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Date: December 5, 2014

VIA ELECTRONIC MAIL

Hon. Kathleen H. Burgess
New York Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re:
Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision
Case 14-M-0094 - Proceeding on Motion of the Commission to Consider a Clean Energy Fund

Dear Secretary Burgess:

Environmental Defense Fund (EDF) hereby submits for filing its comments on the Draft Generic Environmental Impact Statement filed on October 24, 2014 in the above-captioned dockets.

Respectfully submitted,

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Elizabeth B. Stein

Cc: Administrative Law Judge Julia Smead Bielawski
Eleanor Stein
Active Parties

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

Case 14-M-0094 - Proceeding on Motion of the Commission to Consider a Clean Energy Fund

COMMENTS OF ENVIRONMENTAL DEFENSE FUND REGARDING THE DRAFT ENVIRONMENTAL IMPACT STATEMENT FILED OCTOBER 24, 2014

DATED: December 5, 2014

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I. Introduction

The Commission has been prescient in recognizing the conflict between today's goals for the energy system – including decarbonization and more efficient capacity utilization; the regulatory construct that has shaped the business models of incumbent utilities; and the manner in which distributed resources and deployed, optimized, operated, and financed. Together, the Reforming the Energy Vision ("REV") and the Clean Energy Fund ("CEF") have the potential to radically reshape the marketplace in which distribution-level wires companies, service providers, and consumers make energy decisions. These proceedings are driven in part by the need for a new strategy to achieve favorable environmental outcomes at lower cost. However, the Commission also "determined that the proposed action may have an adverse impact on the environment."[1] The Draft Generic Environmental Impact Statement ("DGEIS") examines the impact that the proceedings could have compared to a no-action alternative.

In these comments, we will address three issues discussed in the DGEIS. First, we will briefly address the baseline against which various scenarios in the DGEIS are compared. Second, we will critique the DGEIS's treatment of time-variant pricing, which assumes only modest uptake and fails to recognize the potential for such pricing to transform demand response. Finally, we will discuss the risk of environmental harm arising from increased proliferation of small-scale fossil fuel-based generation, and possible approaches to mitigating this risk.

II. The Baseline

The DGEIS describes a baseline reflecting anticipated 2015 conditions. The baseline is therefore static. In contrast, the assessment of the two major alternatives is based on dynamic conditions with program evolving and typically growing over the five- and ten-year programs. The assessment of the two alternatives could be improved if the baseline were also dynamic. That is, what are conditions in the State likely to look at in terms of central generation, DER, peak demand management and so on without REV initiatives in place or without the CEF in its proposed form? To devise a dynamic baseline scenario, one might rely on the State's draft Energy Plan, which was released before the REV program was publicly announced; Volume 2 of the draft plan includes, at page 59, a "reference case" projecting New York State's electric mix in 2020 and 2030.[2]

[1] N.Y. PUBLIC SERVICE COMMISSION, NOTICE OF DETERMINATION OF SIGNIFICANCE (New York Public Service Commission Cases 14-M-0101 and 14-M-0094), available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={887C00F1-00C3-4309-8EAE-92CAA35C10DB}.

[2] NEW YORK STATE ENERGY PLANNING BOARD, NEW YORK SHAPING THE FUTURE OF ENERGY, 2014 DRAFT, NEW YORK STATE ENERGY PLAN, VOLUME 2, SOURCES, *available at* http://energyplan.ny.gov/-/media/nysenergyplan/2014stateenergyplan-documents/2014-draft-nysep-vol2-sources.pdf.

III. Rate Structures and Innovative Rates

The DGEIS describes the central vision of REV as "increasing the use and coordination of distributed energy resources."[3] The DGEIS refers to the DPS Staff Proposal on Track 1 issues noting that "substantial benefits of reducing system load during the 100 hours of greatest peak demand,"[4] and that "Flattening the top 100 hours translates to a roughly 14 percent reduction in peak load."[5] In effect, the DGEIS is focused on measures that could significantly reduce what could be called "critical peak demand" in contrast to typical seasonal peak demand. For this reason, "Peak demand reduction is selected as the basis for the alternatives to provide a useful metric by which the many possible energy system outcomes and strategies can be compared." [6]

