Valuing and Supporting the Expanded Deployment of Grid-Connected Distributed Generation in New York State

Draft Final Report

Pace Energy and Climate Center

For

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Project in Brief

New York, like many other states, has committed to achieving significant renewable energy targets in the near future. Meeting these targets implies that the penetration level of smaller-scale, interconnected distributed generation (DG) is inevitably going to increase markedly over the next decade or two.

A growing body of research suggests that deploying interconnected DG under certain circumstances could provide many benefits. These may include private benefits, such as on-site economics and power quality enhancements; social benefits, such as reduced emissions and improved critical infrastructure resiliency; and system (grid) benefits, including ancillary services and the deferral of needed transmission and distribution (T&D) investments. However, the increased deployment of interconnected DG on the grid may also impose costs. This report assesses both the opportunities and the challenges posed by the prospect for growing penetration levels of smaller scale DG on New York State's integrated electric power grid, and the adequacy of existing policies, programs, markets and targeted incentives for achieving the level of DG development envisioned by state energy planners.

The State's existing portfolio of policy and program initiatives provides a foundation for expanding the deployment of interconnected DG resources. Yet, progress is slow. The overarching question remains: what are the essential ingredients of a comprehensive effort that could significantly increase the role DG plays in New York's electric service delivery system? This report concludes that four important changes are needed in the existing program framework. These are:

- More study of the true costs and potential benefits of large numbers of small interconnected DG units on the state's electric grid;
- Better coordination of programs, policies and market rules at the state level;
- Lowering barriers to DG development, interconnection, and market participation; and
- Developing markets in which DG can participate, and adjusting market rules to take account of DG's unique attributes.

Project Objectives

This assessment is primarily designed to inform the reader of the existing suite of DG policy activities in New York, but also to address the overarching question of what may be required to significantly increase the cumulative capacity and the social net benefit of DG systems–that is, to change DG's role in the State's energy supply portfolio from that of a modest contributor, perhaps most aptly described as a "marginal contributor," to that of a significant contributor. This report describes needed changes in existing programs, notes recent encouraging initiatives, and recommends needed new initiatives.

This report is part of a larger project, titled "The Future Distribution Grid of New York State – a Test-Bed Validation." Because this larger project focuses on the relationship of DG to distribution grid operation and performance, this report addresses DG applications that are behind the meter and sized at or less than 10 MWs. DG at this smaller-scale range is in almost all instances connected at the distribution level.

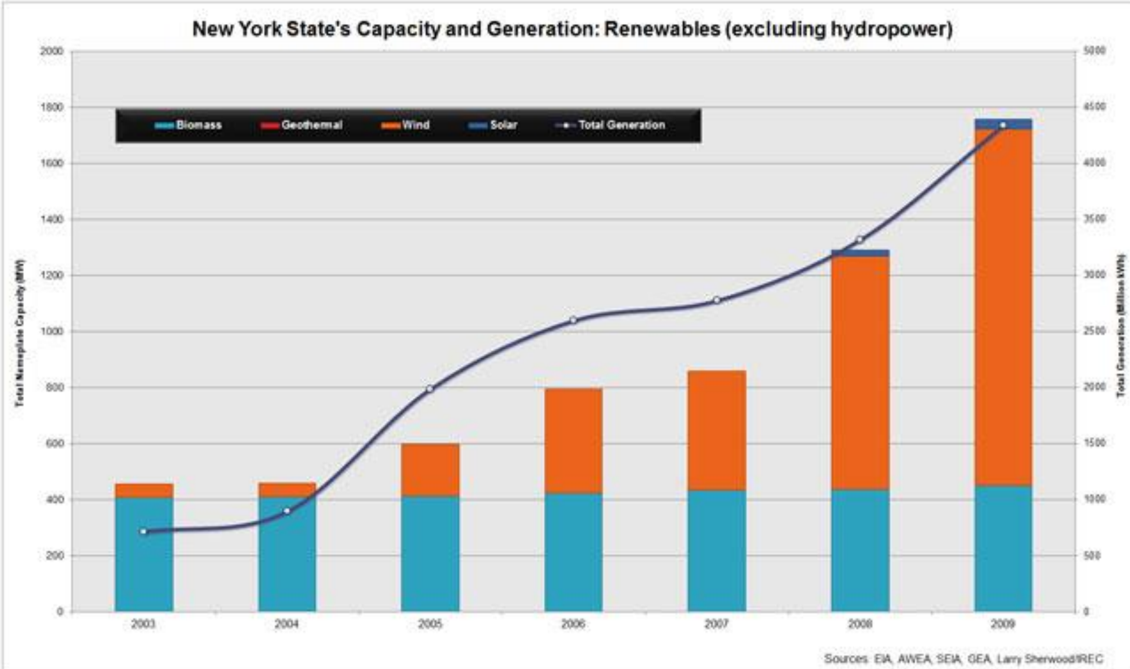
A fundamental aspect of this work is an examination of the benefits of clean DG technologies and existing public policies designed to encourage broader usage of DG to serve consumer electricity service needs statewide. This report addresses how regulatory policies and incentive programs affect the deployment of various types of DG technologies. It reviews the scope of benefits and potential costs accompanying the widespread deployment of small DG systems on the New York electric system grid.

A subsidiary objective of this policy and program focused assessment is to identify steps New York could take to maximize the benefits and minimize the costs of DG, for example, incentives that would accelerate DG deployment by fairly and effectively compensating DG for the societal and system benefits it provides.

Approach

This report has been prepared as a companion to the DG test bed analytical tool contemporaneously developed by the RPI Center for Future Energy Systems. The RPI test bed is designed to assess the performance and grid integration impacts of DG types having three distinct attributes: fast-changing performance (represented by solar PV), slow-changing performance (represented by wind), and moderate-changing performance with power dispatch capability (represented by fuel cells). The test-bed provides a new tool to assess the important features of a distribution grid capable of optimally integrating these various DG types. Such a distribution grid would maximize the benefits DG offers grid system operators, end use consumers, and society at large. The test bed will allow researchers to evaluate the effects of changes in the physical grid and in grid operating practices.

This report focuses primarily on the two types of DG applications: (1) systems that are primarily designed to operate behind the meter at a customer site, and to generate no more power than is necessary to meet the site's demand, often small renewable generation technologies such as solar PV and wind, and (2) systems that are the outcome of an economic decision process that assesses the net costs of generating power onsite and re-using the waste heat in a productive manner to lower total energy bills, systems that are designed to meet some portion of the daily needs of a local facility.



Findings and Results

Despite its potential benefits, DG currently plays a relatively small role in the electric power system in New York State and elsewhere.

Unlocking the benefits of DG has emerged as a key objective for federal, state and local efforts to modernize the electric power grid.

Today's electric power grid reflects historical economies of scale traditionally associated with large, centralized power plants. But returns to scale in power generation have changed. Increased emphasis is being placed on environmental performance, development of T&D projects has become more costly and controversial, and other attributes of power supply, such as supply diversity and a move towards a greater share of renewable generation in the power supply mix, have become more important. With this shift in preferences, interest in clean DG technologies has increased.

Steps have been taken to reduce barriers and provide incentives to create a more robust market for DG technologies in New York. New York State and New York City have both included DG in their overall clean energy strategies.[1] But despite an increased emphasis on clean DG, total

[1] The prime movers in this instance might be reciprocating engines, micro-turbines or smaller-scale gas combustion turbines. Unlike wind and solar, gas-powered CHP is fully dispatchable and not intermittent.

DG capacity still represents a small proportion of the electric generation capacity now used to meet the state's electricity needs.

DG Benefits

Though generally developed to meet the needs of a local facility/electricity consumer, DG systems may also provide valuable benefits to the electric power grid and to society at large. An important challenge for public policy is to ensure that these public benefits are not lost because private investors only receive a return on their investment for the DG project's private benefits, i.e., the benefits of the project to the owner/operator. Public policy may be crafted to provide additional returns on investment that reflect the value a DG project provides to the larger community and/or to the electricity grid.

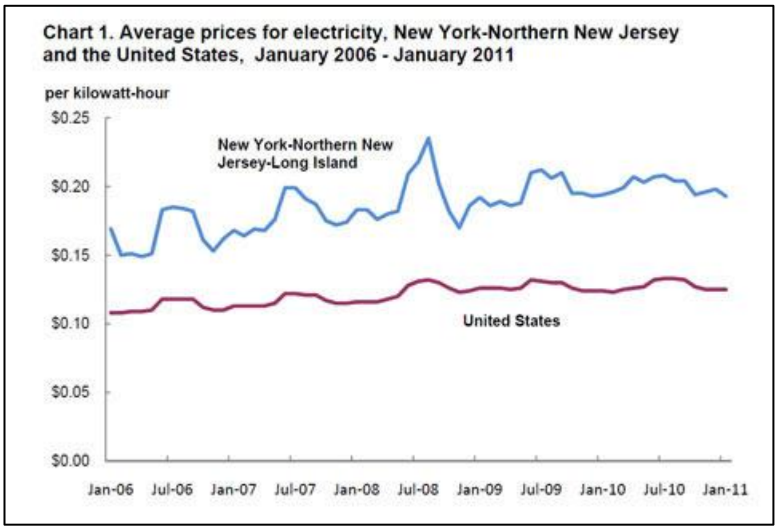
Distributed generation units offer a number of different types of benefits. Private benefits accrue to the DG owner/operator and the host facility or campus; public benefits accrue to society at large; and systems benefits accrue to the grid, its customers, and load serving entities. Particularly important benefits include:

- Private benefits
    - On-site economics
    - On-site power quality and reliability
- Public benefits
    - Enhanced critical infrastructure resiliency
    - Emissions reduction benefits
- Systems benefits
    - Ancillary services
    - T&D investment deferral

<u>Private benefits</u>: A primary motive for most customer investments in DG are the economic benefits obtained by using DG to substitute on-site electric generation for power purchases from the grid. Facilities that have significant simultaneously occurring electricity and thermal power needs over a large fraction of the year can employ CHP systems to secure additional savings by displacing purchased fuel requirements for on-site thermal energy needs. CHP systems become more attractive as the difference between electricity and gas prices widen. The cost of gas is a key driver of making electricity onsite. The cheaper that primary input becomes relative to the costs of purchasing electricity, the more economically attractive is the investment in CHP.

