IR 15-124 Initial Staff Questions for Coalition to Lower Energy Costs/Competitive Energy Services

1. Ref. Competitive Energy Services February 7, 2014 Report. CES assumed that the spot price for natural gas in New England is $5/MMBtu during any hour when the combined demand for natural gas from LDCs and power generation is less than the combined capacities of the region's pipelines. Other consulting firms such as ICF and Black & Veatch assert there is evidence for gas prices to spike whenever pipeline utilization rates are in excess of around 75%. Does CES' assumption suggest that its dispatch model understates gas costs and hence potential cost savings or is the $5/MMBtu average price a conservative estimate that accounts for such price spikes?

Response:

The $5/mmbtu price for pipeline gas was established in our first study done in April 2013. It is designed to measure the price of natural gas delivered to TETCO M3, which we used as the "basis-free" price of gas for New England. Since that study prices at TETCO M3 have trended downward so that today, the forward TETCO M3 price is well below $5/mmbtu for a significant number of years into the future. As a result, all other things being equal, the $5/mmbtu price we have used in our model tends to understate the amount of savings available through pipeline capacity expansion.

We do not dispute the ICF and Black & Veatch assertion of evidence that gas prices tend to spike when pipeline utilization rates are in excess of around 75%. Since we have assumed basis free gas deliveries up to the full capacity of the existing pipelines into New England, our estimate of savings from adding additional pipeline capacity will be understated to the extent that the holders of capacity on the existing pipelines are able to exercise some form of pricing power at capacities below 100%.

On the other hand, we have also assumed that when a new pipeline comes on-line, 100% of its capacity is available at the basis free price. If the same phenomenon that ICF and Black & Veatch have observed for existing pipeline capacity also applies to new capacity additions, then we have somewhat overstated the basis-free capacity associated with those additions and therefore somewhat overstated savings to ratepayers from the incremental pipeline.

On balance we believe that the impacts of the Black & Veatch observation on our study are not significant.

2. Ref. Competitive Energy Services February 7, 2014 Report. CES assumed that the price for LNG delivered into New England's LNG storage facilities is $18/MMBtu. Whenever the demand for natural gas from LDCs plus power generation is higher than pipeline capacity, the excess demand is met first by LNG at the delivered price of $18/MMBtu. Does the fact that the LNG price to generators does not include a mark-up for profit suggest that CES' model understates gas costs and hence potential cost savings?

Response:

Our estimated LNG price of $18/mmbtu is intended to reflect the delivered cost of LNG to generators and therefore is inclusive of regasification costs and mark-ups for reasonable profits but <u>not</u> inclusive of mark-ups that may be possible if a supplier of LNG has pricing power. As we note in our responses to Questions 4 and 15, one serious concern we have with the discussion about pipeline capacity has been an implicit assumption that LNG capacities will remain as they are today after the addition of some amount of incremental pipeline capacity into the region. If this assumption turns out not to be true and some of the existing LNG gasification facilities are unable to remain competitive, we would expect any remaining LNG gasification facility to have substantial pricing power in the market.

3. Ref. Competitive Energy Services' December 5, 2014 Report to TGP. Figure 1 shows the estimated power cost savings relative to the Base Case for increasing increments of pipeline capacity. These savings are driven in large part by reductions in the number of hours LNG fueled generation is on the margin. Are the savings estimates directly proportional to the difference between the price of LNG and the price of natural gas assumed in the dispatch model? That is, if the price of LNG was $10/MMBtu instead of $14/MMBtu, would the savings be reduced by approximately 30 percent? If not, please discuss the relationship between the price of LNG and cost savings and provide revised savings estimates assuming a $10/MMBtu LNG price.

Response:

You are correct – the savings are directly related to the difference in prices between LNG and the basis-free natural gas price of $5/mmbtu. It is not a linear relationship, however, as there are hours in the year when there is simply not enough LNG gasification capability to meet the combined heat and process loads of LDCs plus generation requirements during peak hours on the coldest days of the year. In these instances, some oil (or propane) must be used, and the region's LMPs will reflect oil (propane) prices not LNG prices.[1]

We have re-run the model using two different LNG prices - $12/mmbtu and $10/mmbtu, without changing any other value. The results are shown in the attached Tables, along with Figure 9 (p. 35) of our filing where LNG was priced at $14/mmbtu.

[1] Our modeling allows for injections of LNG from only Distrigas and Canaport. We did not allow for LNG injections from either off-shore platforms – Neptune or Atlantic Gateway.

