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MEMORANDUM

April 17, 2015

TO: RHODE ISLAND PUBLIC UTILITIES COMMISSION

FROM: RICHARD HAHN, LA CAPRA ASSOCIATES INC., ON BEHALF OF THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

SUBJECT: NATIONAL GRID 2016 STANDARD OFFER SUPPLY AND RENEWABLE ENERGY STANDARD PROCUREMENT PLANS, DOCKET NO. 4556

The Rhode Island Division of Public Utilities and Carriers ("Division") requested that La Capra Associates, Inc. review National Grid's ("NGrid" or "the Company") 2016 Standard Offer Supply ("SOS") and Renewable Energy Standard ("RES") Procurement Plans that were filed on March 2, 2015. This memorandum provides the results of my review of the Company's SOS and RES plans. My comments are organized as follows. I begin with a brief review of the current regulatory construct, followed by an overview of current electricity markets. Next, I provide a comparison of the Pascoag and NGRID procurement methods. I then describe NGrid's proposed changes from its 2015 plan. I also respond to some issues raised in the Farley testimony of December 11, 2014 in Docket 4393. Lastly, I discuss options for additional changes for NGrid's 2016 plan.

Brief review of the Current Regulatory Construct

Like many other states, Rhode Island has implemented electric utility restructuring, which included utility divestiture of owned power plants, opening the business of power supply to the competitive market, and allowing all customers to choose the entity that provides its power supplies at unregulated rates. This approach can be contrasted to the pre-restructuring model, where the local utility effectively had a franchise monopoly, owned generation directly or through affiliated companies, and had an obligation to serve all customers at regulated rates.[1] Under the current construct, NGrid, as the local Electric Distribution Company ("EDC") is required to provide Standard Offer Service ("SOS"). SOS is a power supply service for customers who are not willing or able to choose a competitive supplier or if a chosen competitive supplier fails to meet its obligation to deliver power supply. In other states, SOS is referred to as Default Service or the Provider of Last Resort ("POLR").

A logical and perhaps only outcome of such a construct is near exclusive reliance on near-term electricity markets for the provision of power supply. Since customers have no obligation to buy from any power supplier and can switch suppliers at will, few retail power suppliers are willing to make commitments more than two to three years into the future. In fact, some power

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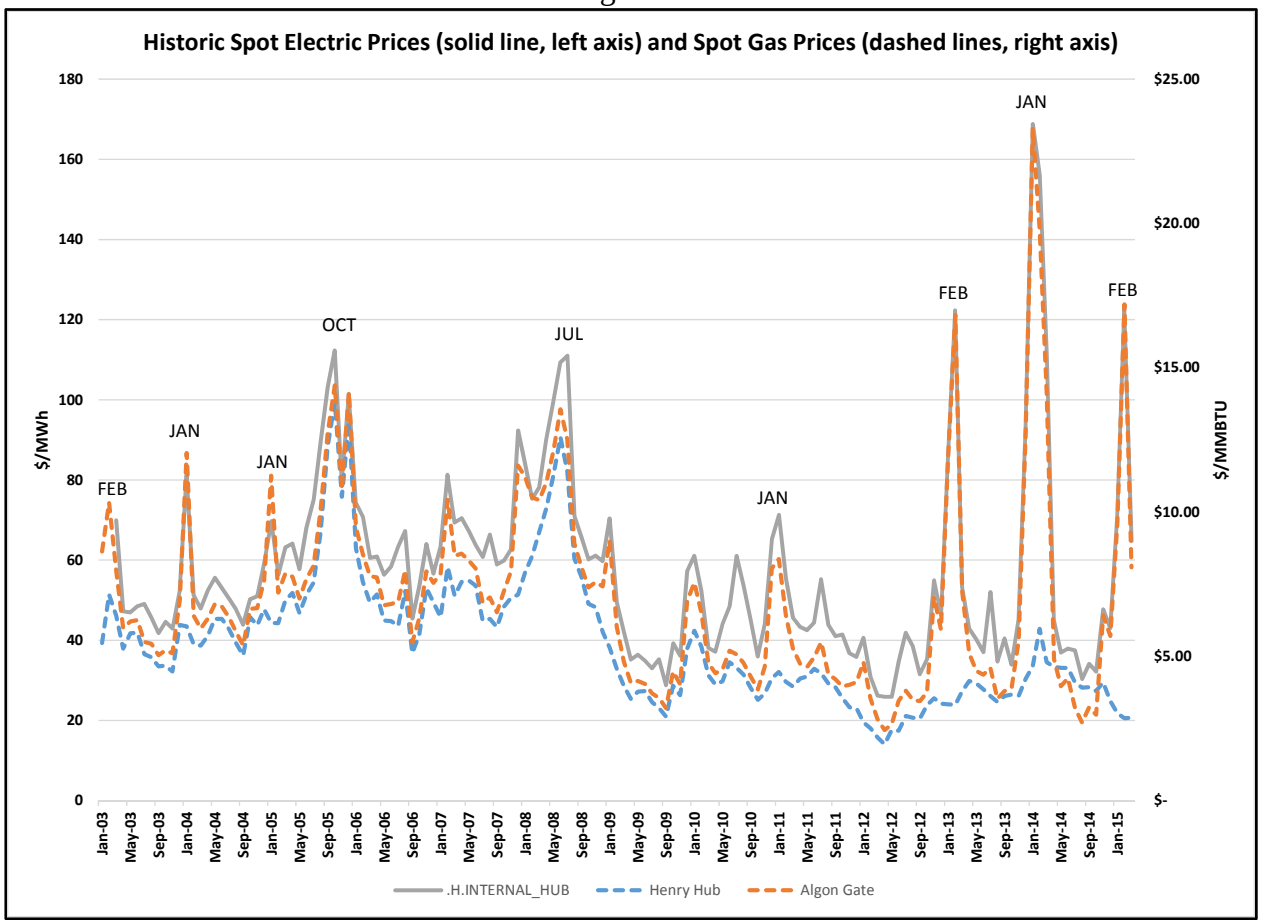
[1] This pre-restructuring model still applies to the distribution portion of the electric utility business.

suppliers do not own any electric generation. Instead, they rely upon physical and financial products that can be liquidly traded over the next 36 months. These trading activities also allow buyers and sellers of power insight into what prices might be over those 36 months. Owning generation may produce, but does not guarantee, benefits to wholesale suppliers. Recently, wholesale market prices have become extremely volatile, especially in the winter months. This volatility in short-term wholesale markets directly affect the prices paid for SOS. This volatility is discussed in the next section of this memorandum. It is important to note that changes to the regulatory construct would require legislation, and some changes may not be possible at all. Thus, it is likely that the existing regulatory construct, which dictates reliance on short-term markets, will be with us for the foreseeable future.

Overview of current electricity markets

Figure 1 below provides monthly historical gas and electric energy prices for the ISO-NE control area. Electric energy prices in $ per MWH are plotted against the left axis, while natural gas prices in $ per mmBTU are plotted against the right axis. Several important observations can be made from this data. There is a very high correlation between ISO-NE wholesale spot market electric energy prices and spot natural gas prices delivered to New England. Winter price spikes have been occurring for a long time, but have become more severe in the last three years. The cause of the recent natural gas price spikes is related, among other things, to the availability of delivery into New England, as the cost of the commodity component as measured at the Henry Hub is at historic lows.

Figure 1



The issues surrounding this volatility are several and include having a high percentage of the region's capacity fueled by natural gas, recent retirements of nuclear and coal power plants, almost exclusive reliance on natural gas for newly constructed power plants, lack of firm natural gas pipeline capacity for new and existing natural gas-fired power plants,[2] and lack of alternative fuel capability at these plants. ISO-NE has more than 16,000 MW of generating capacity that has natural gas as a primary fuel. About 5,000 MW of this capacity, or about 30%, can burn an alternative fuel. Many of these dual fuel units are of an older vintage, such as Manchester Street in Rhode Island or Mystic 7 in Everett, MA. New renewable resources, such as solar and wind, serve to mitigate some of this volatility.

The design of the ISO-NE energy market also contributes to price volatility. Under this design, all generators receive, and all load pays, the market clearing price. Any difference between the generator revenues and their variable cost of production is retained by the generator and is used as an offset to fixed costs. I will refer to this difference as the generator margin.[3] Figure 2 below

[2] Local natural gas distribution companies typically avoid these price spikes by contracting for enough firm pipeline capacity to meet their needs.

