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September 29, 2006

BY HAND

Ms. Debra A. Howland
Executive Director and Secretary
State of New Hampshire
Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

Re: Unitil Energy Systems, Inc: DE 06-061; Investigation into Federal Standards Pursuant to the Energy Policy Act of 2005

Dear Ms. Howland:

On behalf of Unitil Energy Systems, Inc. ("UES"), enclosed please find an original and eight (8) copies of UES' Initial Comments in the above-referenced proceeding.

Thank you for your assistance with this matter.

Sincerely ~~yours~~,

Meabh Purcell

Meabh Purcell

Enclosures
Cc: Service List (via email)

BS111549

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

INVESTIGATION INTO FEDERAL STANDARDS PURSUANT TO THE ENERGY POLICY ACT OF 2005	)	DE 06-061

INITIAL COMMENTS OF UNITIL ENERGY SYSTEMS, INC.

Pursuant to the procedural schedule adopted in the above-referenced proceeding, Unitil Energy Systems, Inc. ("UES") hereby submits its initial comments on the federal standards regarding Time Based Metering and Communications (Section 1251) and Interconnection (Section 1254).

On April 24, 2006, the Commission issued an order of notice in this proceeding regarding five new federal standards that have been added to Title I of the Public Utility Regulatory Policies Act ("PURPA") by the Energy Policy Act of 2005 ("EPAct"), which was signed into law on August 8, 2005. Sections 1251, 1252, and 1254 of EPAct require the state commissions to review the new standards and make specific determinations as to whether or not implementation of each standard is appropriate. The five standards are: (1) Net Metering; (2) Fuel Diversity; (3) Fossil Fuel Generation Efficiency (Standards 1, 2 and 3 are contained in Section 1251); (4) Time-Based Metering and Communications (Section 1252); and (5) Interconnection (Section 1254)[1].

[1] The Commission's review of the standards on Net Metering, Fuel Source Diversity and Fossil Fuel Generation Efficiency under Section 1251 has been postponed until after the Commission has made its determination on Time-Based Metering and Interconnection which are subject to a shorter deadline.

I. Time-Based Metering and Communications ("Smart Metering")

A. The Standard

Section 1252 of EPAct requires that the state commissions determine whether it is appropriate to adopt the following standard by February 7, 2007 (i.e., within 18 months of the date of enactment of EPAct):

> (14) TIME-BASED METERING AND COMMUNICATIONS. - (A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customers classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

Section 1252 further provides that the types of time-based rate schedules include, among others:

- Time of Use pricing (TOU): price is broken into two or three time periods based on typical demand levels (peak, shoulder, off-peak) and is fixed for a predetermined period.
- Critical Peak Pricing (CPP): the price is similar to TOU in most hours except it allows the utility to increase prices to a substantially higher level during extreme peak hours.
- Real-Time Pricing (RTP): Prices are provided in real-time or near real-time with price notification from one hour to one day prior to use. This requires customers to monitor both price and usage in much more detail.
- Credits under peak load reduction agreements that reduce a utility's planned capacity obligations.

The standard also requires that each electric utility provide each customer requesting a time based rate with a time based meter capable of enabling the utility and customer to offer and receive such rate, respectively (also applies to customers whose energy is provided by a third party marketer).

Section 1252 (i) also provides that the time-based metering standard shall not apply in the case of electric utilities in those states where the State has already dealt with the issue, either by statute or in the context of a regulatory proceeding, ie., where:

> (1) the State has implemented for such utility the standard concerned (or a comparable standard);
>
> (2) the State regulatory authority has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility within the previous three years;
>
> (3) or the state legislature has voted on the implementation of such standard for such utility within the previous three years.

B. Unique Role of Distribution Company

In evaluating whether to implement time–based metering and communications, UES respectfully urges the Commission to address the threshold issue of the distinction between a vertically integrated utility and a distribution-only utility, such as UES, which provides Default Service within an unbundled market structure. Default Service, is to be "designed to provide a safety net and to assure universal access and system integrity" and to "not unduly harm the development of competitive markets" (RSA 374-F:3,V(c) and (e). Thus, the focus of the Commission's investigation into smart metering should be on determining the role of the distribution company from the perspective of default service pricing. However, the relevance of this standard notwithstanding, as discussed below, the Commission and the utilities have already taken significant steps towards accomplishing the goal of Section 1251 by installing advanced metering for large customers and making available other optional services that would encourage conservation of supply. The provision of Default Service for UES was also recently considered by the Commission in Docket DE 05-064.