Base Case – LNG Priced at $14/mmbtu

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers

Pipeline Capacity	Pipeline Capacity bcf/d	Hours of Generation by Fuel Type: LNG	Propane	Oil
Base Case	3,136	2113	374	296
+ 0.2 bcf/d Capacity	3,336	1723	267	217
+ 0.4 bcf/d Capacity	3,536	1316	198	158
+ 0.6 bcf/d Capacity	3,736	993	144	120
+ 0.8 bcf/d Capacity	3,936	750	104	78
+ 1.0 bcf/d Capacity	4,136	550	71	56
+ 1.2 bcf/d Capacity	4,336	391	53	46
+ 1.4 bcf/d Capacity	4,536	288	41	35
+ 1.6 bcf/d Capacity	4,736	206	34	28
+ 1.8 bcf/d Capacity	4,936	152	27	22
+ 2.0 bcf/d Capacity	5,136	111	17	12
+ 2.2 bcf/d Capacity	5,336	74	11	9
+ 2.4 bcf/d Capacity	5,536	54	7	6

Pipeline Capacity	Annual Energy Costs ($)	Incremental Savings ($)	Cumulative Savings ($)	Load Weighted Avg. Energy Price ($/MWh)
Base Case	$7,683,828,621			$60.38
+ 0.2 bcf/d Capacity	$7,196,238,670	$487,589,951	$487,589,951	$56.55
+ 0.4 bcf/d Capacity	$6,662,968,905	$533,269,765	$1,020,859,716	$52.36
+ 0.6 bcf/d Capacity	$6,215,782,492	$447,186,412	$1,468,046,128	$48.84
+ 0.8 bcf/d Capacity	$5,862,015,565	$353,766,927	$1,821,813,055	$46.06
+ 1.0 bcf/d Capacity	$5,556,608,801	$305,406,764	$2,127,219,819	$43.66
+ 1.2 bcf/d Capacity	$5,302,503,435	$254,105,366	$2,381,325,185	$41.67
+ 1.4 bcf/d Capacity	$5,129,825,208	$172,678,227	$2,554,003,412	$40.31
+ 1.6 bcf/d Capacity	$4,986,336,567	$143,488,641	$2,697,492,053	$39.18
+ 1.8 bcf/d Capacity	$4,887,791,007	$98,545,560	$2,796,037,613	$38.41
+ 2.0 bcf/d Capacity	$4,809,857,588	$77,933,420	$2,873,971,033	$37.80
+ 2.2 bcf/d Capacity	$4,737,106,541	$72,751,047	$2,946,722,080	$37.22
+ 2.4 bcf/d Capacity	$4,696,129,285	$40,977,255	$2,987,699,335	$36.90

LNG Priced at $12/mmbtu

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers

Pipeline Capacity	Pipeline Capacity bcf/d	Hours of Generation by Fuel Type LNG	Propane	Oil
Base Case	3,136	2113	374	296
+ 0.2 bcf/d Capacity	3,336	1723	267	217
+ 0.4 bcf/d Capacity	3,536	1316	198	158
+ 0.6 bcf/d Capacity	3,736	993	144	120
+ 0.8 bcf/d Capacity	3,936	750	104	78
+ 1.0 bcf/d Capacity	4,136	550	71	56
+ 1.2 bcf/d Capacity	4,336	391	53	46
+ 1.4 bcf/d Capacity	4,536	288	41	35
+ 1.6 bcf/d Capacity	4,736	206	34	28
+ 1.8 bcf/d Capacity	4,936	152	27	22
+ 2.0 bcf/d Capacity	5,136	111	17	12
+ 2.2 bcf/d Capacity	5,336	74	11	9
+ 2.4 bcf/d Capacity	5,536	54	7	6

Pipeline Capacity	Annual Energy Costs ($)	Incremental Savings ($)	Cumulative Savings ($)	Load Weighted Avg. Energy Price ($/MWh)
Base Case	$7,021,317,767			$55.17
+ 0.2 bcf/d Capacity	$6,633,785,329	$387,532,438	$387,532,438	$52.13
+ 0.4 bcf/d Capacity	$6,212,964,214	$420,821,115	$808,353,553	$48.82
+ 0.6 bcf/d Capacity	$5,860,753,794	$352,210,420	$1,160,563,973	$46.05
+ 0.8 bcf/d Capacity	$5,582,396,431	$278,357,363	$1,438,921,336	$43.87
+ 1.0 bcf/d Capacity	$5,342,728,565	$239,667,866	$1,678,589,203	$41.98
+ 1.2 bcf/d Capacity	$5,143,587,033	$199,141,532	$1,877,730,734	$40.42
+ 1.4 bcf/d Capacity	$5,008,165,864	$135,421,170	$2,013,151,904	$39.35
+ 1.6 bcf/d Capacity	$4,895,705,291	$112,460,572	$2,125,612,476	$38.47
+ 1.8 bcf/d Capacity	$4,818,384,460	$77,320,831	$2,202,933,307	$37.86
+ 2.0 bcf/d Capacity	$4,757,285,797	$61,098,663	$2,264,031,970	$37.38
+ 2.2 bcf/d Capacity	$4,700,445,415	$56,840,382	$2,320,872,353	$36.94
+ 2.4 bcf/d Capacity	$4,668,387,691	$32,057,724	$2,352,930,076	$36.68

