STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE	**:**	
COMMISSION AS TO THE POLICIES, PRACTICES	**:**	
AND PORCEDURES FOR UTIITY COMMODITY	**:**	**Case No. 06-M-1017**
SUPPLY SERVICE TO RESIDENTIAL AND SMALL	**:**	
COMMERCIAL AND INDUSTRIAL CUSTOMERS	**:**	

COMMENTS OF CONSTELLATION ENERGY COMMODITIES GROUP, INC. AND CONSTELLATION NEWENERGY, INC.

INTRODUCTION

In its April 19, 2007 Order in the above docketed proceeding ("April 19 Order"),[1] the State of New York Public Service Commission ("Commission" or "PSC") stated that "an examination will be undertaken of the use of long term contracts and other means to facilitate the entry of new resources that would further the public policy goals of the State regarding electric infrastructure."[2] To begin its examination, the Commission presented several questions for interested parties to address regarding this issue ("PSC Questions").[3] Pursuant to the Commission's directives in the April 19 Order, Constellation Energy Commodities Group, Inc. ("CCG") and Constellation NewEnergy, Inc. ("CNE") (collectively, "Constellation") hereby submit their initial comments in response to the PSC Questions.

1 *Order Requiring Development of Utility-Specific Guidelines for Electric Commodity Supply Portfolios and Instituting a Phase II to Address Longer-Term Issues*, Commission Case No. 06-M-1017 (issued Apr. 19, 2007).

2 April 19 Order at pp.35-36.

3 April 19 Order at pp.36-37.

BACKGROUND ON CONSTELLATION

CCG is a power marketer authorized by the Federal Energy Regulatory Commission ("FERC") to sell energy and capacity and certain ancillary services at market-based rates.[4] CCG focuses on serving the full requirements power needs of distribution utilities, co-ops and municipalities that competitively source their load requirements. CCG also sells natural gas and other commodities at wholesale, both in the U.S. and abroad, and holds interests in exploration and production companies. CCG does not own any physical assets for the generation, transmission or distribution of electric power and has no retail electric customers or service territories. However CCG bids energy, capacity and ancillary services into the NYISO administered markets on behalf of generation-owning affiliates.

CNE is a leading national competitive retail energy supplier to commercial and industrial customers, serving more than 10,000 customers in 17 states and 2 Canadian provinces. These 10,000 customers represent approximately 15,500 megawatts of demand. The Company is committed to providing customized energy-related products and services to customers in the competitive electricity marketplace.

Since the introduction of customer choice in the New York electric industry in 1996, CNE has been an active participant in the New York retail market. CNE provides service to commercial and industrial customers in all of New York State utility service territories, as well as in the service territory of the Long Island Power Authority ("LIPA").

CNE and CCG are active in wholesale and retail markets nationwide. Moreover, CNE and CCG have been active in virtually all of the regulatory proceedings before the Commission involving electric restructuring and have served as advocates for fair and competitive open

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4 *See Constellation Power Source, Inc.*, 79 FERC ¶ 61,167 (1997) (FERC order initially granting CCG market-based rate authority).

markets that are designed to provide customers with an array of competitive options. As such, Constellation is well positioned to assist the Commission in examining the issues presented by an examination of long term contracts and other means to facilitate the entry of new resources into the New York electric infrastructure.

CONSTELLATION INITIAL COMMENTS

PSC Question ***1****:* *Should there be a statewide integrated resource planning process to examine long term electricity resource needs? To what extent or in what manner would a statewide integrated resource planning process build on or parallel existing reliability planning processes? What time frame should be examined in such a process and what issues should be considered? What is the role of the utilities and other interested parties in the process? How should the process differ from any previous integrated resource planning processes? What processes should be adopted, if any, to ensure that resource portfolios at the utility and statewide level, satisfy overall planning objectives and public policy considerations? How should immediate concerns and long range considerations be addressed?*

Note that, while Constellation in this answer to PSC Question 1 outlines important reasons why the Commission should refrain from adopting a statewide integrated resource planning ("IRP") process, Constellation in its answers to PSC Questions 5, 10 and 11 provides its suggestions for other more appropriate ways in which to encourage long term contracting in the market. Constellation believes that there are at least seven (7) independent reasons why the State should refrain from adopting a statewide IRP process. **First**, while well-intentioned, IRP provides little ultimate value as it is based on incorrect assumptions that central planning and government-run procurement processes can outperform the market. As a result, the IRP process simply provides for prescriptive lists of actions, such as when to build power plants, what technologies to impose, what percentage of energy efficiency or renewable resources to purchase, what fuel types to favor, and various other rigid directives. However, these actions tend to be outdated shortly after being written. Such prescriptive and rigid directives are unable to respond quickly to the realities of the market on a real-time basis. However, the market itself can more effectively and efficiently respond to changes in fuel price, the development of new technologies, the imposition of new environmental regulations, short- and long- term weather patterns, and other such variables.