[3] A generator margin can also be considered to be a contribution to profits.

provides a one-hour hypothetical example of the ISO-NE energy market using "baseline" natural gas prices, namely prices roughly equal to $5.80 per mmBTU delivered to New England. Under this example, the clearing price or Locational Marginal Price is about $100 per MWH, and customers ultimately pay and generators collectively receive about $2.5 million for this hour. Collectively, these generators incurred about $1.0 million in fuel and variable O&M costs, leaving about $1.5 million in generator margin.

Figure 2

EXAMPLE ONE-HOUR DISPATCH WITH BASELINE GAS & OIL PRICES

Row Labels	Sum of adjusted capacity (mw)	Sum of cleared MW	Sum of production costs	Sum of generator margin
Biomass	1,489	1,489	59,021	92,202
Coal	1,857	1,857	71,173	117,375
Natural Gas	14,097	13,758	675,851	721,289
Other Fuel	122	122	3,995	8,352
Petroleum Products	5,988	643	63,294	1,981
Solar	0	0	0	0
Uranium	4,047	4,047	63,398	347,535
Water	2,672	2,672	71,121	200,233
Wind	413	413	1,030	40,900
Grand Total	**30,684**	**25,000**	**1,008,883**	**1,529,867**

LMP = $101.55

Wholesale Energy Costs to Load = 2,538,750

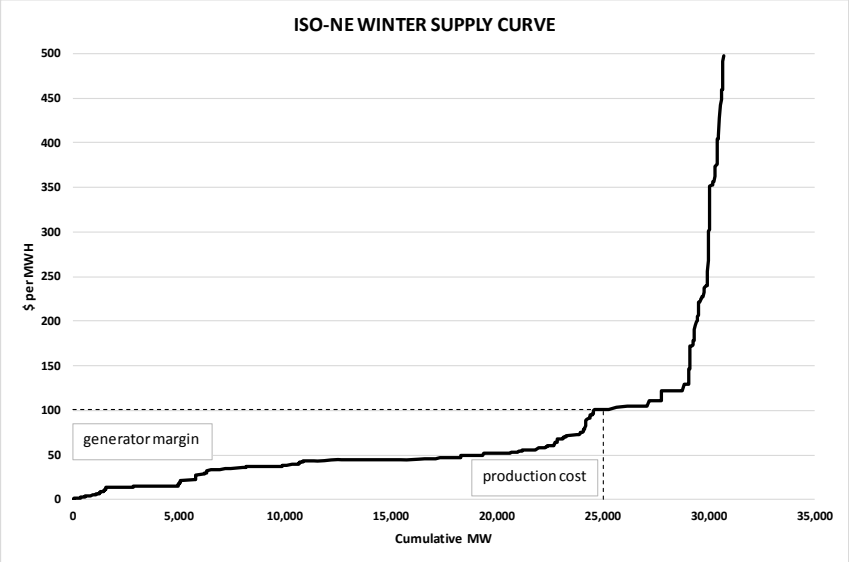


Figure 3 below shows the same example, but with delivered natural gas prices that have spiked by 300%, or to about $23.20 per mmBTU. Oil prices were assumed to experience a similar price spike.[4] As shown below, the clearing price or Locational Marginal Price is almost $360 per MWH, and customers ultimately pay and generators collectively receive about $8.9 million for this hour. Collectively, these generators incurred about $3.0 million in fuel and variable O&M costs, leaving about $5.9 million in generator margin.

[4] This assumption was made to simplify this illustrative example, and should not be interpreted as implying 100% correlation between natural gas prices and oil prices.

Figure 3

EXAMPLE ONE-HOUR DISPATCH WITH GAS & OIL PRICE SPIKE

Row Labels	Sum of adjusted capacity (mw)	Sum of cleared MW	Sum of production costs	Sum of generator margin
Biomass	1,489	1,489	59,021	473,990
Coal	1,857	1,857	71,173	593,396
Natural Gas	14,097	14,088	2,682,409	2,359,947
Other Fuel	122	122	3,995	39,526
Petroleum Products	5,988	313	110,232	1,940
Solar	0	0	0	0
Uranium	4,047	4,047	63,398	1,385,002
Water	2,672	2,672	71,121	885,311
Wind	413	413	1,030	146,759
Grand Total	**30,684**	**25,000**	**3,062,379**	**5,885,871**

LMP = $357.93

Wholesale Energy Costs to Load = 8,948,250

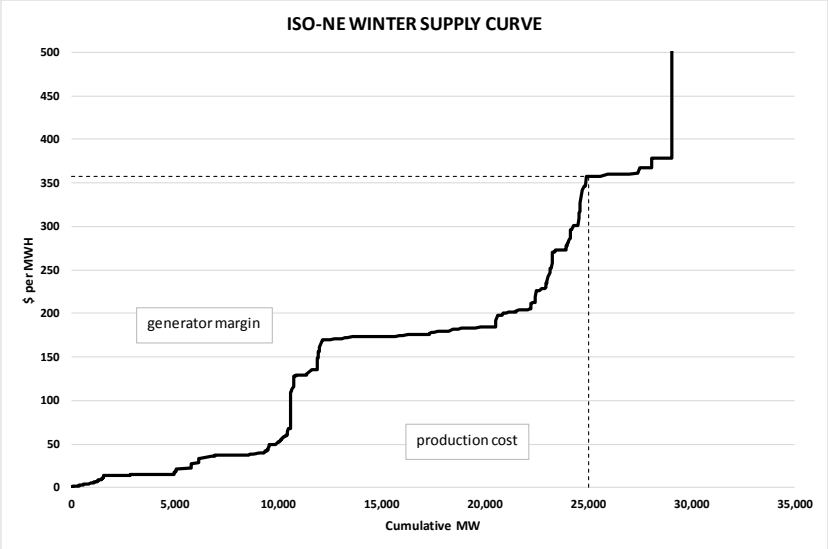


Figure 4 below provides a summary comparison between the two above examples. Natural gas and oil represent about two-thirds of the ISO-NE fuel mix, so a 300% increase in the cost of these two fuels should increase production costs by about 200%. Figure 4 verifies this expectation. But load payments and generator revenues have increased by about $6.4 million, increasing generator margins by almost $4.4 million in this example. It should be noted that this is not a design flaw but rather it is how the market is intended to function. In my opinion, this market design has contributed to the volatility of wholesale electricity prices. This example helps illustrate why owners of existing generators in the ISO-NE control area do not, and have little incentive to, secure firm natural gas pipeline capacity. The cost of hedging is high relative to the gains in the hours when prices spike. And, some generators will earn more money when natural gas (and electricity) prices are high.

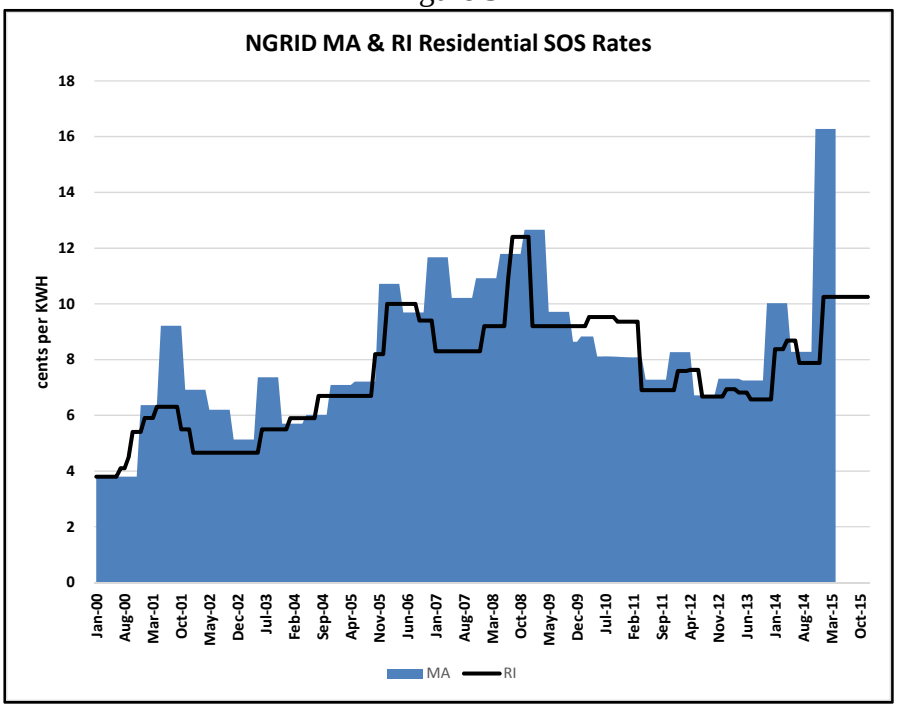
Figure 4

SUMMARY OF ONE-HOUR DISPATCH EXAMPLE

	Gas & Oil Prices			
Item	**Baseline**	**Price Spike**	**$ Difference**	**% Difference**
Load (MW)	25,000	25,000		
LMP ($ per MWH)	$101.55	$357.93	$256.38	252%
Wholesale Energy Costs to Load	$2,538,750	$8,948,250	$6,409,500	252%
Production Costs	$1,008,883	$3,062,379	$2,053,496	204%
Generator Margin - Total	$1,529,867	$5,885,871	$4,356,004	285%

Figure 5 below shows historic monthly residential SOS prices for Rhode Island and Massachusetts. These prices reflect the volatility of the underlying short-term markets when transitioning from one procurement period to another.

