BEFORE THE
STATE OF NEW YORK PUBLIC SERVICE COMMISSION

In the Matter of the Implementation of a Large-Scale Renewable Program	**:** **:**	**Case 15-E-0302**

COMMENTS OF CONSTELLATION ENERGY NUCLEAR GROUP, LLC CONCERNING STAFF WHITE PAPER ON CLEAN ENERGY STANDARD

In response to the Notice Soliciting Comments and Providing for Technical Conference and Public Statement Hearings issued by the State of New York Public Service Commission ("Commission") on January 25, 2016 in the above-captioned proceeding, Constellation Energy Nuclear Group, LLC ("CENG") hereby submits these comments concerning the Staff White Paper on the Clean Energy Standard ("White Paper"). CENG owns and operates the R.E. Ginna and Nine Mile Point nuclear facilities ("Ginna" and "Nine Mile," respectively) located in upstate New York. Together, these facilities generate almost 20 million MWh of emissions-free energy each year, enough to power 2 million homes. These zero-emissions facilities are essential for New York to achieve the environmental goals set forth by Governor Cuomo.[1] However, immediate policy changes are needed in order to ensure their continued operation. The Commission's cost study and the independent analysis of the Brattle Group detail what is at stake. The continued operation of these plants avoids carbon and other air pollution valued at $750 million per year.[2] The direct economic impact of these plants is approximately $2.5 billion per year, and their total economic impact is close to $5 billion per year.[3] CENG focuses these comments on the proposed Tier 3

[1] Letter from Governor Andrew M. Cuomo to Audrey Zibelman, CEO, N.Y. Dep't of Pub. Serv., Dec. 2, 2015 ("Cuomo Letter").
[2] The Brattle Group, *New York's Upstate Nuclear Power Plants' Contribution to the State Economy*, December 2015 at 1, 12 ("Brattle Report") (attached as Exhibit A).
[3] *Id.* at 1, 12 ($750 million in environmental benefits plus $1.7 billion in other direct economic benefits); N.Y. State Dep't of Pub. Serv., *Clean Energy Standard White Paper—Cost Study* (April 8, 2016), at 84 ("DPS Cost Study").

program with the goal of clarifying program elements in order to create a timely, transparent and durable zero-emission credit ("ZEC") that provides certainty to customers and the plants alike.

INTRODUCTION

Today, Ginna and Nine Mile are in jeopardy of premature and permanent closure because there is no policy mechanism to compensate nuclear resources for their zero-emissions attribute. In this stark reality, Governor Cuomo's directive to create a Clean Energy Standard ("CES") that recognizes the value of these zero-emissions resources is a beacon of light that gives hope to facility owners, host communities, and the talented men and women that work at these plants. Urgent and timely action is needed because CENG and other nuclear operators must make critical decisions in 2016 to undertake the substantial fuel and capital investments required for continued plant operations, or, alternatively, to cease operations.

To succeed, the CES must (i) provide a framework that is stable over time to ensure that nuclear facilities serving New York are adequately compensated for the environmental value their generation provides to the state, so that they can continue to produce zero-emissions energy through at least 2029; and (ii) ensure that New York consumers do not pay more than necessary for these environmental benefits. Our comments address the main aspects of the proposed framework as follows.

Eligibility Requirements. CENG urges two changes to the eligibility criteria proposed in the White Paper. First, the Commission should eliminate the need to demonstrate financial distress as a prerequisite to eligibility. This element creates the misimpression that New York is simply attempting to prop up distressed assets rather than appropriately recognizing the environmental value of a nuclear facility's zero-emissions generation. The financial distress requirement creates program ambiguity and is not needed to protect consumers. That protection already is provided by the ZEC calculation methodology, which ensures that New York consumers will pay no more than needed to cover operating costs and risks.

Second, the Commission should limit eligibility to nuclear facilities that are physically capable of delivering their energy and capacity into New York. The State's interest is in reducing the carbon and other air pollutants associated with New Yorkers' consumption of electricity. That goal would not be advanced by procuring ZECs from a facility that is physically incapable of delivering its electricity into the State. New York also has an interest in being able to rely on the zero-emissions production of energy by nuclear facilities, even at times of peak demand—so long as such reliance is consistent with the rules and regulations of independent system operators and (for external resources) other states. Thus, to be eligible, a nuclear unit not only should be capable of delivering into New York, but also should not be subject to recall by another jurisdiction or external independent system operator. New York's emissions-reduction goals cannot readily be met if, at times of peak demand, its main sources of emissions-free generation suddenly become unavailable to New Yorkers and the State is required to rely upon pollution-emitting fossil-fuel plants to keep the lights on.

Procurement Method and Timing. CENG agrees with the Commission that all load-serving entities ("LSEs") should be required to meet the CES mandates and that the New York State Research and Development Authority ("NYSERDA") should act as a backstop procuring authority for LSEs that choose to pay an alternative compliance payment to NYSERDA in lieu of actual ZEC purchases.

To create program certainty, however, NYSERDA should conduct a centralized backstop procurement within 60 days of the Commission's decision approving the program. Program payments would be based upon the ZEC calculation methodology approved by the Commission with periodic and routine program reviews of facility costs and available market revenues. ZECs procured by LSEs directly from participating facilities would be deducted from the volumes that NYSERDA would procure in a given delivery year. Thus, for example, if LSEs meet 100% of their purchase obligation in 2022, the contractual volumes under the NYSERDA contract would fall to zero in that year.

The NYSERDA procurement would give facility owners and customers needed certainty that the program will continue until 2029. In this vein, stakeholders have asked that plant owners commit to continue operations through 2029. While CENG recognizes the value that a long-term operations commitment provides for utilities and transmission planners, nuclear facility owners also need certainty. A program design that leaves open the possibility that the program could be abolished in a handful of years would create market uncertainty at a time when the opposite is needed. Nuclear facility owners must make long-term investments in key mechanical components to ensure that these assets will operate until 2029. In this respect, the need for program certainty is no different than the need for contractual certainty for renewable developers who receive 20-year contracts from NYSERDA.

Costs and Revenues Should be Forecasted on a Facility-Specific or Portfolio-Specific Basis. NYSERDA should procure ZECs at a facility-specific, administratively determined price that reflects the difference between that facility's *own* anticipated costs and its anticipated revenues from electricity sales. For administrative ease, an owner of multiple qualifying facilities could choose to receive a single, weighted-average ZEC price for each of the facilities in its portfolio, recognizing the synergies associated with multiple facility operations. LSEs that self-supply ZECs will be responsible for their pro rata share of the aggregate cost of procuring those ZECs.

Compensation Formula. In determining the ZEC price or Alternative Compliance Payment ("ACP"), the Commission will need to assess the difference between anticipated costs and anticipated revenues from electricity sales. The White Paper makes clear that program compensation will not be in the form of a contract-for-differences. In other words, to the extent that costs are higher than anticipated, or revenues are lower, participating facilities will not be entitled to receive a reconciliation payment. Nor does the White Paper provide for a commercial return as a proxy for market and operational risks. Instead, the Commission proposes to assess *projected* costs per MWh of production *assuming* a certain level of production (that is, a certain capacity factor).

In determining projected costs, we emphasize the importance of accounting for costs resulting from exposure to certain risks that cannot be insured or hedged. These risks, detailed below, all could be avoided by closing a facility and exiting the market; the cost associated with mitigating them is thus properly regarded as a forward cost faced by a facility that is deciding whether to continue operating. Accounting for these risks is essential because the compensation formula is based on projected costs with no reconciliation to actual costs. As a result, if the ZEC price does not reflect the costs associated with incurring certain uninsurable and unhedgable risks, the CES program will not provide sufficient additional compensation over time to justify a facility's continued operation.

Recognizing this reality, the Commission Staff sought input at the technical conference concerning how to measure and account for operational and market risks that result from continued production and that could be avoided by retiring the facilities. These risks include "operational risks" as well as "market risks."

