BEFORE THE
UNITED STATES OF AMERICA
FEDERAL ENERGY REGLATORY COMMISSION

Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators	))	Docket No. AD13-7-000

COMMENTS OF
SUSAN F. TIERNEY, Ph.D.
Managing Principal, Analysis Group

On her own behalf

Considerations for the Future of Centralized Capacity Markets

September 9, 2013

INTRODUCTION

Thank you for the opportunity to comment on potential future directions for centralized capacity markets as a resource adequacy mechanism in three Regional Transmission Organizations ("RTOs"), PJM, New York and New England.[*] This is an important issue affecting wholesale markets that supply 30 percent of the population of the U.S.[1] I commend the Commission for calling attention to it through today's Technical Conference.

I urge the Commission to continue to question whether current centralized capacity market designs in the Northeast are capable of supporting the procurement and retention of resources necessary to meet future reliability and operational needs in light of the significant changes underway in the electric industry. In my comments today, I explain why I think that today's capacity market designs in at least two of the regions (the RTOs serving the Northeast states of New York and New England) need further reforms to accomplish that goal. Before answering the Commission's specific questions, I set the overall context for my remarks.

As the Commission recognized in its notice for this Technical Conference, the changing resource mix in the Northeast will pose different reliability and operational challenges in the future. In my view, however, we don't need to wait for the future to see that changes are needed. Already, the nation's abundant supply of natural gas has created pressures in the market even as it has also produced significant value for consumers and the economy. Already, public policies have introduced substantial efficiencies and clean energy resources into the market, creating significant benefits but also introducing new kinds of challenges for the overall system. Already, we see increased extreme weather events testing the ability of grid operators, power suppliers and delivery companies to maintain and restore electric service at levels consistent with consumer expectations. Already, we see that in a market that depends upon the flow of private capital and diversity in the asset mix, some suppliers of capacity resources (including demand-response and nuclear generation) have recently decided that the markets are not producing financial outcomes consistent with the requirements of private capital markets.

In short, this situation needs focused attention sooner, rather than later. That's why I appreciate that the Commission called for this Technical Conference. While today's focus is on centralized capacity markets, they are part of a larger fabric. That larger context is one where we continuously expect our electric industry to solve a complex 'simultaneous equation' in which

[*] Although I have consulted to a wide variety of stakeholders with interests in many parts of the U.S., including Northeast wholesale and retail electric markets, I am speaking for no one but myself in my comments today. My clients have included RTOs, transmission and distribution utilities, generating companies and project developers, interstate pipeline companies, electricity and natural gas consumers, state government agencies, environmental groups, foundations, Indian tribes, associations, and others. I was previously and am no longer a director of EnerNOC, Inc. I currently serve on several advisory commissions and am on the boards of several non-governmental organizations involved with clean energy issues. I was previously a senior government official in Massachusetts and at the U.S. Department of Energy. In my comments, I am speaking for no one besides myself.

the countless decisions of myriad actors need to produce a reliable, efficient and increasingly clean supply of electricity for the region.

At the moment, we've not on track to solve that 'simultaneous equation' in a sustainable way, at least in New York and New England, two regions with which I am quite familiar. I say that 'we're not on track' without meaning to criticize those regions or the specific stakeholders in them for their aspirations for competitive markets, for clean energy outcomes, or for the provision of reliable electricity supply. In fact, I stand firmly in support of all of those objectives. Rather, I want to point out that in order to accomplish the things that policy makers, consumers, investors, asset owners, power suppliers, grid operators, utilities, and others hope to achieve through their electricity markets, something has to give.

The 'simultaneous equation' challenge results naturally from countless situations where each party[2] acts to advance his or her own particular interests. This is the classic presumption of the "genius" of markets, of course. But this approach, combined with the particular character of wholesale *electricity* markets in the Northeast RTOs (with their mix of competition among market participants to provide an essential service; RTO stakeholder processes resembling legislative processes where negotiations sometimes have to split the differences; and states' exercising their authority to advance their individual state-centric aspirations) can lead to unintended consequences, externalities of one form or another, and situations where the sum of the parts end up undermining the health of the system as a whole.

Something has to change for the numbers to support a sustainable, healthy and vibrant electric industry capable of meeting system operators' technical necessities, consumers' implicit needs, policy makers' explicit demands, and investors' inherent requirements. That entire equation must be satisfied, or the system isn't sustainable.

The Commission has a critical role in examining what is needed to assure a well-functioning and healthy wholesale electric industry in the Northeast. The very fact of today's Technical Conference suggests the possibility that the Commission might decide to exercise its authority creatively to solve new problems in new ways (just as it did, for example, in Order 1000, when it required transmission providers to consider in their transmission plans the implications of public policy requirements established by state or federal law or requirements).

The Northeast wholesale markets administered by NYISO and ISO-NE are one area where considerable creativity is warranted, and concentrated and deliberate effort is needed to reform capacity market design. This is critically important if those regions want to ensure a vibrant competitive market as the means to accomplish the reliable, efficient and clean energy outcomes that policy makers, consumers, and investors require.

To illustrate the essential character of the challenge, let me describe why I worry that a singular focus of attention on using capacity markets only to supply the "missing money" will not

produce a system that satisfies the overall 'simultaneous equation' challenge. Solving the missing money problem is necessary but not sufficient. It is not sufficient, as long as short-run markets (i.e., operating markets for energy and ancillary services, and elements of capacity markets tied to operational performance of assets) in combination with current capacity markets in the Northeast together do not compensate for attributes necessary for system operators or for policy makers or investors on *both* a near-term and sustainable long-term basis.