In this docket, on September 9, 2005, the Commission approved UES' Default Service Supply proposal, as modified to reflect changes agreed upon through settlement, for UES' Large General Service ("G1") and non-G1 customers (all classes except G1), beginning on May 1, 2006. Currently, Default Service prices are set on a six month basis for non-G1 customers, with a fixed price for the six month period and a variable (monthly) price option. Default Service prices for G1 customers are set every three months with variable (monthly) prices only. Pursuant to the settlement, UES is also required to investigate the costs of acquiring the capability of providing hourly pricing for its large G1 customers and the potential impacts on the competitive retail market. UES' report will be filed with the Commission on November 1, 2006.

UES' approved Default Service for non-G1 customers consists of periodic procurement of four 25% load blocks as different periods of time. Two blocks are procured for a one-year period and two blocks are procured for a three year period. The blocks are procured at a fixed monthly price irregardless of time of use during the month. One of the contract blocks that UES has procured does not end until April 2009. Future blocks will be procured even further out in time, thus UES may be significantly limited in its ability to offer time differentiated rates to non-G1 customers over the next several years.

C. Unbundling

As a point of interest to this discussion, after the transition to a competitive model in New Hampshire, UES lost one of the means to convey price signal in the move from demand and energy-based fuel and purchased power rates to pure energy rates. An important cost driver is capacity. Without a demand component to rates for energy supply, customers do not have a price signal to reduce their demand.

D. UES' Metering Capabilities

Advanced metering was considered by the Commission in Docket DE 03-013, which resulted in a settlement for all NHPUC jurisdictional electric utilities. Pursuant to the settlement, UES and the other NHPUC jurisdictional electric utilities agreed to work to install advanced metering for all large commercial and industrial customers. Investigation Into Advanced Customer Metering and Demand Response by Electric Distribution Companies, DE 03-013, Order No. 24,263, p. 16 (NHPUC 2004). The Settlement also requires the utilities to offer optional services to their customers to permit remote access metering, pulse output service and interval data service.

As indicated in Docket DE 03-013, UES has already made advanced metering available to all of its customers through a standard metering package for G1 customers or through tariff provisions that allow for advanced metering for non-G1 customers. Advanced metering is defined as (1) an interval data meter with mass memory capability (i.e., the meter retains data for at least one complete billing month) which (2) includes a modem capable of providing data to the customer, the customer's competitive energy supplier, and/or the distribution company; and (3) is capable of recording and transmitting pulses.

UES has installed advanced meters with all of its G1 customers. These customers are the largest commercial and industrial customers whose usage generally exceeds 200 kilovolt-amperes (kVA) per month. As of August 2006, there are 155 customers in rate class G1. The cost of these meters is recovered from customers through distribution rates for that rate class.

UES currently offers advanced meters to non-G1 customers, for whom the cost is not included in distribution rates, through its tariff for Enhanced Metering Service, Service Option 1: Remote Access. (Unitil Energy System, Inc., NHPUC No. 1 Electricity Delivery Tariff, pages 49-51). This option provides advanced metering for a cost-based fee, either on a monthly basis or for a lump sum amount. Additionally, Service Option 2: Pulse Output Service is provided, for a fee, to both G1 and non-G1 customers. Service Option 2 provides a pulse interface device through which the customer can access real-time meter data for whatever purpose the customer desires.

UES' tariff allows eligible customers to participate in any ISO-NE's Demand Response Program approved by the Federal Energy Regulatory Commission ("FERC"), as amended from time to time. Interested customers may enroll with UES or any other NEPOOL Participant, subject to the Local Regional Price in effect at that time.

The combination of advanced meters currently installed and available to UES' customers and the advanced metering service options in its tariff provides the necessary tools for the measurement and collection of usage information for customers to participate in demand response programs including the ISO-NE Demand Response Programs. These services would permit a customer to participate in RTP options for electric generation service provided to the customer by a competitive electric power supplier. The advanced meter does not include any provision for the relay of real-time price information to the customer. This is normally achieved through the customer purchase of a third party piece of equipment for this purpose.

E. Future Metering Capabilities

As the Commission is also aware, UES is in the process of implementing an advanced metering infrastructure (AMI) for all customer classes to enable remote meter reading for all customers within its service territory. UES currently anticipates completing implementation of

AMI in UES' service territory by the second quarter of 2007. This power line carrier (PLC) based AMI will provide enhanced capability for collection of demand and energy information for all customer classes. An endpoint transceiver is the AMI device installed in each customer meter. Endpoint transceivers are configurable to ensure that existing and future electric rate structures are supported. Daily kWh usages and maximum daily demand data will be provided for all non-demand customers. For demand customers, UES may configure the endpoint to transmit the maximum daily demand, or choose to reset demand registers remotely, thus enabling, for example, demand reset at the end of each billing period as in conventional meter reading practice.