LNG Priced at $10/mmbtu

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers

Pipeline Capacity	Pipeline Capacity bcf/d	Hours of Generation by Fuel Type LNG	Propane	Oil
Base Case	3,136	2113	374	296
+ 0.2 bcf/d Capacity	3,336	1723	267	217
+ 0.4 bcf/d Capacity	3,536	1316	198	158
+ 0.6 bcf/d Capacity	3,736	993	144	120
+ 0.8 bcf/d Capacity	3,936	750	104	78
+ 1.0 bcf/d Capacity	4,136	550	71	56
+ 1.2 bcf/d Capacity	4,336	391	53	46
+ 1.4 bcf/d Capacity	4,536	288	41	35
+ 1.6 bcf/d Capacity	4,736	206	34	28
+ 1.8 bcf/d Capacity	4,936	152	27	22
+ 2.0 bcf/d Capacity	5,136	111	17	12
+ 2.2 bcf/d Capacity	5,336	74	11	9
+ 2.4 bcf/d Capacity	5,536	54	7	6

Pipeline Capacity	Annual Energy Costs ($)	Incremental Savings ($)	Cumulative Savings ($)	Load Weighted Avg. Energy Price ($/MWh)
Base Case	$6,358,806,914			$49.97
+ 0.2 bcf/d Capacity	$6,071,331,989	$287,474,925	$287,474,925	$47.71
+ 0.4 bcf/d Capacity	$5,762,959,523	$308,372,466	$595,847,391	$45.28
+ 0.6 bcf/d Capacity	$5,505,725,096	$257,234,427	$853,081,818	$43.26
+ 0.8 bcf/d Capacity	$5,302,777,297	$202,947,799	$1,056,029,617	$41.67
+ 1.0 bcf/d Capacity	$5,128,848,329	$173,928,969	$1,229,958,586	$40.30
+ 1.2 bcf/d Capacity	$4,984,670,631	$144,177,697	$1,374,136,283	$39.17
+ 1.4 bcf/d Capacity	$4,886,506,519	$98,164,112	$1,472,300,395	$38.40
+ 1.6 bcf/d Capacity	$4,805,074,015	$81,432,504	$1,553,732,900	$37.76
+ 1.8 bcf/d Capacity	$4,748,977,913	$56,096,101	$1,609,829,001	$37.32
+ 2.0 bcf/d Capacity	$4,704,714,006	$44,263,907	$1,654,092,908	$36.97
+ 2.2 bcf/d Capacity	$4,663,784,289	$40,929,717	$1,695,022,625	$36.65
+ 2.4 bcf/d Capacity	$4,640,646,097	$23,138,192	$1,718,160,817	$36.47

4. Ref. Competitive Energy Services February 7, 2014 Report. The results of CES' dispatch model indicate that as the amount of incremental pipeline capacity increases the number of hours LNG is on the margin falls as does the volume of gas supplied by the region's two large LNG storage facilities. To the extent the reduction in LNG volumes results in the closure of one of the LNG facilities and higher LNG prices as the sole supplier seeks to recover its fixed costs over a smaller volume, please comment on the likely impact of these changes on power cost and hence the benefits of increased pipeline capacity.

Response:

Please also see our responses to Questions 2 and 15.

The ability to retain LNG regasification capability in New England as total LNG demands fall is a serious matter that has, in our view, not received enough consideration in the discussion of incremental natural gas pipeline capacity. Our concern, which we have expressed in our filings in Maine, New Hampshire and Massachusetts, is that it will be very difficult to maintain multiple LNG regasification facilities if new pipeline capacity is developed that reduces the demand for regasified LNG in the region during winter months. We are specifically concerned about the Canaport facility, since the Distrigas plant retains the Mystic generating complex as a captive customer.

This is not a hypothetical concern. Our experience is that customers that use Residual Oil (#6 fuel oil) for heat and/or industrial processes are finding it more difficult to obtain supply in the region as other customers that once relied on that fuel have switched to natural gas or a cleaner alternative. Further, customers that have the ability to switch to residual oil as a second fuel when natural gas prices spike are having difficulty securing reliable supply at reasonable prices.