Think about the scenario that reflects the economic, policy, technical, technological, and market realities of the Northeast's electricity systems:

a. Public policies that point to reliance on a set of generating resources that emits increasingly fewer carbon pollution and increasingly quantities of renewable energy – and which have already led to a system which already rests predominantly on natural-gas-fired capacity, nuclear generation, renewable energy, and demand-side resources;[3]
b. An outlook for flat demand, in light of the states' commitment to pursuing cost-effective energy efficiency and supporting distributed generation;[4]
c. Low natural gas prices resulting from the nation's shale gas 'revolution,' with an outlook for continued relatively low gas prices for the foreseeable future;[5]
d. An generating fleet that relies on natural gas and a market design that causes natural gas to set prices in the vast majority of hours in the short-term electricity product markets;[6]
e. An increasing set of zero-carbon resources that tend to be price takers, contributing to price suppression in the operating product markets;
f. An overall asset mix that will tend toward lower levels of capacity utilization (e.g., with more renewable resources, whose intermittency leaves them with lower capacity factors; and with need for the system's dispatchable resources to operate less as they provide less energy overall and increasingly supply balancing services for non-dispatchable renewable energy);
g. A technological toolkit that does not yet allow for sufficient commercially available and competitively priced electricity storage and/or load-shifting capabilities to help mitigate the asset-utilization problem any time soon;
h. A market where even suppliers of low-carbon resources (demand-response services provided by EnerNOC and nuclear generation provided by Vermont Yankee) have recently decided to exit New England's market and thus leave region even more reliance on natural gas for capacity resources;[7] and
i. A system which, in the end, needs to produce sufficient revenues across all short-term and long-term product markets and across an adequate base of resource suppliers in ways that meet the requirements of private investors on which virtually the entire asset base depends.

In this scenario, there needs to be reform of the markets overall, including the capacity markets, to support continued commitment of capital to flow into this region. Those reforms must also focus on means to produce the varied types of attributes that will be needed in the system's electrical resource tool kit.

In theory, one could imagine such reforms occurring in short-term markets instruments (e.g., operational performance incentives, on top of energy and traditional ancillary services). (ISO-NE, for example, is clearly attempting to address some performance issues through its proposed "Forward Capacity Market – Performance Incentive" ("FCM-PI").[8]) But even assuming some (or major) improvement in capacity suppliers' operating performance during tight conditions, it's hard to imagine that short-term product markets will suffice to resolve the 'simultaneous equation' challenge in a sustainable way. Relying on short-term product markets (whether in New England, or New York, or other places, for that matter) requires that both:

- The *design* of new operating-market instruments will work to support investor compensation expectations, so as to retain and/or induce entry of the suite of assets needed to meet the multiple technical, operational, policy, and economic goals of stakeholders; and
- The *implementation* of those operating product markets will act in ways that allow for scarcity prices to rise sufficiently high for investors' returns without invoking reactions from market monitors and regulators (and the imposition of market-power mitigation measures that dampen such prices) and/or from politicians (demanding that such sufficiently high scarcity prices not be permitted to occur).

This challenge of both design *and* implementation seems particularly daunting as the impact of increasingly lower asset-utilization factors is felt over time and asset owners realize fewer sales into operating product markets.

In the end, I am skeptical that we can crack the simultaneous equation through sharpening the tools in the operating markets alone. It seems wise also to consider the option of using reformed capacity markets as a way to deal with the missing money issue, the "system attribute" issue, and the resource adequacy challenges of a system with low asset utilization.

The rest of my comments focus on the Commission's three questions addressed to members of the Technical Conference's panel on "considerations for the future." In essence, I urge the Commission to recognize that currently, the Northeast's centralized capacity markets do not point us to sustainable outcomes, given the larger context of wholesale power market rules, practical bulk-power system operations, state and federal policy imperatives, consumer expectations, and private investor requirements. A strong investment climate is essential to the solving the simultaneous equation, because it underpins the ability of the Northeast region to provide what its consumers and policy makers want: an electric system with adequate investment, competition, innovation, efficient and secure energy production and delivery, and clean energy attributes.

I strongly encourage the Commission to entertain and consider proposal to reform centralized capacity markets to help ensure that strong investment climate as part of the outcomes consistent with the demands of the changing electric system in the Northeast.

RESPONSES TO COMMISSION QUESTIONS ON THE FUTURE OF CENTRALIZED CAPACITY MARKETS

Q1: What are the main challenges facing centralized capacity markets today or that can be anticipated going forward? Are the current centralized capacity market designs able to effectively manage those challenges? If not, what change in current design elements should be pursued going forward?

This question only implicitly recognizes that centralized capacity markets in the Northeast are part of a larger wholesale market context. It's hard to assess the performance of capacity markets in isolation, without addressing their interplay with other market elements and factors affecting those markets.

As such, my answer to the Commission's first question starts by discussing challenges that arise from two clusters of influences today and going forward: (1) factors internal to particular RTOs ("Internal RTO Market Factors"); and (2) external forces shaping the character of market outcomes and the ability of current centralized capacity markets to manage those challenges ("External Market Factors"). I discuss each cluster, and note the important fact that no two regions – not even those as closely connected as New York's and New England's – have organized and evolved their markets in identical ways. I note, too, my view that wholesale competitive markets in the Northeast have delivered value to consumers, but must adapt to the combination of internal factors and external influences in order to continue to do so.[9]

Internal RTO Factors Creating Challenges for Northeast Capacity Markets: The Commission knows well that competitive wholesale markets in the Northeast include multiple elements: energy markets, provision of ancillary services through markets and other mechanisms, assurance of resource adequacy in part through capacity markets, open access transmission, market monitoring and mitigation, RTO governance, and primary reliance on private investment.

Starting from the premise that resource adequacy depends upon private investment (and in turn, on investor confidence in the markets), it seems to me that one critical success factor for centralized wholesale market design and implementation is that it can produce "enough" revenue to keep and attract a combination of assets capable of providing supply consistent with the 'simultaneous equation' I described above. (This presumes, of course, that the system also depends upon private investment on the retail side and customer-side of the meter.) Across all of the resources needed to meet load and reserve requirements at essentially all times, the dollars and cents have to add up.

Capacity markets arise in first instance because of the "missing money problem."[10] Resource adequacy fundamentally requires that some amount of capacity stands in reserve (above expected demand), does not operate around the clock or even very often, and, except for the presence of genuine scarcity pricing from time to time, expects to recover little compensation in short-term operating markets. Legitimate costs to stay open for business include the need to

recover return of and on investment, in addition to any fixed or variable operating costs, over the long run. If spot prices in energy and ancillary services markets do not or cannot rise to cover costs of capacity held in reserve and not operating much or at all, then the "missing money" must be provided somehow if that capacity is to remain in (or enter) the market. Capacity markets have been designed, in theory, to provide for this purpose.

