ignored. For example, suppose a utility and a Qualifying Facility enter into a power purchase contract with a term of twenty years, and power flow from the utility to the Qualifying Facility is expected to comprise 10% of total power flows in the first year (the taxable year in which the facility is placed in service), 1% in the second and third years, and 0.5% in each of the fourth through tenth years. Total power flows are projected to be 100 megawatt hours ("MWH") in the first and second years, and 200 MWH in the third through tenth years. Assume that the taxpayer excludes the first year of the contract from the projection. Thus, the taxpayer reasonably projects that power flow to the Qualifying Facility will be 0.59% of total power flows over the intertie for the applicable nine-year period ((1% X 100 MWH + 1% X 200 MWH + 7 X (0.5% X 200 MWH))/(100 MWH + 8 × 200 MWH)). Under the 5% test provided in this notice, the contribution of the intertie to the utility by the Qualifying Facility will be treated as a QF transfer and, therefore, shall be nontaxable.

3. Excluded Transfers.

Certain transfers that would otherwise qualify as QF transfers are excluded from the definition of QF transfers if such transfers are described in this section 3 of this notice. A transfer from a Qualifying Facility to a utility will not be treated as a QF transfer under this notice to the extent the intertie is included in the utility's rate base. Moreover, a transfer of an intertie to a utility will not be treated as a QF transfer under this notice if the term of the power purchase contract is less than ten years.

4. Termination of Safe Harbor.

The fact that a transfer constitutes a QF transfer under this notice does not establish that a utility will never recognize income attributable to receipt of the transferred property. The occurrence of an event specified below in section 4(A) or 4(B) shall terminate the safe harbor and require the utility to recognize income as a consequence of the QF transfer.

(A) *Proportionate Disqualification.* If, for each of any three taxable years within any period of five consecutive taxable years, more than 5% of the total power **<Page 543>** flows over the intertie flow from the utility to the Qualifying Facility (a "disqualification event"), then the Qualifying Facility will be deemed to have made a transfer to the utility which constitutes a CIAC under section 118(b) as of the last day of the third such year. At the option of the utility, the taxable year in which the property is placed in service shall not be taken into account in determining whether there has been a disqualification event. The amount of the CIAC shall be that percentage of the fair market value of the intertie as of the date of the deemed transfer which is reflective of the use of the intertie for the purpose of selling power to the Qualifying Facility, determined by the Internal Revenue Service by taking into account all facts and circumstances. Relevant factors include (1) the use of the intertie during the period immediately preceding the disqualification event; (2) the use of the intertie since the date it was placed in service; (3) the reasonably anticipated use of the intertie during the remaining term of the power purchase contract. See section III of Notice 87-82 for guidance as to the fair market value of a CIAC. For example, suppose a Qualifying Facility contributes an intertie to a utility that is a calendar year taxpayer. The utility places the intertie in service in 1990, and reasonably projects that over the ten taxable years beginning in 1990 power flows over the intertie to the Qualifying Facility will be less than 5% of total power flows over the intertie. Power flows over the intertie to the Qualifying Facility constitute the following percentages of total flows over the intertie: 10% in 1990; 7% in 1991; 6% in 1992; 3% in 1993; 1% in 1994; and 6% in 1995. The utility excludes 1990 (the year in which the intertie is placed in service) from the determination of whether a disqualification event has occurred. A disqualification event occurs due to power flows in 1995, the third year within the five year period from 1991 to 1995 in which more than 5% of power flows over the intertie flow to the Qualifying Facility. Therefore, the Qualifying Facility is deemed to have made a CIAC transfer to the utility as of December 31, 1995.

Proportionate disqualification does not apply to any property necessary for, and used solely to facilitate, the transmission of power by the Qualifying Facility to the utility. For example, suppose the contract between a Qualifying Facility and a utility requires the utility to relocate a major transmission line and to construct an intertie to the Qualifying Facility including protective devices which are necessary and used solely for the delivery of power to the utility. Several years into the contract, the use of the intertie by the utility for delivery of power results in a disqualification event. Payments made for the construction of the protective devices are not subject to proportionate disqualification, while payments made for the relocation of the transmission lines are subject to proportionate disqualification (because the transmission line is used for the delivery of power over the intertie by the utility to the Qualifying Facility).