Figure 5



Recently, several initiatives, such as the Governors' Infrastructure Initiative or the Tri-State Renewable RFP by Rhode Island, Massachusetts, and Connecticut, have been developed to address the adequacy of natural gas pipeline capacity for electric generation. These initiatives include the construction of new natural gas pipeline capacity for use by electric generators. By

my estimate, if all natural gas-fired electric generators in New England secured new firm pipeline capacity, the amount of incremental pipeline capacity needed could exceed 3 billion cubic feet per day. Other potential measures to mitigate price spikes include constructing new electric transmission lines to increase imports of renewable energy that would displace or reduce reliance on natural gas-fired electric generators. Retail electric customers will be asked to pay for the fixed cost of these initiatives, with the expectation of lower energy costs. Implemented solutions are several years away at best.

As with the existing regulatory construct, the design of existing energy markets is difficult and perhaps unlikely to change, especially in the near term. This market design is approved by FERC and is well entrenched in much of the country. Given that these markets are expected to remain volatile, it becomes necessary to develop an appropriate hedging plan to attempt to mitigate those risks.

Comparison of Pascoag and NGRID hedging methods

In the Janzen testimony in this proceeding and Farley testimony filed in Docket 4393, considerable discussion has occurred relative to the power supply procurement plans of NGrid and Pascoag. In this section of this memorandum, I will review and compare these two methodologies of hedging future SOS prices. It is my understanding that on or about April 23, 2014, Pascoag entered into a power supply agreement with TransCanada for an energy-only contract at a fixed price of $70.30 per MWH from 1/1/2015 through 12/31/2017. The agreement is characterized as load-following service, as the amount of energy purchased each hour is Pascoag's actual load less energy received from its existing resources. Pascoag will procure any needed capacity and ancillary services for this portion of its load via other mechanisms.

Figure 6 below shows the market outlook for natural gas for calendar years 2015 to 2017 as of the end of April 22, 2014, the day before the deal with TransCanada was made. This figure also shows actual natural gas prices from January 2012 through March 2014. The commodity component of the delivered natural gas price, namely the Henry Hub ("HH") price, was expected to remain flat. Winter delivered prices, as measured at the Algonquin city gate ("ALGONCG") were expected to continue to experience spikes, but at lower levels than in recent actual winters.

Figure 6

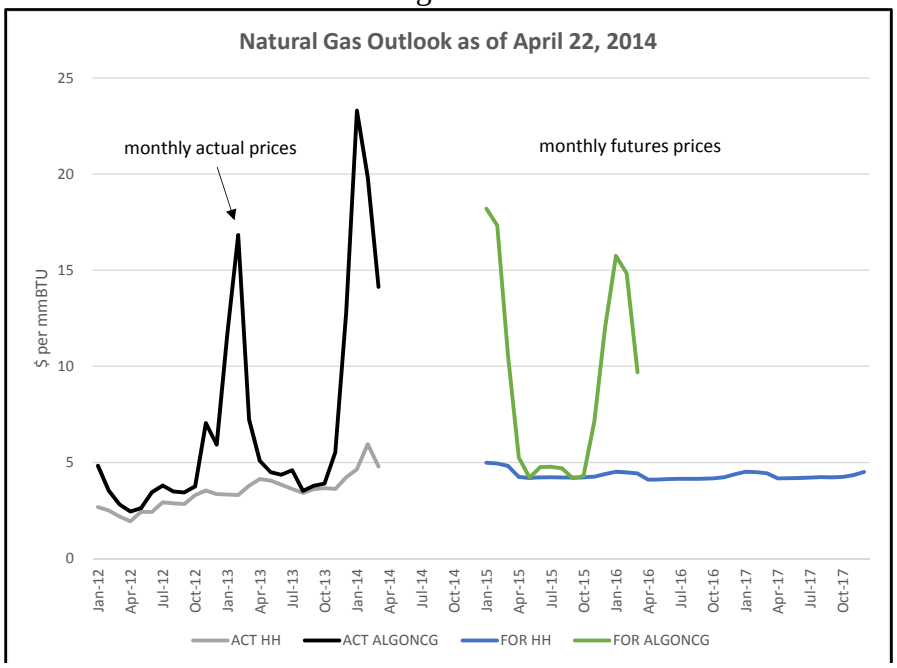


Figure 7 shows the market outlook for wholesale electric energy on this same day, including futures prices for 2015 through 2017. These prices are based upon the ISO New England internal hub ("ISO HUB").[5] Over this time period, winter prices spikes were expected, but the average energy price was $57.92 per MWH,[6] which was lower than the most recent twelve month average cost of about $71.77 per MWH.

5 Recent actual ISO HUB prices were very close to prices in the Rhode Island load zone.

6 A simple arithmetic monthly average, as opposed to a load-weighted monthly average, was used in this comparison for simplicity purposes.

Figure 7

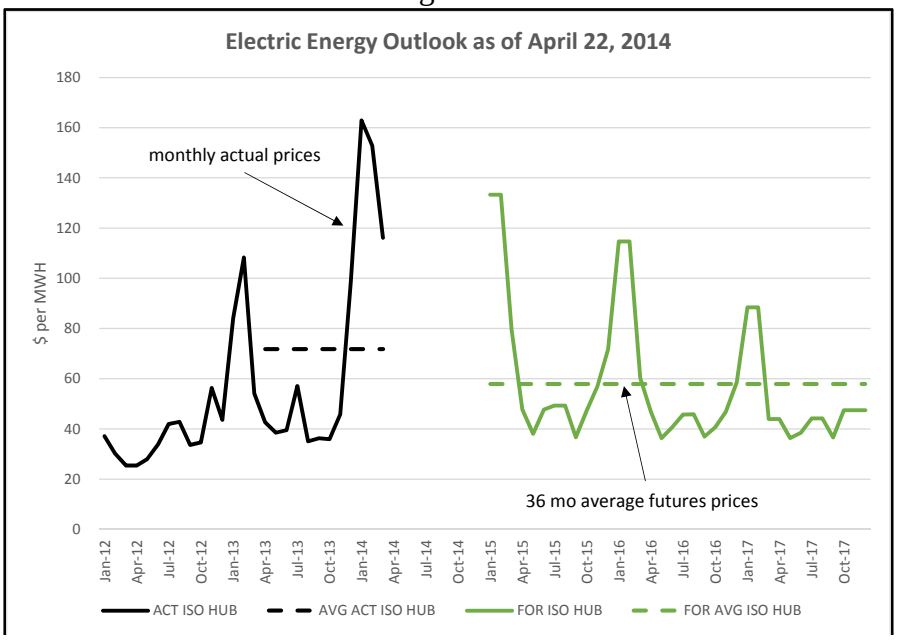
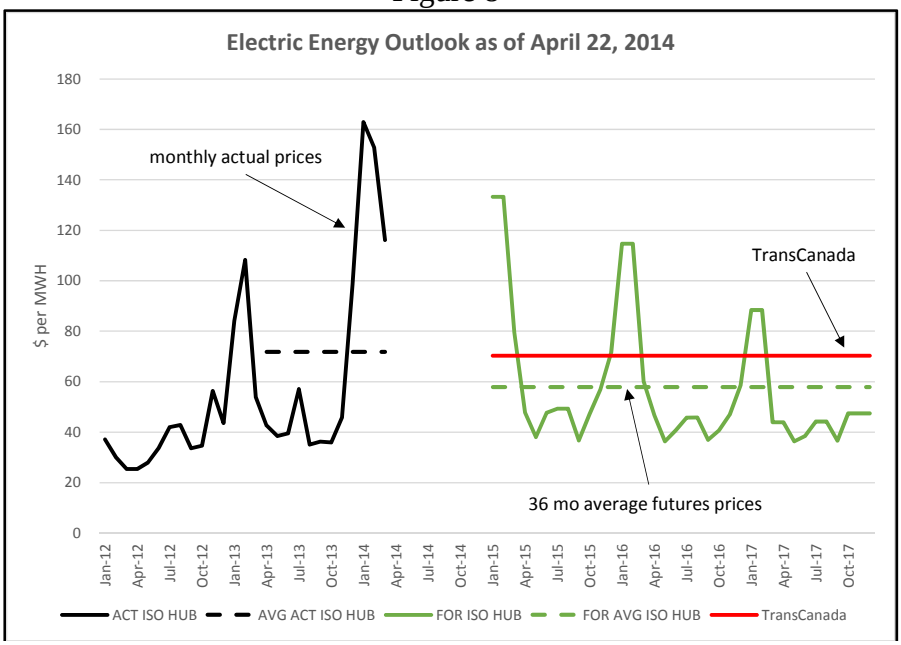


Figure 8 shows how the TransCanada deal of $70.30 per MWH comports with the market outlook.