But in current and anticipated future conditions in the Northeast, the markets are not cooperating with that premise. The same underlying factors that contributed over time to the region's high dependence on natural gas for power generation also mean that clearing prices in short-term operating markets are relatively low. This effect is exacerbated by several external conditions (which I describe in "External Market Factors," below) and internal RTO market rules and practices that – in the view of ISO-NE's External Market Monitor ("ISO-NE EMM") – contribute to energy prices that do not reflect fully the cost of providing power and thus under-compensate suppliers for their contribution to the market.[11]

Examples from New England include:

- not allowing the full costs of fast-start resources or demand-response resources into the calculation of hourly energy prices during tight market operating conditions;
- averaging prices over an hour rather than on sub-hourly time frames during such periods;
- committing out-of-merit order dispatchable plants at minimum level to maintain their ability to provide ramping capability for system security, and committing additional non-gas-dependent capacity at times for system reliability, both of which "can often lead to significant surplus capacity in real time, which tends to depress energy and ancillary services prices in the real-time market;"[12]
- not allowing power plants maintained on the system for reliability purposes (e.g., through reliability must-run agreements) to be included in the calculation of energy prices;
- using a "vertical demand curve" in the forward capacity market, leading to a tendency to drive capacity prices (and payments to capacity suppliers) to very low levels during even modest, let alone high, capacity surplus conditions;[13]
- not yet providing sufficient incentives (through the combination of forward capacity markets and operating markets) to cause capacity-suppliers to perform at times of scarcity conditions.

(ISO-NE is urgently trying to address the latter issue. Through its proposed FCM-PI mechanism, ISO-NE hopes to create financial incentives for capacity suppliers who receive payments from centralized capacity markets to supply actively in energy and ancillary service markets during scarcity conditions (such as arise in the face of constraints on the real-time delivery of natural gas), with penalties for suppliers that cannot be dispatched and bonus payments to suppliers who can.[14] More broadly, ISO-NE has a work plan to tackle a number of other strategic issues ISO-NE has identified as most important to the region.[15])

Such market rules and practices send inappropriately low price signals through market revenues to suppliers of capacity. As the ISO-NE EMM concludes, the revenues in New England markets will not support entry of new generation, and they in fact inhibit the exit of

resources as well. "Before the current surplus of capacity declines, it will be important to put in place market reforms that will enable the FCM to facilitate the efficient entry and exist of capacity resources."[16]

Note that the external market monitor for NYISO also concluded in the most recent State of the Market Report, that "estimated net revenues [from all NYISO markets] were well below the estimated CONE [cost of new entry] values in both 2011 and 2012 for both combustion turbines and combined cycles at the locations for which such estimates were made. In 2012, for a new combustion turbine unit, estimated net revenues were lower than the estimated CONE by 71 percent in the capital zone, 45 percent in New York City, and 31 percent in Long Island. For a new combined cycle unit, estimated net revenues were lower than the estimated CONE by 28 percent in New York City."[17] I note that NYISO has recently moved to create a new capacity zone in the area north of NYC (and south of the capital zone), in order to address some of the missing money issues.

A dispute in New York's market also illustrates tensions regarding the market rules and prices that result from them: in a docket currently open before the Commission, the Independent Power Producers of New York ("IPPNY") have contested NYISO;s requirement that generators with a local-reliability must-run contracts bid into the capacity market at a zero-price offer, with IPPNY having raised the concern that this policy inappropriately depresses prices in the capacity market.[18] On the other side is NYISO, its market monitor and others suggesting that because such units are needed for reliability purposes, they represent economic supply and should therefore participate in the forward capacity market and bid in in this way. Because the issue is currently unresolved and before the Commission, let me simply offer this as an example of a disputed market practice with significant implications for the ability of a centralized capacity market to provide the missing money.

In pointing out these concerns, my intention is not to point fingers, but rather to call attention to the pragmatic reality that the capacity market is not producing the missing money. These and other practices combine with the market external market conditions, described below, to squeeze revenues to competitive suppliers across the combination of markets, and to render the situation largely challenging, if not unsustainable.

While addressing such issues is clearly important, there are also other capacity (and other) market reforms that warrant attention, sooner rather than later, especially in light of current external market conditions.

External Market Factors Creating Challenges for Centralized Capacity Markets: The challenges facing centralized capacity markets have become more prominent, in part as a result of the complex economic, technological, policy, environmental, socio-economic, and political realities of today's electric markets in the Northeast.

In New York and New England, owners and operators of power plants and the electric grid have to supply power much more nimbly and in the face of new challenges than in the past. Again, affecting virtually all of those trends is the outlook for natural gas. Although low natural gas prices have provided gains to consumers and to the larger economy, such prices

add to a demanding set of conditions in competitive wholesale power markets, leading to inadequate contribution to capital recovery for their owners.[19] This is true for many types of capacity assets, regardless of technology or fuel (and even in PJM,[20] as well as in NYISO and ISO-NE markets). In the Northeast, in particular, virtually all power plants are owned by non-utility companies, whose shareholders bear the full financial risks associated with earning a profit on their capital investments.[21]

These external market challenges spring from many fundamental changes underway, including:

- the American economy's/society's deepening reliance on electricity, with the value of reliable power supply far exceeding the actual cost of supply;
- the increasing exposure of critical energy infrastructure to extreme weather events playing particular havoc on transmission lines carrying power from far-flung generation resources to consumers;
- the need to introduce pollution controls on many of the nation's dirtiest existing power plants and to reduce overall emissions from electricity production ;
- retirements of many of the oldest and least-efficient fossil-fuel power plants;
- more and more electricity supply coming from non-dispatchable renewable power projects whose output varies with changes in wind and solar radiation conditions;
- the requirement that other power plants turn on and off more frequently to balance out the supplies needed to meet customers' demand; and
- the need to invest in the electric transmission and distribution infrastructure to make it more modern and resilient, less prone to cyber-attack, and more capable of meeting long-term demand and supply requirements in a more complex operating environment.

Given low natural gas prices at present and for the foreseeable future, virtually all types of power plants in competitive wholesale power markets face significant financial and economic pressure. Some – such as the least efficient and oldest coal-fired power plants – are already shutting down.[22] And owners of others – such as nuclear plants (e.g., Entergy's Vermont Yankee) – have decided that market conditions provide inadequate revenues in an investment climate that promises little relief.[23] New renewable projects face large economic hurdles, too, in light of historically low electricity market prices influenced substantially by natural gas prices (as well as expected changes in federal tax policy supporting entry of renewable projects).