The economics of DG technologies vary significantly due to initial capital costs, system efficiency and performance characteristics, and ongoing variable and operation and maintenance costs. DG applications are very rarely designed to handle all of the electric power requirements at a site. The existing utility system is usually relied upon to provide backup and supplementary power services to sites utilizing DG for those periods when sufficient power is not being produced onsite or if the DG equipment is not operating, either for scheduled maintenance or due to an unplanned outage. Because most DG systems rely on supplementary and backup power from the grid, the economics of these systems is affected by the charges they must pay for standby service provided by the distribution company, a subject this report addresses separately in the context of DG-related policies and programs. Furthermore, intermittent DG systems such as wind turbines and solar PV, if not coupled with an energy storage device, will be even more reliant on supplemental electricity from the grid, and as such may be subject to greater additional power supply costs (and may create a greater need for backup generation). These cost factors depend to some degree on utility regulatory policies and programs, such as the net metering benefit provided qualifying renewable resources, also addressed later in this report.

For some types of commercial electricity consumers, maintaining very high levels of power quality—an uninterrupted supply of electricity not subject to variations in voltage—is extremely important. DG, as part of an on-site power quality and reliability system, can cost-effectively improve power quality (PQ) and reliability to customers with PQ-sensitive systems. This makes DG a potentially valuable tool for this important segment of the commercial and industrial market. Studies show that power quality disturbances cost U.S. businesses hundreds of billions of dollars annually.



Of course, not all PQ-sensitive businesses are appropriate sites for distributed generation. Approximately 90% of the market is served by small- and medium-scale PQ equipment or services, such as battery storage systems; these customers would not represent an economic opportunity for DG systems. However, the remaining 10% of the PQ-sensitive market requires facility-scale PQ control (greater than 100 kVA), and it is this segment that represents a market opportunity for integrated DG systems. In the U.S., this market segment suffers PQ and outage-related costs of $450 to $900 million per year. Studies by the Electric Power Research Institute indicate that this market is likely to increase.

Consumers make investments in clean DG for a host of reasons, but very few do so without some consideration of the economic return on the investment. The key point is that potential private economic benefits provide the foundation for investor commitments to developing DG facilities. It is likely that the acceptable return on clean DG investments will differ for investors in different business sectors, but in nearly all cases some measure of attention will be paid to the economics of the project. Today, avoided electricity and fuel cost savings, as well as government incentives, account for the lion's share of the private economic returns from DG development.

However, this report describes other categories of DG benefits, such as emissions reductions, avoided T&D costs, and the delivery of ancillary services to the distribution or transmission grid. Many of these benefits are not compensated in existing markets, but may provide a rationale for other forms of DG incentives such as tax credits, grants, or above market payments. In the few instances where there are markets for these benefits, the associated potential revenue streams are generally not significant enough to contribute to the DG investment decision-making process.

Public benefits: An oft-cited rationale for investing in clean DG is to reduce emissions of criteria air pollutants, lower the rate of atmospheric greenhouse gas accumulation and promote a more sustainable energy production system for the future. Some forms of DG produce electricity without combustion or the use of fossil fuels. Other forms, such as very high efficiency CHP, combust fossil fuels but emit air pollutants and greenhouse gases at a much lower rate per unit of power and thermal energy consumed than traditional separately provided heat and power. Benefits from no or low-emitting DG include reduced or avoided emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), fine particles (PM_{10}), carbon monoxide (CO), and volatile organic compounds (VOCs); greenhouse gases, such as carbon dioxide (CO_2) and methane (CH_4); and, in the case of renewable DG types, emissions to water and soil associated with the life-cycle production and use of fossil fuels.

Some progress has been made in valuing the societal benefits of such emissions reductions and creating market mechanisms to allow DG developers and operators to monetize these benefits. Such markets, created at the federal, regional and state levels, can help defray the costs of DG project development and enhance DG profitability and revenue streams. However, at this writing, viable emissions reduction markets open to small DG units are nearly non-existent in New York State. The few that exist are characterized by low prices, high levels of uncertainty, market fragmentation, procedural barriers, and high transactional costs relative to potential rewards. Pace Energy and Climate Center has addressed a number of these issues in recent reports.

The following markets for creating, certifying and trading emissions reductions currently exist in New York State:

- Emission Reduction Credits (ERCs)
- Emission Allowances (formerly under CAIR[2], now presumably under CATR)
- Regional Greenhouse Gas Initiative (RGGI)
- Renewable Energy Credits (RECs)
- Greenhouse Gas Reductions sold in the voluntary market (e.g. Carbon Offsets)

[2] CAIR is the Clean Air Interstate Rule. Some states have an allowance set-aside for renewable energy and energy efficiency

An additional potential benefit of some DG types is their ability to improve critical infrastructure resiliency, which can play an important role in disaster management planning efforts. This benefit is significant both for the host facility and for the larger community. However, there are not as yet any market or regulatory incentives that would compensate a developer for critical infrastructure benefits realized by the community.

The infrastructure resiliency benefit of DG hinges on the strategic placement of DG systems at select critical infrastructure facilities. The DG system would provide some percentage of electricity requirements (and, in CHP mode, heat and/or cooling) to the host facility under ordinary circumstances. If the grid were to go down during an emergency, the host facility would effectively island, using its DG system to ride through the outage with an uninterrupted supply of electricity. In many instances the onsite generation capacity would not be sized to meet the peak demands of the facility; therefore, available power would be sent to prioritized loads. The uninterrupted functioning of these priority functions at critical facilities during an emergency would in turn increase the resiliency of the entire community by providing uninterrupted services such as medical care and places of refuge.

Systems benefits: A variety of services are required on a continuous basis to support the transmission and distribution of electricity from power plants to end users. Broadly speaking, these ancillary services are performed by electrical generating, transmission, system-control and distribution equipment. The safe and reliable operation of the T&D system requires that demand and supply be in balance at all times. System frequency and voltage levels must be continuously managed to perform within certain ranges. Resources must stand ready to support the system in the case of a loss of a generation or T&D delivery asset (wires, substation, transformers, etc.) Increasing attention is being given to DG's potential to deliver ancillary services at key locations on the distribution and/or transmission grid. Ancillary services include a broad array of support services needed to maintain grid performance during periods of varying loads, varying central station generator availability, and varying transmission and distribution equipment availability/performance. Increasing attention is being given to DG's potential to deliver ancillary services at key locations on the distribution and/or transmission grid. Ancillary services include a broad array of support services needed to maintain grid performance during periods of varying loads, varying central station generator availability, and varying transmission and distribution equipment availability/performance. Certain services are required on a continuous basis, when the system is in a normal state of operation. Other services are required to meet contingency conditions on the system. A contingency is a major event, such as the loss of a generator or a transmission line which causes the system to be out of compliance with applicable reliability standards. Such situations require immediate remedial activities

The technical capacity of DG to provide such services is documented in several studies and has been demonstrated in trials. However, the design of effective markets and compensation policies that would incent DG hosts to provide these services is in its infancy. Where markets do exist, DG participation may be deterred by the high cost of required communication and control equipment. Furthermore, grid management practices and protection schemes can serve as barriers to DG operation during contingency conditions, thus hindering the ability of DG to provide support during critical periods.

Another type of systems benefit is the potential for DG units to enable the deferral of investment in transmission and distribution system upgrades. To meet this need, DG would be deployed at specific locations to relieve load pockets and transmission constraints. This use of DG requires significant involvement from the T&D utilities. Traditionally, these utilities have relied on "wires" solutions, but studies have shown that DG can, in the right circumstances, provide a more cost-effective solution. However, there are rarely formal markets through which distribution utilities can identify and compensate DG operators for these services.

Barriers

Although small DG has been shown to offer a number of significant private, public and systems benefits, deployment of grid-integrated DG units in New York State continues to lag. A number of barriers must be addressed if the state wishes to meaningfully expand DG development:

- Interconnection requirements that impose high costs on small DG
- Utility standby service charges that impose high costs on small DG
- Component costs for DG systems (incremental costs to improve functionality and ease grid integration)
- Poor understanding of the actual impacts and cost implications, of large scale deployment of DG on the grid
- Poor understanding of the potential benefits, and their value, of large scale deployment of DG on the grid
- Lack of effective compensation practices for benefits that DG may provide the grid and society at large, such as ancillary benefits and emissions reductions
- Grid planning and management that focuses on prevailing practices but does not accommodate well the design and performance characteristics of small DG technologies

Existing Policies and Programs

For more than a decade, New York has laid a foundation of policy and program support for small DG development. These efforts have reflected a recognition that DG often can deliver electricity services more efficiently, and with fewer environmental impacts, than central station electric generators. State policymakers have striven to ensure that DG is treated fairly, provided reasonable access to the electric power grid, and accommodated in the associated markets for energy, capacity and ancillary services.