Second, if the State wishes to utilize IRP in part to reach certain environmental goals, such action may prove to be counter productive. A more effective way to achieve laudable environmental goals, such as the development of new renewable energy facilities and the reduction of carbon dioxide and other pollutants, is to implement Renewable Portfolio Standards and cap and trade programs, such as the Regional Greenhouse Gas Initiative and other market mechanisms. These types of market initiatives are much more likely to achieve the desired results at the lowest possible cost than command and control edicts characteristic of IRP processes.

Third, it is unclear how any state agency or utility can properly evaluate an IRP process. How would the Commission or a utility ensure that the least cost purchases have been entered into? What price projections would the Commission or a utility rely on? How would the Commission or a utility itself ensure that the appropriate environmental standards have been adhered to when those standards change regularly and how will those changes affect the price of electricity? How would the Commission or a utility be assured that it is investing in the appropriate, least-cost, technology when advances in technologies are commonplace? The bottom line is that it is simply not possible for the State's utilities or the Commission to plan their way to the least cost purchases in an ever changing market environment.

Fourth, Constellation notes that IRP has failed in the past. In the 1980s and 1990s, New England utilities, for instance, were required to develop IRP processes, to get approval of their respective public utility commissions ("PUCs"), and to make energy purchases or build generating facilities based upon those IRP processes. Close adherence to those PUC-approved IRP processes led to unprecedented stranded costs. Billions of dollars of stranded costs were and are still today being borne by New England utility ratepayers due to long-term independent power contracts, long-term "PURPA" contracts and utility-built generating facilities, all of which were directed under IRP processes. In this way, all of these costs are a direct result of PUC-approved IRP processes that proved to be extremely uneconomic. Because these utility actions were approved by New England's PUCs and allowed to be recovered in rate base, utility ratepayers were required to bear the costs of these decisions. These judgments were made by both the utilities that developed the IRP processes and the state PUCs that required revisions to and approved these plans, and ultimately were incorrect. This dynamic occurred throughout the country. It is clear that state-run command and control IRP methodologies have failed dramatically. In fact, the failure of past IRP policies was a major driver for restructuring the electric industry towards reliance upon competitive and market-driven structures.

By contrast, for the last several years, New York State has pursued a policy of encouraging investment in clean onsite cogeneration facilities through the use of market mechanisms. These mechanisms have included revisions to retail standby rates and wholesale rules governing the capacity market to ensure that customers receive price signals that accurately reflect the costs and benefits associated with onsite cogeneration. Additionally, funds specifically targeting these resources have been offered by the New York State Energy Research and Development Authority ("NYSERDA") to compensate cogeneration facility owners for the societal benefits of these systems that are external to retail and wholesale price signals. New York is now widely considered one of the leading U.S. markets for clean onsite cogeneration investment and the investments being made are with private funds at no risk to rate payers. This success story should be used as a model for achieving a range of reliability, economic and environmental policy goals.