Although less directly influencing wholesale prices, but important in the overall context for today's electric industry, are two other realities. First, countervailing pressures exist on the customer side of the equation. In the U.S., electricity persists in being a necessity of life for everyone, including the elderly and poor, for whom paying electricity bills remains challenging. This creates significant pressure on public officials and wariness among state regulators facing requests to raise electricity rates, even though electric prices remain substantially below the amounts that most Americans say they would be willing to pay for reliable electricity supply.[24]

Second, many households, building operators, large users of electricity, and others are able to invest in such things as energy efficiency measures, combined heat and power systems, or even solar panels and generate their own power on their rooftop, thus lowering demand for power

generated by resources on the grid. While significantly contributing to overall energy productivity and to customers' needs to better control their energy bills, these actions also contribute to lower electricity sales, under-utilization of much of the electric infrastructure, and greater overall financial challenges to the body of electric companies that keep the electric system reliable and secure.[25]

These tensions – towards continued expectations for a reliable, high-performing, efficient and clean electricity system, and the need for financially healthy suppliers of electricity, for continued investment in modernizing the system, and for increased energy productivity – are being felt most acutely in regions, like the Northeast states, with both competitive wholesale markets, generating asset ownership by non-utility companies, strong public policies promoting energy efficiency and deployment of low-carbon and renewable resources, tight air quality standards, and low-carbon requirements.

***Implications for Capacity Markets of these Internal and External Market Factors*:** In recent years (and particularly beginning during the pre-2009 period of high natural gas prices), some state policy makers, grid operators, utilities, power companies, market monitors, and other stakeholders in the Northeast have introduced various interventions of one form or another to fix specific technical problems in the system. In many cases, one-off solutions aimed at fixing a particular concern have led to unintended consequences.

The combination of one-off solutions has produced a patchwork of band aids that renders an insufficient – or worse, an unsustainable – outcome. Much more comprehensive reform is needed to align the benefits of competitive wholesale markets and a healthy grid with the fundamental changes in conditions in the system.

The net effect of those fixes, along with reasonably foreseeable market conditions, is that prices are likely to remain relatively low (or at least suppressed below full cost) in wholesale energy, ancillary and capacity markets for some time in the Northeast. While narrowly attractive in the short term for consumers, this situation raises genuine concerns about the financial health of capacity providers in the near term and about a risky investment environment in the long term.

Again using ISO-NE as an illustrative example, the combined effects of internal and external market factors has led total generating capacity utilization to drop from 50 percent in 2000, to 42 percent in 2008, to 34 percent in 2012.[26] Given that the overall supply curve is very flat (and shaped by relatively efficient gas-fired power plants[27]) and that gas plants set the marginal clearing prices in over 80 percent of the hours of the year in both New York and New England,[28] it is hard even for natural gas plants to recover significant net contribution to capital costs through energy and ancillary service products alone. Operating capacity relative to peak load has remained in high surplus conditions, at 34 percent in 2008 to 43 percent in 2012. [29]

This discussion is not intended to support protection of uneconomic electric infrastructure assets from competition. To the extent that financial losses and asset retirements result from genuine competitive forces and uneconomic asset attributes, such outcomes would be entirely consistent with market principles. And to the extent that well-crafted public policies also serve to overcome market failures (such as those that allow fossil fuel and electricity prices to

understate the economic value of low-carbon power resources), then the outcomes of those 'hybrid' markets also reflect and supports market principles.

But in light of the many ways that prices in New England markets do not reflect fully the cost of providing power and end up under-compensating suppliers for their contributions to the market, reforms are needed for *efficient* entry and exit of suppliers. Investors will move their money elsewhere and/or demand higher returns to remain in the market. This harms consumers by making the grid less reliable and innovation less likely.

In the long run, there may be new, complex and not-yet-imagined developments in the electric system so it no longer retains its 'public necessity' character or no longer depends upon large power plants and a vibrant grid to assure system reliability and meet consumers' diverse electricity requirements. Commercial technologies may evolve at scale and at competitive prices so that today's conventional power generation technologies no longer need to remain on the system for it to be secure and reliable.[30]

But this is not the system we have today, or one that we're likely to have within the investment horizons of today's commercial players in wholesale competitive markets.[31] Most reasonable and informed observers of today's industry, including ones (like me) with strong hopes for a smarter, more advanced and cleaner system in the future, recognize that we have to sustain what consumers want right now – a reliable grid that produces economical electricity – as we try to attract innovation and public/private investment in technologies and assets that move us toward the system we want in the future. Market that fail to provide fair compensation to suppliers end up harming consumers by drying up capital expenditure dollars (or least raising the cost of investment) and by driving out some efficient market players, leaving fewer competitors to meet consumer demand.

Q2: In order to achieve resource adequacy goals, should centralized capacity markets be expected to meet specific reliability and operational system needs (i.e., accommodating new and emerging technologies such as variable energy resources, distributed resources, or demand-side resources)? If so, how should capacity markets be designed to procure resources with specific operational attributes and what should those attributes be?

Yes. First and at a minimum, capacity markets need to truly make up the missing money in order to retain existing and attract new resources needed for resource adequacy. If genuine scarcity pricing is difficult to count on over time and if operations in energy and ancillary services markets end up suppressing spot prices, which are already low from market fundamentals, then capacity markets *must* make up the missing money. If assets are expected to continue to have lower capacity factors, then there'll be more money missing in short-term operating product markets.

Second, capacity markets may be useful in addressing a number of other issues, in addition to providing the "missing money" in the resource adequacy equation. For example, ISO-NE's attempt to better align the provision of capacity-market compensation with capacity suppliers' operational performance during scarcity events seems like a useful direction, assuming that

various technical issues are resolved appropriately. This would take capacity markets one step forward, relative to prior market designs that presumed that "steel is in the ground" would assure resource adequacy as well as system security.