The New York State Public Service Commission, the New York State Energy Research and Development Authority, the New York Independent System Operator, and the utilities themselves have developed what may be described as a portfolio of policy and program initiatives that address existing and potential barriers to DG deployment and, in some cases, offer direct incentives for investments in those types of DG that serve state energy, environmental and economic goals. Major programs and policies that comprise this portfolio include:

- Regulatory standards establishing guidelines for interconnection of DG with electric power grid
- Regulatory policies addressing the design of the rates distribution system utilities may charge DG for standby service
- Market based emissions trading programs that establish emission reduction credits, emission allowances, carbon credits through the Regional Greenhouse Gas Initiative (RGGI), and greenhouse gas reductions certified and traded in voluntary markets
- New York ISO administered market solicitations for ancillary services
- New York ISO managed and distribution utility administered payments for emergency demand reductions and installed capacity resources, including those provided by DG
- The New York Renewable Portfolio Standard solicitation of clean renewable DG thru the Customer Sited Tier program
- Regulatory policy initiatives to encourage distribution utilities to offer incentives for DG capacity installed in locations where it can help defer otherwise-needed distribution system upgrades
- Targeted grants, tax incentives and other payments to reduce the cost of DG investments to project sponsors, including NYSERDA CHP incentives and renewable energy technology demonstration grants, NYS PSC net metering mandates, and federal tax incentives

Virtually all of these programs have been developed and implemented either to remove a specific barrier to DG deployment, or to ensure that existing grid planning and operations allow DG to contribute. This report addresses the entire portfolio of program support, describing in specific terms how each program removes barriers or supports DG investments, and offering observations on the relative effectiveness of each.

To varying degrees, these existing programs have provided substantial support for DG deployment, undoubtedly increasing the number of DG systems in place in New York. Nevertheless, after more than a decade of recognition as a key component of the state's energy supply mix, cumulative DG capacity provides only a modest contribution to New York's electricity supply system, a system that remains based primarily on the historic central generation station model.

With increasing levels of penetration of DG expected over the next few decades, regulators, utilities, grid operators and policymakers should consider the creation of operating frameworks and market rules enabling DG to participate as an active and dynamic asset to the grid. If expected future investments in renewable and clean DG are not made in a context that seeks to optimize and capture potential system benefits, then a significant opportunity for more efficient grid operation will have been forfeited.

Recommendations

1. More study of the true costs and potential benefits of large numbers of small interconnected DG units on the state's electric grid. Closing the knowledge gap is essential because it lowers barriers to development, informs effective policy, allows for more efficient markets and establishes a basis for fair and efficient tariffs and incentives. This recommendation lays the groundwork for all following recommendations.

2. Better coordination of programs, policies and market rules at the state level. A piecemeal approach to promoting and incorporating DG is not effective. Policy, incentives, markets and regulatory structures must work in concert, and these efforts should be based on a much more complete understanding of DG's unique attributes and the technical challenges posed by the incorporation of these attributes into the existing electric grid.

3. Lowering barriers to DG development, interconnection, and market participation. These barriers reflect a poor understanding of DG's technical requirements, and of the true costs and benefits of different DG types in various locations and applications. Given the state's commitment to renewable energy and to the implementation of a smart grid, and the rate of technical innovation in this sector, grid operators and utilities can no longer afford to view DG as a useless and potentially dangerous novelty.

4. Developing markets in which DG can participate, and adjusting market rules to take account of DG's unique attributes. Currently, most DG is developed to serve an on-site load. Bringing DG into a productive and efficient relationship with the grid, where DG's highest potential value can be realized, will require markets to become much more inclusive of DG resources.

I. Introduction

1. About this report

This report was produced by Pace Energy and Climate Center (Pace) in partial fulfillment of a NYSTAR funded CAT Development award (Contract No. C030092) received by the Center for Future Energy Systems (CFES), Rensselaer Polytechnic Institute (RPI). RPI subcontracted with PECC to produce this report, which represents a small portion of the overall project, titled "The Future Distribution Grid of New York State – a Test-Bed Validation."

The RPI Project Team is designing a test-bed to assess the important features of a distribution grid capable of optimally integrating distributed generation (DG). Such a distribution grid would maximize the benefits DG offers grid system operators and the end use consumer. The test-bed will be used to evaluate changes in the physical grid and grid operating practices. RPI will demonstrate the test-bed by analyzing the impacts of three DG technologies on local distribution systems. These technologies—solar, wind and fuel cell generators—were selected for key characteristics: solar for its fast changing performance, wind for its slow changing performance, and fuel cells for their moderate changing performance and capacity for power dispatch (i.e., output control).

Pace's component of the project focuses on the economic models and regulatory practices that affect the construction and operation of DG facilities in New York State. This report describes the benefits offered by DG, including ancillary services; summarizes how existing economic and regulatory structures recognize and reward these benefits (or fail to do so); examines ways to remedy deficiencies and optimize the performance of the future grid to capture important DG benefits; and suggests changes in current economic and regulatory models needed to more equitably and efficiently quantify, recognize and capture the value of DG benefits for the DG system owner.

This report is structured around six main sections. Sections I and II are the executive summary and introduction. Section III presents the various types of DG benefits, which are organized into categories. Private benefits include enhanced power quality and on-site economics; public benefits include environmental and critical infrastructure benefits; and system benefits include ancillary services and T&D investment deferral. Section IV discusses various barriers to DG deployment in New York State, including costs, knowledge deficits and market deficits. Section V surveys the existing programs, policies, markets and incentives that support DG development in New York State; Section V also includes a case study showing the potential impact of various environmental markets on DG system economics, and discusses barriers that may prevent DG systems from participating in the existing markets and programs intended to support distributed and clean generation. Recommendations for addressing barriers are presented in Section VI. This is followed by references section and a number of appendices containing detailed information on benefits, programs, and recommendations.

2. About Distributed Generation

Over the last couple of decades there has been an increasing interest in the development of markets for distributed power generation. There are several compelling reasons for promoting the increased deployment of DG. Proponents have cited these benefits, among others:

- Reduced distribution and transmission losses as a result of siting power generation in close proximity to loads
- Increased fuel efficiency and reduced fuel consumption when renewables or combined heat and power (CHP) technologies are employed
- Improved environmental performance as a consequence of employing generating assets having little or no emissions of criteria air pollutants or greenhouse gases
- The provision of ancillary services such as voltage regulation and reactive power (VAR compensation)
- Enhanced reliability and power quality
- Increased critical infrastructure resiliency as a result of off-grid generation and islanding capability
- The provision of economical alternatives to distribution system investments by deferring or avoiding capital expenditures.

Many of the above benefits accrue not to the private owner of the system but rather to the improved operation of the T&D system (system benefits) or to the general public (societal benefits), creating an uncompensated “positive externality”. Under current market and regulatory regimes, externality benefits (and at times costs) of DG are not captured and not considered explicitly when allocating benefits and costs.

Generally, end-users invest in DG systems to provide several types of services:

1. To provide emergency backup power to meet critical facility needs only at times when service from the grid is interrupted. For example, the DG system might sustain critical functions at a hospital during a natural disaster that temporarily incapacitates the grid.
2. To generate emissions free, or very low-emissions electricity thereby meeting organizational, public policy or personal/organizational goals to reduce climate change and other air emissions impacts associated with electricity generation and consumption.
3. In combined heat and power applications, to reduce total energy costs by producing electricity to serve a portion of the needs of the DG system owner or the owner’s client, while productively employing the waste heat at or near the site. Typically such systems are thermally led, with peak load being supplemented from the grid. When grid prices are particularly low, and/or thermal demands insufficient, the site may elect to purchase power from the grid.

The first application involves DG systems that are designed to operate only for short periods of time during emergencies. These systems are not designed to provide for the normal energy needs of their host facility. While they may be called upon to provide short term services for the grid, they typically are limited in their ability to sustain such contributions. Investments in such facilities are determined primarily by the need of the local facility to protect against loss of electricity service during grid outages. Often, as is the case with hospitals, wastewater treatment plants and some commercial and multifamily buildings, the requirement to own and operate such systems is established by national, state or local codes.

The second application involves DG systems that are primarily designed to operate behind the meter at a customer site, and to generate no more power than is necessary to meet the site's demand. Investments in these types of projects are driven in part by societal goals and objectives and not by a purely economic calculus. In this category are investments in customer sited solar, wind, and other renewable energy projects that reduce greenhouse gases and generate electricity without associated air pollutant emissions. Customers installing such projects might be doing so to meet internal objectives to generate and consume clean energy or to satisfy public commitments.[3]

The third type of DG application is typically the outcome of an economic decision process that assesses the net costs of generating power onsite and re-using the waste heat in a productive manner to lower total energy bills. This approach, combined heat and power ("CHP") is not technically feasible and economically viable at all locations. CHP may be an economic option for sites having a significant and simultaneous need for electric power and thermal energy. If the thermal energy generated at the time of power generation can be fully utilized, if equipment can be used over a significant percentage of the year, and if the cost of making power onsite is markedly less than buying it,[4] then the economics of CHP may be compelling.

This report focuses primarily on the second and third types of DG applications. These DG systems are designed to meet some portion of the daily needs of a local facility. In the case of a CHP system the electric generation will be limited by the ability of the site to simultaneously capture and productively use the waste heat. In some cases and at certain times[5] these units are capable of delivering additional electricity onto the grid. Such DG systems may serve a wide variety of end use electricity consumers, ranging from large commercial or industrial operations to individual residential consumers. The decision making process differs markedly amongst the cases where customers invest in DG facilities to provide energy more economically,[6] as contrasted with decisions based more on sustainability and environmental objectives. Residential and some large institutional or commercial customers may be willing to accept much

[3] For example, the American College & University Presidents' Climate Commitment and Mayor Bloomberg's Hospital Challenge for participants to reduce greenhouse gas emissions 30% in 10 years

[4] The difference between the input fuel cost (natural gas) and the price of purchased electricity is referred to as the "spark spread." The greater is the spark spread, the more likely it is the project will be economically viable.