The endpoint supports TOU rate structures with up to four daily rate periods. In this case, the usage during each 15 minute interval in a day is allocated to one of the four rate periods. The rate periods can be customized for weekday, Saturday, Sunday, and holiday day types. Thus, a high demand rate period can be applied to different time periods and further applied to different day types. The system also allows creating a seasonal schedule accommodating up to eight yearly variations in a TOU rates structure throughout the year.

II. Interconnection

A. The Standard

The federal standard for interconnection is set forth in Section 1254:

> "(15) INTERCONNECTION. – Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers:

Similar to the Smart Metering Standard, Section 1254(b)(3) provides that no state commission action is required if a state commission has already conducted a proceeding to consider implementing the standard, or a comparable standard, or if the issue has been dealt with by the state legislature.

B. Current Interconnection Policy – New Hampshire

The Commission's interconnection policy was originally articulated in a series of orders, including Order No. 14,797 (March 20, 1981)[2] and Order No. 17,104 (July 5, 1984)[3]. In Order No. 14,797, the Commission adopted minimum guidelines for interconnection of qualifying small power producers and cogenerators. The guidelines adopted by the 1981 Order addressed safety and reliability concerns and established that interconnection equipment should be installed and maintained in accordance with national electric standards and local codes. Id. at 90. The Commission agreed with the concern expressed by several parties that final interconnection design should be decided on a site-specific basis, and noted that "overly specific guidelines

[2] Re Small Power Producers and Cogenerators, DE 80-246, Order No. 14,795 (N.H.P.U.C. 1981).
[3] Re Small Energy Producers and Cogenerators, DE 83-62, Order No. 17,104, 67 NHPUC 352 (1984).

would have a negative effect by causing unnecessary equipment to be acquired." In the 1984 proceeding, the Commission affirmed the guidelines adopted in 1981, and confirmed that small power producers are responsible for all costs reasonably incurred by the utility for changes to the distribution system as a result of interconnection. Id. at 361.

The Commission's rules, Puc 900, Net Metering for Customer-Owned Renewable Energy Generation Resources of 25 Kilowatts or Less, also address interconnection. Specifically, Rule Puc 905, et seq., sets forth the technical requirements for interconnection. Because these procedures were adopted prior to IEEE 1547, Rule Puc 900 should be reviewed in this proceeding for compliance with the IEEE standard.

C. Current Interconnection Policy – FERC

On July 24, 2003, the FERC issued a Final Rule (Order No. 2003)[4] requiring all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to have on file standard procedures and a standard agreement for interconnecting generating facilities capable of producing more than 20 megawatts of power (Large Generators) to their facilities. Order No. 2003 required utilities to modify their open access transmission tariffs to incorporate the Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA).

On May 12, 2005 the FERC issued a Final Rule (Order No. 2006) requiring all public utilities to adopt standard rules for interconnecting new sources of electricity no larger than 20 megawatts (MW). This order continued the process begun in Order No. 2003. The documents adopted in this Final Rule, the Small Generator Interconnection Procedures (SGIP) and Small

[4] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 FR 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003).

Generator Interconnection Agreement (SGIA) have been included in ISO New England Inc.'s Transmission, Markets and Service Tariff (ISO Tariff), of which UES is a part.

The SGIP contains the technical procedures the Interconnection Customer and Transmission Provider must follow once the Interconnection Customer requests interconnection. It provides three ways to evaluate the Interconnection Request. They are: the default Study Process that could be used by any Small Generating Facility; the Fast Track Process for a certified Small Generating Facility no larger than 2 MW; and the 10 kW Inverter Process for a certified inverter-based Small Generating Facility no larger than 10 kW. The SGIA contains contractual provisions appropriate for the interconnection of a Small Generating Facility, including provisions for the payment for modifications made to the Transmission Provider's Transmission System to accommodate the interconnection. The SGIA is signed by the Parties after they have successfully completed the evaluation of a proposed interconnection under the SGIP Study Process or Fast Track Process. The SGIA does not apply to requests to interconnect submitted under the 10 kW Inverter Process, however, which uses a simplified all-in-one application form/procedures/terms and conditions document.