Figure 8



Thus, in the TransCanada deal, Pascoag paid about a $12 per MWH differential over the then-current market outlook to lock in its energy costs and protect or hedge against higher price spikes for three years. I understand that there were multiple bidders to supply Pascoag, so Pascoag

could take comfort that the price was reflective of a competitive market. I did not participate in Pascoag's process, but I have no doubt that Pascoag, through its advisor Energy New England ("ENE"), monitored market trends and concluded that late April 2014 was a good time to solicit and procure power supplies. It is important to note that I do not consider what Pascoag did to be speculative. Rather, Pascoag/ ENE followed the market and looked for an opportunity to reach a fair deal that provided Pascoag with benefits and little downside risk. I believe that this deal represents a good outcome for Pascoag. It locked in prices for the previously unhedged portion of its energy needs for the next three years that were below the most recent 12-month average actual prices. If price spikes occur in the future, Pascoag's customers are protected against that increase for the term of this agreement. If prices fall dramatically, Pascoag's customers will likely pay less than they did recently.

NGrid's approved 2015 SOS procurement plan also hedges against price volatility. To illustrate this point, I will focus on NGrid's 2015 SOS rates for residential customers. These rates are set through several solicitations done over time to procure 90% of the residential SOS supply obligation, with 10% to be procured from spot markets. The procurement dates were 11/13/2013, 2/19/2014, 5/14/2014, 8/13/2014, 11/12/2014, and 2/18/2015.[7] Because the market outlook differed at the time of each of these procurements, I compared the results of each solicitation to the sum of the expected prices for energy, capacity, and other cost obligations of load from the day before that solicitation. This other category includes net costs assessed by ISO-NE to Load Serving Entities ("LSE"), such as regulation, forward and real time reserves, auction revenue rights, and ISO-NE and Nepool expenses, all as defined in the ISO-NE tariff. I included these other, non-energy costs because NGrid's solicitations were for fixed price, full requirements contracts ("FPFRC"). I then calculated a weighted average for each month using the percentage weights for each solicitation in the approved procurement plan. Figure 9 below shows the results of this comparison. On average, NGrid paid a differential of about $18 per MWH over then-current market outlooks to hedge SOS rates for 2015. Like Pascoag, NGrid can take comfort that there were multiple bidders in each solicitation, and that therefore the prices were competitive. While NGrid's differential is higher than Pascoag's differential, NGrid is hedging all products, not just energy, although the cost to hedge capacity and ancillary services are not significant. It is also possible that NGrid may have a greater perceived risk of customer migration, which could contribute to a higher differential.

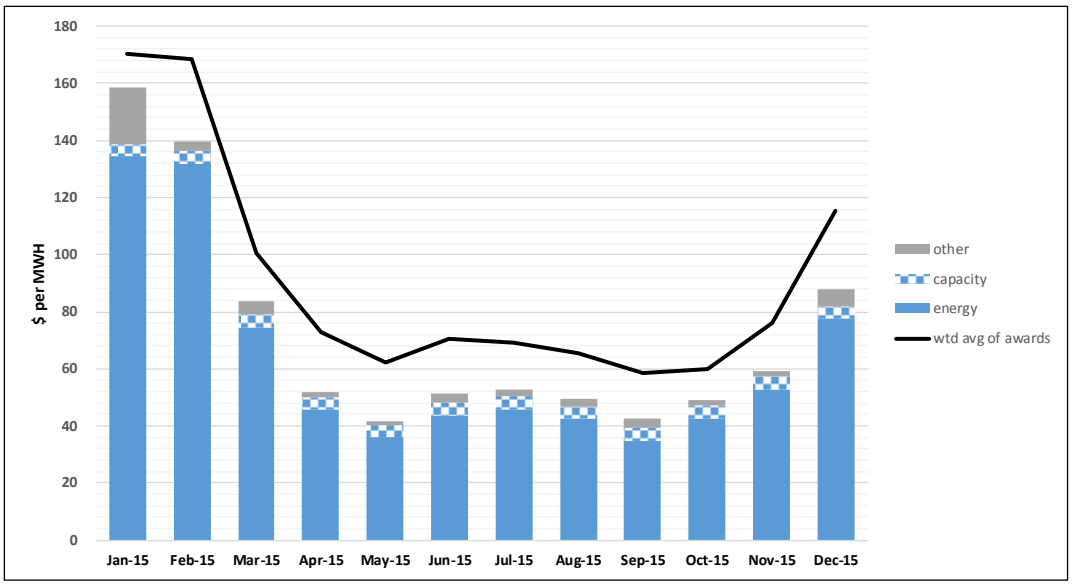
[7] The February 2015 procurement is for the last six months of 2015.

Figure 9

SUMMARY OF NGRID RHODE ISLAND RESIDENTIAL SOS PROCUREMENT RESULTS FOR 2015

Weighted Average of Procurements on 11/13/2013, 2/19/2014, 5/14/2014, 8/13/2014, 11/12/2014, and 2/18/2015
Compared to Wholesale Supply Components as of Procurement Date
Excludes 10% Spot Component

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	average
wtd avg of awards	170.31	168.71	100.59	72.83	62.41	70.38	69.01	65.27	58.51	59.90	76.28	115.51	90.81
energy	134.54	131.55	74.68	45.74	36.21	43.66	45.88	42.48	34.81	42.66	52.72	77.66	63.55
capacity	4.23	4.67	4.21	4.33	4.19	4.63	4.46	4.38	4.53	4.36	4.49	4.35	4.40
other	20.03	3.31	4.62	1.78	1.40	2.89	2.28	2.55	3.29	1.92	2.21	5.95	4.35
total	158.80	139.52	83.51	51.85	41.80	51.18	52.62	49.41	42.62	48.94	59.42	87.97	72.30
													18.51



Note: the "other" cost category in the above graph is defined in the preceding paragraph.

I have long been an advocate of using a managed portfolio approach, which is basically what Pascoag/ ENE uses, as a preferred procurement approach, because I believe that it produces a superior result. I believe that at the end of this deal, Pascoag will be happy that it did the deal. However, the point to be made here is that both the Pascoag and the NGrid procurement methods can hedge against the short-term market price volatility that no one can control and that appears to be with us for the foreseeable future, assuming competitive solicitations and a full analysis of the bids. I should also point out that both procurement methodologies have a "hard stop" or price cliff at the end of the procurement period. That is to say, NGrid has set prices through December 2015. While some of NGrid's contracts from its 2015 procurements for residential SOS continue into 2016, 55%[8] of the 2016 load will be supplied from new contracts effective as of as of January 1, 2016. Prices for 2016 beginning in January will be different from 2015 prices, and could result in a large step increase or step decrease at that time, depending upon the

[8] See Schedule 2C attached to the Janzen testimony in this proceeding.

results of future procurements. For Pascoag, that step change will occur in January 2018, as the TransCanada deal, which represents about 42% of Pascoag's supply, expires at the end of 2017. Thus, even if price volatility is hedged during the procurement period, price volatility could occur when transitioning from one procurement period to another, as shown in Figure 5 above. All of the price changes shown in Figure 5 occur every six months rate when rates change[9].

Review of NGrid Proposed changes from the 2015 plans

NGrid has proposed few changes in its 2016 SOS procurement plan. Two modifications have been proposed, both for the commercial group. One is to increase the level of dollar cost averaging by deploying more solicitations and using longer contract terms for the commercial group, mirroring the residential plan. The current residential procurement is based upon five solicitations per year, plus a 10% spot component. Residential contract terms are 6, 12, 18, and 24 months. The current commercial plan is based upon three procurements per year, each for 30% of the SOS load, plus a 10% spot component. Commercial contract terms are 6 and 12 months. For its 2016 plan for commercial customers, NGrid proposes to transition to the residential procurement plan for its commercial procurements. This transition will commence during 2016 but will not be complete until January 2017.[10] NGrid has also proposed to solicit "flat pricing" whereby, winning bidders would provide the same price for all months in a solicitation period, instead of different prices for each month as is the current practice. The switch to flat prices is intended to mitigate or eliminate the "billing adjustment" that can result when customers switch from SOS to a competitive supplier within the SOS pricing period.

