Unitil

June 2, 2015

BY OVERNIGHT MAIL AND E-MAIL

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

RE: <u>Docket No. IR 15-124</u>
Initial Comments of Unitil Energy Systems, Inc.

Dear Director Howland:

Unitil Energy Systems, Inc. ("Unitil") appreciates this opportunity to provide input into the investigation being undertaken by the Staff ("Staff") of the New Hampshire Public Utilities Commission ("Commission") into possible solutions to address high winter period wholesale market prices. Unitil serves 77,580 customers along the seacoast and capital areas of southern New Hampshire and recognizes the impact of high winter prices on our customers, including those who are served directly by Unitil and those served by third party retail suppliers.

Unitil recognizes the key role that natural gas plays in today's regional electric market and that during periods when access to gas becomes scarce, as has happened during recent winters, wholesale electric prices may become high and volatile. Ideally, regional electric market rules would be changed to enable and require natural gas fired generators to secure more firm access to gas supply. Unitil also recognizes that substantial regulatory and political barriers appear to have stalled efforts to implement such market rule changes. In the absence of such market rule changes, next best alternatives are being sought. Unitil's view is that having the electric distribution companies (EDC) be the contracting entities to bring additional natural gas capacity to the New England region would be an inferior solution. If EDCs are required to enter contracts to backstop natural gas infrastructure, then other parties who might otherwise decide to contract for gas infrastructure may decide not to undertake such investments. As such, it would become a self-fulfilling prophesy that power generators and the merchants who supply them will not support natural gas infrastructure.

Importantly, changes in natural gas infrastructure to New England are already occurring.

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Although the experience of the past few winters has resulted in high winter period electric costs, there have been several publically announced pipeline expansion projects that, taken together, would add over 1 billion cubic feet (Bcf) per day of capacity into New England.[1] Patience should be exercised while these projects are approved and constructed in order to see how the electric market responds before decisions are made to require 15 or 20 year commitments by EDCs. Even if one or more of these projects are delayed or never built, they are supported by commitments from parties who value and intend to utilize the service. Such parties would seek other projects if any of these projects fail.

In addition to incremental pipeline capacity already under contract, there is the prospect of new electric transmission projects which could bring an incremental year-round electric supply to the region, which would reduce overall power demand.

When these new projects go into service, a fresh assessment could then be made as to the ongoing need for additional capacity resources. Employing an iterative approach by assessing the impact of new capacity additions before determining whether EDCs should contract for capacity resources might help avoid unnecessary or excessive contracting. However, the prospect of EDCs continuing to consider such contracting would likely keep other market participants from making commitments of their own.

One reason to wait and take a fresh look, after new facilities are put into service, is that the first units of new natural gas capacity will achieve the greatest electric market cost reductions. This is because the first amounts of new capacity would relieve the greatest number of days of capacity shortage, which would provide the greatest savings in electric costs. As more incremental capacity is added to the system, fewer days of capacity shortage are likely, meaning less savings in electric costs are likely. If, in addition to the approximate 1 Bcf of new natural gas capacity projects, EDCs from some of the larger New England states contract to bring additional pipeline capacity and perhaps liquefied natural gas (LNG) infrastructure to the region, then the relatively small volumes to be added by New Hampshire EDCs would result in that much lower electric cost reductions. In terms of rate impact and cost comparisons, Unitil estimates that the annual demand cost of its execution of an EDC contract under terms generally being discussed within the region would exceed its 2015 budget for Renewable Portfolio Standards (RPS) compliance[2] and would result in an increase of approximately 8 percent in its distribution

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[1] Spectra's AIM Project – 342,000 Dth/day; Kinder Morgan's Connecticut Expansion – 72,100 Dth/day; Spectra's Atlantic Bridge – 153,000 Dth/day; Kinder Morgan's Northeast Energy Direct – approx. 500,000 Dth/day. These projects total 1,067,100 Dth/day.

[2] Unitil's 2015 RPS budget is approximately $5.5 million. Please note that Unitil only provides RPS Compliance for its default service loads and that third party suppliers provide RPS compliance for the customer loads they serve.

rate. Unlike the larger EDCs, who have substantial transmission assets on their balance sheets, Unitil is capitalized only to cover its distribution assets. Assuming the obligations of assets that are intended to fuel power generation could negatively impact Unitil's balance sheet.

In terms of cost effectiveness, at a high level, Unitil estimates that a regional annual demand cost commitment of $0.5 billion in natural gas pipeline or LNG infrastructure would resolve the high basis cost issue raised in the investigation.[3] Assuming the experience of the past few winters resulted in wholesale electric costs that were $2.0 billion higher than they could have been but for availability of gas supply, this may seem a relative bargain. However, this past winter had periods of very sustained cold weather and new resources under contract have not yet been brought to market. It remains to be seen how costly a normal winter would be after the new resources are placed into service. Making a commitment to accept an annual cost of $0.5 billion for a period of 15 to 20 years could be more costly in the long run.

In the event Staff and the Commission decide that EDCs in New Hampshire are the best entities to contract for new natural gas capacity resources, then certain considerations and precautions should be taken to help avoid a result where electric customers end up overpaying for resources that provide them with little value.

If EDC contracting for pipeline or LNG capacity resources is undertaken, the following points should be considered:

- Such contracts should be considered interim and temporary. Contractual provisions and Commission expectations should provide for permanent assignment of such contracts to affiliated gas local distribution companies (LDC) or to power generators, and failing such assignment it should be understood that the EDC will allow the contract to terminate following the initial term. An LDC affiliate assignment would only occur if the LDC determines it has a need and that the contracted resource best meets that need. Other exit strategies should be sought.
- A measured approach to determining volumes should be adopted, with the volumes sought being significantly less than the evaluated need in any one series of contracting. A reasonable approach would be to contract for one-third of the evaluated need initially and then to reassess the need for additional contract volumes after the initial resource is put into service and market conditions are reconsidered. If warranted, additional volumes could then be sought.

[3] This estimate assumes 1.0 Bcf/day of incremental capacity. An annual demand charge of $0.5 billion would equate to a daily demand rate of $1.37 per Dth.

- Strong consideration should be given to LNG based solutions. Since the identified problem is a winter period only problem, LNG may be a very cost effective resource to serve the demand. There appears to be adequate availability of natural gas during the summer. Once pending projects go into service, this will be even more the case.
- Value should be placed on diversity of new projects and reasonably proportional investment in the regional pipelines that serve existing gas fired generators should be pursued. Price and contract terms of the capacity resource should be key considerations. EDCs should have discretion over all contract terms, including receipt and delivery points; however a showing should be required to demonstrate how any such new capacity resource is deliverable to gas-fired power generating stations.
- The net costs of the capacity should be assessed to all of the EDC's customers on a non-by-passable basis. Strong retail rate recovery provisions should be provided by the Commission to ensure the EDC's ability to recover cost and enhance credit to support the transaction as needed. The EDC's approach to management of the capacity resources should be understood in advance.

In closing, Unitil cautions against opening the door to EDC contracting for natural gas infrastructure. If decisions are made to pursue such contracts, Unitil recommends a measured approach with a defined exit strategy. At a high level, we should not underestimate what the market can do to address this issue. The existence of large basis spreads should create opportunities for some market players, who are better positioned than the EDCs to bring investment dollars to new infrastructure.

Unitil looks forward to the comments of others and participating in the next steps in this investigation.

Sincerely,

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Robert S. Furino
Vice-President, Unitil Energy Systems, Inc.

cc: Alexander F. Speidel (via e-mail and overnight mail, as instructed)