Wholesale Investigation (IR 15-124) Initial Staff Questions for Unitil Energy Systems (UES)
June 22, 2015
Instructions for responses: Please e-mail responses in PDF format to alexander.speidel@puc.nh.gov; responses will be promptly posted to the NHPUC website here:
http://puc.nh.gov/Electric/Investigation_into_Potential_Approaches_to_Mitigate_Wholesale_Electricity_Prices.html

UES Responses:

1. Page 1. UES states that "substantial regulatory and political barriers appear to have stalled efforts to implement such market rule changes." Please identify the "regulatory and political barriers" referenced in that statement and cite to any documents that address those barriers.

   RESPONSE: UES understands that efforts to modify wholesale market rules to require fuel assurance standards on the part of power generators, which would incent (and compensate) generators to acquire longer term and firmer access to supply, particularly including natural gas, have been slow coming and would likely be very contentious. UES has not participated in related proceedings or advocacy efforts, but has had related discussions with other entities and also cites the Comments of the New Hampshire Public Utilities Commission in AD13-7 and AD14-8, which were circulated in this investigation.

2. Page 2. Is it UES' position that the over 1 Bcf/day of publicly announced pipeline expansion projects will meaningfully reduce winter period natural gas prices and in turn wholesale electricity prices? If yes, please explain the basis for that view and provide all analytical support including the assumptions used in the analyses. In your response, please provide an estimate of the expected natural gas or electricity price reduction.

   RESPONSE: Yes, UES believes that the announced projects will favorably and meaningfully reduce winter period basis to New England. The forward market already reflects what is known and expected to occur. For example, the table below, which is an excerpt from UES' affiliate Northern Utilities' 2015 Integrated Resource Plan, at III-45, shows that forward winter period basis differentials from Algonquin Citygates to Henry Hub are priced as declining by approximately 30 percent from 2015/16 ($7.28) to 2016/2017 ($5.23), as quoted in December 2014. This drop reflects the expected impact of the AIM project and the Kinder Morgan Connecticut Expansion, which are projected to go into service on November 1, 2016. Moreover, these market prices expectations are likely to be partly muted to reflect the risk that the projects are delayed or abandoned. Add to these projects the Atlantic Bridge and Northeast Energy Direct projects, and a further reduction in basis to New England would be expected.

Table III-5: Forward Basis Differentials[1]

Split-Yr (Nov-Oct)	Winter (Nov-Mar) TETCO M3-Henry Hub	Winter ALGCG-Henry Hub	Winter ALGCG-TETCO M3	Summer (Apr-Oct) TETCO M3-Henry Hub	Summer ALGCG-Henry Hub	Summer ALGCG-TETCO M3	Annual (Nov-Oct) TETCO M3-Henry Hub	Annual ALGCG-Henry Hub	Annual ALGCG-TETCO M3
2014/2015*	$ 0.70	$ 7.10	$ 6.40	$ (1.13)	$ (0.09)	$ 1.05	$ (0.37)	$ 2.91	$ 3.28
2015/2016	$ 0.64	$ 7.28	$ 6.64	$ (1.04)	$ (0.24)	$ 0.80	$ (0.34)	$ 2.90	$ 3.24
2016/2017	$ 0.64	$ 5.23	$ 4.59	$ (0.74)	$ (0.24)	$ 0.50	$ (0.17)	$ 2.04	$ 2.21
Forward Avg. (2014/15-2016/17)	**$ 0.66**	**$ 6.54**	**$ 5.88**	**$ (0.97)**	**$ (0.19)**	**$ 0.78**	**$ (0.29)**	**$ 2.61**	**$ 2.91**

* 2014/2015 calculated as average of historical Nov-2014 and Dec-2014 spot prices; and forward contracts for Jan-2015 to Mar-2015.

3. Page 2. When does UES expect each of the pipeline projects referenced in footnote 1 to be placed into commercial operation? Also, how many years after these projects are placed into commercial operation does UES believe should elapse before an accurate assessment of the impact on wholesale electricity prices can be determined?