But even so, there could be situations where such approaches may not go the distance in providing the missing money discussed above. Let's assume, for example, that every asset owner were to respond positively to the type of operating incentives being proposed in ISO-NE's FCM-PI proposal. Accomplishing that outcome, through investments, expenditures and other actions by asset owners and others, might actually be successful for what the grid operator hopes to accomplish: adequate capability in operational terms. But it might do so by actually eliminating the very missing money originally anticipated through use of the performance-incentive program. If more than enough market participants responded to the incentives program such that there was a surplus of capacity and few if any hours of scarcity, then there might be few if any performance payments for holders of capacity obligations. In such case, suppliers would have added more cost (including fixed costs in many instances) without changing the "base" capacity payment, and without receiving performance payments to compensate for such added value to the system. In fact, it's imaginable that there could be situations where a generator would operate in energy markets at a net cost in certain periods in order to avoid not performing during a scarcity event (and thus paying capacity-market penalties), and in so doing also contribute to lowering spot prices in energy markets.

This example suggests that unless the design of the basic forward capacity market is also addressed, one should assume that the missing money problem will continue to fester.[32] Given current and future needs to induce private investment in a set of resource attributes that satisfies the system's reliability, policy, economic, and technical requirements. I think that more reform will be needed. And assuming that natural gas prices remain low, short-term markets (e.g., energy and ancillary service markets) alone are not likely to be able to provide adequate to support near-term investments in capacity – and even to sustain participation of certain types of capital-intensive projects. (Note that two sets of capacity resources not dependent on natural gas – i.e., demand-response and nuclear generation – decided in 2012 to exit the New England market.) Going forward, other instruments with longer forward periods are needed to support investment in flexible capacity resources with the operational attributes (e.g., fast-ramping capability; quick-start; routine cycling; inertia and voltage support) of value to the system.[33]

I think that the recent suggestion by the Regulatory Assistance Project ("RAP") of potential modifications to capacity markets ("beyond capacity markets") provides a useful contribution to the option set.[34] Although RAP authors do not ignore the possibility of improving operating markets, they do suggest that changes in capacity markets may be needed to induce investment in a full suite of system attributes and capabilities needed for reliable, clean and efficient power supply. RAP suggests that the "rise of low-marginal-cost variable resources poses a different investment challenge: the right quantity of capacity is now a contingent metric – *how much* depends on *what kind*."[35]

In the first instance it may be sufficient to strengthen and expand the suite of

> short-term ancillary services markets [e.g., long-term auctions for selected non-energy services, such as 10-minute spinning reserves, 10-minute non-spinning reserves, 30 minute operating reserves, non-reserve ramping capability, frequent short-cycling capability] that compensate all resources, including demand-side resources, for making their flexibility options available to system operators as needed. Such short-term markets may no longer suffice, however, when integrating significantly higher shares of variable production....This will depend in part on the pace of transformation in the resource mix, particularly in the share of variable resources.[36]

RAP's proposal further suggests potential modifications of centralized capacity market designs in those areas with deepening reliance on renewable resources:

> An alternative approach, in markets where capacity mechanisms have been deployed or are under active consideration, involves simply apportioning the capacity mechanism into tranches based on the target mix of resource capabilities derived from the net demand forecast. This option leverages whatever resource adequacy mechanism is in place by breaking the total quantity of firm resources required into successive tranches based on specified resource attributes. All firm resources, including qualifying demand-response and end-use energy efficiency resources, would bid into the highest-value tranche for which they could qualify. The most flexible tranche of firm resources is cleared first, followed by the next most flexible tranche, and so on. The least flexible firm resource tranche would be cleared last at whatever residual quantity of resource requirement remains unfilled. The demand curves for each tranche would reflect the relative values of the resources specified, with the clearing price for each successive tranche also expected to be lower than the last, until the final tranche which would be expected to clear at a very low price in both relative and absolute terms. The desired realignment among resources would be driven by the size of each tranche, with value set by the relationship between the size of the tranche and the supply and costs of appropriate resources.[37]

The reason I find such a proposal intriguing is that although valuable resource attributes can be incentivized in theory through advanced operating products, they provide less predictable revenue streams for investors/financiers/lenders. Further, assuming that over time power plants operate less, then it would be riskier to expect to obtain both sufficient and predictable revenues through such short-term energy and ancillary service markets.

Why does it matter that we look at new approaches such as RAPs? To me, it's due to the transformations occurring in the electric industry that raise profound challenges to efficiency market design as well as resource adequacy and system security. We need to fix the "missing money" problem as well as the "needed attributes" in light of an electric system with potentially low levels of capacity utilization and an industry that depends on provide

investment to provide a necessary public service. It's that combination which demands new ways of thinking about assuring adequate compensation for suppliers providing useful attributes to the system.

Q3: Going forward, should centralized capacity markets be designed to meet additional or different goals than those established to date?

Please see my response to Q2, above.

CONCLUSION

I encourage the Commission to focus on one more question – one that too often falls between the cracks: Do the elements of the overall markets and system add up to a system capable of producing a sustainable outcome?

I have explained my thoughts on that particular question above. I think that we need to focus high-level attention among RTOs, federal and state regulators, and other stakeholders, on whether the sum of the parts do (or do not) add up to the whole cost of a system that meets its reliability, economic, public policy, customer, and other objectives. If the numbers don't add up and allow key actors to remain financially viable, then we should work to design reforms that will keep that goal in mind.

This last point is worth repeating, in light of the inherently and highly fractured (and/or shared) nature of decision-making on matters affecting interstate commence in the electric industry. Someone needs to make sure that we're focusing on the big picture, because the actions of so many invisible and visible hands affect the outcomes for everyone.

Clearly, under current law and policy, the Commission occupies the leadership position on regulating wholesale power markets (even as we recognize the influence of state policies and regulatory actions on the character of such markets in different regions). .

It's for this reason that I appreciate the Commission's hosting of today's Technical Conference, and for giving me the opportunity to share my ideas about the future of centralized capacity markets in the Northeast.

The American electric system has been called one of the greatest machines ever invented. It is made up of vast and diverse assets owned by thousands of companies backed by countless investors, with their operations coordinated by grid operators with operational authority over the assets on those systems. The system meets the instantaneous demands of hundreds of millions of consumers simultaneously, with perfect balance of supply and demand. It has to provide affordable power for a necessity of life, and do so with near-perfect reliability, even in the face of big storms and changing conditions. The system must operate according to laws of physics, politicians, courts, and markets. Often we take for granted that investors will support the system that we want and need. But to sustain their interest, we need to make sure that the dollars and cents add up, as we hope for a system that evolves with the needs of the 21st century. Reforms in wholesale capacity markets should be part of the change.