[5] During times when generation capacity exceeds expected site demand

[6] Some sites take account of reliability/power quality as part of the return on investment assessment

longer payback periods and a lower return on investment, perhaps placing greater weight on the environmental benefits of zero or very low emitting onsite energy systems.

Though developed to meet the needs of a local facility/electricity consumer, these DG systems may provide valuable benefits to the electric power grid and to the society at large. One challenge for public policy is to ensure that these public benefits are not lost because private investors only receive a return on their investment reflecting a DG project's private benefits, i.e., the benefits of the project to the owner/operator. Public policy may be crafted in such a way that it facilitates additional returns on investment that reflect the value a DG project provides to the larger community and/or to the electricity grid. Policymakers in New York and many states around the country have made commitments to renewable and clean energy goals. In support of those goals a system of incentives has been developed. Regulators and policymakers should take care that existing incentive structures, public programs or regulatory policies serving other objectives do not pose unintended and unnecessary barriers to obtaining the public benefits private DG investments may offer.

3. DG Technology Types Addressed in This Report

The RPI test bed is designed to assess the performance and grid integration of DG having three distinct attributes: fast-changing performance (represented by solar PV), slow-changing performance (represented by wind), and moderate-changing performance with power dispatch capability (represented by fuel cells). The RPI project is concerned with the "Distribution System of the Future." With that in mind, this report addresses DG applications that are behind the meter and sized at or less than 10 MWs. DG at this smaller-scale range is in almost all instances connected at the distribution level.

This report also addresses other DG technologies such as gas and renewables-based CHP that New York State and New York City[7] have cited as part of their overall clean energy strategies. The prime movers in this instance might be reciprocating engines, micro-turbines or smaller-scale gas combustion turbines. These DG types are fully dispatchable and not intermittent.

Various types of DG will be differently affected by various policies and market-based mechanisms. For example, natural-gas powered CHP that supplies heat as well as electricity can benefit from markets and incentives that support reductions in local combustion-related emissions if they replace residual oil boilers. This is not true of DG types that produce electricity without heat, such as solar PV and wind turbines. These differences are important, especially because, at this point in time, state incentives are an important driver influencing the rate of investment in smaller-scale DG. The proportion of a particular technology's total fixed and operating cost that is offset by the existing incentive structure will play a significant role in determining asset selection.

[7] PlaNYC Initiative 13 calls for an incremental 800 MWs of clean DG in New York City, contributing 10% of the GHG reductions to meet the 30 x 17 goal.

II. DG Benefits

Distributed generation units offer a number of different types of benefits. On-site benefits accrue to the DG owner/operator and the host facility or campus; social benefits accrue to society at large; and systems benefits accrue to the grid, its customers, and the load serving entities. These benefits are discussed at greater length below.

1. On-Site Benefits

Power Quality

In 2005, Pace Energy and Climate Center (then the Pace Energy Project), in collaboration with Energy and Environmental Analysis, Inc., produced a report for NYSERDA titled "The Role of Distributed Generation in Power Quality and Reliability"[8] (NYSERDA, 2005). The premise of the report was the idea that distributed generation, as part of an on-site power quality and reliability system, could cost-effectively improve power quality (PQ) and reliability to customers with PQ-sensitive systems; and that, in doing so, the value of DG systems would be increased for an important segment of the commercial and industrial market. The report evaluated two DG applications, peak shaving and combined heat and power, in terms of their value to an on-site, integrated PQ/reliability system. In both cases, the analysis revealed that the incorporation of DG resulted in significant improvements in system reliability, as well as a reduction in capital costs due to avoided investment in an otherwise-necessary diesel standby generator. In the case of the CHP system, capital costs were reduced by up to 40%, while the mean time between failures (MTBF) increased to 27 years. By comparison, a UPS system coupled with a diesel standby generator had an MTBF of 4.4 years. Integration with an on-site PQ system also made the DG investment much more economic, reducing the payback period in the CHP case from 12.2 to 6.6 years.

On-Site power quality benefits are potentially quite valuable. Estimates show that power quality disturbances cost U.S. businesses hundreds of billions each year. Customers most sensitive to these disturbances fall into categories:

- The digital economy—firms that rely heavily on data storage and retrieval, data processing, or research and development.

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[8] Reliability is defined as the ability of the electric grid to deliver uninterrupted electric power; power quality is defined as the ability of the electric grid to deliver a clean signal without variations in the nominal voltage or current characteristics. Minor variations (those within 10% of nominal) are considered normal.

- Mission critical computer systems—banks, depository institutions and other financial companies, stock markets, investment offices, insurance companies, computer processing companies, airline reservation systems, and corporate headquarters.
- Communications facilities—telephone companies, television and radio stations, internet service providers, cellular phone stations, repeater stations, military facilities, and satellite communication systems

Electric Power Research Institute (EPRI, 1995) monitored the power quality and reliability delivered by 24 utilities to 300 sites on 100 distribution feeders throughout the U.S. EPRI found there were nearly 75 events per customer per year. Although most were minor voltage sags, the average site also experienced 8.5 momentary or longer service interruptions per year. The cost of these events varies widely, depending on the industry; measured in terms of dollars per kVA per event, costs range from $3-$8 per kVA for the textile industry to $80-$120 per kVA event for sensitive process industries. Downtime can cost a cellular communications facility $41,000 per hour; by comparison, a brokerage house could find itself facing several million dollars in damages if it were shut down for an hour.

EPRI evaluated two million business establishments to determine the cumulative costs of power outages and power quality disturbances. [9] The results of this analysis are shown in Table 1. According to the study, New York ranks third in the U.S. behind California and Texas with an estimated $8.0 to $12.6 billion in costs associated with outages and power quality phenomena.

Table 1: Estimated Total U.S. Cost of Power Quality Disturbances per Year

	Outage Costs ($billions)	Power Quality Costs ($billions)
Digital Economy	$13.5	$1.0
Continuous-Process Manufacturing	$3.0	
Fabrication and Essential Services	$29.2	$5.7
Total PQ Sensitive Sectors	$45.7	$6.7
Estimate of All Business Sectors	$104-$164	$15-$24

Source: EPRI

[9] Data comes from a series of EPRI studies: *Markets for Distributed Resources: Business Cases for DR Applications*, EPRI Report TR-109234-V2, November 1997; *Distributed Resources Premium Power Solutions*, EPRI Report 1004451, January 2003; *Understanding Premium Power Grades*, EPRI Report 100406, November 2000; and *Information to Support Distribution Resources (DR) Business Strategies*, EPRI Report TR-114272, December 1999.

Of course, not all PQ-sensitive businesses are appropriate sites for distributed generation. Approximately 90% of the market is served by small- and medium-scale PQ equipment or services; these customers would not represent an economic opportunity for DG systems. However, the remaining 10% of the PQ-sensitive market requires facility-scale PQ control (greater than 100 kVA), and it is this market segment that represents the greatest potential for integrated DG systems. In the U.S., this market segment suffers PQ and outage-related costs of $450 to $900 million per year. This market is likely to increase; an EPRI study (EPRI, 2000) projected 13% growth in the market for PQ equipment and services throughout the forecast period.[10]

Economics

Many DG systems are developed primarily because they promise a positive economic impact for the host facility. This generally includes reduced power purchase costs (and, for CHP systems, a reduced cost for space or process heating), although it can also include anticipated incomes from the marketing of various attributes and services.

It is difficult to overestimate the role of direct, on-site economic impacts in the DG development decision making process. Unless the host facility has non-economic motives—for example, a college campus looking to fulfill a low-carbon pledge and develop on-site DG as an education resource—the direct economic impact of the project is likely to trump all other considerations.

2. Social Benefits

Critical Infrastructure Resiliency

During and in the aftermath of emergency situations – such as hurricanes, floods, and severe ice storms – continuous operation of certain facilities, such as hospitals and wastewater treatment facilities, is seen as a critical societal concern. Critical infrastructure is a term applied to facilities providing health care, clean water, food and shelter to the displaced during emergency situations. An additional potential benefit of some DG applications is their ability to improve the resiliency of critical infrastructure assets which play an important role in disaster management planning efforts. This benefit is significant both for the host facility and for the larger community. However, the development of incentives that would compensate a site for these community benefits is in its infancy.

[10] Power Quality Equipment & Services: Selected industrial & Commercial Market Segments of Interest to Electric Utilities, EPRI ReportTR-1000202, Frost & Sullivan, June 2000 (Results summarized in EPRI 1004451 previously cited.)

In February, 2009, Pace Energy and Climate Center produced a report in partnership with Energetics, Incorporated and Energy and Environmental Analysis, Inc., titled "The Contribution of CHP to Infrastructure Resiliency in New York State" (NYSERDA, 2009*b*) The purpose of the report, produced for NYSERDA under Agreement Number 9931, was to "identify and recommend the most opportune uses for CHP as a way to address critical infrastructure resiliency in selected end-use sectors in New York State."

Although the focus of the report was on CHP systems in particular rather than DG in general, its conclusions, summarized below, apply as well to any DG technology that is dispatchable in nature and capable of islanding in case of grid failure. The report's conclusions could also apply to intermittent generation types, such as wind and solar PV, with the addition of appropriately sized on-site energy storage (batteries and/or hydrogen, for example) or backup generation source. However, this type of application would not be appropriate for stand-alone intermittent generation systems.