The table below shows our estimate of the total amount of LNG by month that will be required under the Base Case in our model and under the case where 1 bcf/d of incremental pipeline capacity is added in the region. These are shown in columns 3 and 4, respectively. We also include the amount of LNG injected into the Maritimes and Northeast pipeline by Canaport, as reported by Bloomberg for 2013 and 2014 by month in columns 1 and 2.

A few items are noteworthy. Canaport's injections were off considerably in 2014 compared to 2013. In part this represents upgrades to the facility that reduced the amount of vaporization that occurs at Canaport and thus needs to be injected into the pipeline every day. It also reflects differences in weather conditions and therefore LDC and generator demands.

The reduction in model estimates from the Base Case to the 1 bcf/day of incremental capacity shows how much LNG will be displaced by pipeline natural gas. At 1 bcf/d of new pipeline capacity, LNG required in the New England region falls by more than 75% to levels below the Canaport injections in 2014.

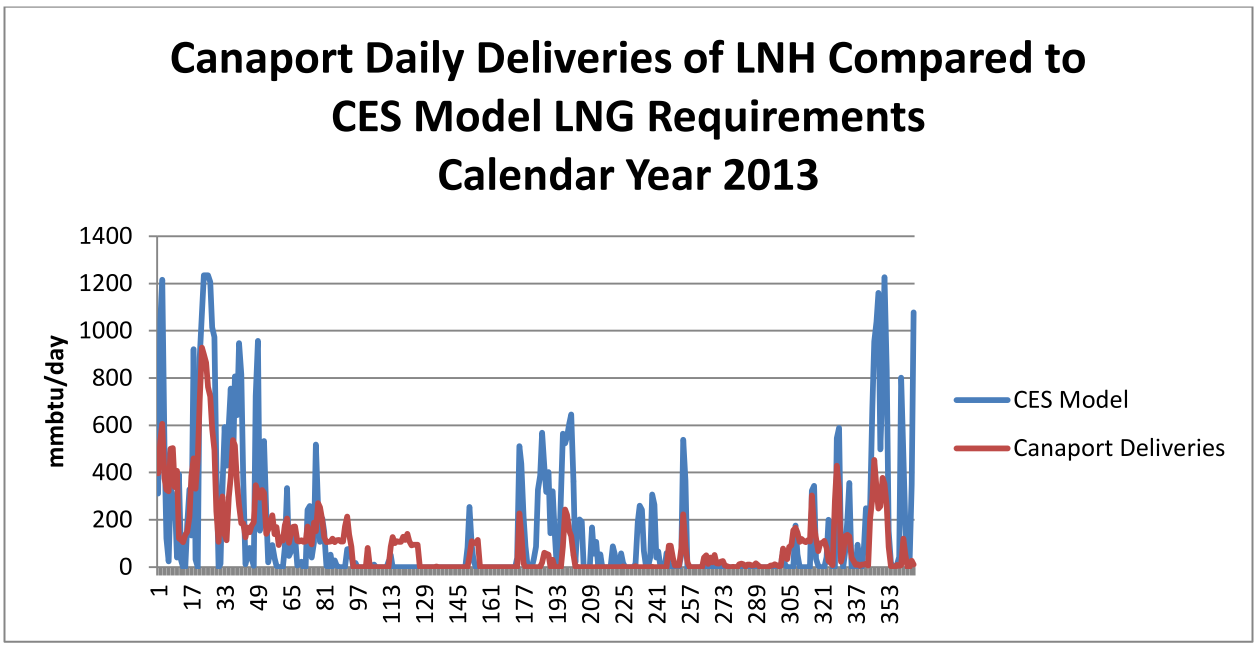
Canaport Deliveries and CES Model Results

	Canaport Deliveries into M&N Pipeline		Monthly LNG from Model Calendar year 2013	
	2013	**2014**	**Base Case**	**1 bcf/d New Pipeline Capacity**
Jan	26,125	6,609	15,508	6,865
Feb	19,460	3,419	9,914	988
Mar	9,688	2,697	2,829	102
Apr	2,076	209	301	0
May	1,281	297	339	0
Jun	1,464	321	1,411	130
Jul	1,693	274	7,662	866
Aug	474	325	1,775	0
Sep	1,395	451	1,026	142
Oct	707	397	94	0
Nov	4,229	292	3,158	116
Dec	5,920	2,681	11,139	2,946
TOTAL	74,512	17,972	55,156	12,155

5. Ref. Competitive Energy Services February 7, 2014 Report and Competitive Energy Services' December 5, 2014 Report to TGP. The results of CES' dispatch model under different Base Cases show LNG on the margin in 2013 for approximately 1,000 and 2,000 hours when existing pipeline capacity is not adequate. Are these result supported by empirical evidence? If so, please provide all support.

