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The Northeast Utilities System

June 6, 2006

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: Investigation of Implementation of the Energy Policy Act of 2005
Docket No. DE 06-061

Dear Secretary Howland:

Enclosed please find an original and eight copies of three outlines of discussion topics to consider five new federal standards which are found in Sections 1251, 1252 and 1254 of the Energy Policy Act of 2005. Pursuant to the parties' agreement at the technical session, these scoping documents were prepared by Granite State Electric Company d/b/a National Grid, Unitil Energy Systems and Public Service Company of New Hampshire. The documents were not circulated to the Commission's Staff and the other parties until today; therefore, they do not yet include input from participants other than the three utilities mentioned above. The Secretarial Letter issued on May 30, 2006 in this proceeding stated that the Commission may want "to review the initial scoping document and raise any concerns with the views of the utilities with respect to how the issues in this proceeding are to be defined."

Copies of this letter and the enclosed outlines have been provided electronically to the persons on the attached service list.

Very truly yours,

Gerald M. Eaton

Gerald M. Eaton
Senior Counsel

Enclosures

DE 06-061
Net Metering, Fuel Sources and Fossil Fuel Generation Efficiency
Section 1251 of the Energy Policy Act of 2005

Timing Issues

Not later than 2 years after enactment of the standard (August 8, 2007), each state regulatory authority shall commence consideration or set a hearing date for consideration, with respect to the standard.

Not later than 3 years after enactment of the standard (August 8, 2008), each state regulatory authority shall complete the consideration and shall make a determination as to whether to adopt the standard.

The Standard

(11) Net metering. Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

State Action

A. The Commission is free to adopt the standard, adopt the standard in part, or decline to adopt the standard.

B. The Commission need not take up the standard if:

(1) the PUC has implemented the standard concerned (or a comparable standard);

(2) the PUC has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard); or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

C. The legislature has enacted RSA 362-A: I-a, III-a[1] and RSA 362-A:9 on Net Energy Metering.

D. The Commission has adopted NH Code Admin. Rules Chapter Puc 900 which implements the legislative standard.

Issues

1. How many customers from each utility have used net metering? How close are each of the utilities to the maximum limit established by RSA 362-A:9,I?

2. Have the Legislature and the Commission addressed this PURPA standard and adopted a comparable standard? If so, should the Commission decide not to address this standard?

3. Can the Commission change the limits already established without prior legislative approval? If so, should the Commission do so?
   a. Generator cannot exceed 25 kilowatts. RSA 362-A:1-a, II-b
   b. Limited to 0.05 % of utility's peak. RSA 362-A:9, I

4. Can the Commission change the design? If so, what changes ought to be appropriate? Should non-renewable sources be eligible for net metering, or would such eligibility result in other customers subsidizing the nonrenewable source through payment of stranded cost charges and System Benefits Charges to the nonrenewable source? Would eligibility of nonrenewable sources be contrary to the fuel source standard?
   a. Currently only solar, wind, and/or hydro powered are permitted.
   b. Other renewables – wood, bio-diesel, methane gas (waste)

[1] "Net energy metering" means measuring the difference between the electricity supplied over the electric distribution system and the electricity generated by an eligible customer-generator which is fed back into the electric distribution system over a billing period.

c. Fuel cells, fossil fuels, combined heat and power projects (cogeneration)
d. Efficiency standards for generators

5. What are the advantages and disadvantages of net metering?
   a. Fuel diversity, distributed generation, renewable portfolio standards.
   b. Inefficient or unreliable generation,

6. Should the parties recommend amending PUC Chapter 900?
   a. Inverter specifications reference out of date IEEE guidelines
   b. Specific surge test requirements are now incorporated into UL1741 testing that are more stringent than those listed in PUC900.

7. The EPACT net metering standard applies to "energy" and not distribution services. Electric distribution utilities provide delivery services when receiving energy from and delivering energy to a net metered customer. Should net metering permit bypass of stranded costs, system benefits, energy consumption tax, distribution and transmission charges?

The Standard

(12) Fuel sources. Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

I. Current Status of Power from Diverse Fuel Sources
   A. PSNH's existing generation portfolio
      1. Coal - Merrimack I and II (coal only) and Schiller Units 4 and 6 (coal and oil capable)
      2. Wood – Schiller Unit 5 (wood and coal capable)
      3. Residual Oil – Wyman Unit No. 4

4. Dual Fuel - Newington (Oil and natural gas capable)
4. Hydro
5. Distillates (kerosene and/or diesel - (Combustion turbines at White Lake, Schiller, Merrimack, and Lost Nation)
6. Nuclear – Vermont Yankee
7. Wind – PSNH purchased power contracts with Lempster and Jericho Mountains

B. PSNH's fuel purchasing

1. Coal, - mix of multi-year and spot contracts; domestic and foreign suppliers; rail, ship, barge and truck deliveries
2. Residual and distillate oil – Mix of annual and spot contracts; multiple suppliers
3. Wood supply – Multiple suppliers from three states

C. PURPA Independent power producers. New Hampshire's regulatory scheme of encouraging off system power producers has led to the development of (PSNH only) 54 megawatts of hydro, 84 megawatts of wood fired generation, 41 megawatts of waste to energy (trash plants, landfill gas).