Reducing "critical" peak demand that occurs during the 100 hours of highest demand during a year has, as the DGEIS and other documents filed in the REV proceeding note, very significant economic and environmental benefits. The economic benefits are based on avoided high energy costs, as well as avoided high marginal costs of expanding generation and transmission and distribution (T&D) infrastructure capacity as critical peak demand grows and stresses on the generation and T&D systems. The DGEIS estimates that the long-term avoided capacity and energy savings from the increased system efficiency that would occur by the flattening of the 100 hours of great peak demand would be in the range of $1 and $2 billion per year.[7]

EDF is concerned with the DGEIS's separation of Demand Response and Innovative Pricing. A basic principle of economics is that optimal prices and quantities are achieved in a marketplace where customers make purchasing decisions based on meaningful, informative price signals. When structured properly, electricity markets should be no exception. A major purpose of demand response programs is to flatten load during critical peak demand periods to achieve capacity and energy savings as noted above.[8] A discussion of demand response is inherently incomplete if it fails to integrate the load shifting potential that rate structures such as critical peak pricing can make possible. Conversely, where rate design is valued for its ability to moderate peak loads, it should not be addressed as an isolated mechanism, with "demand

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[3] DGEIS at 4-2.
[4] DGEIS at 4-2.
[5] DGEIS at 4-2.
[6] DGEIS at 4-2.
[7] DGEIS at ES-10.
[8] DGEIS at ES-10.

response" also presented as a separate strategy. The DGEIS assessment of rate structures is unnecessarily limited in its utility by its segregation of rate design and demand response, and the relatively low expectations for the power of rate design.

Insofar as "customer knowledge, market animation" and "system-wide efficiency" comprise three of the six policy outcomes noted at ES-1, it is clear that rate structures that communicate useful information to customers about costs, effectively coupled with technology that would promote load shifting or outright reductions in use during critical peak periods, would play a central role in advancing the REV program. Indeed, one could question whether the economic, environmental and social goals of REV can be achieved *unless* the rate structure system is substantially transformed.

We urge the Commission to consider a much more thorough discussion of the role of time-variant pricing. Effectively integrating innovative pricing into well-designed demand response programs – i.e., those which incorporate technologies, tools, information, and effective customer engagement – can help achieve truly significant load reductions during critical peak periods and reduce overall baseline and typical seasonal loads. To ensure that the DGEIS properly considers the relevant information, it should consider evidence from recent pilot studies in other jurisdictions, which we have described in our comments on the Con Edison BQDM Program and its time-sensitive rate pilot proposal.

Critical peak rates have been evaluated in a number of recent reports that include data from utility field studies that evaluated, among other things, the effectiveness of critical peak rates and other time-sensitive prices such as time-of-use rates and hourly pricing in supporting reductions in critical peak loads by participating customers. Of particular interest here is the experience that these utilities have had with critical peak rates combined with enabling technologies – such as those that allow for convenient adjustments to air conditioning temperatures and timing devices thereby helping customers shift load to off-peak periods – in getting customers to reduce consumption significantly during those limited critical peak hours of the year. These studies demonstrate that such rates and tools together could be a powerful driver of peak moderation even where customers do not formally commit to a "demand response" program.

For example, the Sacramento Municipal Utility District ("SMUD") report to the U.S. Department of Energy dated September 5, 2014, entitled "Smart Pricing Options Final

Evaluation",[9] evaluated customers on seven different time-based rate plans over a two-year period. The study concluded that if all of SMUD's customers were defaulted to a time-of-use/critical peak pricing plan with an in-home display (with the option to opt-out), the net present value of customer energy savings over a ten-year period could reach $87 million. It also demonstrated peak load reductions of 8 to 26%, with the higher reductions associated with critical peak rates coupled with technology.

Similarly, the Oklahoma Gas & Electric Company ("OG&E") conducted a pilot study in 2011 that tested a time-of-use rate and a critical peak rate, jointly with the impact of two types of technologies: in-home displays and smart thermostats.[10] The results of the pilot showed that customers with access to smart thermostats were able to have up to three times larger peak reductions than those without thermostats. Customers on the pilot reported high levels of satisfaction with their tariffs and on average saved $150 per month during the summer. These positive experiences (both in terms of customer satisfaction and observed peak demand reductions) launched an expansion of the critical peak price tariff to 150,000 customers, who were also offered free smart thermostats for signing up.