Fifth, the future risk of procurement and investment decisions in the State has been appropriately placed on market players and not, as it was in the past, with utility ratepayers. Pursuant to the PSC-approved settlements, utilities sold off their generating assets and were allowed to recover the uneconomic value of those resources via stranded costs. There were a number of reasons for restructuring the electric industry in New York, including placing downward pressure on the price of electricity via the introduction of competitive forces and providing consumers with the ability to choose their electricity provider. Another important consideration was shifting the risk of unintended consequences of economic decisions by utilities and the Commission from ratepayers to market players. Indeed, a number of market players were driven into bankruptcy because of uneconomic investments. The losses incurred were borne by the market and not by ratepayers. As an illustration, Exelon in late 2003 turned over 800 MW units at Mystic, 8 and 9, and its then new 800 MW Fore River plant to a consortium of lenders. After borrowing $1.1 billion to finance the construction of Mystic 8 and 9 and Fore River, Exelon decided to give up its $700 million investment and ownership in the plants, citing construction delays, cost overruns and falling prices in the New England wholesale power market. The move came only 10 months after Exelon bought full ownership in the plants by acquiring the remaining 50 percent stake in Sithe New England that it did not already own for $543 million in notes. Rather than relying on consumers to shoulder the burden for investments for this new generation, as would have been the case under long term contracts with a utility for new generation construction, private industry – Exelon and its lenders – assumed the risks associated with the construction of the Mystic Station and Fore River projects. Reintroducing IRP would be a move back to pre-restructuring days by incorrectly and unfairly placing the risk of such investments with utility ratepayers.

Sixth, IRP would be redundant to a number of established planning tools already employed by policy makers in New York. First, the NYISO already has its Comprehensive Reliability Planning Process ("CRPP"), which identifies generation and transmission resources needed to maintain statewide reliability standards. As part of this process the NYISO updates its data on load forecasts and anticipated changes in resources resulting from new capacity or retirement of existing capacity, and issues an annual Reliability Needs Assessment ("RNA"). This process is already well established and is consistent with competitive markets. To the extent that the Commission believes that utilities should enter into long term contracts due to reliability concerns, the Commission should rely on NYISO's existing RNA process to identify reliability gaps, if any. In addition to the NYISO's CRPP, NYSERDA regularly commissions market potential studies to support a range of energy policy objectives, particularly for new and green technologies. A recent example of this is the "Gas Efficiency Market Potential Study" commissioned by NYSERDA. The study was requested by the PSC to support its investigation into the possible creation of new statewide gas efficiency programs. The study is now being used a resource in considering the possible creation of new efficiency programs specifically targeted to the Con Edison and Keyspan territories. These established initiatives demonstrate approaches to resource planning that utilize markets and avoid many of the risks of traditional IRP.

Finally, a reintroduction of IRP could be perceived as a statement by the Commission that electric industry restructuring has failed. Nothing could be further from the truth. A number of regional and national studies have proven the benefits that have accrued to end-use customers through the introduction of electric industry restructuring:

- A 2007 study by The Analysis Group on behalf of NYISO found that significant benefits have resulted from NYISO's operations and certain market incentive effects, and that it is reasonable to expect that at least some of these benefits will flow through to consumers over time.[5]
- An Alliance for Retail Choice's May 2007 study found that New York has achieved good progress in retail choice, noting that 635,000 or 11% of residential consumers are purchasing their energy from competitive electric suppliers, a growth of 55 percent in one year, and that in aggregate, 41 percent of the total residential electric usage in New York is currently provided by competitive suppliers. With respect to commercial and industrial customers, the study found that 56 percent of such customers are served by competitive suppliers, representing 77 percent of the total commercial and industrial load. The study noted also that retail electric choice is thriving in New York because the market structure has advanced sufficiently for competitive markets to work effectively.[6]
- The New York State Department of Public Service in a 2006 report found, through an evaluation of New York's wholesale electricity markets under several metrics, that New York's wholesale markets are among the most advanced in the nation and that wholesale competition has led to significant efficiencies.[7]

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[5] *See, generally, A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years*, The Analysis Group (Mar. 2007), http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2007/03/nyiso_anlyss_grp_rprt_031307.pdf.

[6] *See, generally, ARC's Baseline Assessment of Choice in the United States*, Alliance for Retail Choice (May 2007), http://www.allianceforretailchoice.com/ProjectCenter/Portals/13/ABACUS_publication%202007%20May23.pdf.

[7] *See, generally, 2006 Staff Report on the State of Competitive Energy Markets: Progress To Date and Future Opportunities*, New York State Department of Public Service (Mar. 2, 2006), http://www.dps.state.ny.us/

- A 2005 report by Cambridge Energy Research Associates found that consumers nationwide have saved $34 billion over the past seven years compared to what they would have paid under traditional electricity regulation.[8]
- A 2005 study by Global Energy Decisions found that consumers in the eastern United States have saved $15.1 billion between 1999 and 2003 as a direct result of electric restructuring.[9]

This empirical research demonstrates that electric industry restructuring has been a success nationally and in New York. As of December 2006, 74% of large commercial and industrial customers and 49% of small commercial and industrial customers had chosen to switch to one of the over 75 competitive retail suppliers now active in New York. In fact, as additional large well-financed competitive suppliers have entered the New York market over the last two years, bringing with them a proliferation of new and innovative competitive products for customers to choose from, the rate of switching has markedly increased. There exists no reason to go back to a market of vertically integrated utilities and rate-based generation via the introduction of IRP processes. Therefore, for all of the above reasons, Constellation urges the Commission to reject the use of IRP processes.