"Operational risks" include:

- The risk that operating costs will be higher than anticipated due, for example, to unanticipated regulatory mandates or unexpected equipment failures.
- The risk that operating costs per megawatt-hour will be higher than anticipated due to a lower-than-expected capacity factor, forcing the owner to recover the same fixed costs over a smaller number of megawatt-hours.

To value these operational risks, CENG examined nuclear capacity factor data and created a probability distribution of nuclear capacity factors. CENG's normal business practice for pricing risk is to set the cost of self-insuring against a risk at the fifth percentile outcome in the probability distribution, so that CENG has 95 percent confidence that it will not incur a loss as a result of a given risk. Based on that methodology, capacity factor risk alone requires an adjustment of a facility's operating costs upward by 21 percent. At the same time, the Federal Energy Regulatory Commission ("FERC") has approved as just and reasonable a 10 percent upward adjustment to reflect operational risks in the context of regulating cost-based energy bids. FERC explained that such an adjustment is appropriate to "account for uncertainty in the values of the costs utilized in computing … cost-based offers before all costs are known."[4] Accordingly, a cost adjustment to reflect operational risks of between 10 percent and 21 percent would be appropriate.

In addition to these "operational risks," facilities also face "market risks." "Market risks" include:

- The risk that, in the event of an unexpected outage, the facility owner will be forced to cover a forward sale obligation by purchasing electricity on the spot market at a higher price than the buyer has agreed to pay under the forward contract.
- The risk that a facility owner will be unable to sell its output forward at the price used in the ACP formula to reflect the facility's expected revenues. Although the ACP formula uses forward prices, the market is dynamic, and forward prices may fall when a facility owner enters the market to attempt to sell a large quantity of electricity forward. That is especially so when the market has anticipated that the facility would retire.

[4] *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61289, P 30 (2015).

- The risk that a facility's basis – that is, the difference between its nodal energy price and the zone-wide energy price used as a reference by the ACP formula – will exceed the expected basis.

As detailed below, CENG has analyzed the probability distribution of these market risks using the methodology for valuing risk that it generally uses in its business, and these market risks result in an additional facility cost of $4/MWh.

Altogether, CENG estimates that the costs faced by the portfolio of its upstate New York plants, including a 10 percent adjustment for operational risks and the $4/MWh cost for market risks, amount to approximately $50/MWh of production. Thus, CENG would need a ZEC price equal to $50/MWh of production for its portfolio, less its anticipated capacity and energy revenues, in order to make the CES program effective. In a Confidential Appendix, attached as Exhibit E, we set forth in detail the calculations and data supporting the $50/MWh cost estimate. This cost estimate is less than the cost used by the Commission in its Cost Study.

It should be emphasized that, although participating facilities will recover the cost of self-insuring against operational and market risks, that does not guarantee a participating facility its cost of service. To the contrary, the facilities remain exposed to the costs that will result if operational or market risks result in costs that are even greater than those assumed in the CES compensation formula. For example, the unexpected failure of a major piece of equipment may result in a prolonged outage that increases actual per-MWh operational costs by far more than 10 percent. Likewise, if a nuclear plant is forced out for a prolonged period and must cover a forward contractual obligation by making purchases on the spot market, the resulting costs resulting from that market risk could be far higher than the $50/MWh cost estimate reflects. There is no true up to recover those costs. Thus, facilities participating in the CES program will remain exposed to operational and market risks, and operators will have every incentive to continue to try to minimize those risks.

Procurement Quantity. The White Paper proposes to phase in the program by capping the quantity of ZECs available in increasing amounts from 2017 until 2020 and beyond.[5] CENG urges that the Commission eliminate the quantity phase-in and allow all qualifying facilities to sell ZECs at the ACP beginning April 1, 2017. The Nine Mile facility is projected to lose [CONFIDENTIAL][6] in 2016. In light of the fact that the benefits of the program strongly outweigh the costs, and that critical decisions on all of CENG's facilities must be made in 2016, the Commission should eliminate the quantity phase-in.

Commitment. As noted above, both consumers and facility owners need a long-term commitment from the ZEC program. As commenters indicated at the March 9, 2016 Technical Conference, New York consumers need to be able to rely on a participating facility's clean energy attributes as a bridge to its 2030 emissions-reduction goals. They cannot do so if a participating facility retires after just a few years in the program.[7] Facility owners likewise need a long-term commitment, because they need long-term revenue assurance in order to justify making the significant expenditures needed to keep their facilities operating through the 2020s. Accordingly, CENG supports a 12-year contract term, running from April 1, 2017 through December 31, 2028. However, a facility should be released from any commitment under specified circumstances, such as a change to the CES program structure, an unexpected capital expenditure exceeding a certain threshold, the termination of an NRC license, or in the event of catastrophic damage to the facility due to a force majeure event.

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[5] White Paper at 45.
[6] See Exhibit 2 to Exhibit E.
[7] DPS Cost Study at 284.

CENG and other owners of New York nuclear facilities must make imminent decisions whether to shutter their facilities or to make new investments needed to remain in operation.[8] Timely approval of the CES by June/July 2016 and a procurement to be conducted within 60 days of the Commission's Order, with the modifications described below, is essential to ensuring that New York will continue to receive the benefit of these facilities' emissions-free production and that New York will remain on a glide path to achieving its 2030 environmental goals.

COMMENTS

I. New York Cannot Achieve Its Emissions-Reduction Goals Without Existing Nuclear Facilities.

The Nuclear Tier (Tier 3) is the most cost-effective element of the CES in achieving carbon abatement. In the early years of the CES program, the Nuclear Tier accounts for over 75% of the carbon avoided by the program. Over the longer term, the Nuclear Tier accounts for approximately 21 percent of gross CES program costs, but provides more than half of the carbon abatement benefits.[9] As the White Paper makes clear, and as the Brattle Group's December 2015 independent analysis confirms, emissions of carbon dioxide, sulfur dioxide, and nitrogen dioxide would increase significantly if the State's nuclear facilities shut down.[10] The retirement of a nuclear facility leaves an enormous hole to be filled: each nuclear facility dependably generates so much electricity that it simply cannot feasibly be replaced by currently available zero-emissions generation technology with much lower capacity factors, such as wind or solar.[11]

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[8] With respect to Ginna, for example, CENG must indicate by September 30, 2016 whether it intends to continue commercial operations. *See* Clean Revised Settlement Agreement, *R.E. Ginna Nuclear Power Plant*, FERC Docket No. ER15-1047-000 (Mar. 23, 2016), Attach. A § 4.1.3.7.

[9] Brattle Group, "Comments on the New York DPS "Clean Energy Standard White Paper – Cost Study" (Apr. 18, 2014), at 1 ("Brattle Cost Study") (attached as Exhibit B); CES Cost Study Supplement (April 12, 2016), tabs 38-39, 84, 87-88, and 91.

[10] White Paper at 29; Brattle Report at 11.