Other pilot studies across the country noted similar kinds of peak demand reductions from well-designed tariffs that incorporate critical peak pricing with technologies. Faruqui and Sergici (2010)[11] document 15 pilots throughout North America and find that CPP tariffs with technology offerings resulted in average peak reductions of 36%; similar CPP tariffs without technology resulted in only 17% reductions.

Further, these pilot studies provide extensive evidence that low income customers are both able to respond to time variant pricing and experience high levels of satisfaction with the tariffs. However, while the DGEIS in Exhibit 5-4 under "Variable and time-sensitive rates" states pricing tied to peak and off-peak times should consider the impact on "customers that are least able to change behavior and respond to price signals", it provides no evidence of utility

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[9]SACRAMENTO MUNICIPAL UTILITY DISTRICT, SMARTPRICING OPTIONS FINAL EVALUATION (2014), *available at* https://www.smartgrid.gov/sites/default/files/doc/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf

[10] US DEP'T OF ENERGY, DEMAND REDUCTIONS FROM THE APPLICATION OF ADVANCED METERING INFRASTRUCTURE, PRICING PROGRAMS, AND CUSTOMER-BASED SYSTEMS – INITIAL RESULTS (2012), available at http://energy.gov/sites/prod/files/DemandReductionsReport_Dec2012Final.pdf

[11] FARUQUI, A. AND S. SERGICI, (2010). "HOUSEHOLD RESPONSE TO DYNAMIC PRICING OF ELECTRICITY: A SURVEY OF 15 EXPERIMENTS", J Regul Econ, (2010) 38:193–225.

initiatives that have addressed these concerns. We urge full consideration in a supplemental discussion of what these well-designed pilot studies have found on this subject.

As the DGEIS recognizes, critical peak pricing models tend to demonstrate more substantial system benefits than less customized time of use pricing models. Faruqui and Sergici's review of pilot studies also demonstrated that critical peak pricing can produce peak time reductions up to 7 times larger than a time-of-use pricing mechanism (with a set daily peak and off-peak period). This is likely due to two factors: first, critical peak pricing provides a much larger price signal during critical times, with the peak price far exceeding a time-of-use peak price, resulting in a larger behavioral response; and second, customer fatigue can set in with daily pricing[12]- as critical peak pricing only provides a signal when there is an observed critical peak day, customers may only need to respond a few times per year. Thus, critical peak pricing plans can provide the framework for customers to reduce demand on precisely the right hours of the year, and reduce in larger quantities, thereby achieving optimal benefits to the electricity system.

The Brooklyn Queens Demand Management Program is, like the relevant portions of the DGEIS, properly focused on the advantages of finding alternative ways of reducing critical peak demand. A contributing factor to the growth of critical peak demand in parts of the State is that the energy costs and incremental infrastructure costs of provision of critical peak demand power are not reflected in prices that utilities charge to commercial and residential customers effectively.

For small and modest-sized commercial and residential customers, knowledge of these incremental energy and infrastructure costs is typically very limited. Even for large commercial customers that participate in the Mandatory Hourly Pricing program, those costs are less than transparent as only the supply portion of the bill is subject to variable pricing. While utilities may use such critical peak demand marginal cost information to assign revenue allocation responsibility to customer classes, that information is not imparted to those customers.

The DGEIS, Exhibit 5-4,[13] intimates that an obstacle to introduction of critical peak pricing or any kind of time-sensitive pricing for residential and smaller commercial customers is the cost of

[12] Customer fatigue can also present itself when several days of critical peak are called in a row. *See* STATE OF CALIFORNIA PUBLIC UTILITIES COMMISSION, LESSONS LEARNED FROM SUMMER 2012 SOUTHERN CALIFORNIA INVESTOR OWNED UTILITIES' DEMAND RESPONSE PROGRAMS (2013), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/523B9D94-ABC4-4AF6-AA09-DD9ED8C81AAD/0/StaffReport_2012DRLessonsLearned.pdf

advanced metering. At the same time, the DGEIS includes no incremental cost for "Rate Structures", one of the eight resource types evaluated for illustrative cost impacts in Exhibit 4-3.[14] If costliness of implementation is to be proffered as an impediment, the DGEIS should provide evidence in support. SMUD and OG&E in their pilot investigations described above utilized advanced metering, and California as a whole has comprehensively deployed advanced metering. The DGEIS should incorporate applicable data and formulate statements about the cost of advanced metering taking advantage of experience elsewhere.