The infrastructure resiliency benefit of DG hinges on the strategic placement of DG systems at select critical infrastructure facilities. The DG system would provide some percentage of electricity requirements (and, in CHP mode, heat and/or cooling) to the host facility under ordinary circumstances. If the grid were to go down during an emergency, the host facility would effectively island, using its DG system to ride through the outage with an uninterrupted supply of electricity. In many instances the onsite generation capacity would not be sized to meet the peak demands of the facility therefore available power would be sent to prioritized loads. The uninterrupted functioning of these priority functions at critical facilities during an emergency would in turn increase the resiliency of the entire community by providing uninterrupted services such as medical care, clean water and places of refuge.

The decision about where to locate such DG systems would necessarily be part of a larger disaster preparedness plan specific to the host community and responsive to its needs. The NYSERDA report identified seven primary market sectors as potential hosts for CHP systems. These sectors were identified based on both the function of providing critical services during an emergency and their ability to economically host a CHP system:

Primary market sectors

- Hospitals
- Water treatment and sanitary facilities
- Nursing homes
- Food processing and food sales facilities
- Prisons
- Places of Refuge
  - Schools, colleges and universities

    - Armories
    - Government buildings
    - Hotels and convention centers
    - Sports arenas
    - Other facilities, as appropriate
- Chemicals (due to the important pharmaceuticals subsector)

(NYSERDA, 2009*b*)

In addition to the primary market sectors listed above, the report identified secondary market sectors. These offer significant potential contributions to community resiliency but do not have strong technical potential for CHP:

Secondary market sectors

- Gas stations
- Mass transit
- Fire protection
- Police
- Telecommunications
- Banking and finance
- Refrigerated warehouses

(NYSERDA, 2009*b*)

In order to provide uninterrupted electric power during a grid failure, DG systems must meet certain technical criteria, such as "black start" capability (the ability to be started using only an onsite battery) and the use of synchronous rather than induction generation systems (synchronous generators do not require a signal from the grid in order to function). These requirements impose additional costs on both the DG developer and the utility. For example, when synchronous generators are connected to the grid, specialized interconnection equipment may be needed to ensure the safety of utility personnel working on the grid during a power outage (to make sure the synchronous generator does not feed power onto the grid while it is undergoing repairs). Currently, this equipment is available in some areas and not others; Con Edison, for example, is incrementally upgrading various sections of its NYC metro service area to allow synchronous generation, but these upgrades will not be complete in some communities for more than a decade.

Likewise, the DG operator will need to install specialized switchgear and controls to isolate and serve critical facility loads without overloading the generator. During a grid failure, the DG host facility's critical loads must be isolated from the non-critical loads, which will be shut down until normal grid service is resumed (this assumes the DG system is sized to meet critical facility load, but not to meet the entire facility load during peak load times). Various control configurations will add various levels of cost to a DG system.[11]

Emissions Benefits

One of the characteristics of DG is that it frequently offers emissions benefits relative to centralized, fossil fuel-based electricity generation. Such benefits include reduced or avoided emissions of air pollutants such as nitrogen oxides (NO_x), sulfur dioxide (SO_2), fine particles (PM_{10}), carbon monoxide (CO), and volatile organic compounds (VOCs); greenhouse gases, such as carbon dioxide (CO_2) and methane (CH_4); and, in the case of renewable DG types, emissions to water and soil associated with the production and use of fossil fuels. Associated benefits include reduced fuel use and increased fuel efficiency.

Some progress has been made in valuing the societal benefits of such emissions reductions and creating mechanisms to allow DG developers and operators to monetize these benefits. Such mechanisms can help defray the costs of DG project development and enhance DG profitability and revenue streams.

However, a number of barriers remain that make it difficult for DG operators to fully monetize the societal benefits they provide through increased efficiency, decreased fuel use and emissions reductions. These include:

- Not all emissions reductions are rewarded under current mechanisms
- Emissions reductions that are rewarded are often valued insufficiently to stimulate DG development
- Many market-based mechanisms for emission reductions do not include smaller-scale DG as eligible participants
- Where market-based mechanisms for emissions reductions do allow participation by small DG, many small DG units typically need to aggregate in order to achieve salable benefits
- The future value of emissions reductions is uncertain
- The future of some major regulatory mechanisms is uncertain

[11] For more information on the potential use of DG for critical infrastructure resiliency, see the Energetics/Pace/EEA report, available on the NYSERDA website (http://www.nyserda.org/chpnys/nyserda-chp-final-report-optimized.pdf). More information is also available in Appendix D.

- Smaller emissions markets may lack sufficient buyers and sellers to achieve high liquidity, and market size is often restricted by political considerations
- Transactional costs for small DG developers and operators to participate in emissions markets can be high relative to the potential rewards

Although it may seem obvious that emissions benefits exist for many types of DG, measuring and pricing these benefits accurately is not a straightforward task. Since the emissions value of DG-provided electricity relates to the grid-provided electricity that it displaces, it is necessary to characterize the emissions profile of this displaced electricity. A simplified method for assessing DG emissions benefits, known as generation portfolio analysis, assumes that DG added to a system displaces generation equally from all assets in the system's portfolio. A more sophisticated method, economic dispatch analysis, assumes that DG added to a system displaces those generators that are last called upon in the system loading order.[12] The relative emissions benefits of DG will usually be lower under the latter type of analysis.

Another example of a crediting mechanism, that used in the NO_X State Budget Program and its successor the Clean Air Interstate Rule (CAIR), was to assume that the an average value of NO_X displaced in the affected region was 1.5 lbs NO_X/MWH. Therefore, for every MWH generated by an emission free DG resource participating in the program, that resource could be credited with 1.5 lbs of NO_X displaced. The situation is more complicated for clean DG that utilizes fossil fuels. For example if microturbines are certified to generate electricity with a NO_X emission rate of 0.25 lbs NO_X/MWH then every MWH generated by this asset, if participating in a program, can be credited with 1.25 lbs of NO_X displaced. If a 1 MW microturbine installation runs 8,000 hours per year, generating 8,000 MWHs, it could be credited with 10,000 lbs of displaced NO_X, or 2.25 tons per year.

Another complicating issue arises when the penetration of intermittent DG in a grid system becomes great enough to require low-level operation and fast ramping of dispatchable generators to maintain load service when intermittent DG types rapidly increase or decrease their output. Under these conditions, where large-scale hydroelectric power is not available, gas-fired turbines will be required to operate under less-than-optimal conditions, potentially increasing their per-unit emissions. One recent study found that with a 20% RPS comprised of wind and/or solar PV, NO_x emissions could actually increase significantly over the entire system, due to increased emissions from gas-fired turbines (Katzenstein and Apt, 2009). This result depends greatly on the specific type of gas turbine used and the level of penetration of intermittent renewables on the system.

Although the above referenced study is based on utility-scale renewable generation, it illustrates the importance of assessing emissions benefits of DG on a case-by-case basis, taking into account the specific attributes of the DG generator as well as the type of generation it will displace on the grid, in order to fairly and accurately value the net benefits of a DG facility. In

[12] These are referred to as the "units operating on the margin" in the hourly wholesale market and having the highest marginal costs of operation (typically, older inefficient natural gas-and oil-fired turbines).

the case of CHP systems, this assessment of displaced emissions from grid-sourced electricity must be complimented by an assessment of local emissions displacement due to the thermal energy produced by the CHP system. When a CHP system utilizes the waste heat at a site for a productive purpose, it is supplanting fossil fuel combustion that otherwise would have been required to provide that thermal energy.

Markets for emissions reduction and displacement have been created at the state, regional and federal levels. Currently, markets available to DG project developers in New York State are nearly non-existent and those few where smaller-scale DG can participate are fragmented, rules and procedures differ from market to market, and the cost to participate can be high relative to the potential rewards. Pace Energy and Climate Center has addressed a number of these issues in recent reports.

The following markets for creating, certifying and trading emissions reductions currently exist in New York State:

- Emission Reduction Credits (ERCs)
- Emission Allowances (formerly CAIR, now presumably under CATR)
- Regional Greenhouse Gas Initiative (RGGI)
- Renewable Energy Credits (RECs)
- Greenhouse Gas Reductions sold in the voluntary market (e.g. Carbon Offsets)

Of these only the ERCs market and voluntary markets for greenhouse gas reductions are open to participation by clean DG systems operating in New York.

Less formal emissions reductions opportunities also exist via such activities as GHG reduction "challenges" adopted by some municipalities and large corporations and facilities, such as universities and hospitals[13]. For example, New York City has set a target of 30% reduction in GHG emissions by 2030. These challenges do not constitute formal markets for emission reductions but can serve as drivers for increasing the installation and operation of clean DG technologies.