Response:

We have compared the results in our Base Case model for daily LNG requirements in New England to the actual daily injections from Canaport for Calendar Year 2013. The graph below shows the daily comparisons. The correlation coefficient between the two variables is 0.74. One reason why our model is higher than Canaport deliveries during the winter months is that we have assumed that dual-fuel generators operate on LNG before they operate on oil during winter months when pipeline gas is not available to them. This assumption may not hold under ISO-NE's Winter Reliability Program. However, since the delivered prices of oil and LNG are similar, this would have little effect on the cost of energy in the New England wholesale market.



6. Spectra has said that the combination of AIM, Atlantic Bridge and Access Northeast will significantly reduce the bottlenecks on the Algonquin system. Assuming the NED project does not go forward, does CES believe such pipeline expansions will also reduce the constraints on TGP's existing system? If so, please describe the process that results in this effect. Similarly, assuming the Access Northeast project does not go forward, does CES believe the NED project will reduce the constraints on the Algonquin system? If so, please explain why.

Response:

This question does not have an easy answer. It is important to differentiate between "can" and "will".

Let's focus first on the Algonquin expansions. Currently, TGP delivers gas into the Algonquin pipeline at its interconnection point in Mendon. Presumably, this gas was scheduled by LDCs and/or gas marketers to serve natural gas loads on the Algonquin system that could not be served or could be served but at a higher delivered price by gas flowing on Algonquin from the south.

If the capacity on the Algonquin pipeline is expanded upstream of the interconnection point, CES believes it will be physically possible to displace some or all of the gas that had been flowing on TGP into Algonquin. This would enable that gas to meet loads served off of TGP that would otherwise not have been able to secure gas on TGP.

Whether or not the above scenario will actually occur in practice depends on a number of factors, including:

a. Whether the incremental capacity on Algonquin will be used by loads upstream of the TGP interconnection point and therefore permit the displacement of TGP gas at and downstream of the interconnection point.
b. Whether holders of capacity on TGP that is used for gas delivered into Algonquin will sell their capacity to TGP loads upstream of the interconnection point.

CES has not studied this situation and therefore is not in a position to assess the likelihood of either of the above factors occurring. As a general matter, CES believes that markets will work over time to move gas to its highest and best use.

We now turn to the second part of the question – whether the NED project will reduce constraints on the Algonquin pipeline assuming that Access Northeast does not get built. The NED pipeline is capable of delivering up to 1.3 bcf/d, only a portion of which will be taken off prior to its termination point at Dracut. Assuming that NED is constructed to its maximum capacity and that loads prior to Dracut account for 0.3 bcf/d, NED will be capable of delivering up to 1 bcf/d into Dracut. Some of that gas is likely to be contracted for delivery north on the Maritimes and Northeast pipeline. Since Algonquin does not now deliver into Maritimes, any gas flowing north on Maritimes is not displacing gas that would otherwise have flowed on Algonquin, and therefore will not reduce any constraints on Algonquin.

The remaining amount of NED capacity available at Dracut (1.3 bcf/d less 0.3 bcf/d less flows north on Maritimes) is available to displace gas flowing south-to-north on Algonquin, assuming that NED interconnects with Algonquin at or near Dracut and the design permits gas to flow into Algonquin at this interconnection point. Further, as above, the ability to flow and therefore displace other flows will depend on LDCs and gas marketers that hold capacity on the northern sections of Algonquin selling or releasing this capacity to loads further south and displacing this capacity with newly purchased capacity on TGP plus backhaul capacity on Algonquin.

CES has not studied this situation and therefore is not in a position to assess the likelihood that these or similar conditions will occur. As noted above, as a general matter, CES believes that markets will work over time to move gas to its highest and best use.

7. Ref. Direct Testimony of Competitive Energy Services, June 2, 2015. Figure 7 provides estimates of the declining annual power cost savings associated with each 0.20 Bcf/day increment of pipeline capacity up to a total of 2.4 Bcf/day. Does CES's finding that incremental power cost savings decline significantly as the total pipeline capacity increment approaches 2.4 Bcf/day mean that a pipeline project that provides incremental capacity of 2.4 Bcf/day will largely eliminate regional pipeline constraints? If not, how should the decreasing rate of power cost savings be interpreted?

Response:

Yes – your interpretation of Figure 7 is correct.

8. Liberty and other Anchor Shippers on NED have entered into precedent agreements with TGP for capacity on the NED Supply Path. In the case of Liberty, the amount of capacity on the Supply Path is 60% of the capacity purchased on the Market Path. (Check regarding others) Do these actions suggest, in CES' opinion, that the Anchor Shippers share the concern that the price of natural gas at Wright, NY will materially exceed the price in the Marcellus production area plus transportation to Wright for a significant portion of the contract term? If not, please discuss.

Response:

CES is not comfortable speaking for Liberty or any other Anchor Shippers on NED.