IV. The Risk of Proliferation of Fossil-Fueled Distributed Energy Resources

We are pleased to see, on page 5-11 of the DGEIS, focused attention devoted to a risk inherent in REV: the potential for proliferation of small fossil-fueled generation, with negative environmental consequences. EDF appreciates the potential power of small distributed resources, many of which are emissions-free and/or can contribute to more optimal operation of the electric grid, to help achieve decarbonization at relatively low cost. This is among the major reasons why we see such promise in the REV and CEF proceedings. When viewed in context, this risk is real and potentially material; however, there is a paucity of information about the present scope of the problem and/or the magnitude of the additional risk as a consequence of these proceedings. We encourage the Commission to work in concert with the Department of Environmental Conservation and other regional regulators to examine this risk in considerably more detail to assess the magnitude of the risk and develop a portfolio of tools (some of which may be outside the scope of the Commission's authority) properly tailored to mitigate it.

A. Context: Decarbonization of Large Generation, High Proliferation of Back-Up Generation

1. RGGI/CPP

New York, together with the other Regional Greenhouse Gas Initiative ("RGGI") states, is at the vanguard of decarbonizing its electric system, having enjoyed considerable success during the cap-and-trade program's early years.[15] The Clean Power Plan ("CPP") rule proposed by the Environmental Protection Agency ("EPA") expressly recognizes RGGI as an available compliance pathway,[16] and we

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[15] *See, e.g.,* Union of Concerned Scientists, *Regional Greenhouse Gas Initiative*, *available at* http://www.ucsusa.org/global_warming/solutions/reduce-emissions/regional-greenhouse-gas.html#.VIEU1THF-So; Regional Greenhouse Gas Initiative, Inc., *Regional Investment of RGGI CO2 Allowance Proceeds*, 2012 (February 2014), *available at* http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf.

[16] *See* 79 Fed. Reg. 34830 at 34838 ("Plans that do directly assure that affected EGUs achieve all of the required emission reductions (such as the mass-based programs being implemented in California and the RGGI states) would also be approvable provided that they meet other key requirements, such as achieving the required emission reductions over the appropriate timeframes.").

understand that the RGGI states are likely to use that pathway.[17] Therefore, we anticipate that even as the CPP goes into effect, New York's participation in RGGI will remain the chief regulatory mechanism requiring decarbonization in New York's electric generation sector for the foreseeable future.

However, for all its success, the RGGI program does not reach all electric generation. The RGGI cap and trade regime is applicable only to "electricity generator[] with a nameplate capacity equal to or greater than 25 MWe".[18] A cap and trade regime, by its nature, enables the marketplace to find the lowest-cost carbon reductions. More efficient large generators become comparatively more cost-effective per unit of energy produced, because they need fewer allowances to produce the same number of megawatt-hours of power. Emissions-free generation becomes comparatively more cost-effective because, regardless of their size, zero-emissions generators need never carry carbon allowances. Energy efficiency becomes comparatively more cost-effective compared to the more costly generation that may be avoided. (Many of the RGGI states, including New York State, have leveraged the cap and trade regime to give energy efficiency an additional boost by using auction proceeds to fund energy efficiency.) The more expensive the allowances that fossil-fueled central generators need to carry, the greater the incentive to identify lower-cost substitutes for fossil-fueled generation.

In addition to lower-carbon central generation and reductions in electricity use (whether at all times or at the peak times), another resource that a well-functioning market might choose to substitute for high-carbon central generation would be generation, even if high-carbon, that is not burdened with the obligation to carry allowances, and as such is cheaper per megawatt-hour. In a centralized system, where most power generation occurs at large central plants and customers consume grid-based power indiscriminately, there may have been little opportunity for customers to avoid (or even notice) the most expensive central generation – let alone substitute other electricity for that power – and so this risk may have been minimal. However, as the marketplace matures and more customers acquire tools to control their load, develop awareness of grid conditions, and acquire some self-generation capacity, this risk may be increasing.