*PSC Question **2**:* *Should major regulated electric utilities be required or encouraged to enter into long-term contracts, with existing generators, proposed generators, and other entities, that facilitate the construction of new generation, the development of additional energy efficiency, the development of additional renewable generation resources, the re-powering of existing generation, or the relief of transmission congestion? Should such contracts be entered into*

StaffReportCompetition.pdf.

8 *See, generally, Beyond the Crossroads: The Future Direction of Power Industry Restructuring*, Cambridge Energy Research Associates (Sept. 30, 2005), http://www.cera.com/aspx/cda/client/MCS/MCSChapter.aspx?CID=7691&KID=170.

9 *See, generally, Putting Competitive Power Markets to the Test, The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies*, Global Energy Decisions, LLC (July 2005), http://www.globalenergy.com/competitivepower/competitivepower.pdf.

for the purposes of improving fuel diversity, mitigating market power, or furthering environmental policies?

At the outset it is important to define the meaning of "long term contracts." Specifically, Constellation understands that the phrase, in this context, refers to contracts under which the utility buyer will collect the purchase costs from ratepayers pursuant to regulated rates over a term which is designed to allow for debt financing of new generation investment. We do not take use of the phrase here to refer to bilateral agreements which are voluntary and do not involve any regulated recovery.

Constellation notes first that any need for long term contracts is vastly overstated. In the past, the emerging merchant power industry relied heavily upon traditional debt financing of 80 to 100 percent that was supported by long term contracts with utility customers. Today, however, other sources of capital are pouring into energy infrastructure. Balance sheet equity, hedge funds and private equity firms are all coming forward to invest in and acquire new renewable generating resources, traditional fossil generating resources and demand reduction technologies. The recent implementation of forward capacity markets in several regions has further added to the interest of these investors and is further increasing the amount of capital available. The Texas market provides proof of this, where its market has witnessed a major construction boom in new generation capacity – including gas, oil, coal, and wind – all without long term rate base contracts. In addition, companies like Constellation are in some cases entering into long term bilateral purchase agreements with generators in order to supply either retail or wholesale customers, without the need for a traditional rate base from which to recover the cost of those purchases.

At the same time, the costs which result from long-term contracts are becoming more apparent. The stranded costs which arose from implementation of the Public Utility Regulatory

Policies Act ("PURPA"), and more recently the costs of the contracts entered into by the State of California during that state's energy crisis, have revealed the risk to rate base customers of being locked into paying for long term investment decisions which are made on their behalf by regulators and utilities. In addition, rating agencies such as Standard & Poor's are now treating long term contracts as imputed debt obligations of the purchasing utility, reflecting the view that it is the utility and its customers who bear all of the investment risk under such long term contracts.

The State need only look to its own recent past with Niagara Mohawk ("NiMo"), PURPA and the "6-Cent Law" to understand the significant risks that long term contracts pose to consumers, especially due to the uncertainty of long term energy prices. Recall that Congress enacted PURPA in part to help foster the development of energy resources by requiring utilities to purchase the output from qualifying facilities ("QFs"). New York Public Service Law § 66-c (the "6-Cent Law") was enacted soon thereafter at the State level and took PURPA one step further, by additionally providing for a minimum sales price of six cents per kilowatt hour for electricity purchased from QFs by utilities, essentially establishing, at the time, a floor on avoided costs for new generation projects less than 80 megawatts in size. The 6-cent floor represented New York's best estimate of trends in energy costs, and was made under the assumption that energy prices would continue to soar. Energy prices in the 1990s, however, decreased significantly.