   RESPONSE: UES expects Spectra's AIM project and Kinder Morgan's Connecticut Expansion to go into service on November 1, 2016, Spectra's Atlantic Bridge project to go into service on November 1, 2017 and Kinder Morgan's Northeast Energy Direct project to go into service on November 1, 2018. Although other factors are likely to contribute to wholesale electricity market conditions, prices during the first winter after the projects are placed into service would be sufficient to assess their impact.

4. Page 2. Is there an expectation by UES that the shippers responsible for the pipeline capacity quantities referenced in footnote 1 are unlikely to fully utilize the purchased capacity? If yes, provide all support for that expectation and provide annual estimates of the expected under-utilization of capacity. If the answer is no, please explain.

   RESPONSE: UES is not aware of the utilization of the portfolios of other parties.

5. Page 2. Please provide the calculation, together with all assumptions, that supports the claimed distribution rate increase of approximately 8 percent. Also, provide the resulting distribution surcharge in $/kWh.

   RESPONSE: The figure below provides UES' calculations, assumptions and formulas. The pricing reflects projected capacity cost only, and no assessment has been made with regard to natural gas commodity pricing. UES assumes an aggregate of 1.0 Bcf worth of natural gas capacity additions, which could be in the form of pipeline capacity or LNG storage. Aggregate cost and price assumptions are shown. In determining UES' prospective share, UES applied its share of the 2014 annual ISO-NE system peak and assumed that 80 percent of electrical load in New England would support the projects. Although no specific analysis was conducted, this assumption allows for the likelihood that municipal utilities will not participate and that

[1] Source: Sussex analysis of the simple average of daily basis differentials based on historical spot prices from SNL Financial; and forward settlement prices as of December 11, 2014 from Bloomberg Professional.

participation among investor owned utilities may be less than 100 percent. UES' annual cost is determined by the estimated daily demand rate and UES contract volume. Annual kWh sales from 2014 and an assumed 10 percent contribution from mitigation activities were used to establish the estimated rate of $0.00525 per kWh. This rate was compared to UES' Domestic Service rate, which is structured in two blocks, to establish the rate impact estimate of approximately 8 percent.

UES Rate Impact Calculation

	AGGREGATE REGIONAL PROJECT ASSUMPTIONS				
	Description	Values		Units/ Notes	Formula
A	Project Volume		1,000,000	Dth	
B	Daily Demand Rate	$	1.3699	$/Dth/day	= D/A/C
C	Days/ Yr		365	Days	
D	Annual Cost	$	500,000,000	$	Estimate
	UES SHARE of PROJECTS				
E	ISO-NE Peak, 7/2/14, HE14		24,067.773	MWH	Actual
F	UES Peak, 7/2/14, HE14		275.047	MWH	Actual
G	UES Pct		1.14%	%	= F/E
H	Participation Rate		80%	%	Estimate
I	UES Contract Volume		14,285	Dth/day	= A*G*H
	UES COST / RATE				
J	UES Annual Cost	$	7,142,513	$	= I*B*C
K	UES kWh, 2014		1,225,202,098	Annual dist sales	Actual
L	UES Gross Cost per kWh	$	0.00583	$/kWh	= J/K
M	Mitigation		10%	%	Estimate
N	UES Net $/kWh	$	0.00525	$/kWh	= L*(1-M)
	UES RATE IMPACT (DOMESTIC)				
O	First 250 kWh		$0.05880	$/kWh	Tariff, Eff. 12/1/2014
P	Excess 250 kWh		$0.06380	$/kWh	Tariff, Eff. 12/1/2014
Q	Typical Bill Monthly Volume		646	kWh	Convention
R	UES Distribution Rate (D)		$0.06187	$/kWh	Actual
S	UES Rate Impact		8.48%	%	= N/R

6. Page 3. Unitil Corp. also owns the LDC Northern Utilities (Northern). Is Northern only or mostly capitalized to cover its distribution assets? If yes, is Unitil Corp. also concerned about Northern entering into long-term pipeline capacity contracts? If the answer is no, please explain why not.