CES would advise a client to purchase capacity from Kinder Morgan on its Supply Path (in addition to any capacity purchase on Kinder Morgan's Market Path portion of NED) if:

- CES expected that such a purchase was essential in getting the Supply Path portion of the NED project constructed
- CES expected the price at Wright to be higher than the price at Marcellus plus the tariff on the Supply Path portion of the NED project

9. Ref. Competitive Energy Services, Report to Tennessee Gas Pipeline Company, December 5, 2014, page 10. Please elaborate on the statement that throughput on the NED pipeline would be less than the combined electric and non-electric market demand for natural gas in New England on most days of the year based, if the capacity of the project was less than 1 Bcf/day. Is CES saying that on most days of the year, and particularly on winter days, the total demand for natural gas will exceed the supply from the NED pipeline and hence the remaining gas demand must be met by existing/other new pipelines at prices based in large part on the price of gas at receipt points other than Wright, NY? And that it will be prices on these other pipelines that will set the clearing prices in the New England natural gas market? Also, under what circumstances, if any, is the price of gas delivered to New England on cold winter days by the proposed NED pipeline likely to set market clearing prices? Finally, if the answer to the previous question is that there are no circumstances under which gas delivered by the proposed NED project will set clearing prices, is the benefit the NED project bring to regional electricity consumers set by the impact the incremental pipeline capacity has on clearing prices and hence power cost savings.

Response:

Our response to the first question posed is “YES”.

Our response to the second question posed is “YES”.

Our response to the third question posed is:

Whether or not NED is ever the incremental pipeline capacity and therefore sets the clearing price, the benefit the NED project brings to New England electricity consumers is tied to the reduction in LMPs in New England resulting from the NED plus any other incremental pipeline capacity. If a generator shipping gas on NED is able to secure gas delivered to its facility at a lower price than other generators (with comparable heat rates) shipping on other pipelines, then the price of the higher gas cost generator will set the LMP (assuming it is the highest in the market whose bid is accepted by ISO), and the difference between the LMP and the bid of the lower gas cost generator on NED is retained by that generator as a form of energy-market rents.

10. Ref. Competitive Energy Services, Report to Tennessee Gas Pipeline Company, December 5, 2014, page 11. CES goes on to say that under the conditions set forth on page 10, the lower delivered gas price associated with the NED project “will redound to the benefit of the holder(s) of firm capacity on that pipeline”. Would CES agree that the holders of firm capacity on the NED pipeline may not be limited to generators directly connected to the existing TGP system but could include generators directly connected to the Algonquin and M&N pipelines and, moreover, that this potential benefit could function as an incentive to gas generators to bid for EDC capacity that comprises receipt and delivery points on the NED pipeline?

Response:

Our response to the first part of the question is “YES”.

Our response to the second part of the question is: Yes, but the incentive will be tempered by any additional costs such generators incur related to moving gas downstream of the interconnection points of NED and Algonquin or M&N.

11. Staff understands that the interconnection of the NED project with the Joint Facilities, together with the anticipated reversal of gas flow along the Joint Facilities, will enable the NED project to access more New England gas generators in New Hampshire, Maine and in the Atlantic Canada region. To the extent such generators choose to purchase gas supplies transported on the NED pipeline instead of Access Northeast, will those generators incur the cost of firm transportation on both the Joint Facilities and NED pipelines? Also, to CES' knowledge, will a single transportation rate be levied for the whole of the Access Northeast project or separate rates for Algonquin and M&N pipelines?

Response:

Our response to the first question posed is:

Our understanding is that all gas transported on the Joint Facilities must pay the tariff rate. Whether the incidence of that tariff rate is borne by the pipeline company, the gas producers, the gas marketers or the end-user/generator will depend on market conditions. For example, if we compare the daily spot gas price at Marcellus with that at Algonquin, we see differences that range from as low as $0.25 per mmbtu to more than $20.00 per mmbtu over the course of the year, yet the tariff rate to move gas from Marcellus to Algonquin is fixed. In order to understand which party is bearing the incidence of the pipeline tariffs between Marcellus and Algonquin, it is necessary to evaluate market conditions.

Our response to the second question posed is:

CES does not know the answer to this question. We have not seen any of the tariff information filed by Spectra regarding Access Northeast in this proceeding or in any other proceeding in New England.

12. Similarly, is it CES' understanding that gas generators directly served by Algonquin that receive firm gas supplies via the NED project will incur the additional cost of firm transportation on Access Northeast. Additionally, is it CES's understanding that such firm transportation will be available only if the Access Northeast project goes ahead?

Response:

Our response to the first part of the question posed is:

Our answer to this part of the question is the same as our answer to the first part of Question 11. We are unable to say definitively how the incidence of any Access Northeast tariffs will fall upon the various parties.