Although the REV proceeding seeks to take the bull by the horns and build a well-functioning distributed resource marketplace, it is critical to recognize that this evolution has begun on its own, thanks to revolutions in customer-sited technology. The REV proceeding seeks to make sure the electric grid keeps apace with and makes the most of these developments, as they offer new opportunities for system

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[17] The RGGI States indicated that they were pleased to see RGGI recognized as a compliance pathway in their comments to the Clean Power Plan filed on November 5, 2014.
http://www.dec.ny.gov/docs/administration_pdf/rggicppcomments1114.pdf

[18] *See* Letter, Docket ID No. EPA-HQ-OAR-2013-0602 – RGGI States' Comments onProposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FR 34830 (June 18, 2014), *available at*
http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Model_Rule_FINAL.pdf.

efficiency and decarbonization. But the risk of fossil-fueled generation below 25MW (whose carbon output is unregulated) being substituted for generation by plants that face increasingly tight carbon limitations is inherent in the RGGI regime. The REV proceeding, for all its benefits, does have the potential to intensify this existing risk in various ways. First, by animating the marketplace for distributed energy resources, the REV proceeding can be expected to result in distributed energy resources ("DER") (including distributed generation of all kinds – fossil-fueled and emissions-free) becoming more readily available to more customers. Second, insofar as the REV proceeding may usher in a regime of more meaningful price signals, it may greatly increase the circumstances in which the owners of fossil-fueled backup generation may have economic reasons to operate their resources in non-emergency situations. Taken together, the environmental regulations embodied in RGGI/CPP and the utility regulatory changes coming through REV may yield environmental consequences that are not the intention of either body of law, and not directly within the purview of either program to mitigate.

2. Private Resiliency Arrangements

Electric reliability has suffered in the severe weather that has become increasingly commonplace in the northeast in recent years. Anecdotal evidence, much of it published in the aftermath of Hurricane Sandy, suggests that emergency generators have become increasingly commonplace in residential settings in the northeast, with options at various price points, including deluxe systems (sometimes running on natural gas) becoming increasingly common in high-end homes and apartment buildings.[19] Although we anticipate that in the future, the Distributed System Platform Provider will perform a Benefit Cost Analysis that will include consideration of carbon impacts in accordance with the social cost of carbon, individual customers deploying backup power for resiliency purposes cannot be expected to be taking the social cost of carbon into consideration. We have been unable to locate comprehensive information describing the prevalence and types of these resources, and believe that it is likely that no one party has it.[20] The likelihood that there has been a recent surge in the prevalence of back-up generation which has not been accounted for make the risk that regulatory changes could lead to these resources being operated

[19] *See* Marianne Lavelle, *After Hurricane Sandy, Need for Backup Power Hits Home*, NATIONAL GEOGRAPHIC (October 28, 2013), *available at* http://news.nationalgeographic.com/news/energy/2013/10/131028-hurricane-sandy-aftermath-need-for-backup-power/; Ken Belson, *Power Grid Iffy, Populous Areas Go for Generators*, N.Y. TIMES (April 24, 2013), *available at* http://www.nytimes.com/2013/04/25/business/energy-environment/generators-become-must-have-appliances-in-storm-battered-areas.html?pagewanted=all; Julia Satow, *The Generator is the Machine of the Moment*, N.Y. TIMES (January 11, 2013), *available at* http://www.nytimes.com/2013/01/13/realestate/post-sandy-the-generator-is-machine-of-the-moment.html?pagewanted=all.

[20] A 2012 report by the Northeast States for Coordinated Air Use Management ("NESCAUM") estimated that there might be up to 30,000 back-up generators in the northeast, totaling up to 10 GW, but cited its own 2003 report for this finding. NESCAUM, *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast* (August 1, 2012), *available at* http://www.eenews.net/assets/2012/08/01/document_pm_01.pdf.

more frequently (including in non-emergencies) all the more alarming.