[11] White Paper at 29; Remarks of Raj Addepalli, Managing Director of Utility Rates & Services at DPS, Clean Energy Standard Workshop #2 (March 9, 2016) ("[I]f one plant, like, Ginna, for example, retires, it's equal to replacing it with almost … 2,000 megawatts of renewable resources to get the same amount of clean

Instead, a retiring nuclear plant is most likely to be replaced by natural gas-fired plants, which emit carbon and other air pollutants. Indeed, the Brattle Group projects that "[a]verage annual CO_2 emissions would be almost 16 million tons higher absent the generation from" the nuclear plants located in upstate New York (Ginna and Nine Mile, along with FitzPatrick Nuclear Power Plant).[12] The upstate nuclear plants also prevent the emission of 13,000 tons of NO_x, 3,000 tons of sulfur dioxide, and 2,000 tons of particulate matter each year. Closure of the three upstate nuclear plants thus would adversely affect air emissions and make it extremely difficult, if not impossible, for the State to meet its emissions-reduction goals.[13]

Germany's recent experience provides a cautionary tale. Since 2010, Germany has reduced its nuclear generation by 30 percent. Despite paying more than $100 billion in subsidies to support renewable generation, Germany has fallen far short of its carbon reduction goals. Indeed, Germany has reduced its carbon emissions by 16 million tons—far below its stated goal—for an implied cost of $1,250/metric ton of carbon reduced, which is orders of magnitude higher than the federal government's $45/metric ton social cost of carbon.[14] Governor Cuomo clearly understood the adverse impact that losing the upstate nuclear plants would have on the State's ability to meet its emissions reduction goals, stating that it "would eviscerate the emission reductions achieved through the State's renewable energy programs, diminish fuel diversity, increase price volatility, and financially harm[] host communities."[15]

The economic value of the emissions prevented by the three upstate nuclear plants is enormous. The Brattle Group estimates that the value of avoiding 16 million tons of CO_2 is $675

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energy. And to put that in context, over the last decade the whole RPS program produced close to 2,000 megawatts of renewable resources.").

[12] Brattle Report at 11.

[13] Draft Supplemental Environmental Impact Statement at 5-15 (Feb. 23, 2016).

[14] The social cost of carbon is calculated by the U.S. Government's Interagency Working Group on Social Cost of Carbon and is intended to capture the economic damages resulting from the emission of carbon. *See* EPA, The Social Cost of Carbon, https://www3.epa.gov/climatechange/EPAactivities/economics/scc.html.

[15] Cuomo Letter.

million *annually*, based on the federal government's social cost of carbon. The economic value of preventing the increase in SO_2, NO_x, and particulate matter emissions that would result if the upstate nuclear plants were closed comes to an additional $61 million in benefits annually.[16]

Although the purpose of the CES program is environmental, the upstate nuclear plants also bring substantial non-environmental benefits to New York. The Brattle Group finds that the direct economic benefits of the three upstate plants amount to an additional $1.7 billion annually beyond the value of the environmental benefits, for a total of $2.5 billion in direct annual benefits. In addition, the plants contribute approximately $3.16 billion to state gross domestic product and are responsible for $144 million in net state tax revenues.[17]

These benefits far exceed the costs. Even considering only the carbon abatement benefits, the benefits of the Nuclear Tier are six times larger than the costs through 2023.[18] In addition, as the Commission found in its Cost Study, the ZEC program is likely to result in net economic benefits of approximately $1 billion through 2023 in present value terms.[19] Incorporating all economic benefits with all environmental benefits resulting from the Nuclear Tier of CES, the benefits exceed program costs by a factor of *over 70*.[20]

II. Only Those Nuclear Facilities that Can Help New York Achieve Its Goals of Reducing Carbon Consumption Should Be Eligible for the ZEC Program.

The White Paper proposes that, in order to qualify as a resource eligible to sell Tier 3 ZECs, a nuclear resource (1) must have an in-service date of January 1, 2015 or earlier, (2) be facing financial difficulty as determined by a Commission inspection of books and records, and (3) be operating pursuant to a fully-renewed NRC license until 2029 or later and consistent with any other

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[16] Brattle Report at 12.
[17] Brattle Report at 1.
[18] Brattle Cost Study at 1. Indeed, this understates the benefits from the program, because the Commission's cost study, analyzed by the Brattle Group, assumed a phase-in of procurement quantity, effectively assuming that otherwise-qualifying nuclear facilities would stay open in the initial years of the program without receiving revenue from selling ZECs.
[19] DPS Cost Study at 84, 102-07.

federal and state authorizations.[21] CENG believes that the "financial distress" requirement is duplicative, misleading, and unnecessarily burdensome. Additionally, CENG proposes that, to be eligible, a resource must demonstrate that it is capable of delivering its energy and capacity to New York for the duration of the program and that its energy and capacity cannot be recalled by an external independent system operator.

A. The Commission Should Eliminate the Financial Distress Requirement.

CENG recommends that the Commission eliminate financial distress as an eligibility requirement. The financial distress requirement presumably was designed to protect consumers from paying more than necessary to receive the environmental benefits from nuclear units. However, in light of the Commission's method for calculating the ACP, we believe that the financial distress requirement is both duplicative and burdensome. It should be eliminated.

As we discuss below, we support the Staff's proposal to calculate an ACP based on the difference between a measure of projected costs and projected revenues of participating nuclear facilities. This ACP approach protects consumers by reducing the maximum value of a ZEC if participating plants grow more profitable and are able to provide their environmental attributes for less. Indeed, upstate energy prices have fluctuated widely over the last fifteen years and currently are at historically low levels. If energy prices rise in the future, the ACP could well turn out to be zero. For example, if energy prices increase to the 15-year historical average, the CENG portfolio ACP would be zero, as total capacity and energy revenue ($52.5/MWh) would exceed CENG portfolio costs (~$50/MWh). Thus, the financial distress requirement is not needed in order to prevent New York consumers from paying plants unnecessarily.

Given the consumer protection inherent in the method for calculating the ACP, CENG submits that requiring an additional showing of financial distress as a requirement for eligibility is

[20] Brattle Cost Study at 2.

not necessary to achieve the Commission's objectives. It would add significant administrative burden and expense for the Commission and eligible nuclear facilities, but would not provide any additional benefit to consumers.

Finally, the financial distress eligibility requirement in the White Paper would also create significant uncertainty for potential participants, because the proposal is vague about how financial distress is to be measured and demonstrated. That uncertainty would be magnified by a requirement that financial distress be reproven annually, particularly if participants must make a long-term commitment to remain in operation. Forcing participating generators to reprove financial distress to remain eligible for the program, without any clear definition regarding what constitutes "distress," undercuts that certainty and discourages participation. In sum, the compensation methodology proposed by the White Paper will allow New York to secure the desired environmental attributes, at a price that is protective of consumers, without needing to condition eligibility on a showing of financial distress.

B. Eligible Resources Should Be Required to Demonstrate Deliverability.

CENG proposes that the Commission require, as a condition for eligibility, that a participating plant demonstrate that it is capable of physically delivering all of its energy into New York for the duration of a procurement cycle. The State's interest in adopting this program is to reduce the air pollution resulting from New Yorkers' consumption of electricity. That interest can only be served if a facility's energy can actually be delivered in the State to be consumed by New York residents and businesses. Relatedly, New York has an interest in compensating nuclear facilities that can *dependably* provide New Yorkers with its zero-emissions environmental attributes, including at times of peak demand, while at the same time respecting other jurisdictions' authority over resources within their boundaries. Thus, to be eligible, a nuclear facility not only

[21] White Paper at 31.

should be capable of delivering in to New York, but also should not be subject to recall by another jurisdiction or external system operator. New York cannot meet its emissions-reduction goals if its main sources of emissions-free generation can suddenly become unavailable to New Yorkers when they are needed most. Together, these eligibility requirements—physical deliverability and non-recallability—will ensure that the nuclear facilities receiving payment for their environmental attributes are providing New Yorkers with the benefits of those attributes.

The easiest way for a resource to demonstrate that it has satisfied these criteria is to demonstrate, both initially and on an ongoing basis throughout the life of the program, that it satisfies the eligibility requirements to be an Installed Capacity Supplier in accordance with the NYISO Market Administration and Control Area Services Tariff ("NYISO Tariff"). Among other things, the NYISO Tariff requires that an Installed Capacity Supplier's energy and capacity be deliverable to the NY Control Area and that it cannot be subject to recall by an external system operator.[22] To be clear, CENG does not propose that the Commission require an eligible facility to offer into any NYISO auction, let alone make the generation of ZECs conditional on the successful sale of energy or capacity in FERC jurisdictional markets. Rather, to be eligible, a facility would simply need to demonstrate that it is capable of reliably serving the New York market. Without such a requirement, New York has no means of ensuring that a facility participating in the program is capable of reducing the carbon intensity of the electricity consumed in New York.