It is my understanding that the billing adjustment results from a mismatch between NGrid's SOS revenues and costs. Currently, SOS suppliers are paid a monthly price. However, NGrid charges the same rate for a six month period, which is based upon the average of the monthly rates paid to suppliers. If a customer takes SOS in January, it pays NGrid a lower amount than NGrid pays the suppliers. If that customer leaves SOS and switches to a competitive supplier, NGrid seeks to be made whole for the shortfall. It is my further understanding that this billing adjustment is difficult to explain to customers, is exacerbated by the recent market volatility, and has been the cause of recent complaints.

I believe that it is reasonable to try and match revenues and costs. Charging monthly rates for SOS to match monthly rates paid to suppliers will result in very high rate volatility, so this approach doesn't seem desirable. Seeking flat pricing from SOS suppliers to match flat SOS rates is likely a better approach to matching revenues and costs. The concern with this approach is that SOS suppliers will include a higher risk premium in their flat pricing. The Janzen testimony states that "suppliers have indicated that an incremental premium would not be added to create a flat bid price".[11] Division data request 1-7 asked for the basis of that opinion. The response stated that most of the suppliers that NGrid spoke to on this issue would prefer monthly

[9] The one exception to this would be the RI residential price change effective 1/1/15, which is expected to be in place for all of 2015, as the PUC directed NGrid to set the price based on averaging the costs over a 12 month period.

[10] See Schedule 2B attached to the Janzen testimony in this proceeding.

[11] See page 19 of the Janzen testimony in this proceeding.

prices, that there would be negative implications to flat bid prices, but did not indicate the size of any risk premium. One way to address this issues is to seek both monthly and flat bid prices during the SOS solicitations, and compare them to gauge the size of any risk premium.

Another approach is to eliminate the billing adjustment, keep prices paid to suppliers as monthly, keep SOS rates fixed for six months, and the include the difference in the annual reconciliation. The Commission could establish a tracking mechanism to monitor how big the impact on the reconciliation gets. Massachusetts has recently adopted this policy[12].

In Rhode Island, I believe that a combination of these approaches makes sense, namely immediately eliminate the billing adjustment, track its impact, and seek both flat and monthly bids from suppliers in upcoming solicitations. If the risk premium in flat supplier bids is deemed to be too large, NGrid can accept the monthly bids, and continue to track the impact. If the risk premium in flat supplier bids is deemed to be acceptable, NGrid can accept the flat bids, and there will be no impact on the reconciliation.

If the Commission desires to keep the 2016 plan similar to the 2015 plan, then these changes make sense, and should be approved. In a later section of this memorandum, I discuss alternatives for revisions to the plan in the event that more significant changes are desired.

The 2016 RES plan is a continuation of the 2015 plan, with few if any changes to the relevant documentation. This plan should be approved.

Response to the Farley testimony on behalf of the Lieutenant Governor in Docket 4393.

The Farley testimony that was filed on December 11, 2014 in Docket 4393 in response to the large standard offer rate increases proposed significant changes to the NGrid 2016 SOS procurement plan. Mr. Farley advocated primarily for small commercial customers. He proposed a temporary rate credit to deal with the current price spikes, an issue that is now moot. Mr. Farley did propose a structured portfolio approach similar to what Pascoag does now (and did in April 2014). This structured portfolio approach could include using judgment to decide when to procure, including longer term contracts, requiring that winning bidders have a firm fuel supply, creative procurements of renewable energy resources, generating unit ownership, and providing financial incentives (and presumably financial penalties) to NGrid based upon the procurement results. Mr. Farley also suggested a greater notice period for informing customers about upcoming price changes.

As stated previously, I support the use of a managed portfolio approach. I so advocated in 2010 when the Commissioned considered such a possibility, and continue to believe that such a procurement approach will over time produce superior results. So at a high level, I support some of the recommendations made in the Farley testimony. As discussed in the next section, implementing this approach would require significant changes to the NGrid plan. However, it is important to understand what such an approach can and cannot do. A structured portfolio approach can effectively hedge against some price risk, but it cannot eliminate market risk, beat

[12] See Massachusetts Department of Public Utilities Order issued April 13, 2015 in Docket DPU-14-140-A.

the market on a consistent basis, or eliminate abrupt price changes when transitioning from one procurement period to another when extreme price spikes occur in the wholesale market. Some of Mr. Farley's suggestions might not produce the intended result. For example, requiring winning SOS bidders to have procured firm fuel supplies might not be practical, as some, if not most bidders, do not directly base their bids on specific unit outputs. Instead, they rely upon physical and financial products to backstop their bids. Ownership of generation is another of Mr. Farley's suggestions that may not produce favorable results. One only needs to look at the experience of Public Service of New Hampshire in not divesting its power plants and using them as direct supply sources for SOS In recent years, ownership of these plants for SOS has produced higher costs, not lower costs. Furthermore, it is my understanding that, pursuant Rhode Island statute, NGrid cannot own generation. Lastly, I note that Rhode Island already has implemented a creative renewable procurement plan, namely the Long Term Contracts for Renewable Energy program. Under this program, NGrid procures renewable energy under long term contracts, and the benefits and costs accrue to all Rhode Island customers, not just SOS customers. Many of these contracts are at fixed $ per MWH rates. When market prices spike, the revenues from the sale of the purchased attributes exceed the cost, and all customers receive a credit. Thus, these contracts serve as a hedge against higher prices. However, when prices fall or renewable energy is purchased at extremely high rates, this program can increase customer costs.[13]

I agree with Mr. Farley that additional notice of changing SOS rates may be helpful. It would give customers more time to find a competitive supplier, and give competitive suppliers more time to market their products. This can be accomplished under the current plan by holding NGrid's last solicitation earlier. For example, the last NGrid solicitation for deliveries beginning on January 1st occurs around mid-November, which sets rates about 45 days in advance. If this solicitation were held in October, the notice period would be 75 days.

Lastly, on the issue of incentives and penalties for NGrid, it can be extremely difficult to design a mechanism that is just and reasonable. It would become necessary to identify what portion of the results is due to the performance of the SOS provider, and what portion is the result of market conditions, which cannot be controlled by one supplier. I do not recommend that the Commission embark upon this approach with NGrid.

Options for additional changes for NGrid's 2016 plan

Despite the above discussion of the things that cannot be controlled, there are options for the Commission if it wishes to make changes to the currently proposed 2016 SOS procurement plan. The initial action is to choose one of two generic approaches. The first is the fixed program approach where procurements are made by NGrid on a fixed schedule at various times in the year. This is NGrid's current approach. The second approach would be to use a managed or structured portfolio approach, similar to what Pascoag does now. I will discuss each of the alternatives in the remainder of the section of the memorandum.

However, regardless of the approach, the Commission could take steps to encourage customers,

[13] It should be noted that the Long Term Contracts for Renewable Energy program is currently capped at 90 MW, and much of that amount has already been procured.

especially those in the commercial class, to investigate competitive suppliers to determine if more favorable terms than the standard offer are available. It is important to remember that SOS is not and should not be the only option.

If the Commission wishes to retain the fixed program approach, then the following changes should be considered.

1. Revise the procurement schedule to move the November procurements for delivery starting in January to take place, earlier, such as in October. This will give 75 days' notice of any rate change.
2. Revise the SOS price year to be congruent with ISO-NE power year (i.e., June 1st thru May 31st). This approach would change the current January through June six-month price period to June through November, and the current July through December six-month price period to December through May. The advantage of this change is that it aligns the Rhode Island SOS year with the ISO-NE planning year, and the first month of the price year would be June, which typically has a monthly price that is below the annual average. Under the current approach, the first month of the SOS price year is January, which has a monthly price that is well above the annual average. If this change is made, it will be necessary to adjust future procurement schedules to transition to this price year.
3. Evaluate flat prices from SOS providers for the procurement period and compare to the monthly pricing for residential and small commercial class, as described above.
4. Transition small commercial customers to the residential procurement model, as NGrid has proposed.
5. Require NGRID to estimate the risk premium in each winning bid (as they used to do), and to decide to accept or reject bids based upon the results.
6. Mitigate the price cliff at the end of the six-month SOS procurement period by deploying more layering and laddering.
7. Simultaneously solicit bids for fixed price, full requirements contracts and for block and spot or block and indexed products. The results of these bids can be used to decide which one to accept. This can be done in conjunction with the staggered contracts mentioned above.