B. Strategies and Tools

1. Information

Although the DGEIS is correct to note that increasing use of backup generation is a risk, the lack of information – in the DGEIS or, so far as we can tell, anywhere else – about the real penetration of back-up generation resources in New York State now (let alone estimates about how that might change in the future, depending on the scenario) makes it impossible to gauge the magnitude of that risk. As various mitigation options would present different costs and implementation challenges, there is little hope of selecting among mitigation alternatives without a better formed statement of the problem. The risk of increased carbon emissions due to distributed resources may be the single greatest environmental risk associated with REV – since, if it occurs, it will spring directly from the push for decentralization that is fundamental to the market transformation contemplated in REV. Therefore, this further diligence would be of great value. We suggest that the authors of the DGEIS attempt to develop a reliable estimate of the amount and nature of back-up generation already in place in New York State, and a profile of the amount and type of backup generation likely to come online in the foreseeable future. As further discussed below, aggregate information about these resources may not yet be in anyone's possession; those estimates that exist suggest that the numbers are large, and as some estimates are dated and private generators appear to be increasingly popular as resiliency measures, today's reality may be considerably worse than older estimates imply. This further information could be set forth in a Supplemental Environmental Impact Statement or in the Final Generic Environmental Impact Statement, as appropriate. To the extent that such information cannot be readily obtained due to the lack of any centralized directory of such resources, we note that in the future, developing such a directory would be a valuable first step toward evaluating and, ultimately, mitigating, the environmental impact of these resources.

2. Pollution regulation

a) Criteria and hazardous air toxic emissions from back-up generators

The DGEIS observes that the risk of "proliferation of small combustion sources which, in the aggregate, could result in more emissions than an energy structure based on centralized sources of fossil fuel generation, or could result in adverse local impacts"… "exists even if all facilities are in compliance with applicable codes and regulations."[21] With respect to carbon emissions, we expect that this is clearly true, since carbon regulation is still relatively limited in its reach (as described above). In addition, while

[21] DGEIS at 5-11.

we understand that the Environmental Protection Agency has adopted emissions standards for both new and existing backup generators intended to address the risk of criteria and hazardous air emissions (New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP")),[22] we are concerned that they do not fully mitigate the risk of "adverse local impacts". Only the newest engines operating today have NOx and PM emission rates comparable to the large-scale fossil-fueled generation operating in the northeast. But these are not representative of the vast majority of installed stationary diesel generators that would be used in emergency situations or demand response programs and have far greater emissions rates.[23] While emergency engines are limited to emergency situations, they are not subject to any meaningful emissions standards because of their expected limited use.[24] Non-emergency generators are not subject to time limit operating restrictions and must comply with emission standards that, at best, require only basic controls for particulates and other harmful pollutants. Moreover, whether a generator is subject to the operating restrictions applied to emergency generators, or to the pollution restrictions applied to non-emergency generators, is in part a function of how that generator is deployed by its owner, and can even change over time; thus, not only is the state likely unaware of the range of back-up generation resources that are installed statewide, but many owners of private generators are themselves not necessarily aware of what rules, if any, are applicable to their units. For additional information on the harmful health and environmental impacts of diesel backup generators, please see EDF's comments on EPA's National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines submitted on August 9, 2012 (attached and incorporated into these comments by reference).

At the same time, a recent EPA proposal to strengthen the National Ambient Air Quality Standards (NAAQS) for ground-level ozone, based on extensive scientific evidence about the harmful effects of ozone on public health and welfare, will make it even more urgent that New York mitigate the risk of its new distributed marketplace causing increased use of older dirtier back-up generators, which can contribute significantly to local ozone problems.

To develop further mitigation recommendations, it would be helpful to have a more complete understanding of what local impacts are addressed by this rule, as well as what types of generation are

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[22] 40 C.F.R. ss 63.6580-6675 (NESHAP for Stationary Reciprocating Internal Combustion Engines); 40 C.F.R. ss 60.4230-4248 (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines); 40 C.F.R. ss 60.4200-4248 (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines).

[23] Emergency generators are allowed to provide back-up power to the facilities they serve during genuine emergencies, but may only provide power to the grid as part of an emergency demand response program during designated emergencies that meet criteria set forth in the RICE NESHAP rule.

[24] NESCAUM, *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast* (August 1, 2012), *available at* http://www.eenews.net/assets/2012/08/01/document_pm_01.pdf, at page 37.

covered by the rule and how they are regulated under the rule. Together with a more complete picture of the amounts and types of back-up generation that may be installed at customers' premises, now and in the future, this information would make it possible for environmental regulators, utility regulators, and other interested parties to identify the contours of the problem that actually exists, and develop effective mitigation strategies.

b) Participation in Markets as the Trigger for Regulation

The DGEIS conceives of several types of mitigation, all of which are based on the generators' participation in REV markets – i.e.:

- "One option would be to establish limits, with respect to particular distribution feeders or networks, on the extent to which combustion facilities can participate in REV markets";
- "Another option is to impose eligibility criteria as a condition for participating in REV markets"; and
- "Another approach to mitigating this risk is market pricing."