D. UES Interconnection Policy

UES' interconnection policy, Interconnection Requirements for Customer Owned Generation (rev. 05/01/2000), covers the minimum requirements for safe and effective design, installation and operation of interconnection equipment for customer-owned generators. These requirements are applicable to Qualifying Facilities, On-Site Generating Facilities, Limited Electrical Energy Producers, Eligible Customer-Generators, Small Power Producers, Cogenerators, and other interconnections of customer generation to the Company's electrical system.

This document in intended to work in conjunction with the ISO New England requirements (LGIA/LGIP, SGIA/SGIP), and the Net Metering requirements (PUC 900 Rules). The ISO New England requirements include the FERC generation requirements as Schedules 22 and 23 of the ISO Tariff and the Transmission Operating Agreement ("TOA"); and ISO Planning Procedure 5-1, "Requirements, Procedures and Forms for Submitting Proposed Plan Applications" which is the detailed procedure to comply with the provisions of Section I.3.9 of the Tariff. Section I.3.9 of the ISO Tariff states that:

> "Each Market Participant and Transmission Owner shall submit to ISO, in such form, manner and detail as ISO may reasonably prescribe, (i) any new or materially changed plan for additions to, retirements of, or changes in the capacity of any supply and demand-side resources or transmission facilities rated 69 kV or above subject to control of such Market Participant or Transmission Owner, and (ii) any new or materially changed plan for any other action to be taken by the Market Participant or Transmission Owner which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant."

Given the complexity of applicable procedures and overlapping responsibilities, the ISO has drafted a responsibilities matrix to assist with determination of applicable procedures, stakeholder involvement, and transmission owner (TO) responsibilities (see attachment 1) based on the size of the generation and market applicability. After determination of responsibilities, UES generally follows a standardized process flow (see attachment 2) for all studies where UES has the "lead" responsibility. This standardized process, designed for consistency and simplicity, was developed by the Massachusetts Distributed Generation Collaborative in compliance with D.T.E. Order 02-38-B and includes a number of technical screens that assist in expediting the interconnection review of smaller generators connected to radial systems.

E. IEEE 1547

The IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE Std 1547-2003, is the first in the 1547 series of interconnection standards[5] which focuses on the technical specifications and testing of the interconnection of distributed resources (distributed generation), and is meant to be a minimum standard for interconnection. The Standard further outlines:

> "It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. It includes general requirements, response to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests. The criteria and requirements are applicable to all DR technologies, with aggregate capacity of 10 MVA or less at the point of common coupling, interconnected to electric power systems at typical primary and/or secondary distribution voltages. Installation of DR on radial primary and secondary distribution systems is the main emphasis of this document, although installation of DR on primary and secondary network distribution systems is considered. This standard is written considering that the DR is a 60 Hz source."

The FERC interconnection policies incorporate the IEEE interconnection specifications. UES' interconnection policies were developed prior to the release of the IEEE Standard, but there are no substantive differences between the two. Additionally, the UES policy allows for application of established standards of good utility practice for the New England region, of which the IEEE Standard would apply. There are two small differences between the IEEE Standard and UES' procedures, specifically:

- Synchronizing instantaneous variation in voltage: Section V.O of the UES Requirements specify no more than 3% instantaneous variation in voltage (flicker) and Section 4.1.3 of the IEEE Standard allows for 5%
- Breaker Voltage Withstand Capability: Section VI.C of the UES Requirement specifies 200% and section 4.1.8.3 of the IEEE Standard specifies 220%

[5] Other, more detailed Standards are in development. IEEE is currently working on P1547.1 Draft Standard for Conformance Test Procedures; P1547.2 Draft Application Guide for IEEE Std 1547-2003; P1547.3 Draft Guide for Monitoring, Information Exchange, and Control; P1547.4 Draft Guide for Design, Operation, and Integration of Distribution Resource Island Systems; and P1547.5 Draft Technical Guidelines for Interconnection of Electric Power Sources Greater than 10MVA; and P1547.6 Draft Recommended Practice For Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks.

UES has had a long-standing operating and planning requirement to limit instantaneous voltage variation to 3% for motor starts and capacitor switching, and has adopted this same limit for generation. The breaker voltage withstand requirement of the IEEE Standard are more stringent and would apply as a primary requirement. UES would allow for engineering judgment to determine if the lesser requirement was appropriate for a given situation.

III. Conclusion

UES appreciates this opportunity to comment on these standards. As evident by the scoping document filed by the parties on July 25, 2006, there are several issues that need to be explored. However, in particular with respect to time-based pricing, as a threshold issue, the Commission should define the role of the distribution company with respect to providing Default Service. UES looks forward to working with the parties in this docket to further explore these issues.