Our response to the second part of the question is:

CES does not know whether NED will be able to flow gas into and down Algonquin without the Access Northeast project moving forward. Assuming that the interconnection work is undertaken, CES is not aware of any constraint that would prohibit the flows absent the development of Access Northeast.

13. ISO-NE in a recent whitepaper tiled *The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future* (June 2015)contends that energy market price reductions caused by subsidized renewable resources put upward pressure on capacity market prices. Has CES considered the potential impact on capacity prices caused by energy price reductions driven by EDC funded pipeline expansion projects? If so, please discuss.

Response:

CES is aware of and shares the ISO-NE concern that increasing renewable energy generation in New England will, all other things constant, put upward pressure on capacity prices. The cause and effect relationship, however, is not an easy one to disentangle.

We begin with a few underlying assumptions that form the basis of ISO-NE's concerns:

a. The supply curve for incremental generation that will determine the price of capacity in the FCM in New England is not flat at a specific price per kW, i.e., the supply curve is upward sloping.
b. Renewable generation bids into the energy market at $0/MWh and is therefore dispatched prior to any non-zero bid.
c. Increases in the amount of renewable generation lower energy clearing prices and displace marginal generation that would otherwise run, and such marginal generation is generally natural gas-fired generation.
d. By reducing the number of hours natural gas-fired generators run in the energy market, those generators are able to earn less energy market rents.
e. By lowering LMPs, all generators that do run receive lower energy market rents than they would otherwise have received.
f. Since all generators earn lower energy market rents, they will require higher capacity prices in order to remain in the market.

This is the general argument advanced by those who have drawn the relationship between increased renewable generation and increases in capacity costs in New England.

In point of fact, however, the relationship is much more complicated than the above for the following reasons:

- Low natural gas prices have driven LMPs so low that energy market rents available to non-natural gas-fired generators such as nuclear plants and capacity-capable renewable generators now represent an insufficient source of revenues to support new market entry. To the extent that the price of capacity might ever have been set by these types of units, it is unlikely that they will be in the low gas price future.
- As a result, the most likely type of generator to set capacity prices in the FCM is simple cycle natural gas-fired combustion turbines.

- These types of generators are likely to bid into the capacity market assuming that they receive no energy market rents (when they are called upon to run, they will be setting the LMP) and therefore will need to derive all (or nearly all) of their revenues from capacity payments.
- The supply curve for this type of generator is likely to be relatively (if not perfectly) flat – at least over the range of new capacity ISO-NE is expected to require over the next 10 years, since its installed cost reflects largely the technology and not its location or other factors that may vary by projects.

As a result, all things being equal, capacity prices will likely track the cost of new entry of this type of generator into the market. We have seen this playing out as the FCA results are significantly higher than the prices historically experienced.

In addition, the diffusion of small-scale behind-the-meter solar PV systems, coupled with increased energy efficiency especially in those end-uses that tend to be coincident with peak usage (e.g., air conditioning and commercial lighting) has the effect of lowering peak demand levels within the ISO-NE Control Region. This, in turn, lowers Installed Capability Requirements (ICRs) which reduces the need for capacity. As this need falls, we might see the region experience the types of excess capacity it has experienced over the last decade with a consequent drop in capacity prices.

Increases in natural gas pipeline capacity, however, do not have the same effect on capacity market conditions as increases in the level of renewable generation. As we noted in our comments in the Massachusetts case – DPU Case 15-37 provided at the end of this response (1), while additional natural gas pipeline capacity will suppress energy prices, it also results in increasing the hours during which natural gas-fired generators are able to run. Since natural gas-fired generators are operating at the margin, their energy market rents are determined more by the number of hours they run and less by the absolute price of natural gas. This is not necessarily true of other types of generators such as nuclear plants; however, we do not believe that these types of generating plants will ever drive pricing in the capacity market.

As a result, we do not believe that increasing natural gas pipeline capacities into New England will result in higher capacity prices for the region.

(1)See footnote 44 on page 57 of the CES filing in the Massachusetts DPU Case 15-37, which we reproduce below:

There was some question as to whether the benefits estimated by CES should be adjusted for potentially higher capacity costs to offset lost revenues in the energy market. We do not believe this is necessary, since the market clearing price for capacity is expected to be driven by natural gas-fired generation and since gas fired generators simply pass through gas prices, there should be no change in the profitability of these generators as a result of changes in gas prices and thus no need for additional capacity payments. Indeed it is likely that the economics tend in the opposite direction. As additional pipeline and gas generation is added to the system the hours of oil generation will decline, the hours of gas generation will increase, the value captured from the energy market by gas generators will increase and the need for capacity payments may actually decline.