Figure 10 below illustrates one way to mitigate the partial hard stop or price cliff at the end of the six-month procurement periods. Figure 10 illustrates what happens if the same contracts have more staggered terms, so that no two contracts start or expire on the same date. Under this procurement schedule, wholesale market price changes (both increases and decreases) are blended in sooner, which should somewhat smooth out price spikes. Solicitations are scheduled closer to the delivery date. Price changes occur quarterly instead of annually, and reconciliations could also be performed quarterly or semi-annually. While this schedule can somewhat mitigate wholesale price changes, it will not eliminate the impact of very extreme price spikes.

Figure 10

						2015												2016											
term	done date	%	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
12	2/15/2015	25.00%					x		25	25	25	25	25	25	25	25	25	25	25	25									
12	5/15/2015	25.00%								x		25	25	25	25	25	25	25	25	25	25	25	25						
12	8/15/2015	25.00%											x		25	25	25	25	25	25	25	25	25	25	25	25			
12	11/15/2015	25.00%														x		25	25	25	25	25	25	25	25	25	25	25	25
12	2/15/2016	25.00%																	x		25	25	25	25	25	25	25	25	25
12	5/15/2016	25.00%																				x		25	25	25	25	25	25
12	8/15/2016	25.00%																							x		25	25	25

An alternative approach is to utilize a managed or structured portfolio approach, similar to what Pascoag does now. NGrid has made it clear that it does not favor such an approach, and it does not seem like a good idea to force NGrid to do something it doesn't want to do. It would be possible to outsource this activity to third party manager, similar to what Energy New England does for Pascoag. NGRID or the Commission could use a competitive solicitation to select the third party portfolio manager. Potential candidates would describe their approach and propose a fixed fee price for this work. NGrid or the Commission could also ask candidate portfolio managers to propose a fee structured with incentives and penalties. It would still be necessary to have NGRID remain as the counterparty to any contracts, but NGrid would have no responsibility or liability in procurement and would serve as a collection agency and accounts payable resource.

It is not unique to have an entity other than the local electric distribution company implement the procurement process. For example, the New Jersey Board of Public Utilities retains an auction manager to implement a state-wide procurement process for New Jersey's four electric companies. It is my understanding that the auction manager generally somewhat follows a fixed program approach, but can recommend adjustments to the procurement schedule if conditions warrant it. In Maine, the Maine Public Utilities Commission is responsible for SOS procurement for Central Maine Power and Bangor Hydro and issues the RFPs and chooses the winning bids. RFPs are issued about four months in advance of the commencement of deliveries, and the awards are made about three months in advance. The Maine Commission uses a fixed program approach, similar to what is currently used by NGrid in Rhode Island. While these are examples of entities other than the local EDC being responsible, I would not recommend removing NGrid as the entity responsible for SOS procurement if the Commission continues a fixed program approach. A third party manager should only be used if a structured portfolio approach was used.

I offer both of these paths forward – the fixed program approach and the structured portfolio approach - for the Commission's consideration.

La Capra Associates

Richard S. Hahn

Principal Consultant

Mr. Hahn is a senior executive in the energy industry, with diverse experience in both regulated and unregulated companies. He joined La Capra Associates in 2004. Mr. Hahn has a proven track record of analyzing energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, creating operational excellence, managing full P&Ls, and developing start-ups. He has demonstrated expertise in electricity markets, utility planning and operations, sales and marketing, engineering, business development, and R&D. Mr. Hahn also has extensive knowledge and experience in both the energy and telecommunications industries. He has testified on numerous occasions before the Massachusetts Department of Public Utilities, and also before FERC.

SELECTED EXPERIENCE – LA CAPRA ASSOCIATES

1. In 2014 and 2015, La Capra Associates was retained by the Wisconsin Citizens Utility Board (WI CUB) to evaluate the application American Transmission Company ("ATC") for a Certificate of Public Convenience and Necessity (CPCN) to construct a 345 kV and a 230 KV transmission line from eastern Wisconsin to the Upper Peninsula of Michigan.
2. La Capra Associates was retained by the Citizens Utility Board of Wisconsin (WI CUB) to evaluate the proposed merger between WEC and Integrys. Our assignment was to review the transaction and determine whether it complied with the Wisconsin merger standard, and if not, to develop implementable actions to ensure compliance.
3. Maine Public Utilities Commission ("MPUC") retained La Capra Associates, Inc. ("La Capra Associates") to evaluate possible non-transmission alternatives ("NTAs") to a proposed transmission substation and other ancillary transmission upgrades in the Lakes Region. This transmission project is proposed by Central Maine Power Company ("CMP"). CMP has filed for a Certificate of Public Convenience and Necessity ("CPCN") for the proposed transmission enhancements and its filing states that this project is needed to resolve reliability concerns. La Capra Associates performed an independent reliability assessment and developed Alternative Resource Configurations ("ARCs") that could serve as NTAs and adequately address the reliability issues over the 2015 to 2030 planning horizon for this project. La Capra Associates also performed a life-cycle economic analysis of the ARCs versus the transmission project.
4. Maine Public Utilities Commission ("MPUC") retained La Capra Associates, Inc. ("La Capra Associates") to evaluate possible non-transmission alternatives ("NTAs") to a proposed transmission substation and other ancillary transmission upgrades in the Waterville-Winslow Region. This transmission project is proposed by Central Maine Power Company ("CMP"). CMP has filed for a Certificate of Public Convenience and Necessity ("CPCN") for the proposed transmission enhancements and its filing states that this project is needed to resolve reliability concerns. La Capra Associates performed an independent reliability assessment and developed Alternative Resource Configurations ("ARCs") that could serve as NTAs and adequately address the reliability issues over the 2015 to 2030 planning horizon for this project. La Capra Associates also performed a life-cycle economic analysis of the ARCs versus the transmission project.

5. Reviewed the Application of Rocky Mountain Power seeking approval from the Public Service Commission of Utah to increase electric rates. The scope of the assignment was to review the proposed additions to plant in-service
6. Performed an audit of Rocky Mountain Power Company's 2013 Energy Balancing Account, including a review of the Company's hedging program.
7. Performed an asset valuation to estimate the market value of all power plants owned by Public Service of New Hampshire. Presented results to the New Hampshire Public Utilities
8. Reviewed a proposed Default Service Procurement Plan for PECO Energy for 2015-2017
9. Reviewed a proposed Default Service Procurement Plan for PPL Electric Utilities for 2015-2017
10. Reviewed a request by Wisconsin Public Service to increase retail rates.
11. Reviewed and analyzed a proposed tariff and related documents for Rhode Island to acquire street lighting assets owned by NGRID. Presented findings to the Rhode Island Public utilities Commission.
12. Analyzed a proposed interconnection of a 30mw off-shore wind project to the ISO New England grid. Presented findings to the Rhode Island Public Utilities Commission
13. Reviewed NGRID's 2014 Electric Retail Rate Filing requesting Commission approval of various charges and adjustment factors as well as NGRID's 2014 RES Charge and Reconciliation filing.
14. Reviewed proposed TOU rates by PPL Electric on behalf of the Pennsylvania Office of Consumer Advocate
15. Performed an analysis of a proposal to convert the Valley Power Plant in Milwaukee to switch from coal to natural gas; included a reliability assessment of the need for the plant to maintain local reliability
16. Reviewed the adequacy of the supply of renewable energy certificates for 2015 and 2016 for impact on the Rhode Island Renewable Energy Standard
17. Reviewed a purchased power agreement between National Grid and Champlain / Bowers Wind for the Rhode Island Division of Public Utilities and Carriers
18. La Capra Associates was retained by the Nova Scotia Small Business Advocate to review and analyze the 2013 Annual Capital Expenditure ("ACE") Plan for Nova Scotia Power Incorporated ("the Company" or "NSPI"). I served as a key member of the team responsible for reviewed transmission projects.
19. Served as an advisor to the Belmont Municipal Light Department in its efforts to upgrade its transmission interconnection to 115KV.
20. Performed an assessment of the proposed merger of Peoples Natural Gas and Equitable Gas Company for the Pennsylvania Office of Consumer Advocate.
21. Reviewed the proposed default service procurement of UGI Utilities to procure standard offer service power supplies for its non-shopping customers for 2014 to 2017.
22. Performed an audit of Rocky Mountain Power Company's 2012 Energy Balancing Account, including a review of the Company's hedging program.