When combined with the area's existing energy infrastructure and availability of cogeneration hosts, the 6-Cent Law attracted significant levels of cogeneration development in upstate New York. Use of a simplified form contract further attracted these developers to seek long term contracts with NiMo. By the mid-1990s, NiMo – in keeping with the requirements of

PURPA and the 6-Cent Law – had signed hundreds of QF contracts that far exceeded its actual demand. The 6-Cent Law was repealed in 1992, but for contracts signed prior to the date of the repeal the damage was done. As energy costs decreased over time, and as more of the proposed QFs under the QF contracts came online, NiMo's costs due to the QFs continued to increase, and its customers rates, in turn, continued to rise. To avoid bankruptcy, NiMo in 1999 was faced with having to reach a settlement with its QFs in the amount of $3.45-billion, paying the QFs in order to revise or terminate their contracts with NiMo.[10]

Because the need is overstated and because the costs are becoming increasingly apparent as the industry evolves, Constellation urges the Commission to order the use of long term contracts only very sparingly, if at all. With respect to nearly all renewable and traditional fossil based resources, *siting* rather than financing is the major impediment to new investment. This is not to say that there are not perhaps some resources whose development may require some form of long term commitment. The only example of such a resource which we presently are convinced may require such long term commitment is investment in nuclear power. Nuclear plants require a very long lead time for development, with significant capital costs, as well as a very long time period over which capital outlays must be recovered. Assuring safe and secure operations, proper handling of nuclear material, adequate funding of future decommissioning and investment in twenty-first century nuclear generation technology all make these investments unique and require greater financial stability and continuity of ownership than investment in any other type of generation resource. For these reasons, Constellation supports the use of long term contracts, if any, only to support unique resources such as nuclear generation as part of policy of fuel diversity and to address the compelling problem of global climate change.

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[10] *See* "Niagara Mohawk has $3.45-billion financing package," CNY Business Journal (Jan. 29, 1999), http://findarticles.com/p/articles/mi_qa3718/is_199901/ai_n8839439.

In addition, if the Commission orders the use of long term contracts for utilities, such contracts should only be for capacity, and *not* energy. The State essentially would use such long term contracts only as a hedge to capacity prices, and would refrain from burdening consumers with the additional risks and costs posed by long term *energy* contracts. The underlying energy, in this way, would still be made available to be sold in the market, at market based rates, rather than committed long term at an established rate, with consumers' having to shoulder the risks.

*PSC Question **3**:* *Should Load Serving Entities other than utilities, including the New York Power Authority and the Long Island Power Authority, be required or encouraged to enter into long-term contracts as described above? What role, if any, might entities other than Load Serving Entities play in such resource procurement?*

No. For the reasons stated above, long term contracts should only be acceptable, if at all, in limited and compelling circumstances, regardless of whether the buyer is a regulated distribution company or a State or local power authority.

*PSC Question **4**:* *Should resource procurement, as described in Question 1, be coordinated on a statewide basis? What regulatory oversight, if any, would be appropriate?*

Procurement outside long term contracts is addressed in the April 19 Order. The Commission should have a single policy that does not mandate or encourage long term contracts other than in exceptional and compelling circumstances.

*PSC Question **5**:* *What barriers, if any, exist that discourage long-term contracts for development of new electricity resources? What other barriers exist, if any, for the development of new electricity resources? Should incentives beyond what exist today be created to encourage entry into long-term contracts generally, or to foster the development of any particular type of resource? How could those incentives be structured consistent with the goal of acquiring the most cost-effective resources?*

The goal of a well-functioning wholesale market is to provide information to buyers and sellers to allow them to make rational economic decisions. There is nothing inherent in the structure of New York's market today that permits parties to enter into short-term transactions but somehow impedes or prohibits them from making longer-term arrangements, nor should there be. The market's goal is not and should not be to promote arbitrary contract lengths. Rather, clear market signals should provide buyers and sellers the information needed to assess risks and make the best decisions.