(B) *Termination of Power Purchase Contract.* Upon the termination of the power purchase contract between a Qualifying Facility and a utility, if the utility obtains or retains ownership (for tax purposes) of property transferred in a QF transfer, the Qualified Facility will be deemed to have made a transfer to the utility which constitutes a CIAC under section 118(b) as of the first day of such termination. The amount of the CIAC shall be the fair market value of the intertie, less the amount, if any, paid by the utility to obtain or retain ownership of the property for tax purposes. Therefore, if the amount paid by the utility is fair market value, the Qualified Facility will not be deemed to have made a CIAC transfer. See Section III of Notice 87-82 for guidance as to the fair market value of a CIAC.

5. Notification Requirements.

If for any taxable year power flows to the Qualifying Facility exceed 5% of total power flows over the intertie, then the utility must attach a statement to this effect to its return for such taxable year. If a power supply contract subject to the provisions of this notice terminates, the utility must attach a statement to this effect to its return for the year in which the termination occurs. The notification requirements of this section 5 apply to taxable years ending more than 180 days after December 27, 1988, the date this notice is published in the Bulletin.

6. Cost Recovery of QF Transfer Property.

Sections 1.461-1(a)(1) and (2) of the Income Tax Regulations provide that taxpayers using the cash and accrual methods of accounting, respectively, may not currently deduct the total amount of an expenditure which results in the creation of an asset having a useful life which extends substantially beyond the close of the taxable year. Instead, such taxpayers are required to capitalize such expenditures as assets and recover the cost of the expenditures over the useful life of the asset in question. See, e.g., Rev. Rul. 70-413, 1970-2 C.B. 103. The cost of property transferred in a QF transfer must be capitalized by the Qualified Facility as an intangible asset and recovered as appropriate. Cf. Section VII of Notice 87-82 (amortization of the cost of a CIAC by the contributor).

A utility may not take depreciation (or amortization) deductions with respect to property transferred in a QF transfer. This rule applies regardless of whether the Qualifying Facility initially transfers intertie property to the utility or whether the Qualifying Facility initially transfers cash followed by a deemed QF transfer to the utility. However, if property which is the subject of a QF transfer is subsequently transferred or deemed transferred to the utility as a CIAC, the utility may be allowed to take depreciation deductions with respect to the property.

This document serves as an "administrative pronouncement" as that term is described in section 1.6661-3(b)(2) of the Income Tax Regulations and may be relied upon to the same extent as a revenue ruling or a revenue procedure.

Part III - Administrative, Procedural, and Miscellaneous

Expansion of Safe Harbor Provisions Under Notice 88-129

Notice 2001-82

PURPOSE

This notice amplifies and modifies Notice 88-129, 1988-2 C.B. 541, as modified and amplified by Notice 90-60, 1990-2 C.B. 345. Notice 88-129 provides that a regulated public utility (utility) will not realize income upon transfers of interties from qualifying small power producers and qualifying cogenerators (collectively, Qualifying Facilities), as defined in section 3 of the Federal Power Act, as amended by section 201 of the Public Utilities Regulatory Policies Act of 1978 (PURPA). This notice extends the safe harbor provisions of Notice 88-129 to include transfers of interties from non-Qualifying Facilities. The safe harbor also is extended to transactions in which there is not a long-term power purchase contract between the utility and the power producer but rather the intertie is transferred pursuant to a long-term interconnection agreement and in which the intertie is used exclusively to transmit power across the utility's transmission grid for sale to consumers or intermediaries.

BACKGROUND

At the time Notice 88-129 was issued, most generators that were not owned by regulated public utilities (stand-alone generators) were Qualifying Facilities for regulatory purposes. As a stand-alone generator, the Qualifying Facility had to be connected to a utility's transmission lines in order to move its power to market. PURPA required that a utility interconnect with a Qualifying Facility for the purpose of allowing the sale of power produced by the Qualifying Facility. A Qualifying Facility generally sold its electricity under a long-term power purchase contract to the local utility with whom it was interconnecting at the utility's avoided cost. A Qualifying Facility also arranged in certain cases for the interconnected utility to transmit electricity across its transmission grid for sale to another utility (wheeling) at that utility's avoided cost.