Respectfully submitted
UNITIL ENERGY SYSTEMS, INC

By its attorney,

Meabh Purcell

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Dated: September 29, 2006

Attachment 1

Generation Interconnection Responsibilities
ISO New England Proposal
August 26, 2005

Line #	State Sched 22 Sched 23	Intent to Sell to Market at Time of Application	Generator Size	Rate Class at POI at Time of Application	Receives Request	Responsible for Request or Application	Administers Deposit	Dist Co Involvement in study	T.O. Involvement in study	ISO-NE Involvement in study	Dist Co Involvement in IA	T.O. Involvement in IA
1,2	State	(a)	</= 2 MW	Distribution	Utility	Utility	Utility	Lead(1)	Participant(2)	Not Involved	Signs	None
9,10	State	(a)	2-20 MW	Distribution	ISO-NE	Utility	Utility	Lead(1)	Participant	Participant(10)	Signs	None
17,18	State	(a)	> 20 MW	Distribution	ISO-NE	Utility	Utility	Lead(1)	Participant	Participant(10)	Signs	None
3	State	No	</= 2 MW	Distribution under OATT	Utility	Utility	Utility	Lead(1)	Participant(2)	Not Involved	Signs	None
5	State	No	</= 2 MW	Non-PTF	Utility	Utility	Utility	Participant	Lead(1,2)	Not Involved	None	Signs
7	State	No	</= 2 MW	PTF	Utility	Utility	Utility	Participant	Lead(1,2)	Participant(9)	None	Signs
11	State	No	2-20 MW	Distribution under OATT	ISO-NE	Utility	Utility	Lead(1)	Participant	Participant(10)	Signs	None
13	State	No	2-20 MW	Non-PTF	ISO-NE	Utility	Utility	Participant	Lead(1)	Participant(10)	None	Signs
15	State	No	2-20 MW	PTF	ISO-NE	Utility	Utility	Participant	Lead(1)	Participant(9)	None	Signs
19	State	No	> 20 MW	Distribution under OATT	ISO-NE	Utility	Utility	Lead(1)	Participant	Participant(10)	Signs	None
21	State	No	> 20 MW	Non-PTF	ISO-NE	Utility	Utility	Participant	Lead(1)	Participant(10)	None	Signs
23	State	No	> 20 MW	PTF	ISO-NE	Utility	Utility	Participant	Lead(1)	Participant(9)	None	Signs
4	Sched 23	Yes (b)	</= 2 MW	Distribution under OATT	Utility	Utility	Utility	Lead(1)	Participant(2)	Dispute Resolution(3)	Signs	Signs
6	Sched 23	Yes (b)	</= 2 MW	Non-PTF	Utility	Utility	Utility	Participant	Lead(1,2)	Dispute Resolution(3)	None	Signs
8	Sched 23	Yes (b)	</= 2 MW	PTF	Utility	Utility	Utility	Participant	Lead(1,2)	Participant(9)	None	Signs
12	Sched 23	Yes (b)	2-20 MW	Distribution under OATT (e)	ISO-NE	ISO-NE	ISO-NE	Lead(1)	Participant	Participant(10)	Signs	Signs
14	Sched 23	Yes (b)	2-20 MW	Non-PTF (e)	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead(1)	None	Signs
16	Sched 23	Yes (b)	2-20 MW	PTF	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead(1)	None	Signs
20	Sched 22	Yes (b)	> 20 MW	Distribution under OATT (e)	ISO-NE	ISO-NE	ISO-NE	Lead(1)	Participant	Participant(10)	Signs	Signs
22	Sched 22	Yes (b)	> 20 MW	Non-PTF (e)	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead(1)	None	Signs
24	Sched 22	Yes (b)	> 20 MW	PTF	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead(1)	None	Signs

(a) Interconnections to the distribution fall under the state procedures, whether they intend to make wholesale transactions or not.

(b) For the purposes of Sched 22 & Sched 23, an Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consun retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Interconnection Customer does not intend to make wholesale sal request to interconnect a Qualifying Facility, where the owner intends to sell 100% of the output to its host utility.