ENDNOTES

[1] Together, PJM, NYISO and ISO-NE serve 95 million of the nation's total population of 314 million. Sources: U.S. Census Bureau; ISO/RTO Council for population data for the RTOs. http://www.isorto.org/site/c.jhKQIZPBImE/b.8641109/k.E59C/Members_At_A_Glance.htm.

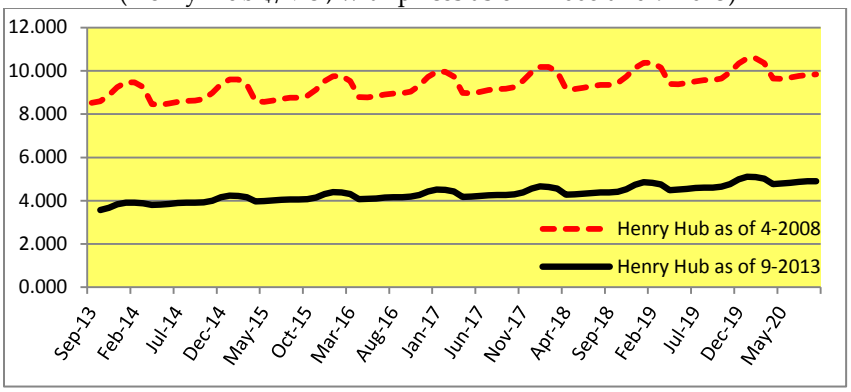
[2] By "party," I mean to include not only the "Market Participants" as they exercise their roles in decision-making in RTO committees, but also others outside that system, including the RTOs themselves, the individual states (and their various policy-making entities that make countless decisions affecting the wholesale power market environment), and actors of various forms in investment communities (e.g., rating agencies, investment advisors, fund managements, and so forth).

[3] In New York and the New England states have strong energy efficiency, renewable energy and low-carbon energy supply goals. For example, New York State has adopted a "45 x 15"goal, in which 45 percent of the state's electricity demand in 2015 would be provided through energy efficiency and renewable power (with 15 percent coming from energy efficiency and 30 percent produced by renewable sources). In New York State in 2011, renewable energy accounted for 23.75 percent of power (up from 21 percent in 2010). (Source: NYISO, "Power Trends, 2012," pp. 38, 58. Every New England state except Vermont has a mandatory requirement for adoption of renewable energy. By the year 2020, my own analyses indicate that New England will require 21,300 GWh of renewable energy, with increasing amounts thereafter. This is approximately five times the amount of supplies of renewable power in the region in 2012 (i.e., 4,120 GWh). (Source: Prefiled Direct Testimony of Susan Tierney, Petition of NSTAR Electric Company for approval by the Department of Public Utilities of a long-term contract to purchase wind power and renewable energy certificates, Docket No. D.P.U. No. 12-30, Exhibit NSTAR-SFT-4, p. 9 of 25.)

[4] In the most recent "state energy efficiency scorecard" issued in 2012 by the American Council for an Energy Efficient Economy ("ACEEE"), the Northeast states ranked highly among the 50 states in terms of their pursuit of cost-effective energy efficiency measures: Massachusetts (#1); New York (#3); Vermont (#5); Connecticut (#6); Rhode Island (#7); New Hampshire (#18); and Maine (#25). See ACEEE, "The 2012 State Energy Efficiency Scorecard," October 2012, p. viii.

[5] Forward prices for natural gas (measured at Henry Hub), have dropped by approximately a half since 2008:

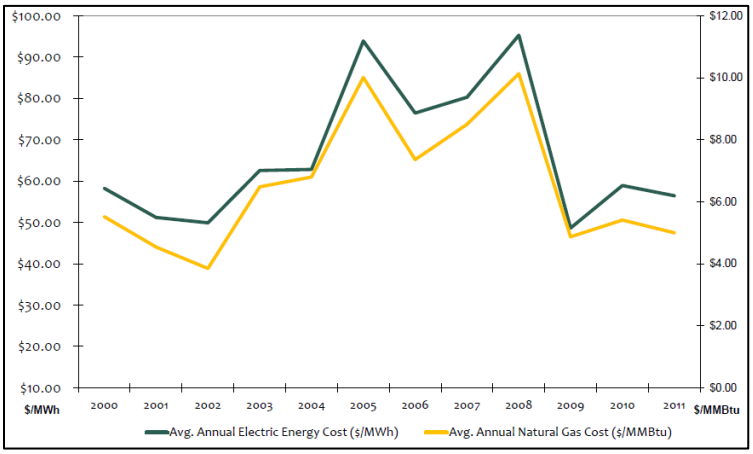
NYMEX Natural Gas Futures Prices - for May 2013 to December 2020
(Henry Hub $/Mcf, with prices as of 4-2008 and 9-2013)



Source: SNL Financial.

Electric energy prices in the Northeast have been highly correlated with natural gas prices over the past decade. See, for example, "Natural gas prices and electric energy prices in New York State: 2000-2011," from

NYISO, "Power Trends," 2012, p. 15, Figure 7:



[6] In 2012, the percentage of time that hourly energy prices were set by natural gas (as the marginal unit) was 83 percent in NYISO and 81 percent in ISO-NE. Potomac Economics, "2012 NYISO State of the Market Report," p. 7; ISO-NE Internal Market Monitor, "2012 State of the Market Report," p. 17.

[7] Platts, "Enernoc thinning position in New England forward capacity market," April 9, 2013, http://www.platts.com/latest-news/electric-power/Washington/Enernoc-thinning-position-in-New-England-forward-21928104; Entergy Corporation news release, "Entergy to Close, Decommission Vermont Yankee," August 27, 2013, http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.