3. Systems Benefits

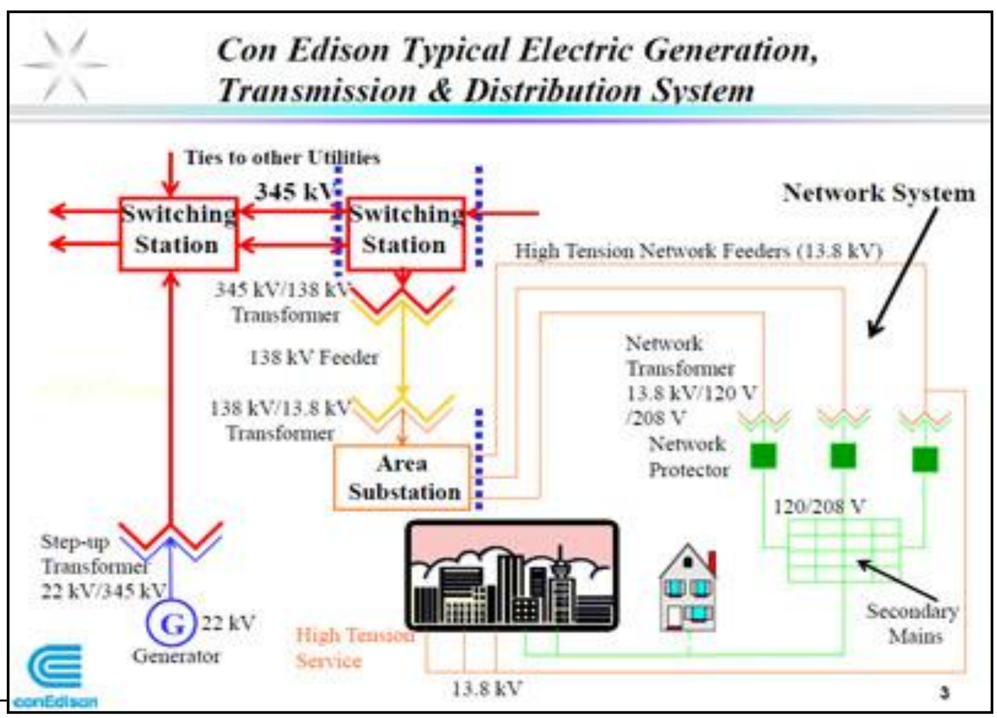
Ancillary Services

Introduction

[13] Examples include the American College & University Presidents' Climate Commitment and Mayor Bloomberg's challenge in New York City for hospitals and universities to reduce greenhouse gas emissions by 30% over the next 10 years.

Ancillary services are discrete functions that support the transmission and distribution of electricity from power plants to end users. The ideal power system has specific parameters, including nominal voltage, frequency, current levels, etc., that must be maintained to ensure safe and reliable operation. In actuality, the power systems that surround us in everyday life constantly deviate from this ideal state. There are acceptable levels of deviation in these parameters that must be adhered to by distribution utilities, transmission operators and the NYISO. To ensure operating within these tolerances, T&D system managers rely on certain assets, some procured in real-time or hourly markets, others acquired by contract and still others that are self-supplied. The services provided by this suite of assets are known as ancillary services, and they are critical to maintaining the electric grid within safe operating limits (Hirst and Kirby, 1996).[14]

Services that support the safe and reliable operation of the T&D system have traditionally been provided by large generators, or by other assets owned and operated by the T&D utilities. However, in recent years there has been a growing interest in examining the role that DG might play in providing these services. New mandates will expand renewable generation connected to the T&D system.[15] As more distributed generation is connected with the distribution system it is possible to do so in a manner whereby it can provide additional value to the system. Failing to plan for and incorporate these potential benefits of future DG assets could be considered a significant lost opportunity.



[14] Ancillary ... ry.

[15] The type ... level.

Figure 1

It is important to note that capturing these potential benefits of DG will require incremental investments by the utility and by the DG host site. Many potential benefits will not be realized unless the DG systems are properly configured to provide the benefit, and the design and operation of the T&D system facilitates the delivery of the benefit. Furthermore, appropriate markets are needed to properly value such benefits. Although grid operators have established a market for ancillary services supporting the transmission system, there is no comparable market supporting the delivery of ancillary services to the distribution system. In particular, regulators have not identified the existence, definition, and pricing parameters of ancillary services supporting the distribution system. Instead, the provision of ancillary services at the distribution level has traditionally been achieved by use of "wires-based" infrastructure assets, ranging from series capacitors to circuit breakers and phase-shifting transformers. Providing these services with distributed generation rather than traditional infrastructure assets would require the deployment of enabling technologies, including communications systems and controls, and the development of new regulatory models and market-based mechanisms.

Transmission System Ancillary Services

The Federal Energy Regulatory Commission (FERC) has identified six specific ancillary services required to maintain the reliable flow of electricity from producers to consumers across the interconnected transmission system.

1. Scheduling, system control and dispatch service
2. Regulation and frequency response service
3. Energy imbalance service
4. Operating reserve service
5. Voltage support service
6. Black start capability service[16]

The FERC ancillary services list provides a good starting point for considering the contributions DG may provide. But these six services are hardly dispositive. Researchers have identified more than a dozen ancillary services not included in FERC's list.[17]

In New York the Independent System Operator (NYISO), which is responsible for administering the electric grid, coordinates the provision of ancillary services supporting the transmission

[16] U.S. Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Docket RM95-8-000, Washington, DC, March 29, 1995.
[17] *See* Kirby, Hirst and Van Coevering 1995

system through New York's wholesale energy market.[18] Each of the six FERC ancillary service categories is discussed briefly below.

[18] The NYISO was created to carry out the Federal Energy Regulatory Commission mandate to provide fair and open access to the electric grid within the New York Power Control Area. The NYSISO carries out the range of operation management, planning and research functions required to ensure the interconnected electric grid not only meets this market access mandate but also meets high standards for system reliability and efficiency. See www.nyiso.com

Scheduling, System Control and Dispatch Service

These are the functions of the System Operator—in New York, the NYISO. The NYISO Ancillary Services Manual breaks this set of services into two broad categories:

- System Security Management in real-time
- Capacity Management

Regulation and Frequency Response Service

The production and consumption of electricity must be matched instantaneously and continuously. Mismatches between generation and load leads to system power frequency deviations. Too much generation and the system frequency increases, too little and the system frequency decreases. Large shifts in frequency can damage equipment, degrade load performance and interfere with system protection schemes which may ultimately lead to system collapse. Regulation services are provided on a continuous basis, typically by assets that are able to dynamically alter generation (up or down). Response rates must be near instantaneous in order to maintain the real time balance of the system.

Energy Imbalance Services

Because electricity consumption varies from hour to hour, electricity generation supply must be continually balanced with electricity consumption. Transmission system managers continually monitor the scheduled supply of generation, usually on an hourly basis, to ensure that sufficient supply will be available to meet demand. The objective is to ensure that scheduled generation matched with scheduled customer loads. Deviations are corrected in the “balancing” market. Any generator can provide energy balancing services if it is located close enough to the load area that transmission limitations do not prevent the movement of power to the area experiencing a load imbalance. Energy balancing generally is handled in real time energy markets, with generators responding to real time energy prices (Kirby 2007). The NYISO addresses energy balancing for transmission customers taking service under the NYISO Service Tariff through the real time market and the real time settlement process (NYISO, 2011).

Operating Reserve Service

Operating reserve service addresses the need to match electric generation with electric consumption in response to emergency conditions, such as the loss of a major generating unit or transmission facility. Operating reserve service is provided by flexible generation (spinning and non-spinning reserves) and/or demand response (reducing site loads or increasing output from generators serving on-site loads).[19]

Operating reserves are differentiated by speed and duration of response. Spinning reserves are quick response resources that are available to support the system by maintaining reliability in the event of a contingency such as the loss of a major generator or transmission line that results in a failure to meet binding reliability criteria. These assets must be online and operating with the capability to respond to requests from the system operator to increase/decrease output. Spinning reserves typically must respond within seconds.

Non-spinning reserves are similar to spinning reserves in that they are available to provide system support in the event of a contingency. Non spinning reserves need not be connected (synchronized) and operating, but must be able to respond within 10 minutes to a call. Once spinning and non-spinning reserves have been committed, the necessary reserve margins for safe and reliable operation of the system fall below prescribed limits. A subset of non-spinning reserves, supplemental or backup reserves, responds to a contingency within a 20 minute to 1 hour timeframe, but once committed the duration period is typically longer.

Voltage Support Services

Voltage support is another service that is required continuously for the reliable operation of the interconnected transmission and distribution system. Voltage support entails injecting or absorbing reactive power to maintain system voltages within specific tolerance levels. Voltage support is required both at the transmission system level and at the buses of critical sensitive loads (ORNL, 2005). The transmission system relies on generators to provide voltage support. Generators either produce or absorb reactive power to maintain system voltage. The asset must be able to automatically respond to voltage control signals, which for generators requires that they have a functioning Automatic Voltage Regulator. The asset must be able to maintain a specific voltage level under both normal operating and post-contingency conditions.[20]

Black Start Capability Service

Black start capability describes the ability of some generators to start up without the aid of electrical service from the grid. The transmission system contracts with generators capable of black starts to assist with restarting the power system when a major blackout occurs. The New York ISO selects generation facilities for black start service by considering the following operating characteristics:[21]

[19] NYISO 2011. Section 6
[20] NYISO Ancillary Service Manual Version 3.19 3/9/2011 Section 3
[21] NYISO 2011 p. 6-23

- Location within a control area
- Startup time, from the request for service to minimum power delivery
- Maximum capacity response, MW per minute above minimum output
- Maximum power output

Distribution-Level Ancillary Services

While the general definition of “ancillary services” is well-established, the scope of specific ancillary services needed (and available) to support the transmission and distribution systems are not necessarily identical.

The Federal Energy Regulatory Commission (FERC 1995) defined ancillary services as “those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.”[22]

Grid operators have established a market for the provision of ancillary services for the transmission system. FERC identified six ancillary services: reactive power and voltage control, loss compensation, scheduling and dispatch, load following, system protection, and energy imbalance. Transmission system operators (TSOs) have relied heavily on ancillary services to integrate growing levels of renewable-energy resources into the power grid without compromising the system’s reliability. Although the market for ancillary services is well established at the transmission level, no comparable market exists for the distribution system.