III. NYSERDA Should Conduct a Centralized Procurement for ZECs Within 60 Days of the Commission's Order Approving the Program.

The White Paper proposes that LSEs should be responsible for acquiring ZECs to meet the CES mandates, and that NYSERDA will act as a backup procurement authority in the event that the LSEs choose to pay an alternative compliance payment in lieu of acquiring ZECs.

[22] *See* NYISO Tariff at § 5.12.

To create program certainty, NYSERDA should conduct a centralized backstop procurement within 60 days of the Commission's decision approving the program. That procurement should be for a 12-year contract term, beginning April 1, 2017. A centralized NYSERDA procurement need not be exclusive; the Commission could still preserve the option for LSEs to enter into bilateral agreements for ZECs with participating facilities at a different price or for a longer or shorter term than the NYSERDA's procurement. For example, if an LSE decides after the NYSERDA procurement to enter its own bilateral agreement with a participating facility for ZECs procured by NYSERDA, the participating facility would be released from its commitment to sell those ZECs to NYSERDA.[23] Thus, if LSEs meet 100% of their purchase obligation in 2022, the contractual volumes under the NYSERDA contract would fall to zero in that year.

This arrangement—a centralized NYSERDA procurement within 60 days of the Commission's Order approving the CES program, for a 12-year term, with the option for LSEs to procure directly from participating facilities—would combine the efficiency of a central procurement by NYSERDA with the flexibility afforded by bilateral arrangements, while giving facility owners and customers needed certainty that the program will continue until 2029.

IV. NYSERDA Should Acquire ZECs at a Facility-Specific or Portfolio-Specific Price.

CENG supports the basic concept set forth in the White Paper under which the ACP—effectively, the maximum ZEC price—would be updated each year based on the difference between the average anticipated operating costs of qualifying nuclear facilities and their forecasted revenues from the sale of electricity products. The proposed ACP reflects the additional compensation beyond projected revenues from the sale of electricity products that the participating nuclear facilities need in order to continue to make their environmental attributes available. That general

[23] The LIPA share of Nine Mile #2 could be treated as an implied bilateral transaction, so that NYSERDA would not procure ZECs from LIPA's share of Nine Mile #2 and LIPA would receive a credit from NYSERDA for the ZECs produced by LIPA's share of Nine Mile #2.

method of calculating the ACP provides an important protection for New York consumers. As average projected revenues increase, the ACP decreases to zero.

The White Paper posits that each term in the ACP formula will be a single program-wide value denominated in dollars per megawatt-hour and will be the same for every nuclear facility participating in the nuclear tier. According to the White Paper, a single ACP, rather than multiple facility-specific ACPs, is desirable under the White Paper's design because the ACP is an alternative compliance payment that an LSE must make if it chooses *not* to procure ZECs. In a decentralized market for ZECs with each LSE managing its own compliance obligation, having multiple facility-specific ACPs is more difficult to administer.

In light of our recommendation that NYSERDA conduct a centralized backup procurement, the Commission should reconsider whether a single, program-wide ACP best serves the program's goals. A single, program-wide ACP based on average facility costs will result in the overpayment of some facilities and the underpayment of others, interfering with the Commission's ability to achieve its objectives. Facilities with costs lower than average will end up being able to sell their ZECs at a price that exceeds the amount they need in order to continue producing the zero-emissions attribute. Meanwhile, facilities with costs higher than average will be unable to cover their costs even with the benefit of ZECs.

CENG proposes an alternative approach in which NYSERDA (rather than the LSEs) procures ZECs from eligible nuclear facilities at an administratively determined price based on that facility's *own* anticipated costs and anticipated revenues from electricity sales (with anticipated costs and revenues calculated in the same manner as they would be under the single, program-wide ACP approach). An owner of multiple facilities could, for administrative ease, take the average of those facilities' costs and revenues and receive a bundled price for the portfolio's environmental attributes, reflecting that average. NYSERDA would then charge LSEs for their pro rata share of the aggregated cost of acquiring the ZECs. This approach would ensure that ZECs would only have value when sold by a facility that, but for the CES program, would not recover its costs.

V. The Compensation Formula Requires Further Specification.

Regardless of whether the Commission adopts the White Paper's proposal for a single ACP applicable to all participating nuclear facilities, or an alternative in which each facility may sell at its own administratively determined unit-specific (or portfolio-specific) price, the Commission will need to determine the anticipated costs and anticipated revenues of the participating facilities. At the technical conference, the Commission Staff asked parties to provide input regarding how to measure anticipated costs and anticipated revenues. CENG proposes the following formula (which is summarized in the spreadsheet attached as Exhibit C):

ACP = facility costs – projected energy revenues – projected capacity revenues

Below, we consider each of those component elements in turn.

A. Facility Costs.

Calculating facility costs. The White Paper states that the ACP would be based in part on the "anticipated operating costs" of participating nuclear facilities.[24] A nuclear facility's operating costs include, among other things:

- Site-level operations and maintenance expense;
- Fully-allocated overhead expenses, allocated using the methodology developed by the Institute for Nuclear Power Operations ("INPO"), which is normally used by the company in its budgeting process;
- Forward-looking (i.e., not sunk) non-fuel capital expenditures;
- Forward-looking fuel expenditures;
- Department of Energy spent fuel charges in the event that they are re-instituted;

[24] White Paper at 32.

- A return on working capital required for ongoing operation of the facility, such as prepayments, parts and inventories, and cash needed to support operations and sale of plant output; and

- Any costs imposed on a facility or determined prior to the date of the Clean Energy Standard implementation that are contingent upon a facility's continued operation and have been authorized previously by the Commission.

We propose that anticipated facility costs be set at a fixed, constant level for the first four years of the program (2017 through 2020), with the determination of anticipated costs to take place by September 2016.[25] That value would be equal to the aggregate projected operating costs of participating facilities over the four year cost measurement period (2017 to 2020 initially) divided by the projected aggregate annual production of all participating facilities over that same period. Using multiple years of data to project costs in this manner serves to average out variability in cost due to a plant's fuel cycle. Following the initial measurement period, anticipated costs would be adjusted annually on a three-year-ahead basis. For example, the facility costs applicable to 2021 would be determined in late 2017 by calculating anticipated facility costs over the period 2018-2021 divided by the projected total annual production of participating facilities over that same period and then adjusting for inflation as necessary.[26] This approach ensures that compensation is predictable because it is always determined three years ahead, but at the same time accounts for changes in costs over time.

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[25] If a plant is only participating for a partial year (such as if the program were to begin in April 2017), that plant's operating costs would be prorated by the share of output falling in the portion of the year in which the plant is participating. Operating cost items (such as refueling costs) that fall disproportionally or entirely within the period of participation would be included if they were incurred during the period of participation.

[26] An inflation adjustment is necessary because the facility costs for the incremental year fall in the final year of the 4-year average, rather than the middle, and thus if costs are rising (or falling) the final year will be higher (or lower) than the 4-year average. Mechanically, the inflation adjustment should be implemented via a three-step process: (1) calculate the annualized embedded inflation rate by calculating the percentage change in the average facility cost per MWh over the current four year period (e.g. 2018-21) relative to the average facility cost per MWh over the prior four year period (e.g. 2017-20), (2) calculate an inflation adjustment applicable to the final year of the current 4-year period (e.g. 2021) using the following formula: inflation adjustment = (1+i)^3 / average(1, 1+i, (1+i)^2, (1+i)^3) - 1, where i=the annualized embedded inflation rate calculated in step 1, (3) multiply the average facility costs per MWh over the current 4 year

Alternatively, the Commission may prefer to incorporate some consideration of historical costs to ensure that participating facilities are not overstating cost projections. For example, one could look backward at the two preceding years (with an appropriate adjustment for inflation) and forward at the following two years. In all events, costs should be considered at a facility level rather than a unit level. For multiple reactor facilities, overhead costs are typically shared among the units, so it makes sense for those units to be aggregated and treated collectively.[27]

Risk component of facility costs. In addition to the costs of operation set forth above, nuclear units also bear costs associated with exposure to certain types of risk. These risk-related costs stem from the facilities' operation and could be avoided by the facilities' retirement. Accordingly, they should be included in the calculation of a facility's costs. Indeed, in its February 24, 2016 Order, the Commission recognized as much when it included operating risk as an element of cost to be considered when determining "the certification, selection of funding for zero carbon electric generating facilities."[28] In the context of the CES, a voluntary program that is an alternative to retirement, these risks must be included as costs, because they would be avoided by retirement.