Deregulation of the electric power industry has significantly changed the operation of the industry. Today, few new stand-alone generators are Qualifying Facilities. The Federal Energy Regulatory Commission (FERC) encouraged the construction of non-Qualifying Facilities starting in the late 1980's by issuing a number of orders to individual projects (known in the industry as independent power producers) approving sales of power at market rates. In addition, the Energy Policy Act of 1992 created a new class of stand-alone generators, called exempt wholesale generators, that are permitted to sell their power at market rates with FERC approval, and are exempted from certain utility regulation. Unlike PURPA, the Energy Policy Act has no requirement that utilities buy electricity from stand-alone generators.

In 1996, FERC issued Order No. 888 in an effort to ensure that every wholesale supplier of electricity, including, for example, power marketers and stand-alone generators, has open access to the national transmission grid. The order requires regulated utilities to allow stand-alone generators to interconnect to the grid and to file nondiscriminatory tariffs under which any wholesale supplier can pay to have its electricity wheeled. Stand-alone generators (including Qualifying Facilities) have additional outlets for their power today that they did not have in 1988, including sales of power at auction on regional power exchanges or spot markets and under short and medium-term contracts to specific customers or to power marketers that trade electricity. Regulated utilities have many more sources of supply for electricity than in 1988. As a result of these changes, very few utilities enter into long-term power purchase contracts with stand-alone generators. Electricity produced by stand-alone generators is more likely today than in 1988 to be wheeled across the transmission grid of the interconnected utility for sale to consumers or intermediaries rather than to be sold directly to the interconnected utility.

The new stand-alone generators still need to be interconnected to the transmission grid in order for a customer to take the power. Therefore, the stand-alone generator enters into a long-term interconnection agreement with the local utility. The term of a long-term interconnection agreement may be tied to the period that the stand-alone generator remains in commercial operation. This agreement may permit assignment of the agreement by the utility to accommodate future consolidation of local grids into regional transmission systems that will cover broad regions of the country.

MODIFICATIONS TO NOTICE 88-129 AND NOTICE 90-60

In light of the above-mentioned changes in the electric power industry, the safe harbor provisions of Notice 88-129 are modified as follows:

1. The safe harbor provisions are extended to include transfers of interties from non-Qualifying Facilities. Accordingly, the term “QF transfer” appearing in Notice 88-129 will be construed as including “qualified transfers” of interties from non-Qualifying Facilities that meet the other requirements of the safe harbor provisions. Similarly, the term “Qualifying Facility” for purposes of Notice 88-129 will be construed as including “stand-alone generators” that are not Qualifying Facilities.

2. The safe harbor provisions also are extended to include transfers of interties used exclusively or in part to transmit power over the utility’s transmission grid for sale to consumers or intermediaries, including affiliated intermediaries (wheeling). This safe harbor only applies to transactions in which the intertie is transferred pursuant to a long-term interconnection agreement and in which ownership of the electricity wheeled passes to the purchaser prior to its transmission on the utility’s transmission grid. The ownership requirement of the preceding sentence is deemed satisfied if title to electricity wheeled passes to the purchaser at the busbar on the generator’s end of the intertie. The terms “power purchase contract” and “power supply contract” appearing in Notice 88-129 will be construed as including interconnection agreements in transactions in which the intertie is used for wheeling. Accordingly, a long-term interconnection agreement in lieu of a long-term power purchase contract or power supply contract may be used to satisfy the safe harbor provisions of Notice 88-129 in such transactions.

The term “dual-use intertie” appearing in Notice 88-129 will be construed as including an intertie which may be used to transmit power from a third party for sale to the Qualifying Facility.

3. Section 6, sentence 4, of Notice 88-129, states, “The cost of property transferred in a QF transfer must be capitalized by the Qualifying Facility as an intangible asset and recovered as appropriate.” This sentence is modified to read as follows: “The cost of property transferred in a QF transfer must be capitalized by the Qualified Facility as an intangible asset and recovered using the straight-line method over a useful life of 20 years.”