Organized markets such as NYISO consist of the highly visible spot markets (real-time and day-ahead) as well as the over the counter ("OTC") or bilateral markets. Buyers and sellers in NYISO all have the option of transacting in the daily markets or through forward contracts of various terms. To forego an opportunity to transact in the daily market and instead reach agreement on terms and price in a forward contract, necessarily entails an assessment of the probable outcomes in the daily market for some period in the future. It is, therefore, no surprise that regions with well-designed and well administered spot markets also have the most robust forward bilateral markets. Buyers and sellers who want to transact bilaterally must have confidence in the functioning of the daily market and be able to form their independent views about future price outcomes in order to reach agreement on a forward contract price. To best facilitate market participants' entry into long term contracts in their ordinary course of business in NYISO, the Commission can:

- Improve price formation by encouraging NYISO to (1) adopt market mechanisms and designs that rely upon commodity prices, (2) minimize out of market compensation mechanisms such as uplift charges or reliability must-run contracts;
- Avoid after the fact determinations and modifications to prices, which impede the development of the bilateral market by creating uncertainty of outcome for both buyers and sellers; and

- Promote greater liquidity by encouraging NYISO to facilitate trading transactions across the seams between markets and to bring NYISO's operational practices and information systems up to the highest possible standards.

For both buyers and sellers, contracts of various terms are desirable risk management tools in organized markets. It is instructive to consider reasons why parties may opt not to enter long-term contracts or prefer daily markets over forward contractual relationships of various lengths. Forward contracts can provide greater price certainty but they may require other economic trade-offs. In the end, it is incumbent on the Commission and NYISO to ensure that market constructs do not prevent parties from accurately assessing these economic trade-offs in making their contracting decisions between short-term markets and longer-term commitments.

Fundamentally, contracts involve agreement among the parties on term (length), volume (quantity) and price, each of which implicates various risks the parties must assess and value. One example is credit. Contracting parties are faced with a trade-off between the cost of a financial default times the probability it will occur versus the direct cost of a financial guaranty to insure against it. Because the probability of default increases over time due to the uncertainty of each party's future economic circumstance, the default or credit costs are greater the longer the term of the transaction. This is not an impediment to an otherwise economic transaction but rather the manifestation of an underlying cost which is part of the economics of the transaction itself. Quantity is another term that manifests a greater cost in longer dated transactions. A seller can supply a fixed quantity but the buyer may have real uncertainty as to its own future demand and will want to embed that risk in the price. Alternatively, the seller could offer a load following product, in which case the cost is merely shifted to the seller; but the uncertainty, and hence the underlying cost of that uncertainty, remains and must be reflected in the price somehow.

The costs associated with managing these risks represent the trade-offs that must be made in a forward agreement whose terms are certain but which must fit somehow within an uncertain and changing economic future. Conflicting opinions about how to value these risks may lead parties to prefer shorter-term transactions. Valuing these costs and risks may lead some parties to participate in daily markets rather than enter longer-term contracts, or to opt for shorter rather than longer-term contracts. These costs should not, however, be considered as impediments to desirable long term contracts. They are merely the natural economic trade-offs which are inherent in such transactions.

The perception of inadequate long term contracting opportunities may indeed be a matter of different expectations. Differing perceptions about depreciated embedded costs or long-run marginal costs do affect parties' views about whether price formation within the market design is efficient or optimal, but are not determinative of whether or not it makes sense to enter into a forward contract. Once again, the critical perception for both the seller and the buyer must be the opportunity cost of transacting instead in the shorter-term market. As long as the risk trade-offs associated with contracting forward are perceived as costlier than the alternative of the expected outcome in the spot market, the parties will choose not to contract forward. The point is not that the opportunities to contract forward are inadequate but rather that the opportunities to transact shorter-term are more attractive. This is simply buyers and sellers making rational decisions in the marketplace. This is not to say, however, that there are no opportunities for improving the contracting climate for parties in both the daily and forward markets. Increasing the efficiency and stability of the organized markets will allow parties to form clearer and more consistent expectations about the daily market, thereby enhancing their ability to contract forward on the basis of those expectations.

*PSC Question **6**: Should constraints be imposed that would, under certain circumstances, restrict the resource types eligible for long-term contracts, limit the length of contract terms or establish the content of other contract conditions? What steps should be taken to limit any anti-competitive impacts long-term contracts might create?*

Yes, as explained above in more detail, long term contracts by utilities should be employed, if at all, only in very limited circumstances. In addition, the Commission should take steps to minimize the chances that long term contracts, if entered into by utilities, will impede the development of competitive markets. This will be accomplished by ensuring that utilities' customers pay in their retail rates all of the costs that the utility incurs as their service provider through a competitively neutral structure. Price comparability for consumers (*i.e.*, between a utility's retail rates and the offers of competitive energy service companies) can be ensured by the inclusion of retail administrative charges in a utility's retail rates that reflect all of the costs to provide that service, including all of the costs the utility incurs under long term contracts; such price comparability will allow competitive retail suppliers to compete to serve consumers' electric supply requirements.