D. The restructured wholesale generation market includes exempt wholesale merchant plants located in New Hampshire that produce 1,200 megawatts of nuclear power (constructed under vertically integrated utility paradigm) and 1,245 megawatts of natural gas combined cycle (720 MW Granite Ridge) (525 MW Newington Energy).

<u>Issues</u>

1. Application of this standard beyond PSNH to Unitil and Nat. Grid.
   a. Should RFPs for Default Energy Service include a requirement that power supply be generated from diverse fuels/sources? Would such a

requirement be contrary to the principle that market forces should dictate energy supply?

b. Should RFPs for Default Energy Service include a requirement that a percentage of the power supply be generated from renewable fuels/sources? Given legislative activity surrounding renewable energy portfolio, is this an issue the PUC should undertake on its own?

2. If standard does not apply to Unitil and Nat. Grid, should the parties recommend that the PUC need not adopt such a standard because New Hampshire is not dependent upon a single source of fuel but is supplied with a variety of sources fueled with a diverse supply?

3. Does PSNH and/or the market need to do more? If so, what should the Commission do to foster greater fuel diversity or sources of supply in the near term?

4. If it has jurisdiction, what standard should the Commission adopt to direct the next generation of resources to satisfy the need for continued diverse and renewable fuel sources?

5. Regulation external to the utility industry could negatively affect fuel diversity. Limits on carbon dioxide emission may have modest environmental goals that more seriously affect fuel diversity. Recognition by the PUC that fuel diversity is a priority would establish an important balance.

<u>The Standard</u>

(13) Fossil fuel generation efficiency. Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation. (Assume this standard applies only to PSNH.)

Historical Perspective

Definition of efficiency – Involves equipment upgrades and replacement, system operational improvements, overall station performance

Planned outages, periodic overhauls, capital improvements focus on maintaining and/or improving efficiency and reliability of existing generation fleet.

Pollution control editions negatively affect efficiency and increase station load

Recent Accomplishments

What efficiency gains are achieved during annual outages?

Projects In Process/On the Drawing Board

Issues

What factors are to be considered in deciding to pursue efficiency improvements?

A. Cost/benefit
B. Payback in years
C. Environmental factors
D. Effect upon reliability
E. Regulatory considerations
   1. Modification or addition to plant net out put
   2. Timely cost recovery
F. Reduced or increased maintenance activities
G. Measurable efficiency improvement

Development of a plan

A. Short and long term plan
   1. Major equipment – repair or replace
   2. Key systems
   3. Minor equipment – repair or replace
B. Develop hierarchy of priorities
   1. Reliability - most critical in base load plants
   2. Efficiency - critical in base load plants
   3. Cycling capability – most critical in intermediate + peaker plants

DE 06-061
Time Based Metering and Communications ("Smart Metering")
Section 1252 of Energy Policy Act of 2005

Timing Issues: Compliance deadlines are different than other sections and are a bit confusing. The standard states "not later than 18 months after the date of enactment.. each electric utility shall offer each of its customer classes… a time based rate schedule. If strictly adhered to, this would be before the end of the two year regulatory decision making period. Regulatory authorities can alter the time period within the standard to accommodate their schedules and practical limits of a utility program. Section 1252(g) of the Act then reverts to similar language as the first three standards in the new law. In brief, the 18 month language is in the federal standard that states must consider, but need not adopt. Thus, regulatory authorities have 2 years to decide whether or not to complete a study within 18 months of enactment.

The Standard

Utilities must offer a Time Based Rate Schedule to each customer class within 18 months (February 18, 2007) after the date of enactment.

Rate varies by time period and rate reflects variance, if any, in the cost of generating/purchasing at wholesale level.

Rate enables consumer to manage energy use and cost through smart metering.

The types of time based rate schedules that may be offered include:

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:

Each electric utility shall 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).

Regulatory authority must conduct investigation within 18 months, or February 8, 2007, commencing within 12 months (Aug. 8, 2006) and completing within 24 months (Aug. 8, 2007):

> Determine whether or not it is appropriate for electric utilities to provide and install time based meters and communications devices for each of their customers which enable such customers to participate in time based pricing rate schedules and other demand response programs.