EFFECT ON OTHER DOCUMENTS

Notice 88-129, as amplified and modified by Notice 90-60, is further amplified and modified.

EFFECTIVE DATE

This notice applies to transfers of property to regulated public utilities pursuant to interconnection agreements completed after December 24, 2001, the date this notice is published in the Bulletin. For transfers of interties occurring on or before December 24, 2001 and meeting the requirements of this notice, taxpayers may request application of this notice through a request for a private letter ruling (including, in appropriate circumstances, where the taxpayer’s return for the year of transfer has already been filed).

DRAFTING INFORMATION

The principal author of this notice is Gregory N. Doran of the Office of Associate Chief Counsel (Passthroughs and Special Industries). For further information regarding this notice contact Mr. Doran at (202) 622-3040 (not a toll-free call).

LexisNexis®

1 of 1 DOCUMENT

General Laws of Rhode Island

*** Current through the January 2013 Session ***
*** Annotations current through May 16, 2014 ***

TITLE 39. PUBLIC UTILITIES AND CARRIERS
CHAPTER 26.3. DISTRIBUTED GENERATION INTERCONNECTION

Go to the Rhode Island Code Archive Directory

R.I. Gen. Laws § 39-26.3-4 (2013)

§ 39-26.3-4. Study cost fees

(a) After thirty (30) days from the enactment of this chapter until the end of calendar year 2012, the feasibility study fee shall be in accordance with the schedule set forth below:

(1) Residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is twenty-five kilowatts (25 kw) or less: zero dollars ($ 0).

(2) Residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is greater than twenty-five kilowatts (25 kw): fifty dollars ($ 50.00).

(3) Non-residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is one hundred kilowatts (100 kw) or less: one hundred dollars ($ 100).

(4) Non-residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is two hundred fifty kilowatts (250 kw) or less: three hundred dollars ($ 300).

(5) Non-residential applicants for interconnections of renewable distributed generation that is greater than two hundred fifty kilowatts (250 kw), up to one megawatt: one thousand dollars ($ 1,000).

(6) Non-residential applicants for interconnections of renewable distributed generation greater than one mega-watt: two thousand five hundred dollars ($ 2,500).

Beginning January 1, 2013 and for every year thereafter, the commission shall set a new fee schedule that is no less than what is specified herein. The purpose of the fee schedule is to provide a disincentive to applicants contemplating a renewable distributed generation project from requesting order of magnitude estimates unless they are serious about pursuing such projects.

(b) After thirty (30) days from the enactment of this chapter until the end of calendar year 2012, the impact study fee shall be in accordance with the schedule set forth below:

(1) Residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is twenty-five kilowatts (25 kw) or less: zero dollars ($ 0).

(2) Residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is greater than twenty-five kilowatts (25 kw): one hundred dollars ($ 100).

(3) Non-residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is one hundred kilowatts (100 kw) or less: five hundred dollars ($ 500)

(4) Non-residential applicants for interconnections of UL 1741.1 approved renewable distributed generation that is two hundred fifty kilowatts (250 kw) or less: one thousand five hundred dollars ($ 1,500).

(5) Non-residential applicants for interconnections of renewable distributed generation that is greater than two hundred fifty kilowatts (250 kw), up to one megawatt: five thousand dollars ($ 5,000).

(6) Non-residential applicants for interconnections of renewable distributed generation greater than one megawatt: ten thousand dollars ($ 10,000).

Beginning January 1, 2013 and for every year thereafter, the commission shall set a new fee schedule that is no less than what is specified herein. The purpose of the impact study fee schedule is to assure that an applicant is responsible for paying a reasonable amount of the cost of the study in advance of installing the distributed generation, but that the advance cost is not so high as to discourage an applicant from pursuing a project.

(c) To the extent that an impact study fee established under this section does not cover the reasonable cost of an impact study for a given non-residential project that commences operation, the balance of such costs shall be recovered from such applicant through billings after the project is online. The electric distribution company may, at its sole election, offset net metering credits or any standard contract payments until the full fee(s) is reimbursed, if it finds it administratively convenient to use that means of billing for the balance of the fee for a given project.

HISTORY: P.L. 2011, ch. 140, § 1; P.L. 2011, ch. 144, § 1.