*PSC Question **7**: Should restrictions or guidelines be imposed on the resource procurement practices employed in selecting the resources that would be acquired under the long-term contracts?*

Generally speaking, competitive processes such as auctions or request for proposal processes are best to procure energy and energy-related services for utilities, especially in order to provide appropriate protections from affiliate preference and to encourage market-based, competitively priced services; if the Commission orders utilities to enter into long term contracts, Constellation recommends that such a competitive practice be employed for their procurements.

In order to allow for the most reasonable opportunity for success for the procurements, the solicitations should be narrowly tailored, such that bidders know exactly the type of uniform product (*i.e.*, term length, size (MW) and other such characteristics) for which they are bidding to supply. The winners of a competitive procurement should be chosen based on the pricing of their bids alone, once they have met appropriate and uniform credit and application requirements for such procurement.

In addition, to protect consumers and assure non-discriminatory and transparent processes, the Commission can maintain stewardship of procurements, including through the use of an independent third party overseer and consultant for such processes. To further uphold consumers' interests, the Commission could provide the independent third party with the authority and the ability to establish price expectations for procurement processes in order to increase the likelihood of a competitive outcome. The third party consultant could evaluate, calculate and announce an appropriate starting price for a procurement, based on factors and characteristics of the market just prior to each procurement.

PSC Question ***8****:* *How should long-term contract costs be recovered from customers, and should different recovery mechanisms be developed based on the type of resource that is acquired under the contract, the length of the contract, or other factors?*

As explained above in Constellation's answer to PSC Question 6, the Commission should assure that utilities' customers pay in their retail rates all of the costs that the utility incurs as their service provider, including all of the costs utilities incur under long term contracts, and such costs should be recovered at that time those costs are incurred, as opposed to recovery on a longer, delayed basis.

*PSC Question **9**: What procedures should be followed in reviewing a long-term contract and in establishing its qualification for cost recovery? Under what circumstances, if any, should recovery of contract costs be pre-approved?*

Potential bidders may be more likely to decline participating in a procurement process for long term contracts if they perceive a broad risk that the procurement's results might be rejected by the Commission, or if there is a delay between award and approval of a procurement's results. Moreover, to the extent the Commission retains broad discretion to reject supplier's bids, to the extent suppliers participate, they may include a bid premium to reflect the option – *i.e.*, the cost of keeping their offers open pending approval. In order to avoid a lack of interest in procurement processes or additional premiums to account for risks of rejection, the Commission should (1) carefully consider and approve a competitive procurement process for a utility which is developed with all interested stakeholders' input and (2) limit the Commission's right to reject the results of a competitive procurement process only to situations where the process is found not to be in accordance with the Commission's pre-approved procurement plan. In turn, a utility should be permitted to fully recover the costs of any contracts it enters into as a result of such a Commission-approved process, if the process was run correctly and fairly.

*PSC Question **10**: Can long-term contracts (energy and/or capacity) be harmonized with existing NYISO rules for energy and capacity markets, and with potential NYISO forward capacity markets? If so, how can they best be harmonized? What changes to NYISO market rules, if any, would be necessary or appropriate for the purpose of accommodating long-term contracts? Should NYISO market rules recognize or ameliorate the impact, if any, of long-term contracting on the NYISO capacity prices paid existing generators, or, if amelioration is appropriate, should it be accomplished through non-NYISO mechanisms?*

As discussed above in our answer to PSC Question 5, long term contracts should be entered into not by directing parties to enter into such contracts, but by encouraging long term contracts through NYISO's existing market structures. As discussed above, to best facilitate market participants' entry into long term contracts in their ordinary course of business in NYISO, the Commission can help NYISO to improve price formation and promote greater liquidity.