Participating nuclear units will face two broad categories of risk that must be accounted for: operational risks and market risks. These risks can be avoided by retiring a unit, but cannot be avoided if the unit operates. Unless the cost of self-insuring against these risks is accounted for, the maximum ZEC price will be too low for participating facilities to recover the costs of operation, and they will choose to retire instead of opting into the program.

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period (e.g. 2018-21) by 1 plus the inflation adjustment to arrive at a facility cost value for the incremental year (e.g. 2021).

[27] The Commission would need to take steps to preserve the confidentiality of cost data from public disclosure.

[28] New York Public Service Commission, Order Further Expanding Scope of Proceeding and Seeking Comments 2 (Feb. 24, 2016).

Operational Risks

Operating cost risk. Participating nuclear facilities face operating cost risk because the projected costs per MWh are set on a three-year-ahead basis with no true up for actual realized costs per MWh. As a result, participating units run the risk that actual realized operating costs may be higher than those projected costs. For example, changing regulatory mandates or unanticipated equipment failures can result in significant costs that will not be reflected under the compensation mechanism, which operates on a forward-looking basis. That risk is particularly pronounced for nuclear plants, which are subject to stringent oversight and can face additional, unforeseen regulatory requirements at any time.

Capacity factor risk. Nuclear facilities face capacity factor risk because their costs are largely fixed—that is, they remain largely the same even if plant output declines. As a result, lower than expected output (that is, a lower than expected capacity factor) results in an increase in costs per MWh of output. Moreover, while nuclear facilities generally are highly reliable and operate at extremely high capacity factors, when a nuclear outage does occur, it tends to be prolonged and the resulting increase in cost per MWh of output will be substantial.

The cost increase related to a reduced capacity factor is proportional to the reduction in output. Specifically, actual costs equal projected costs multiplied by 1 / (1 – reduction in capacity factor). For example, if a facility's projected costs are $1,000 million and projected output is 20 million MWh, this translates to a cost of $50/MWh ($1,000 million / 20 million MWh). If instead, that facility's output is reduced by 10 percent to 18 million MWh, then costs become $55.55/MWh ($1,000 million / 18 million). So, given a 10 percent reduction in output, actual costs per MWh turn out to be 11.1 percent higher than projected.

These two types of operational risk—operating cost risk and capacity factor risk—tend to be realized together. For example, if an unexpected equipment failure takes a facility offline, the facility will face the unanticipated cost of repairing the equipment failure *and* its costs will be spread over fewer megawatt-hours of output than anticipated. Operational risks are magnified still further if facilities, by participating in the program, make a commitment to remain in operation until at least 2029. During that time, a facility may need to make significant and unanticipated capital investments to remain operational and may experience lower than expected output for a prolonged period. Because the calculation of a facility's costs is not trued-up, participating facilities will bear the risk of such unanticipated expenditures and lost output.

In order to estimate the cost associated with operational risk, CENG examined capacity factor data and created a probability distribution of nuclear capacity factors. CENG's normal business practice when pricing risks that produce significant losses at low probabilities—such as capacity factor risks—is to set the cost of self-insurance at the fifth percentile level of the outcome distribution. That is, the effective self-insurance premium is set at a level that provides 95 percent confidence that the unit will not incur a loss due to a risk. The table set forth in Exhibit D, which shows year-to-year actual realized capacity factors for each of the approximately 100 units in the U.S. fleet from 2008 to 2014, as reported by the Nuclear Regulatory Commission, indicates that the fifth percentile capacity factor in each year has been on average about 17 percent below the average. In other words, each year, there is a 5 percent probability that forced outages for a given facility will result in a capacity factor approximately 17 percent or more below the expected capacity factor—equivalent to a 21 percent increase in operating costs per MWh of production.[29]

In the context of assessing a generating unit's costs for purposes of reviewing cost-based energy offers, FERC has determined that it is just and reasonable to assume that operational risks will increase a facility's operating costs by 10 percent. According to FERC, adjusting a generator's costs upward by 10 percent "account[s] for uncertainty in the values of the costs utilized in

[29] The impact on per-MWh costs is calculated as 1 / (1 – 0.17) = 1.21.

computing … cost-based offers before all costs are known."[30] Accordingly, FERC has approved PJM's tariff, which adjusts a generator's going-forward costs upward 10 percent to "provide for a margin of error for understatement of costs."[31] Based on the capacity factor data and FERC's practice, it would be appropriate to adjust operating costs by between 10 percent and 21 percent to account for operational risks.

Market Risks

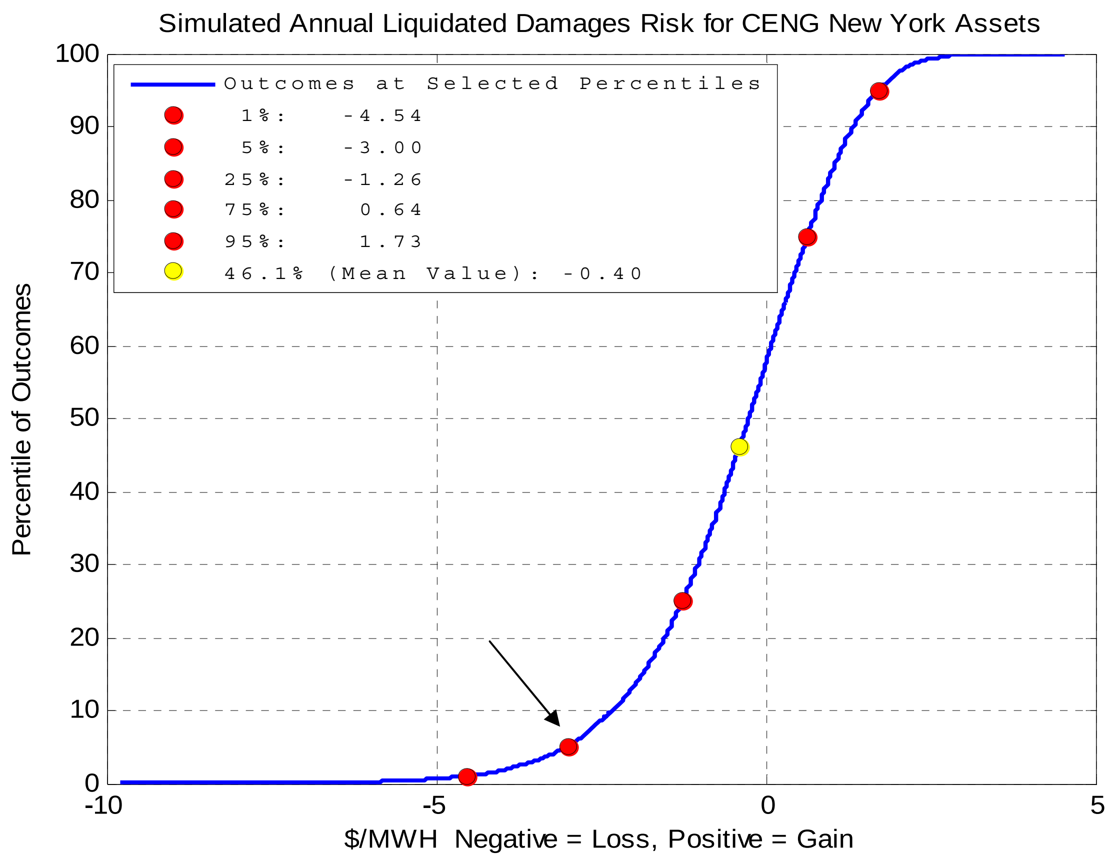
In addition to operational risks, nuclear facilities also face market risks that could be avoided by retirement. In particular, they face three types of market risk: liquidated damages risk, volatility risk, and basis risk.