RESPONSE: Northern's capitalization is appropriately sized for its distribution assets, business needs and risk, including its requirements for working capital and credit support to fund long-term pipeline contracts. In addition, the regulatory structure or compact under which Northern operates as an LDC is long-standing and is critical to the company being able to enter into long-term contracts for pipeline capacity as part of meeting its obligations to deliver gas to customers at a reasonable cost. Northern's regulatory structure provides for a consistent cost recovery policy and practice, with a high degree of certainty that the cost of pipeline capacity will be recovered on a timely basis throughout the term of the contract.

In contrast, the purchase of long-term pipeline capacity by an EDC for resale into the market is an entirely new obligation and business function that is not currently reflected in UES' capitalization or regulatory processes. There is a risk of substantial loss associated with these contracts, and without a well-structured regulatory model and precedent to ensure recovery and offsetting of risks, these contracts will be viewed differently by financial counterparties and other stakeholders.

7. Page 3. For clarification, identify the "new resources under contract."

   RESPONSE: By new resources under contract, as listed in footnote 1, UES refers to Spectra's AIM Project, Kinder Morgan's Connecticut Expansion, Spectra's Atlantic Bridge and Kinder Morgan's Northeast Energy Direct project.

8. Page 3. Does UES agree that last winter New England's generation resources included over 1,000 MW of coal-fired generation that is scheduled to retire before 2018 and that an additional 6,000 MW of oil and coal-fired generation will be at-risk for retirement by 2020?

   RESPONSE: UES agrees.

9. Page 4. Regarding the statement that strong consideration should be given to LNG based solutions, please explain why UES believes LNG can solve or contribute to solving the high winter period electricity price problem. Provide copies of all studies in UES' possession that show LNG service -based on the liquefaction of domestic natural gas supplies - to be a more cost effective solution than firm pipeline capacity.

   RESPONSE: The fact that LNG can be stored in the market area points to LNG as a resource that could contribute to ameliorating wholesale electric prices. Although current LNG pricing reflects global price competition and a limited number of storage operators in the region, prospective new projects to add liquefaction and storage in the market area should considered. To their credit, the sponsors of the Access Northeast project have included an LNG component as part of their proposed solution.

10. Page 4. Please clarify the following sentence: "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."

    RESPONSE: UES recommends that to the extent the Commission directs the EDCs to contract for pipeline capacity, no single pipeline project should be presumed to be the best solution. While pipeline demand costs, project viability and access to liquid supplies are critical considerations, maintaining a preference for diversity among projects will improve the likelihood that all or most gas-fired generators will be able to access the additional natural gas supplies.

11. National Grid in its comments contends that since "all electric distribution customers in New England will ultimately benefit from the lower energy costs and enhanced reliability resulting from increased pipeline capacity sufficient to allow generally unconstrained access to the lower priced domestic gas supplies available just outside the region …..it is critical that electric distribution customers across New England together support the costs of the additional natural gas delivery infrastructure investments." Does UES agree with that statement and if so would it voluntarily agree to pay a portion of such infrastructure investment costs, regardless of whether it purchased pipeline capacity under an infrastructure project?

    RESPONSE: UES does not oppose requiring its customers to pay their share of reasonably incurred and necessary costs. For instance, if regional market rules were introduced to incent or require generators to secure firm access to gas supply, then UES would expect generator operating costs to include the cost of securing fuel (natural gas pipeline capacity, LNG storage, onsite liquid fuel, etc.) and that such costs would ultimately be reflected in wholesale prices that would be borne by all retail electric customers. UES agrees that costs should follow benefits. UES questions the appropriate level of cost, if any, that should be incurred and whether the majority of benefits will accrue to retail customers. Regarding transaction structure and cost recovery, it would seem feasible to allocate a share of net capacity costs from an EDC who does contract for pipeline capacity to an EDC that does not. Ultimately, UES will comply with the Commission's directives.