PSC Question ***11****: Are there any other creative solutions that might be considered to address the issues identified herein?*

With respect to the issue of long term contracts, generally, Constellation again notes that the best solutions to encourage long term contracting in the marketplace are not through mandatory long term supply contracts for utilities, but through improving existing market structures in order to facilitate long term contracting by market participants in the ordinary course of business. In addition to the improvements to NYISO's rules and structures discussed in the previous question and in PSC Question 5, this can be achieved by:

- Sending a clear message regarding contract sanctity – *i.e.*, how the Commission will view and respect utilities' load supply agreements in order to maintain confidence in the integrity and enforceability of such agreements;
- Promoting long term contracting opportunities by lending stability to the organized markets through regulatory certainty, as regulatory uncertainty is another important cost of long-term agreements, as explained in more detail above; and providing such certainty in and of itself may lead to long term contracting by all market participants, including utilities, wholesale suppliers, retail suppliers, end-use customers, independent power producers and developers of new renewable generation; and
- With respect to the issue of entering into long term contracts for new generation resources including renewable and traditional fossil fuel resources, as mentioned above, improving the process for siting, which (rather than financing) is the major

impediment to new investment; the most important solution to encourage investment in new resources is to evaluate and relieve impediments to timely approvals for siting of new generation.

Constellation appreciates that at times policymakers may wish to specifically encourage development of renewable or experimental technologies because of the common good that is expected to result from such development and investment. However, in addition to improved siting procedures, the best solution for the Commission to encourage investment in specific types of renewable resources is to require that suppliers meet targeted portfolio requirements through a more market-based system than that currently provided under New York's Renewable Portfolio Standards ("RPS") program. The current RPS structure in New York, which involves competitive solicitations issued by NYSERDA, provides little to no forward price visibility, thus impeding efforts to develop long term renewable investment strategies as well large scale individual projects that may have a multi-year development cycle. Constellation urges the Commission to consider a transition to a more market-based system such as those used in New Jersey and Massachusetts, relying on a certificate-based attribute accounting system. In these states, because electric suppliers are required to satisfy certain RPS requirements, they are willing to enter into longer term contracts with private investors in renewable generation in order to meet their obligations. These contracts in turn allow such investors to obtain the necessary financing to build their plants. In this manner, competition at the wholesale and retail level is not adversely impacted and the market works exactly as it should: increased demand for renewable resources leads to increased construction of such resources.

Additional incentives for renewable energy and demand response can be provided in a number of ways and can be made available to all developers of qualified generation within New

York, thereby minimizing the adverse impacts on competition that might arise if other programs are utilized. The Commission could support legislation for financing incentives through various mechanisms, including tax credits, accelerated siting processes and loans. Demand response, moreover, can also be expanded through continued and enhanced NYSERDA rebate programs as well as increased utility investments in advanced metering. Market participants can and should compete for these incentives.

The targeted incentives approach is superior to other options for renewable investment for a number of reasons. First, financing incentives allow all market participants to compete on an equal basis while not transferring the operational/technology risks to customers. Second, by placing RPS requirements on electric suppliers, for instance, plant owners would be able to enter into bilateral contracts with wholesale and retail suppliers who need to obtain renewable energy certificates. If the generator is not commercially successful, penalties and remedies would be resolved among the contracting parties. Third, through this competitive process it is likely that the most efficient projects will be awarded such financing incentives. Fourth, the costs associated with such generation will be appropriately socialized among all of New York’s consumers through appropriate market pricing in suppliers’ rates, recognizing that all consumers benefit from the introduction of new technology to the generation resource mix. Because there is a recognized overall societal good being mandated, the cost of meeting the environmental requirements will be shared by all consumers equally.

CONCLUSION

Constellation reiterates that New York’s utilities should not become engaged in IRP processes or active portfolio management in order to obtain new generation resources. Competition in New York’s energy market should recognize the changing consumer environment and switch risks from customers to entities (and their shareholders) who are capable of best managing price and delivery risk. These entities have appropriate credit credentials and a sophisticated understanding of the physical and financial markets and useful hedging strategies. Constellation moreover urges the Commission to refrain from implementing long term contracts, but recommends that if the Commission orders their use, it should limit their use only for investment in new nuclear resources. Constellation appreciates this opportunity to submit its initial comments in response to the PSC Questions presented in the April 19 Order, and looks forward to continued dialogue regarding all of the issues presented herein and in the comments submitted by all other parties in this proceeding.

Respectfully Submitted,

/s/

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On Behalf of
Constellation Energy Commodities Group, Inc. and
Constellation NewEnergy, Inc.

Dated: June 5, 2007

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have served on this 5th day of June, 2007 the foregoing document by electronic mail to all parties on the Service List for this proceeding.

/s/

Divesh Gupta