Liquidated damages risk. In order to hedge against volatile market prices, nuclear facilities typically sell forward their energy production during all hours at a specified fixed price. The White Paper's proposed method for projecting revenue (discussed below) effectively assumes such a forward sale. However, if the facility experiences an unexpected forced outage, the owner will need to cover its forward obligation by purchasing replacement energy from the spot market.[32] Liquidated damages risk is the risk that a facility experiencing an outage will need to procure replacement electricity from the spot market at prices in excess of its forward sale price. Spot market prices during an unexpected nuclear outage can be much higher than usual, because the forced outage of a large baseload unit will require reliance on higher priced units to fill the gap. The cost associated with covering a forward obligation by purchasing from the spot market at elevated prices is the cost imposed by liquidated damages risk.

[30] *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61289, P 30 (2015).
[31] PJM Open Access Transmission Tariff, Attachment DD, Section 6.8(a).
[32] Remarks of Joseph Dominguez, Executive Vice President, Exelon Corporation, Clean Energy Standard Workshop #2 (March 9, 2016) ("[W]hen we sell forward into this market, if a unit is out of service for any reason, we own that contractual obligation to supply energy at the price that we've contracted for.")

CENG has measured the cost of self-insuring against liquidated damages risk by analyzing the historical spread between liquidated damages energy contracts ("LD contracts") and unit-contingent energy contracts ("UC contracts"). All published benchmark standardized forward energy products are LD products, but UC products do trade periodically in bilateral markets. LD contracts obligate a seller to deliver power to a buyer at a fixed price regardless of the outage status of a given generating unit. UC contracts, by contrast, only obligate the seller to deliver power if the unit to which the sale is linked is available. A seller supplying energy through a contract with LD provisions will thus need to source power out of the spot market (and sell that power at a fixed price) if its facility is unable to generate electricity. By contrast, a UC seller will not need to take on this additional cost and risk. There is almost no expected cost related to selling LD power versus UC power because spot prices at the time of an outage could be lower or higher than the fixed sales price. However, selling LD power is significantly riskier than selling UC power because of the possibility of an extended outage when spot prices are very high. As a result, LD power requires a higher price than UC power to compensate for that risk.

CENG has calculated the cost of self-insuring against liquidated damages risk following its normal risk-pricing business practices. It conducted a forward-looking, joint probabilistic simulation of nuclear outages and market prices, based on 10 years of historical market price and nuclear unit outage data, intended to capture the year-to-year likelihood that a nuclear unit would need to expend significant amounts to cover a liquidated damages forward sale during a forced outage. The chart below depicts the results of this analysis for an upstate New York nuclear unit under current market conditions. The horizontal axis of the chart measures the annualized cost or benefit to the unit of needing to cover a liquidated damages position in the spot energy market due to a forced outage, spread over all of the unit's annual output. A negative value indicates a loss (i.e. spot prices higher than liquidated damages forward price during outages) and a positive value indicates a gain. The y-axis of the chart measures the cumulative probability that the unit experiences a particular level loss or gain. The fifth percentile level for liquidated damages risk is a loss of $3/MWh. Thus, the self-insurance cost should be set at this level. As the chart depicts, however, in the extreme tail of the distribution the potential loss could approach $10/MWh, which would mean CENG could still lose as much as $7/MWh or more under such an outcome even after accounting for self-insurance compensation of $3/MWh.



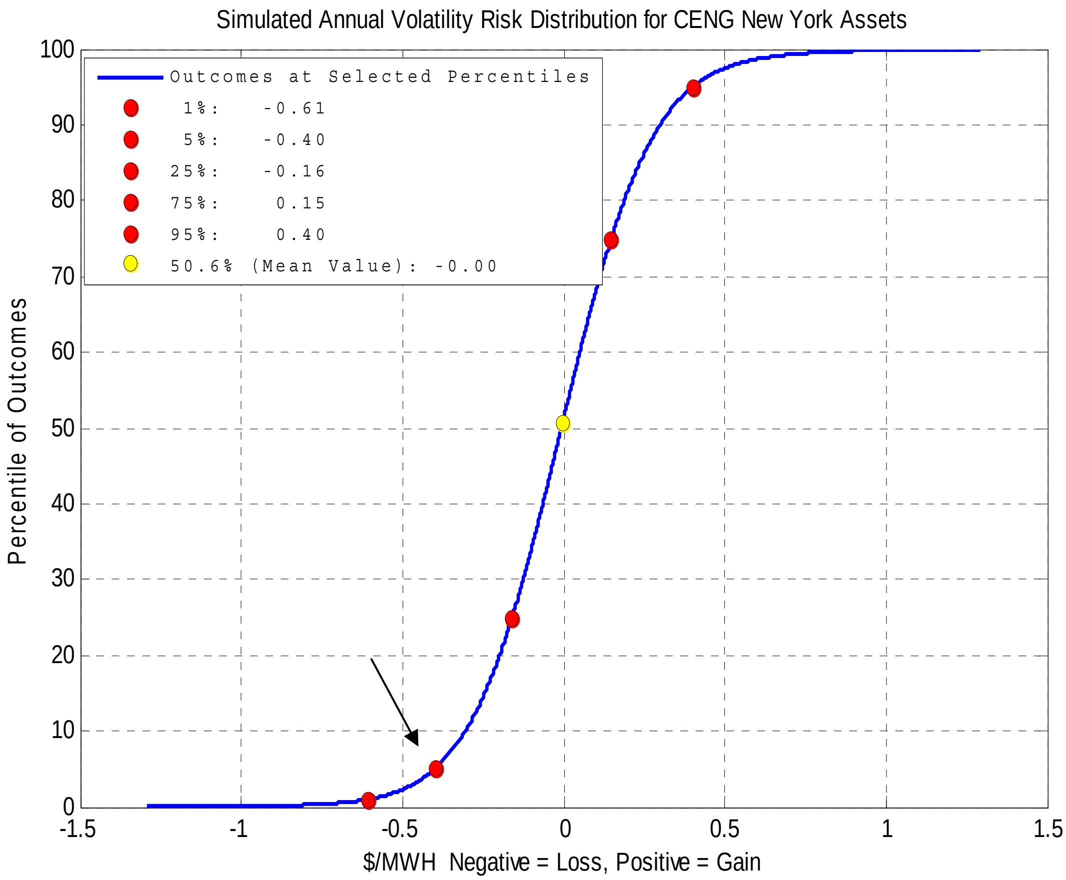
It is appropriate to include the cost associated with self-insurance against liquidated damages risk in the assessment of a facility's costs, because participating facilities must take on liquidated damages risk in order to obtain the higher LD price on which the ACP's revenue projections will be based. At the technical conference, utility representatives agreed with this.[33]

[33] Remarks of David Kimiecik, Rochester Gas & Electric Co., Clean Energy Standard Workshop #2 (March 9, 2016) (stating that "you value it based against a forward price that's a firm Liquidated Damages product. I