In 2005, the European Union sponsored an international survey of ancillary services markets for both the distribution and transmission systems. The survey concluded, “In liberalized international energy markets, the provision of frequency response and reserve services from distributed generators was found to be commonplace [but] . . . Experience regarding the provision of ancillary services to [distribution systems operators], as opposed to TSOs, was found to be limited although niche applications were identified on remote and islanded distribution networks, e.g. the Channel Island and the Isles of Scilly” (Mutale, 2005, p. 14).

Ancillary services supporting the distribution system have traditionally been accomplished with assets procured and deployed within distribution companies. The value of the services across the utilities at various locations and times of the year is known only to the utility, and if requested, the regulator. Because there are no well-developed markets, nor prices to signal system-wide or localized value to outside parties, the scope of ancillary services potentially provided by DG remains unclear at the distribution level. The scope of ancillary services may be more or less expansive at the distribution level compared to the transmission system. Furthermore, the scope

[22] There are existing markets at the system (NYISO) level for ancillary services.

of these services may vary significantly depending on the technical and design parameters of specific distribution systems (e.g. radial vs. network).[23]

[23] For example, Con Edison's service territory includes both network and radial distribution systems – 60 network systems serve roughly 86% of total demand and radial systems serve the remaining 14% of total demand in Con Edison's service territory.

Table 2: Ancillary Services

Distribution System	Transmission Services
Voltage control	Scheduling and dispatch
Regulation	Voltage support
Load following	Frequency regulation
Spinning reserve	Energy imbalance
Non-Spinning reserve	Operating reserve
Backup supply	Black start capability
Harmonic compensation	
Network stability	
Seamless transfer	
Peak shaving	

Unlike the transmission system, most outages on the distribution grid are caused by storms, equipment failure or fallen trees. By reducing equipment loadings at times when the local system is stressed, DG can offer capability to reduce certain forms of distribution system outages. A reliability benefit provided by DG for the distribution system is reduced restoration time (Smertz, 2009).[24] Strategically sited and appropriately configured DG assets could provide significant quality of service, asset optimization and operating-enhancement services at the distribution level, functions utilities currently self-supply.[25]

DG-Based Ancillary Services for the Distribution Grid

There is a growing body of evidence that DG can provide significant benefits to the electricity grid, especially at the local level (ORNL, 2005; Kirby, 2007, Mutale, 2005). However, there is very little practical experience with employing smaller scale DG systems to provide such services.

[24] (Smertz, 2009) Finding that DG provides reduced restoration time by reducing time and complexity of load transfer.

[25] See id. (Finding that inverter-based DG can improve power quality and voltage stability by using the inverter to produce or absorb reactive power.)

Strategically sited and appropriately configured DG on the local distribution system can improve performance, reduce losses and defer capital costs of network reinforcement, load relief and automation facilities.
Likewise, a substantial body of research suggests that DG can provide the full range of ancillary services if appropriately configured and sited in locations where the distribution grid is equipped with requisite enabling technologies. DG can provide voltage control, network stability, load following, and regulation services, backup supply and peak shaving depending on its proximity to the user.

What ancillary services can DG provide?

In theory, certain forms of DG when appropriately configured and operated as a resource on the T&D system, can provide the full range of ancillary services. DG is capable of providing voltage control, network stability, load following, and regulation services. DG can also provide backup supply and peak shaving depending on its proximity to the user.

Although DG might provide such services in actuality it's role is constrained by a variety of factors, some having to do with the essential characteristics of the DG technology itself, others having to do incremental capital costs to enable the service, transaction costs of aggregating the impacts of numerous small generators, or with the state of the existing markets and their ability to measure and compensate a local generator for T&D system operational support.

Table 3

Dispatchability	Can the resource be delivered with certainty when called
How Rapidly can the asset respond?	Instantaneous, <1 minute, <10 minutes, 30 to 60 minutes
Operational Control?	Is this a firm resource that the T&D system can control
Incremental Capital costs	Can the enabling investment in grid and power electronic interfaces be recouped
Aggregation & Transaction costs	Can small generating sources be economically aggregated and managed to provide a service where scale matters

In New York State, a few existing programs demonstrate that many small customer-owned generators, put in place to provide emergency backup power or to regularly serve some portion of the owner's needs, can be harnessed to supplement grid resources. ConEdison, for example, administers its Distribution Load Relief - Tariff Rider U Program, that offers financial payments for load reductions during critical demand periods ("load relief periods"). This is achieved by use of on-site generators or by reducing customer electricity use (Nexant, 2008). However, while these load management programs demonstrate a valuable contribution of small DG capacity to the regular management of the interconnected grid, there are as yet no programs in place that routinely use DG to provide other ancillary services, such as frequency and voltage support, or spinning and non-spinning reserve capacity.

This may change. Emerging smart grid technology promises to improve the ability of grid managers to monitor and control conditions throughout the grid. At the same time, public policy commitments to renewable energy deployment and highly efficient natural gas fueled combined heat and power (CHP) and fuel cell systems promise to increase the number of distributed generators throughout the electric power system. Accordingly, increasing attention is being given to the challenges and opportunities offered by the increasing number of relatively small generators distributed throughout the grid.

A 2005 Oak Ridge National Laboratory report (ORNL, 2005) examines the opportunities for using two common types of small generators, microturbines and internal combustion engines, to provide needed ancillary services to the transmission grid. The report observes,

> *A market for unbundled services (ancillary services) would promote installation of DG where costs could not be justified based purely on real-power generation. The provision to produce ancillary services with DG would greatly alleviate the present demands on an aging power grid.*

This ORNL study examined the potential for using DG technology to supply ten types of ancillary services:

1. Voltage control
2. Regulation
3. Load following
4. Spinning reserve
5. Supplemental reserve (non-spinning)
6. Backup supply
7. Harmonic compensation
8. Network stability
9. Seamless transfer
10. Peak shaving

The ORNL report also addresses the technology paths to tapping the potential for DG technologies to provide much needed reliability and power quality support to local microgrids, benefits for which DG may receive compensation. The analysis observes that the number and scale of opportunities for DG to provide ancillary services may be expected to grow as the number of DG systems located throughout the grid increases (ORNL, 2005).

Brendan Kirby, a co-author of the ORNL report, addresses the potential economic value the owner of a comparatively large merchant DG plant might obtain by optimizing plant performance to capture the economic benefits of providing ancillary services to the grid. This analysis focuses on 100 MW DG units, ten times the size of the largest unit considered in this report; however, the analysis provides compelling evidence that there is value to be had by providing ancillary benefits to the interconnected electric system at the regional and local microgrid levels (Kirby, 2007).

In Europe the DG-GRID Project, supported by the European Commission during 2005-2007, addressed the potential impact of distributed generation on electric system operations.[26] This project addressed the benefits and costs for the interconnected electric supply system of the rapid growth of diverse types of distributed generation associated with the public goal of a sustainable electricity system. The DG-GRID project report concludes that opportunities exist to tap DG to provide important local and transmission level ancillary services.

This project conducted an analysis focused specifically on what contribution DG could make to providing existing transmission ancillary service needs and to providing new distribution network services in the near- to mid-term. The report examined six types of transmission and distribution services that DG may effectively provide:

- Transmission frequency response
- Transmission regulation and stand-by reserve
- Transmission reactive power
- Distribution security of supply
- Distribution quality of supply
- Distribution voltage and power flow management

The study concludes that in the near term three of these --transmission frequency response, transmission regulation and standby reserve, and distribution security of supply -- offer the greatest opportunities for DG contributions.

The report observes that the value DG may contribute to the transmission grid, while small because DG resources represent a very small share of grid generation, is likely to grow as total DG capacity increases. The report cautions that the value of the services provided by any single DG unit is likely to be quite low and, if fairly compensated, is likely to yield only incremental revenues benefits. The report does see the opportunity for some DG facilities to provide ancillary services in niche conditions, in areas where environmental, land use or other constraints on the local grid restrict network development (Mutale, 2005).

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[26] The DG-GRID project was co-financed by the European Commission and carried out by nine European universities and research institutes from eight EU Member States (Austria, Denmark, France, The Netherlands, Spain, Finland, Germany, United Kingdom). It analyzed the technical and economical barriers to integrating distributed generation into electricity distribution networks.

The report also observes that the deployment of DG may impose additional costs on the grid, and that the effective integration of a growing number of DG systems to minimize costs and optimize benefits requires a new approach to grid management. The report characterizes the current approach as *passive*, and the desired new approach as *active management of DG integration* (DG-GRID, 2007).

Another European investigation, "Integrating distributed generation into electric power systems: A review of drivers, challenges and opportunities" (Lopes et al., 2007), offers similar findings. This study acknowledges that DG is being deployed for important purposes (limiting greenhouse gas emissions, deferring investments in transmission upgrades and central station generating plants, improving power quality and supply reliability for individual customers, and increasing electric system security), but points out that deploying increasing amounts of DG capacity on distribution-transmission grids may increase grid operating costs unless the integration of DG is carried out in what one might characterize as a proactive manner. This analysis suggests that the benefits of deploying DG are likely to far exceed incremental costs, but only if active steps are taken to integrate DG effectively into the electric system. The authors describe this as "the need to move from the fit and forget policy of connecting DG to electric power systems to a policy of *integrating* DG into power system planning and operation through active management of distribution networks …" (Lopes et al., 2007).