[8] See, for example, Ron Coutu, "Overview of New England's Forward Capacity Markets. Overview of ISO New England (ISO 101)," October 2, 2012

[9] I have long supported the value of vibrant wholesale market structures and rules as part of providing efficient and reliable supply of power to consumers, and as mechanisms to support modern clean energy goals. The wholesale markets in PJM, NYISO, and ISO-NE have been in operation for about a decade. Together, they have over 253 GW of supply (out the nation's approximately 1,107 GW of generating capacity. (Source: http://www.isorto.org/site/c.jhKQIZPBImE/b.8641109/k.E59C/Members_At_A_Glance.htm) Each RTO has had different phases reflecting start-up conditions, transitions to revised market rules, investment cycles, and so forth. Prices have moved up and down over time in light of changing generating mix and the prices of fuels. Some of the notable outcomes of these markets include:

- Introduction of thousands of megawatts of new power plant investment, including new and efficient gas-fired capacity, wind turbines, and nuclear uprates at nuclear plants during the last decade. In NYISO since 2000, 9,174 MW was added (of in-state generation capacity totaling 39,570 in 2012), of which 1,414 was a wind projects. (Source: NYISO Power Trends, 2012.) In ISO-NE, *14,000 MW of capacity was added since 1999. (*Source: Scott Hogsdon, ISO-NE, "Overview of ISO New England System Planning,*" October 12, 2012/* http://www.iso-ne.com/support/training/courses/isone_101/04_overview_system_planning.pdf*)*
- Improved power plant availability, Greater power production efficiency and operations, including: increases in the efficiency of fuel-consumption (i.e., heat rates) of fossil fuel-fired facilities; decreases in the length of refueling outages, lower operations and maintenance expenses, and greater plant availability at nuclear facilities; and decreases in labor and other non-fuel operations and maintenance costs across all facilities. (Source: Susan Tierney, "Decoding Developments in the Electric Industry: 10 Points in the Prism," October 2007.)
- Introduction of thousands of MW of demand response capacity: in NYISO, 2,173 MW (with 531.6 MW and

153.9 MW in Zone J (NYC) and K (Long Island), respectively, as of 2011 (Source: NYISO Power Trends, 2012, page 10); in ISO-NE (as of 2012), demand resources cleared the FCA to account for up to 10 percent of the region's Installed Capacity Requirement up through the first six FCM auctions (Source: Scott Hogsdon, ISO-NE, "Overview of ISO New England System Planning,," *October 12, 2012,* http://www.iso-ne.com/support/training/courses/ isone_101/04_overview_system_planning.pdf).

[10] See, for example: Peter Cramton, Axel Ockenfels, Steve Stoft, "Capacity Market Fundamentals," Economics of Energy & Environmental Policy, Vol. 2, No. 2, 2013; Potomac Economics, "2012 State of the Market Report for the New York ISO Markets," April 2013, p. 54; Kathleen Spees, Samuel Newell, Johannes Pfeifenberger, "Capacity Markets – Lessons Learned from the First Decade," Economics of Energy & Environmental Policy, Vol. 2, No. 2, 2013..

[11] Potomac Economics, "2012 Assessment of the ISO New England Electricity Markets," page iii.

[12] Potomac Economics, "2012 Assessment of the ISO New England Electricity Markets," page iii.

[13] Potomac Economics, "2012 Assessment of the ISO New England Electricity Markets," page 125.

[14] Ron Coutu, "Overview of New England's Forward Capacity Markets. Overview of ISO New England (ISO 101)," October 2, 2012.

[15] ISO-NE Wholesale Competitive Market Project Plan (2013).

[16] Potomac Economics, "2012 Assessment of the ISO New England Electricity Markets," page 137.

[17] Potomac Economics, "2012 State of the NYISO Market Report," p. A-23.

[18] See, Independent Power Producers of New York, Inc., v. New York Independent System Operator, Inc., Docket No. EL13-62-000, before the Federal Energy Regulatory Commission.

[19] See, for example, papers prepared for the MIT Energy Initiative (MITEI) Symposium on the Interdependency of Natural Gas and Electricity Systems: Growing Concerns, Possible Solutions, April 2013, including S. Tierney, "Framing the Issues: Growing Tensions at the Interface of the Natural Gas and Electricity Markets."

[20] On August 23, 2013, Amy Polszywak of SNL wrote that "Fitch reports dim outlook for PJM generators, highlighting myriad pressures on pricing." SNL reported that "Fitch had been expecting coal retirements to more significantly affect the market by causing a decline in capacity that would have supported higher energy prices as a large amount of generation needs to come offline by 2015. "That didn't happen because new policy mandates, distributed generation, energy efficiency and demand response kind of negated any benefit that coal retirements could have brought in from a cash flow perspective," the analyst said. "The overall decline in the demand, or summer peak, is coming down, and total consumption is coming down as well, so those factors lead us to believe that there's a new paradigm for the market." Bains also noted that most of the existing generating assets in the market are relatively long-term assets, so there are not many options available to companies to cut costs…. "

[21] This is not to say that investor-owned utilities do not bear risk: they do. But once their investments have been approved by utility regulators, the rates they are allowed to charge customers include compensation to shareholders and repayment of debt to lenders. By contrast, non-utility power companies – whether they own power plants, market and sell power, or provide energy-efficiency or demand-response products – do so at market prices and bear the risk that these will not cover their expenses, including profits and financing costs.

[22] See: S. Tierney, "Why Coal Plants Retire: Power Market Fundamentals as of 2012," February 16, 2012.