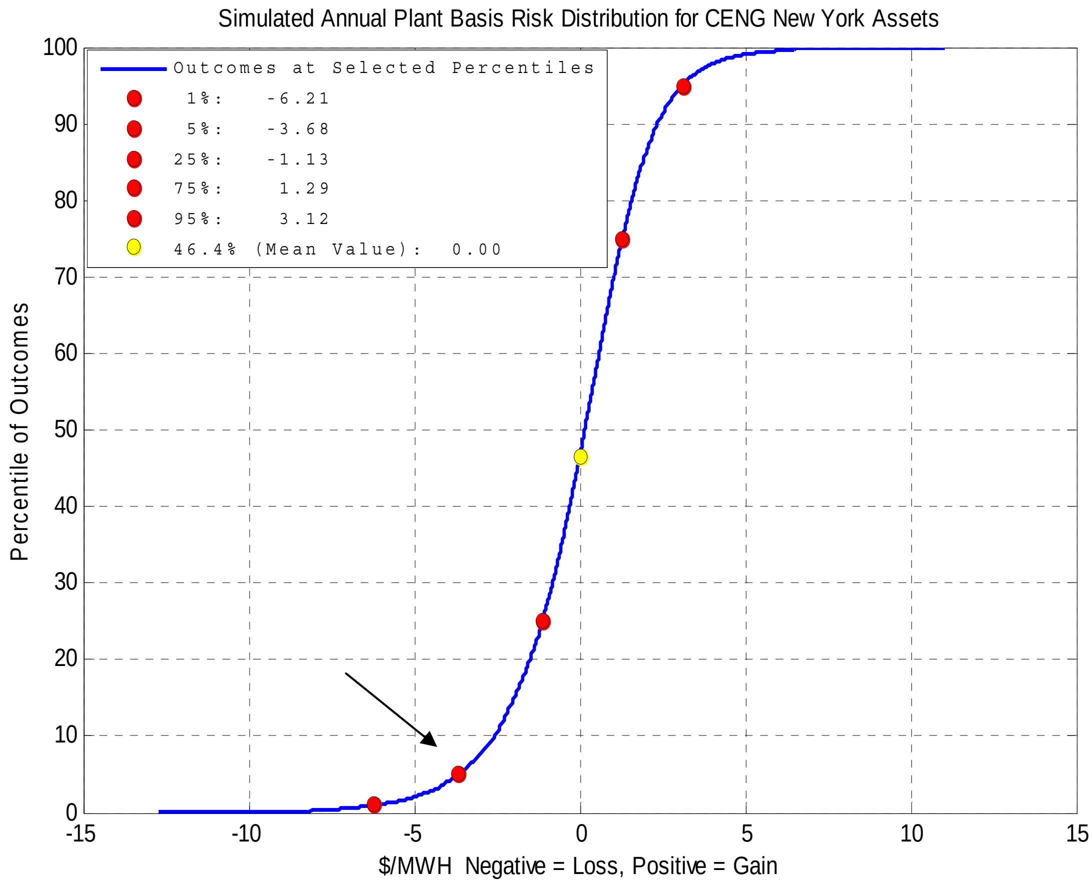
Volatility risk. Volatility risk is the risk that a participating nuclear facility will not actually be able to recover the projected energy and capacity revenues used to calculate the ACP. Those projections, as described below, would be based on forward prices for energy and capacity during a particular period. However, nuclear facilities will not necessarily be able to hedge all of their output during this same time period. If they attempted to do so, they would likely drive down forward prices. As a result, nuclear facilities cannot always obtain in practice the forward prices assumed by revenue projections.

CENG has again used its normal business risk-pricing practices to estimate the cost of self-insuring volatility risk. To do so, CENG conducted a forward looking, probabilistic simulation of the potential for energy market prices at the zonal level to diverge from the values used to set the ACP over a given year, coupled with the potential that the company could be either delayed in setting its forward-market hedges or be forced to sell a portion (potentially up to 20 percent) of the plant's output into short-term spot markets. The chart on the next page depicts the results of this analysis. The fifth percentile outcome is a loss of $0.40/MWh due to volatility risk—that is, under the fifth percentile outcome, the price at which CENG could hedge is $0.40/MWh less than the forward market price used to set the ACP. Thus, the cost of self-insuring against volatility risk is $0.40/MWh.

can understand where you might have some risk," and stating that a "$3-4/MWh discount, I see some validity to that"); *id.* (explaining that "when we're hedging typically we aren't buying a unit contingent product. We're buying a firm Liquidated Damages product so we don't have to deal with the consequence of having to replace that product if something happened…").



Basis risk: Basis is the amount by which energy prices at the particular node where a plant sells its output diverge from the zonal price forecast used to set the ACP. The energy price projection used to set the ACP includes an adjustment for the *expected* difference between the zone-level and plant-level energy price (this difference is known as the "plant basis") based on historical energy spot price data. However, basis risk arises because of the possibility that the actual plant basis over a given year during the program will diverge from the expected plant basis. The plant basis adjustment is not trued-up after the fact based on actual prices in a given year, and thus the plant would sustain a loss if the plant-level price were unexpectedly lower than the zone-level price. The risk of such divergence is difficult to hedge in forward markets. CENG has again utilized its normal business risk-pricing practices to estimate the cost of self-insuring basis risk. To do so, CENG conducted a forward-looking, probabilistic simulation of the potential for the plant basis in a given year to diverge from its recent historical value. The analysis further assumes that the unit in question is unable to hedge this basis risk. The fifth percentile outcome is a loss of $3.68/MWh due to volatility risk. That is, under the fifth percentile outcome, the locational price at which CENG could sell the output of a given facility is $3.68/MWh less than the value used to set the ACP. Thus, the cost of self-insuring against basis risk is $3.68/MWh.



Altogether, the cost of self-insuring liquidated damages, volatility, and plant basis risk is approximately $7/MWh when the individual risk components are simply added together. In its normal business practice for pricing risk, however, CENG considers diversification effects across the various risks embedded in its generating assets, which tend to reduce the impact of a given risk relative to its cost when considered independently. Because of this diversification, the joint combined cost of the three market risks is reduced by approximately 45 percent, to $4/MWh. Thus, $4/MWh is the appropriate cost of jointly self-insuring the overall market risk embedded in the compensation structure for Tier 3.

In sum, CENG estimates that, on a portfolio basis, its costs amount to approximately $50/MWh, including an adjustment of 10 percent to reflect operational risks and accounting for the $4/MWh cost of market risks. The details of this calculation are set forth on the Confidential Appendix included as Exhibit E. This $50/MWh estimate is less than the cost used by the Commission in its Cost Study to calculate the program's net benefits.

It is important to emphasize that accounting for the costs associated with operational and market risks does not actually insulate participating units from the resulting costs if those risks are realized. There would not be any true up or adjustment in the event that unanticipated investments are needed for safe and reliable operation or if a plant experiences an unexpectedly prolonged outage. Rather, these risk adjustment mechanisms reflect the cost of self-insuring against these risks, akin to the premium that would be paid to an insurer. In the event that there is an unexpected unit outage, for example, the actual increase in costs per MWh may be substantially greater than 10 percent, and the cost of covering a forward obligation may significantly exceed $4/MWh—just as an insurance claim may vastly exceed the premium paid. Thus, participating facilities remain exposed to operational and market risks.

B. Projected Energy Revenues.

CENG proposes that the Commission project revenues from energy sales once annually—just prior to the calendar year for which revenues are being projected—based on forward market prices. CENG proposes the following method for calculating projected energy revenues to be used in a single, program-wide ACP applicable to all qualifying nuclear facilities (this method could easily be modified if the Commission chooses to adopt unit-specific prices for ZECs):

Over each trade date in the 12-month window ending November 30 in the calendar year one year prior to the delivery year, the Commission would take a simple average of the on-peak and off-peak monthly liquidated damages energy forward settlement prices for all 12 months of the upcoming delivery year for delivery to New York Independent System Operator Zone A.[34] These prices are published daily by the Intercontinental Exchange. The Commission would then calculate a time-weighted average of those monthly on peak and off-peak prices to generate a single calendar-year around-the-clock forward price for each trade date. The Commission would then take a simple average of the calendar-year around-the-clock forward prices that it calculated for each trade date in the 12-month window, creating a single Zone A forward price.