23. Reviewed a request by Wisconsin Public Service to implement the System Modernization and Reliability Project, a large-scale capital program to improve system reliability in Northern Wisconsin.
24. Served as a member of a La Capra Associates team advising the Arkansas Public Service Commission Staff regarding Entergy's Application to transfer ownership of transmission assets to ITC.
25. Reviewed and analyzed NGRID proposed 2013 LTCRER factor; provided written comments to RI PUC.
26. Reviewed Rocky Mountain Power Company's Energy Balancing Account filing for 2011; filed testimony before the Utah PSC.
27. Reviewed NGRID proposed tariff revisions for recovery of Long-Term Renewable Energy Contracts; provided written comments to RI PUC.
28. Analyzed proposed environmental upgrades to the Flint Creek coal unit in Arkansas; filed written testimony before the Arkansas PSC.
29. WI CUB WEPCO 2013 Rate Case; review prudence of capital and fuel costs; filed written testimony before the Wisconsin PSC.
30. Reviewed and analyzed a request for an Advanced Determination of Prudence for a new wind generation facility; filed written testimony before the North Dakota PSC.
31. Reviewed proposed 2013 -2015 Default Service Procurement Plan for PPL Utilities; filed written testimony before the Pennsylvania PUC.
32. Analyzed forecast of projected capital additions to plant in service for forward-looking test year in Utah rate case. Filed testimony before the Utah Public Service Commission.
33. Review and analysis of National Grid's proposed 2013 Standard Offer Service and Renewable Energy Standard procurement plan on behalf of the Rhode Island Division of Public utilities and Carriers.
34. Review and analysis of National Grid's proposed long term renewable contracting plan on behalf of the Rhode Island Division of Public utilities and Carriers.
35. Review and analysis of a long-term renewable energy contract between Black Bear Hydro and National Grid on behalf of the Rhode Island Division of Public Utilities and Carriers.
36. Reviewed proposed 2013 -2015 Default Service Procurement Plan for PECO Energy on behalf of the Pennsylvania Office of Consumer Advocate.
37. Review National Grid’s 2012 Electric Retail Rate Filing requesting Commission approval of various charges and adjustment factors for the Rhode Island Division of Public Utilities and Carriers.
38. Analyzed the request to the Wisconsin Public Service Commission for a CPCN for the Hampton - Rochester - La Crosse Baseline Reliability Project.
39. Performed an assessment of the TOU rates proposed by PPL Electric Utilities before the Pennsylvania Public Utilities Commission; Presented expert testimony providing the results of that assessment.
40. Reviewed the proposed merger between Exelon and Constellation Energy for its impact on market power; filed testimony before the Pennsylvania Public Utilities Commission.

41. Reviewed the proposed merger between Exelon and Constellation Energy for its impact on market power; filed testimony before the Federal Energy Regulatory Commission and the Maryland Public Service Commission.
42. Conducted an assessment of the request to the North Dakota Public Service Commission for an Advanced Determination of Prudence for the Montana Dakota Utilities GT; filed testimony before the North Dakota Public Service Commission.
43. Conducted an assessment of the request to the North Dakota Public Service Commission for an Advanced Determination of Prudence for the Big Stone Air Quality Control System; filed testimony before the North Dakota Public Service Commission.
44. Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Wisconsin Electric Power; filed testimony before the Public Service Commission of Wisconsin.
45. Analyzed proposed ceiling prices for Distributed Generation procurement for the Rhode Island Division of Public Utilities and Carriers in Docket 4288.
46. Reviewed proposed changes to National Grid's interconnections standards for the Rhode Island Division of Public Utilities and Carriers in Docket 4276.
47. Reviewed proposed changes to National Grid's Distributed Generation Enrollment Process for the Rhode Island Division of Public Utilities and Carriers in Docket 4277.
48. Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Northern States Power Wisconsin; filed testimony before the Public Service Commission of Wisconsin.
49. Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Madison Gas & Electric; filed testimony before the Public Service Commission of Wisconsin.
50. Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Wisconsin Public Service; filed testimony before the Public Service Commission of Wisconsin.
51. Reviewed the proposed merger between Duke Energy and Progress Energy for compliance with merger approval standards and the impact of the merger on customers; filed testimony before the North Carolina Public Utilities Commission and the South Carolina Public Service Commission.
52. Analyzed the De-List Bid submitted by Vermont Yankee in ISO-NE capacity auctions. Filed statement at FERC presenting the results of that assessment.
53. Performed an assessment of a proposal by Nova Scotia Power to increase spending on vegetation management activities as part of the 2012 rate case; filed testimony before the Nova Scotia Utility and Review Board.
54. Reviewed and analyzed a proposed Purchased Power Agreement between National Grid and Orbit Energy; filed testimony before the Rhode Island Public Utility Commission in Docket 4265.
55. Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Ascutney Vermont.
56. Reviewed and analyzed NGRID proposed SOS procurement plan and RES Compliance plan for 2012; provided testimony before the Rhode Island Public Utility Commission in Docket 4227.

57. Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Bennington Vermont.
58. Prepared follow-on analysis of Utah resource acquisition in rate case in Docket 10-035-124
59. Reviewed and analyzed a proposed retail rate increase by Fitchburg Gas and Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Spending Plan, and an accompanying recovery mechanism.
60. Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Georgia, Vermont.
61. Reviewed and analyzed damages claimed in litigation between a developer of renewable energy facilities and the owner of the host site.
62. Evaluated the decision of PacifiCorp to acquire new generating resources in Utah. Filed testimony before the Public Service Commission of Utah.
63. Served as a principal advisor and key team member in La Capra Associates' assessment of strategic options for Entergy Arkansas, Inc. subsequent to its withdrawal from the Entergy System Agreement.
64. Reviewed the issues and documentation related to a complaint regarding the net metering issues for the Portsmouth Wind Turbine for the Rhode Island Divisions of Public Utilities and Carriers
65. Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Jay, Vermont.
66. Reviewed and evaluated the construction of and cost recovery for a large cogeneration plant for a mid-west utility; utilized heat balance analysis to develop new cost allocators between steam and electric sales.
67. Analyzed fuel costs, market sales and revenues, capacity position, and performance parameters for a large- mid-west utility.
68. Performed a review and analysis of the proposed merger between FirstEnergy and Allegheny Energy. Provided expert testimony before the FERC and the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
69. Performed a study of non-transmission alternatives to a proposed transmission project in the Lewiston-Auburn area of Central Maine Power Company's service territory. Testified before the Maine Public Utilities Commission.
70. Analyzed a proposed plan by National Grid to procure 2011 default service power supplies and comply with Renewable Energy Standards. Provided expert testimony before the Rhode Island Public Utilities Commission in Docket 4149.
71. Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for PECO Energy.
72. Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for PPL Electric Utilities.
73. Analyzed a purchase power agreement between National Grid and on offshore wind project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.

74. Reviewed and analyzed a proposed retail rate increase by Western Massachusetts Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Plan, and an accompanying recovery mechanism.

75. Served as an advisor to the developer of a utility-scale Solar PV facility in Massachusetts.

76. Evaluated a proposed Solar PV installation for a large retail customer in Massachusetts. Performed an analysis of the appropriate rate of return and its impact on facility electric costs and financial feasibility.

77. Assessed the economic impact of an additional interconnection between ISO-NE and NYISO; analyzed impact on market prices and congestion.

78. Reviewed and analyzed the capacity position of a large mid-west utility and the impact of that position on electric rates.

79. Performed an economic evaluation of a proposed transmission line in New England. Assessed the project's ability to deliver renewable energy to load centers and the impact of the project on Locational Marginal Prices.

80. Analyzed a proposed interconnection of a large new industrial load in Massachusetts. Evaluated proposed substation configuration and developed alternatives that achieved comparable reliability at lower costs. Assessed cost recovery options.

81. Reviewed the Energy Efficiency and Conservation Programs proposed by Pennsylvania Power & Light in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.

82. Reviewed the Energy Efficiency and Conservation Programs proposed by Philadelphia Electric Company in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.

83. Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Rhode Island Public Utilities Commission. Provided expert testimony before the Rhode Island Public Utilities Commission regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan

84. Reviewed and analyzed Time-of-Use rates proposed by Pennsylvania Power & Light. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding compliance with Commission requirements, rate design, cost recovery, and consumer education issues.

85. Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and it's Facilities Plan.

86. Performed a review and analysis of the proposed merger between Exelon and NRG. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.

87. Reviewed the needs analysis and load forecast supporting a proposed Transmission Project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.

88. Performed an assessment of plans to procure Default Service Power Supplies for a Rhode Island utility. Provided expert testimony before the Rhode Island Public Utilities Commission.

89. Served as an advisor to Vermont electric utilities regarding the evaluation of new power supply alternatives. Developed and applied a probabilistic planning tool to model uncertainty in costs and operating parameters.

90. Conducted a review of Massachusetts Electric Company's proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.

91. Conducted a review of Western Massachusetts Electric Company's proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.

92. Served as a key member of a La Capra Associates Team evaluating wind generation RFPs in Oklahoma.

93. Performed an assessment of plans to procure Default Service Power Supplies for Pennsylvania utilities. Provided expert testimony before the Pennsylvania Public Utilities Commission.