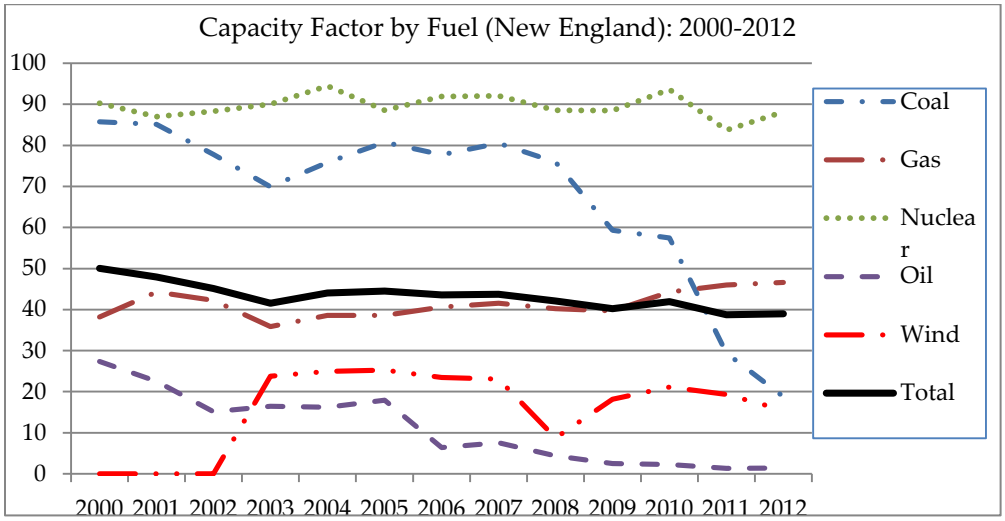
[23] See the "Today in Energy" reporting on September 6, 2013 by the Energy Information Administration: "The pending closure of a 41-year-old nuclear plant located in Vermont will likely affect both natural gas and electricity markets throughout New England. Entergy Corporation's August 27 announcement of the closure of

the Vermont Yankee plant cited economic challenges to continued operations at the 604-megawatt (MW) plant, which since 2007 has generated about 4% of New England's total annual electricity supply. The shutdown is expected in fourth-quarter 2014, when the plant's current fuel cycle ends….Entergy's announcement cited a number of financial factors for the retirement, including: Low wholesale electricity prices, driven in part by lower natural gas prices, which have reduced the profitability of the plant; Significant capital costs for maintaining the unit, which began operations in 1972; Low prices in the regional market for electric generating capacity, which provides revenue to plant owners in addition to their revenues from electricity sales.…New England has significantly increased its reliance on natural gas as a fuel for electric generation in the past few years. Natural gas fueled less than 30% of the electricity generated in New England in 2001, but that figure rose to 52% in 2012…Increased gas use for power generation has contributed to pipeline transportation constraints in the New England regional natural gas market. These pipeline constraints are more pronounced in winter months, when natural gas is used to heat homes and businesses as well as to produce electricity. These supply constraints contributed to extreme price spikes in spot natural gas and electricity prices in New England during January and February 2013….The same day Entergy announced the retirement of the Vermont Yankee nuclear power plant, the Algonquin Citygate ["a key delivery point in New England"] forward basis swap for the January 2015 contract month—the month following the announced retirement date—rose about 50 cents per MMBtu. In 2012, natural gas was the marginal fuel—the fuel price that sets the price for operating generators—in New England about 81% of all operating hours, according to the Independent System Operator of New England." http://www.eia.gov/todayinenergy/detail.cfm?id=12851

[24] Gordon Van Welie (ISO-NE) memo to the New England Power Pool Participants Committee, New England Conference of Public Utilities Commissioners and New England States Committee on Electricity, "Information regarding Potential Benefits and Costs of Solutions to Address the Risks Associated with New England's Reliance on Natural Gas," January 25, 2013, including memo from Paul Hibbard, "Information from the Literature on the Potential Value of Measures that Improve System Reliability," January 24, 2013.

[25] Even owners of utility transmission and distribution systems (and with little to no ownership of power plant capacity) are under revenue pressure, with flat loads, increasing investment requirements to address aging infrastructure and grid resiliency issues, and traditional cost-of-service ratemaking and rate designs that collect substantial amounts of revenues through variable energy and demand charges. A future with much greater on-site generation by customers that lowers use of the wires will increase this tension for wires companies, too.

[26] See trends in capacity utilization by fuel type in New England since 2000, with average overall utilization dropping from 50 percent (in 2000) to approximately 40 percent in 2012 (source: SNL Financial data).



[27] SNL Financial data for ISO-NE.

[28] ISO-NE, 2012 State of the Market Report, Figure 2-5.

[29] SNL Financial data for ISO-NE.

[30] If, for example, cost-effective electricity storage systems were to become commercially viable and could support full integration of non-dispatchable renewables, then nuclear units might not be needed for baseload supply or to provide inertia and voltage support, and fossil generating units might no longer be needed for balancing energy, and competitive forces could serve to drive inefficient and financially unsuccessful players from the market.

[31] Presumably, in the next 10-15 years, large investment in non-dispatchable wind and solar technologies will need substantial support for system balancing purposes from some combination of diverse storage technologies (something that is not yet both cost-effective, commercially available at scale, and/or able to be sited (e.g., pumped storage, compressed air storage, liquid metal battery)), and/or conventional generation. The system will require substantial ramping capability, quick-starts and multiple starts, and could face significantly low capacity factors across various technologies. Should substantial nuclear capacity retire in this period, it will increase complicate the foregoing issues, in light of the loss of low-carbon technologies providing substantial inertia and voltage support in their regions.

[32] This might be in spite of FCM-PI's potential success in delivering greater performance of plants as part of real-time operations and in spite of the system having addressed the problem of ensuring adequate output from the fleet of facilities so heavily dependent upon natural gas.

[33] Note the recent report issued by USB, "IPP Power Shock," August 20, 2013: "we perceive a growing focus in the industry on the impact of renewables. While its steady increase in recent years has been largely limited to rural areas at off-peak hours through wind, we see increased transmission interconnection as increasingly hampering competitive markets across the Midwest and Texas, as well as steady ramp in solar assets in California as squeezing the already-marginal spark spread. …. [for power markets] we believe their greater interconnection will place further pressure to reform markets to allow for more fixed compensation (read: capacity), and for explicit valuation of their ability to backstop intermittent renewables." UBS, p. 3.

[34] Mike Hogan, "What Lies 'Beyond Capacity Markets'? Delivering Least-Cost Reliability Under the New Resource Paradigm; A 'straw man' proposal for discussion," August 14, 2012.

[35] Mike Hogan, "Beyond Capacity Markets," Regulatory Assistance Project, presentation, 2012, p. 8.

[36] Mike Hogan, "What Lies 'Beyond Capacity Markets'? Delivering Least-Cost Reliability Under the New Resource Paradigm; A 'straw man' proposal for discussion," August 14, 2012, pp. 9-10.

[37] Mike Hogan, "What Lies 'Beyond Capacity Markets'? Delivering Least-Cost Reliability Under the New Resource Paradigm; A 'straw man' proposal for discussion," August 14, 2012, p. 13.