To adjust for any expected locational premiums or discounts relative to the Zone A price that the participating facilities receive, the Commission would calculate the historical average hourly real-time energy price difference between Zone A and each participating facility's plant-specific locational marginal price over the year ending on the November 30 prior to the delivery year.[35] The Commission would apply the resulting discount or premium relative to Zone A for each participating facility to generate a unique location-adjusted energy price for each participating facility.[36] The Commission would then calculate an average of the facility-specific energy prices, weighted by each facility's projected energy output over the upcoming delivery year, to arrive at a singular program-wide energy revenue value for use in the ACP formula.

C. Projected Capacity Revenues.

CENG proposes that the Commission determine projected revenues from capacity sales using recent historical spot capacity auction prices. Specifically, the Commission would calculate a

[34] We recommend using the ICE index for this calculation, as that index has the most liquidity.

[35] If a multi-reactor facility has multiple locational marginal price points, the Commission would average those prices, weighted by the generating capacity at each price point.

[36] For a facility operating under a Reliability Services Support Agreement ("RSSA") during a portion of the CES program, energy and capacity revenues should be adjusted to reflect the impact of the RSSA on the facility's revenues during the period that the RSSA overlaps with the CES.

simple average of monthly spot ICAP auctions run by the New York ISO over the 12-month period ending on November 30 prior to the delivery year for delivery to the New York Control Area.[37] The Commission would then transform the resulting value (which would be in dollars per kilowatt-month) into dollars per megawatt-hour terms with an adjustment for the capacity factor embedded in the anticipated energy production and anticipated unforced capacity values of the qualifying facilities for the delivery year.[38]

VI. The Commission Should Not Phase In the Quantity of ZECs Procured.

The White Paper proposes that the quantity of ZECs available to eligible nuclear facilities be subject to an annual limit, which increases over time in order to phase in the program. CENG believes that such a phase-in is unnecessary to ensure that the program's benefits exceed its costs. The Nine Mile facility is projected to lose [CONFIDENTIAL][39] in 2016. Yet the Brattle Report finds that the clean-air attributes of the three upstate nuclear plants are valued at nearly $750 million annually. The indirect economic impact of these plants' continued operation, including the plants' contribution to state gross domestic product and tax revenues and their impact on retail electricity prices, amounts to over $5 billion annually.[40] Indeed, even considering only the carbon abatement benefits, the benefits of the Nuclear Tier proposal are at least six times larger than the costs through 2023.[41] When all economic benefits are considered along with all environmental benefits resulting from the Nuclear Tier of CES, the benefits exceed program costs by more than 70-fold.[42]

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[37] If the Commission adopts a facility-specific or portfolio-specific ZEC price, as CENG suggests above, then capacity revenues should also be estimated on a facility-specific or portfolio-specific basis.

[38] The precise formula for this unit transformation would be Anticipated Capacity Revenues (in $/MWh) = (ICAP price (in $/kw-mo) x 12 x 1000 x Total ICAP value for Facilities (in MW)) / Anticipated Annual Production from Facilities (in MWh).

[39] *See* Exhibit 2 to Exhibit E.

[40] Brattle Report at 1, 12; DPS Cost Study at 84.

[41] Brattle Cost Study at 1. Indeed, this understates the benefits from the program, because the Commission's cost study, analyzed by the Brattle Group, assumed a phase-in of procurement quantity, effectively assuming that otherwise-qualifying nuclear facilities would stay open in the initial years of the program without receiving revenue from selling ZECs.

[42] Brattle Cost Study at 2.

In light of the significant public benefits that flow from the program, and the fact that critical decisions on all of the facilities must be made in 2016, CENG urges the Commission not to impose pre-determined quantity caps on the program, but instead allow all qualifying facilities to sell ZECs at the ACP beginning April 1, 2017.

VII. NYSERDA Should Enter a Twelve-Year Contract for ZECs to Provide the Commitment Needed By Both Participating Facilities and Customers.

At the March 9, 2016 Technical Conference, Michael Mager, on behalf of large industrial consumers, suggested that the Commission must require participating facilities to make a long-term commitment to continue to produce energy. Ivan Kimball of Consolidated Edison made a similar point. The logic of such a requirement, provided that continued operation is otherwise consistent with all applicable federal and state regulatory requirements, is that the point of the CES program is to provide a bridge to achieving New York's ambitious emissions-reduction goals for 2030. That purpose would be frustrated if a plant were to sell ZECs for just a few years and then retire, say, to avoid having to make a significant capital investment.

CENG understands this concern. Accordingly, CENG supports a twelve-year minimum contract term for the sale of ZECs to NYSERDA. Assuming the program begins on April 1, 2017, NYSERDA and participating facilities would be contractually obligated to one another until December 31, 2028. That length of contract term is good for the public, because it provides assurances that participating facilities will continue to operate throughout the transition during the 2020s to a predominantly renewable generation fleet.[43] It is also good for participating facilities, because it provides them the revenue assurance they need in order to make the significant capital expenditures that may be needed to remain in operation. For example, in 2020, the Ginna facility will undergo a generator rewind at an estimated cost of $16 million. It would be wasteful to make

[43] Indeed, the Commission's Cost Study appears to assume that the Tier 3 program will last through 2028. *See* DPS Cost Study at 284 (Figure C.4).

such a significant capital investment only to retire the facility shortly thereafter. A twelve-year contract provides the certainty needed to justify such an expenditure. However, a participating facility should be released from any contractual commitment under certain circumstances such as a change to the ZEC program structure which effectively reduces ZEC payments, an unforeseen and extraordinary required capital investment above a specified threshold, or in the event of catastrophic damage to the facility resulting from a *force majeure* event.

CONCLUSION

CENG appreciates the opportunity to provide these comments and looks forward to working with the Commission and stakeholders on the development of the Clean Energy Standard for the benefit of New York's consumers and its environment.

Dated: April 22, 2016

Respectfully submitted,

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On Behalf of Constellation Energy Nuclear Group, LLC

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Implementation of a Large-Scale Renewable Program	))))	Case 15-E-0302

VERIFICATION

I, James McHugh, being duly sworn according to law, depose and say that I am the Senior Vice President of Portfolio Management and Strategy of Exelon Generation Company, LLC; that I am authorized to and do make this Verification in support of the information concerning the risk components of facility costs set forth in the foregoing Comments of Constellation Energy Nuclear Group LLC Concerning Staff White Paper on Clean Energy Standard ("Comments"); that I have personal knowledge of the facts contained herein; and that the facts set forth in the foregoing Comments are true and correct to the best of my knowledge, information and belief.

James McHugh
111 Market Place, 5th Floor
Baltimore, MD 21202

SUBSCRIBED AND SWORN before me this
22 day of April, 2016

Maria D Munguia, Notary Public
Cook County, State of Illinois
Commission Expires 06/07/2016

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Implementation of a Large-Scale Renewable Program	))))	Case 15-E-0302

VERIFICATION

I, Timothy K. Hanley, being duly sworn according to law, depose and say that I am the Senior Vice President, Nuclear Projects of Exelon Generation Company, LLC; that I am authorized to and do make this Verification in support of the nuclear facility cost information set forth in the foregoing Comments of Constellation Energy Nuclear Group LLC Concerning Staff White Paper on Clean Energy Standard ("Comments"); that I have personal knowledge of the facts contained herein; and that the facts set forth in the foregoing Comments are true and correct to the best of my knowledge, information and belief.

Timothy K Hanley

Timothy K. Hanley
4300 Winfield Road
Warrenville, IL 60555

SUBSCRIBED AND SWORN before me this
22 day of April, 2016

Yvette Enright

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NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:09/24/17