Prior State Action (has it already been taken?) – The Standard shall not apply in the case of any electric utility in a state, if before the enactment of the provision:

> The state has implemented for such utility the standard concerned;
>
> 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; or
>
> The state legislature has voted on the implementation of such standard for such utility within the previous three years.

Goal of the Statute is to encourage conservation of energy supplied by electric utilities and optimize efficiency of electric utilities' facilities and resources:

> Allow consumers to pay prices that more accurately reflect the cost of providing the service.
>
> Properly designed time based rates are intended to provide price signals to consumers on the time based rates so they can make decisions on when or whether to use electricity.
>
> Reductions in peak demand can lead to reduced transmission congestion, possibly allowing lower cost imports to enter the market.
>
> Reductions in peak demand may permit more expensive generators to run less often and may reduce the need for the addition of peaking capacity..

The Investigation

> Which time based rate is appropriate, and if so for which customer groups and utilities?

What are the options for delivering this information to the customer? (smart meters, internet, other) What are the strengths, weaknesses and costs of each? Should be used and should they differ by class?

Should enrollment be mandatory, voluntary, or default (with opt-out)?

Will consumers respond to price signals?

What are the goals that staff would hope to achieve with TOU and would TOU achieve similar goals as real time pricing?

What are the benefits to consider?

What are the costs to consider?

What types of implementation issues should be considered?

How will existing Default Service wholesale supply contracts be treated if time based or real time Default Service, if implemented, starts before the end of the existing contract(s).

What pricing information is available and how is it obtained? Five-minute pricing, hourly pricing, daily or day ahead pricing.

How will we reconcile "real time" prices with actual supply prices. Prices will be subject to later settlement from ISO. What do customers actually pay? Can the utilities provide billing information on an hourly basis which reflects both real time price and eventual settlement price?

How to handle customers with utility supply and customers with competitive supply. Can PUC impose a standard on competitive suppliers?

How will this information be used? What control equipment is available on the customer end? If pricing information is provided, what technology exists to take this information and use it to control load based on pricing inputs.

Is there an early consensus about how pricing signals could/should be delivered in the world of "smart metering".

Consideration of metering and communications technology

DE 06-061
Interconnection of Distributed Resources
Section 1254 of the Energy Policy Act of 2005

Timing Issues

Not later than 1 year after enactment of the standard (August 8, 2006), each state regulatory authority shall commence consideration or set a hearing date for consideration, with respect to the standard.

Not later than 2 years after enactment of the standard (August 8, 2007), each state regulatory authority shall complete the consideration and shall make a determination as to whether to adopt the standard.

The Standard

Each 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: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies.

Prior State Action

The standard shall not apply in the case of any electric utility in a state, if before enactment of the provision:

> The state has implemented for such utility the standard concerned;
>
> The state regulatory authority has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or
>
> The state legislature has voted on the implementation of such standard or a comparable standard for such utility.

Issues

1. What are NH utilities doing now with regard to interconnection?

2. Should NH consider standard interconnection policies across utilities? If not, why not? If so, what should the standard be? May want to consider Massachusetts interconnection tariff

    a. Best practices for designing effective interconnection standards that balance the needs of utilities, owners of on-site generation and the public.
    b. PUC 900 Rules: Net Metering for Customer-Owned Renewable Energy Generation Resources of 25 Kilowatts or less;
    c. Review existing procedures in NH and whether they encompass IEEE Standard and whether they are consistent with "best practices" and are reasonable, and not unduly discriminatory or preferential":
    d. Advantages and disadvantages of: (i) adopting the IEEE 1547 interconnection standard; (ii) adopting NARUC's "Model Interconnection Procedures Agreement for Small Distributed Generation Resources" or (iii) applying FERC's interconnection rules (FERC Order 2006) to NH on-site generators. (Also address any conflicts with FERC procedures – LGIP/LGIA, SGIP/SGIA)
    e. ISO Section 1.3.9 Procedures
    f. Grandfathered contracts
    g. Rate QF procedures

3. Other issues:

    a. Safety and reliability issues for customers and/or utility workers associated with customer-owned generation.
    b. Interconnection agreements – proper operation of system and insurance requirements.
    c. Costs – upgrades to utility system and on-going reporting of annual maintenance tests.
    d. Stand-by rates – mechanism to account for utility lost revenues.
    e. Requirement for utilities to study proposed equipment and the impact on the utility system via an impact study.
        i. Responsibility for investment and monitoring. What type, size and electrical interconnection should be studied? Are there other pilot programs in effect?
    f. Commissioning or witness testing – mechanism to ensure proper operation of unit during normal and emergency conditions on utility system.
        i. Determination as to when a unit can operate in islanded mode.
    g. Should utility ownership be allowed for reliability or capacity projects?