94. Performed an assessment of a merchant generator proposal to construct, own, and operate 800 MW of large scale PV solar generating units in Maine.

95. Analyzed proposed environmental upgrades to the Columbia Energy Center coal-fired generating station in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.

96. Analyzed proposed environmental upgrades to the Edgewater 5 coal-fired generating unit in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.

97. Analyzed proposed environmental upgrades to the Oak Creek coal-fired generating units in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.

98. Reviewed Pennsylvania Act 129 and Commission rules for Energy Efficiency Plans

99. Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Maine.

100. Served as a key member of the La Capra Associates Team advising the Connecticut Energy Advisory Board (CEAB) on a wide range of energy issues, including integrated resources plan and the need for and alternatives to new transmission projects.

101. Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Vermont.

102. Served as an advisor to the Delaware Public Service Commission and three other state agencies in the review of Delmarva Power & Light's integrated resource plan and the procurement of power supplies to meet SOS obligations.

103. Served as an expert witness in litigation involving a contract dispute between the owner of a merchant powerplant and the purchasers of the output of the plant.

104. Served as an advisor to the Maryland Attorney General's Office in the proposed merger between Constellation Energy and the FPL Group.

105. Reviewed and analyzed outages for Connecticut utilities during the August 2006 heat wave. Prepared an assessment of utility filed reports and corrective actions.

106. Conducted a study of required planning data and prepared forecasts of the key drivers of future power supply costs for public power systems in New England.

107. Reviewed and analyzed Hawaiian Electric Company integrated resource plan and its DSM programs for the State of Hawaii. Prepared written statement of position and testified in panel discussions before the Hawaii Public Utility Commission.

108. Assisted the Town of Hingham, MA in reviewing alternatives to improve wireless coverage within the Town and to leverage existing telecommunication assets of the Hingham Municipal Light Plant.

109. Conducted an extensive study of distributed generation technologies, options, costs, and performance parameters for VELCO and CVPS.

110. Analyzed and evaluated proposals for three substations in Connecticut. Prepared and issued RFPs to seek alternatives in accordance with state law.

111. Performed an assessment of merger savings from the First Energy – GPU merger. Developed a rate mechanism to deliver the ratepayers share of those savings. Filed testimony before the PA PUC.

112. Prepared long term price forecasts for energy and capacity in the ISO-NE control area for evaluating the acquisition of existing powerplants.

113. Conducted an assessment of market power in PJM electricity markets as a result of the proposed merger between Exelon and PSEG. Developed a mitigation plan to alleviate potential exercise of market power. Filed testimony before the PA PUC.

114. Performed a long-term locational installed capacity (LICAP) price forecast for the NYC zone of the NYISO control area for generating asset acquisition.

115. Served as an Independent Evaluator of a purchase power agreement between a large mid-west utility and a very large cogeneration plant. Evaluated the implementation of amendments to the purchase power agreement, and audited compliance with very complex contract terms and operating procedures and practices.

116. Performed asset valuation for energy investors targeting acquisition of major electric generating facility in New England. Prepared forecast of market prices for capacity and energy products. Presented overview of the market rules and operation of ISO-NE to investors.

117. Assisted in the performance of an asset valuation of major fleet of coal-fired electric generating plants in New York. Prepared forecast of market prices for capacity and energy

products. Analyzed cost and operations impacts of major environmental legislation and the effects on market prices and asset valuations.

118. Conducted an analysis of the cost impact of two undersea electric cable outages within the NYISO control area for litigation support. Reviewed claims of cost impacts from loss of sales of transmission congestion contracts and replacement power costs.

119. Reviewed technical studies of the operational and system impacts of major electric transmission upgrades in the state of Connecticut. Analysis including an assessment of harmonic resonance and type of cable construction to be deployed.

120. Conducted a review of amendments to a purchased power agreement between an independent merchant generator and the host utility. Assessed the economic and reliability impacts and all contract terms for reasonableness.

121. Assisted in the development of an energy strategy for a large Midwest manufacturing facility with on-site generation. Reviewed electric restructuring rules, electric rate availability, purchase & sale options, and operational capability to determine the least cost approach to maximizing the value of the on-site generation.

122. Assisted in the review of the impact of a major transmission upgrade in Northern New England.

123. Negotiated a new interconnection agreement for a large hotel in Northeastern Massachusetts.

SELECTED EXPERIENCE – NSTAR ELECTRIC & GAS

President & COO of NSTAR Unregulated Subsidiaries

Concurrently served as President and COO of three unregulated NSTAR subsidiaries: Advanced Energy Systems, Inc., NSTAR Steam Corporation, and NSTAR Communications, Inc.

Advanced Energy Systems, Inc.

- Responsible for all aspects of this unregulated business, a large merchant cogeneration facility in Eastern Massachusetts that sold electricity, steam, and chilled water. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Steam Corporation

- Responsible for all aspects of this unregulated business, a district energy system in Eastern Massachusetts that sold steam for heating, cooling, and process loads. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Communications, Inc.

- Responsible for all aspects of this unregulated business, a start-up provider of telecommunications services in Eastern Massachusetts. Duties included management, operations, finance and accounting, sales, and P&L responsibility.
- Established a joint venture with RCN to deliver a bundled package of voice, video, and data services to residential and business customers. Negotiated complex indefeasible-right-to-use and stock conversion agreements.
- Installed 2,800 miles of network in three years. Built capacity for 230,000 residential and 500 major enterprise customers.
- Testified before the Congress of the United States on increasing competition under the Telecommunications Act of 1996.

VP, Technology, Research, & Development, Boston Edison Company

- Responsible for identifying, evaluating, and deploying technological innovation at every level of the business.
- Reviewed Electric Power Research Institute (EPRI), national laboratories, vendor, and manufacturer R&D sources. Assessed state-of-the-art electro-technologies, from nuclear power plant operations to energy conservation.

VP of Marketing, Boston Edison Company

- Promoted and sold residential and commercial energy-efficiency products and customer service programs.
- Conducted market research to develop an energy-usage profile. Designed a variable time-of-use pricing structure, significantly reducing on-peak utilization for residential and commercial customers.
- Designed and marketed energy-efficiency programs.
- Established new distribution channels. Negotiated agreements with major contractors, retailers, and state and federal agencies to promote new energy-efficient electro-technologies.

Vice President, Energy Planning, Boston Edison Company

- Responsible for energy-usage forecasting, pricing, contract negotiations, and small power and cogeneration activities. Directed fuel and power purchases
- Implemented an integrated, least-cost resource planning process. Created Boston Edison's first state-approved long-range plan.
- Assessed non-traditional supply sources, developed conservation and load-management programs, and purchased from cogeneration and small power-production plants.
- Negotiated and administered over 200 transmission and purchased power contracts.
- Represented the company with external agencies. Served on the Power Planning Committee of the New England Power Pool.
- Testified before federal and state regulatory agencies.

EMPLOYMENT HISTORY

La Capra Associates, Inc. **Boston, MA**
Principal Consultant 2004 – present

Advanced Energy Systems, Inc. **Boston, MA**
President and COO 2001-2003

NSTAR Steam Corporation **Cambridge, MA**
President and COO 2001-2003

NSTAR Communications, Inc.
President and COO 1995-2003

Boston Edison Company Boston, MA

VP, Technology, Research, & Development	1993-1995
VP, Marketing, Boston Edison Company	1991-1993
Vice President, Energy Planning, Boston Edison Company	1987-1991
Manager, Supply & Demand Planning	1984-1987
Manager, Fuel Regulation & Performance	1982-1984
Assistant to Senior Vice President, Fossil Power Plants	1981-1982
Division Head, Information Resources	1978-1981
Senior Engineer, Information Resource Division	1977-1978
Assistant to VP, Steam Operations	1976-1977
Electrical Engineer, Research & Planning Department	1973-1976

EDUCATION

Boston College Boston, MA
Masters in Business Administration 1982

Northeastern University Boston, MA
Masters in Science, Electrical Engineering 1974

Northeastern University Boston, MA
Bachelors in Science, Electrical Engineering 1973

PROFESSIONAL AFFILLIATIONS

Director, La Capra Associates, Inc.	2005-2015
Director, NSTAR Communications, Inc.	1997-2003
Director, Advanced Energy Systems, Inc.	2001-2003
Director, Neuco, Inc.	2001-2003
Director, United Telecom Council	1999-2003
Head, Business Development Division, United Telecom Council	2000-2003
Elected Commissioner – Reading Municipal Light Board	2005-2012
Registered Professional Electrical Engineer in Massachusetts	