14. Assuming the New England states decide to purchase a specific amount of incremental pipeline capacity at the lowest reasonable cost, and three regional projects are capable of supplying that capacity via purchases made by EDCs, what approach would CES recommend the New England states employ to select among competing pipeline projects? Also, does CES see any downside to requiring pipeline projects to compete to supply the needed capacity?

Response:

Our response to the first questions is:

CES believes that EDCs should purchase long-term firm capacity contracts from pipeline companies using the same competitive bid processes they currently use to enter into long-term contracts for renewable generation. The important issue is less the structure of the competitive process (although we strongly recommend that no EDC affiliate be prohibited to bid in any such solicitation) and more the criteria that is used to evaluate bids received.

As in most efforts to procure a long-term contract for any good or service, we believe the most important criteria should be the price. There are, however, certain secondary considerations that we believe are important and need to be factored in by the EDC or regulatory body:

- The estimated benefits EDC ratepayers can expect to receive from the incremental pipeline capacity in conjunction with all other incremental pipeline capacity acquired by LDCs and EDCs in the region.
- Additional value should be given where the EDC contract enables a pipeline project to be built – that is, it gets the pipeline project over the throughput threshold to support its construction.
- Additional value should be given to a pipeline that can be readily expanded through the addition of compression or similar incremental investments – as opposed to replacement of actual pipe.
- Since delays in pipeline on-line dates are extremely costly to the region and to an EDCs ratepayers, additional value should be given to pipeline projects that can be brought on-line sooner rather than later.

Our response to the second question is:

No, so long as the competitive process is well designed.

15. Assuming the New England states decide to support a single regional pipeline project, does CES see any downside to such a decision?

Response:

Yes. CES sees a number of downsides.

a. We are concerned that the time required to secure cooperative support among the New England states could be lengthy and therefore delay the on-line dates of additional pipeline capacity.
b. We do not believe that a single pipeline (at least among those options currently presented by pipeline developers) provides sufficient capacity to meet New England's current and expected future natural gas requirements. A single pipeline (NED, Access Northeast or C2C) will leave the region short pipeline natural gas during many hours and therefore not maximize net savings available to the region's natural gas and electricity consumers.
c. Depending on the size of the single pipeline, such an option could leave the region with too little LNG requirements to support multiple regasification facilities, while leaving the region fundamentally dependent on LNG to meet its requirements. This could vest significant pricing power with Distrigas, which, as we have noted in responses to other questions, is a major concern.
d. If the region does decide to proceed with a single pipeline, it should give serious consideration to reliability and the consequences of N-1 conditions on the natural gas pipeline system into New England. We note, for example, that a recently announced maintenance outage by Algonquin for October caused a spike in Algonquin basis pricing for October of $0.40. This, in turn, will lead to an expected $30 million increase in LMPs during the month. [The rough calculation is - Assuming that the $0.40 increase noted above is the ultimate price impact of the maintenance shutdown, at an October average heat rate of 8500 btu/kWh, this will translate into an increase in electricity prices of about $3/MWh. October consumption is roughly 10 million MWhs, so this will cost New England ratepayers about $30 million.]

16. In the Mass DPU proceeding DPU 15-37, CES is quoted as claiming that the average price of gas for the period December 1, 2013 through November 30, 2014 at the Tennessee Z4 Marcellus trading point was $2.57/MMBtu compared to $5.28/MMBtu at the TETCO M3 trading point. Is it reasonable to conclude from this comparison that the NED project will provide greater benefits to the region than the Access Northeast project, all other things being equal? If yes, please explain why. If no, what was CES' purpose in making this comparison?

Response:

The prices quoted in the question for Tennessee Z4 Marcellus and TETCO M3 were in our Maine filing in Docket No. 2014-00071 dated December 4, 2014. In both our Massachusetts and New Hampshire filings we used updated prices for the period May 27, 2014 through May 26, 2015. These prices were $1.737 and $3.252, respectively, for Tennessee Z4 Marcellus and TETCO M3.

The purpose of providing this information was to examine more carefully an important issue with respect to each pipeline proposal – the price of natural gas at the receipt point on the pipeline. This is important, since, all other things being equal, a pipeline that can access cheaper natural gas supplies will provide greater benefits to New England ratepayers than one that accesses more expensive natural gas supplies.

As we note in our filings in Massachusetts and New Hampshire, current market conditions show a slight advantage to the NED project compared to Access Northeast, based on the assumptions we have made regarding pipeline tariffs (see Figure 11 on page 41 of the New Hampshire filing). We also indicate that we expect market forces to reduce any delivered price differential over time between the southern path out of Marcellus on the Spectra system and the northern path out of Marcellus on the NED system.