(e) Functional pass through of "local" service/interconnection applications as described in Article 3.03(a)(ii) of the TOA, paraphrased below.
ISO forwards application to appropriate PTO. ISO reviews application to determine whether interconnection would have impact on facilities used for the provision of regional transmission service (P
If yes, the ISO performs studies to address impacts on facilities used for the provision of regional transmission service (PTF). The PTO is responsible for performing studies to address impacts on

(1) Lead is responsible for meeting study deadlines, arranging for contractors if needed, etc.
(2) T.O. responsible to notify ISO of situations where multiple small generators may have cumulative impacts.
(3) Interconnection Customer can contact ISO to help resolve disputes. ISO's role in dispute resolution will ensure non-discriminatory treatment of small generators.
(6) Small facilities (</= 2 MW) should not affect other interconnections.
(9) ISO should participate in the study as it is responsible for impacts on (and interconnections to) the facilities used for the provision of regional transmission service (PTF).
(10) I.3.9 required, because there is a potential impact on the PTF of interconnections to the distribution system or to the Non-PTF of generators that are 2MW or greater, ISO should participate in stud

Attachment 2

Figure 1 – Schematic of Massachusetts DG Interconnection Process

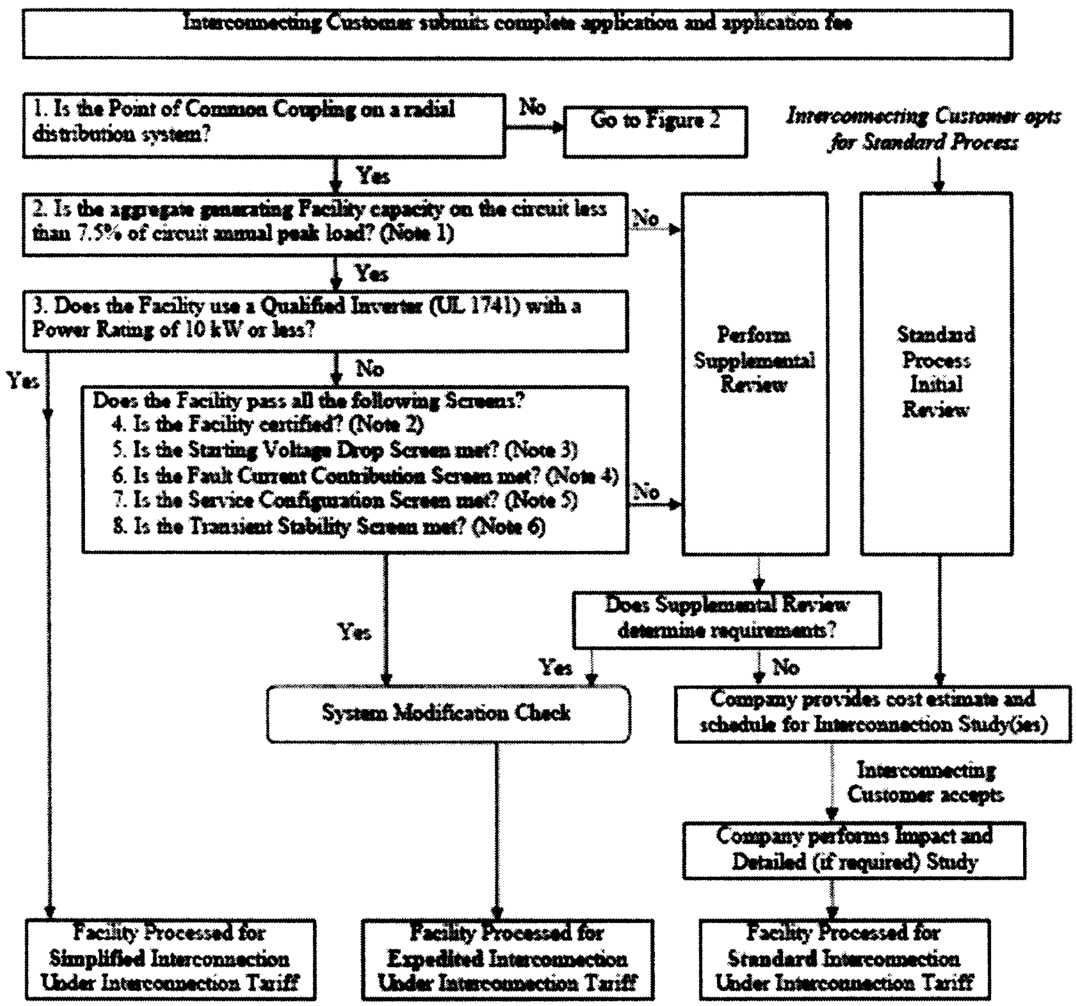

Figure 2 – Simplified Interconnection to Networks