While each of these approaches may have much to recommend it, the "market participation" threshold may be so easy to avoid that these approaches may turn out to be meaningless. What, after all, constitutes "market participation"? Any mitigation strategy must be promulgated in a manner that will not fail simply because owners of back-up generation make economic decisions without overtly "participating" in the market (other than by buying some power from the grid – perhaps rather less than they otherwise would have done). For example, as discussed above, the REV proceeding may ultimately pave the way for more nuanced pricing for energy service than most mass market customers see today, in which case customers with behind-the-meter generation ("BTMG") might "demand respond" solely by avoiding high prices that occur at certain times, without formally enrolling in any "demand response" program. Where an electric customer facing time-sensitive pricing elects to operate BTMG to reduce load at times when power from the grid is especially expensive, that customer may do so without expressly entering into a transaction to sell services (including "demand response") to anyone in the market, and (under present conditions) without anyone even knowing that the BTMG was deployed. Yet such an action would not be a non-market action: such a customer would be making a market-based decision and would in effect be compensated based on the difference between the retail market price of grid power at that time and the (presumably lower) cost of self-generated power at that time. The Commission and environmental regulatory authorities need to develop tools that will not fail simply because the relevant emissions sources are hidden behind a customer's meter.

c)Form of Regulation: Command and control, pay to pollute, or cap and trade

Once the contours of the back-up generation fleet and the applicable regulatory framework are better understood, the Commission and the Department of Environmental Conservation can consider various options, which might reasonably include limiting the amount of economic operation of backup generation for non-emergency purposes permitted in a defined geographic area (to the extent not addressed by the backup generator NESHAP rule or other applicable rules); performance standards; and imposing regulatory costs on polluters. Where polluters are overtly participating in markets, it may be possible for those regulatory costs to be embedded in the pricing paid for services in the market, but emissions from these resources should be accounted for and mitigated irrespective of the particular business arrangements employed by polluters. This again suggests that, as alluded to above, some communications/information challenges must be addressed in order for regulators and/or market makers to have the requisite visibility about the resources producing emissions, and for the owners of those resources to be kept apprised of any new responsibilities that may be imposed on them in connection with non-emergency use of their back-up generation. New York's regulators can also work with their counterparts in the other RGGI states to explore opportunities to extend cap and trade to cover more small resources.

d) Monitoring and Metrics

As discussed above, the operation of small BTMG today may be invisible to the utility and to regulators; that in itself is already a problem, although the magnitude of that problem is apparently unknown. Any effective strategy to mitigate increased emissions from these resources is likely to require far closer monitoring of them. Stopping BTMG resources from operating invisibly may require advances in permitting and metering. The behind-the-meter location of such resources, combined with their small size and the owners' decision not to draw attention to them by offering to sell services to any third party, should not insulate the owners of such resources from responsibility for their contribution to toxic or GHG emissions; otherwise, REV's success in driving decentralization risks seriously undermining the public policy goals of that proceeding.

Relatedly, the suggestion, on page 5-11, that performance metrics be used to limit the total amount of emissions resulting from facilities participating in REV markets is essential. How those resources are deployed will be directly related to how the "REV markets" are operating, regardless of whether customers with BTMG offer any service overtly backed by the BTMG. In the event that overall emissions performance is unsatisfactory (including emissions from BTMG), that would suggest that the REV markets are not performing in accordance with expectations. Here, too, it is essential that the "REV markets" be understood to include behind the meter resources, irrespective of their size and precisely how they are being deployed to support the electric system, lest the environmental performance of the REV markets be interpreted in a far more favorable light than an honest accounting would yield.

V. Conclusion

The REV and CEF proceedings provide an opportunity to give holistic attention to the transformation that is underway in the electric sector. Projecting possible outcomes from such a sweeping transformation cannot be done with certainty, and the DGEIS represents a serious effort to grapple with a highly complex and uncertain subject. We thank the Commission, Staff, Administrative Law Judge Julia Smead Bielawski and Eleanor Stein for the opportunity to provide comments on this challenging analysis.

Respectfully Submitted,

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