The California Energy Commission has initiated a careful examination of lessons from the European experience with DG deployment. In April, 2011, KEMA, Inc. presented the first of three reports that will examine lessons of the European experience that may be applied in California. The report examined physical differences in grid design and operations, and offered a number of observations. For example, the KEMA analysis observed that "Differences in the basic distribution infrastructure design between Germany, Spain, and California do not appear to be a major factor in how much DG can be integrated into the respective systems, with one important exception – the requirement under German grid codes that all DG projects above 100 kW must have telemetry which provides the TSO with both visibility and remote control of these units" (KEMA, 2011).

Transmission and Distribution Investment Deferral

Customer sited DG assets, operating at the right locations and time periods, can serve as a substitute for utility distribution capital investments. In certain circumstances, where distribution investments are particularly expensive, or where the scale of the DG solution better matches the need, DG could be the most economical choice.

In certain areas on the Con Edison system, avoided distribution costs have been cited to be in excess of $600/kW-year. Where the costs of the traditional utility investment significantly exceeds a "non-wires alternative," such as targeted DG, demand response and/or efficiency measures, there is a case for employing the DG/DR alternative.

T&D projects are "lumpy" in nature. This means that distribution capital investments come in discrete sizes that may not be well matched to the imminent need. It may be years before the local demand catches up with the scale of the distribution capital investment. In that interim period, the capacity of the new investment is underutilized. In some cases, investment decisions based on demand forecasts do not materialize for years, as for example with forecasts made just prior to the 2008-2009 recession.

By contrast, the DG/DR solution is potentially much more scalable, providing a better match of the investment to the local need. A DG solution, by "buying time" and deferring the utility capital investment, gives the utility greater flexibility in its planning process. This temporary deferral option allows the utility to avoid the cost of a large, irreversible capital investment made on the basis of a projection that did not anticipate a multi-year period of slower growth.

In order for DG to serve as a technically viable and cost effective substitute for T&D investment, certain conditions must be met. Some of the circumstances favoring the feasibility of a non-wires alternative include:[27]

(1) The DG project will be located near areas of grid congestion

(2) The DG project will operate at the right time of day (i.e., the local peak times for distribution deferral and system peak times for transmission project deferral)

(3) The peak demand will last for a short period of time (i.e., a sharp load duration curve) or the DG project will have long run times

(4) The project economics will include a need for a T&D project with a large capital outlay relative to the capacity installed or upgraded (DG is more feasible as an alternative in cases of an expensive T&D project meeting only a small capacity requirement)

(5) There will be slow load growth in the area of the deferral

(6) The DG project will operate reliably

(7) The DG resource(s) will be of sufficient scale to serve as a close substitute for the T&D investment which is being offset.

Even under the most favorable conditions for the use of DG to defer a more costly utility capital investment, such outcomes are rare to nearly non-existent. Prior work conducted by Pace Energy & Climate Center and Synapse Energy Economics found just a handful of actual examples where utilities were employing DG as a mechanism for lowering overall T&D capital outlays.[28]

Private (non-utility owned) DG has the potential to contribute to T&D investment deferral efforts. However, several barriers would have to be overcome for this to be feasible. First,

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[27] EPRI. *Case Studies and Methodologies for Using Distributed Energy Resources*, 2005; Personal communication with Fran Cummings at MTC Collaborative and Gerry Bingham at Massachusetts DOER.

[28] *Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure*. NYSERDA Contract Nos. 10472. NYSERDA Project Manager Michael Razanousky. Prepared by Pace Energy & Climate Center and Synapse Energy Economics. December 2010.

customers would have to be incentivized to develop the appropriate type and capacity DG unit at a location where it could contribute to T&D system reliability. Second, the utility would require expensive communications and control equipment at the site. And third, the customer would have to be compensated for giving up some measure of operational control over the DG unit.

At the root of these issues is a basic conflict of interests. For the most part, T&D investment deferral is not among the objectives of DG developers. Customers operating DG at their site are not doing so to enhance the reliability of the T&D system, but to serve their core business needs. Utilities, on the other hand, have an overriding obligation to insure the reliability (and safety) of the electric grid. When the utility cedes to an external party control of assets that it relies upon to meet reliability standards, there must be sufficient guarantees that the asset, or suite of assets, will be available when required. This brings up questions of liability; if the DG unit does not run when called upon, leading to a failure of grid reliability, who is legally responsible? For these reasons, utilities prefer to own T&D assets outright. However, in other contexts, such as the capacity market, grid operators rely on contracted services from privately owned demand response assets. Thus, there is a precedent to develop contractual relationships between utilities and private DG assets providing T&D services.

A report prepared by Pace on Deployment of DG Generation for Grid Support and Distribution Infrastructure offered the following set of key findings when considering DG deployment models:

KEY FINDINGS

1. DG/CHP can serve as a substitute for distribution capital investment –when sited in the right locations, operating at the right times and offering the required level of reliability.
2. The paramount concern of the utility is safe and reliable operation of the distribution system whereas the DG CHP owner is primarily interested in economic operation at their site. This can create some complications in program design, but is not an insurmountable obstacle.
3. Where the objectives of the utility (reliability) and private owner (economics) are not entirely compatible, they can be harmonized with some mix of physical and operational controls, contractual arrangements and incentives or penalties.
4. Distribution system capital cost savings benefits of DG are typically not captured in existing markets. Utilities may internalize the benefit by owning the DG asset themselves, or create a market (via RFP process or incentive payments) that compensates private sites for this otherwise non-market benefit.
5. The utility owned solution internalizes the benefits of the DG asset, while maintaining a high level of utility control and without the additional time and resource costs of creating a market, executing contracts and marketing programs.
6. However, the utility owned solution raises questions of market power and perceptions of unfair competitive advantage.
7. Creating private market solutions may require more time and costs, but may yield innovative solutions that otherwise would not have been conceived.

8. The existing distribution planning process in large measure does not contemplate DG solutions. Consequently:
    a. Modeling tools that would identify DG investments as cost-effective solutions are not well developed,
    b. forecasting methodologies that predict high-value DG deployment opportunities based on network loading, equipment ratings and demand projections are typically not employed,
    c. Program budgets that would identify DG alternatives are not in place.
9. The types of capital investments potentially addressable by DG projects has not been inventoried and prioritized in a manner facilitating comparative analysis of DG deferral relative to traditional solutions (e.g. load growth related investments, strategic business operations related, replacement of antiquated equipment and processes with new methods).
10. Where utility capital budgets are growing and putting increasing pressure on rates over time, utilities may consider private investment in the form of customer owned-DG assets as a substitute for traditional utility solutions.

III. Barriers to DG Deployment

The previous section outlines the many benefits DG systems may provide to the grid. Here the focus is on barriers to the development of interconnected DG. The following section will address existing policies and programs intended to address these barriers and support DG deployment.

1. Costs Associated With Interconnected DG

Interconnection Costs

> *Well-designed interconnection standards facilitate the deployment of renewables and other forms of DG by specifying the technical and institutional requirements and terms by which utilities and DG system owners must abide* (IREC, 2009*a*).

Making the electric interconnection with the power grid can represent a significant investment of time and resources on the part of a DG developer. In order to make this process more predictable, the New York Public Service Commission (PSC) has established interconnection standards defining a six-step process for DG systems with a nameplate rating of 25 kW or less, and an eleven-step process for systems larger than 25 kW, up to a maximum capacity of 2 MW. However, projects with capacity greater than 2 MW must meet the interconnection requirements established by individual utilities. These requirements will vary from location to location. In some cases, the costs, time commitment, and uncertainty associated with interconnection can represent a barrier to the development of interconnected DG.

In addition, there are some areas of the grid where interconnection of synchronous generators (those best suited to applications where the DG unit will island in case of a grid outage) is not yet possible. In the Con Edison service territory, for example, there remain many “red areas” on the utility’s fault current maps, where synchronous generators cannot interconnect until circuit breakers at substations are replaced. At this writing, Con Edison has replaced 644 circuit breakers out of a total 1,910 that require replacement in order to allow the interconnection of synchronous generators throughout its service territory. With 1,266 circuit breakers remaining to be replaced, only 34% of the Con Edison breaker replacement schedule is complete. Some areas of Con Edison’s territory are not scheduled for circuit breaker upgrades until 2026. While DG can locate in these areas, the inability to use synchronous generators eliminates several potential benefits of DG units that depend on black start capability, including critical infrastructure resiliency, some ancillary services capabilities, and some on-site power quality benefits. These benefits are potentially quite valuable to DG developers and host facilities.

Standby Tariffs

Although DG units will generally self-supply a major portion of their electricity needs, they must often purchase supplemental electricity from the electric grid, either because the DG unit is temporarily removed from service, or because the local load exceeds the capacity of the DG unit, which is often significantly less than the regular maximum demand of the host facility. For this "standby service" the distribution utility charges standby rates, as defined in approved tariff schedules. These charges offset, to a greater or lesser degree, the savings a DG plant may provide. New York has for more than a decade been taking steps to develop standby tariffs that serve DG deployment objectives and longstanding commitment to fair and equitable electricity rates.

Standby rates are designed to recover the costs incurred by electric distribution utilities when they deliver only a portion of the customer's electricity requirement. However, they can sometimes undermine the economics of DG development by imposing large capacity based costs on customers that use the grid only infrequently, or only for small amounts of supplemental energy.

The major cost components addressed by standby rates include:

- Backup service in case the on-site DG unit experiences an unplanned outage
- Maintenance service when the on-site DG unit goes offline for planned maintenance
- Supplemental service that provides the electricity required on site that exceeds the capacity of the on-site DG unit (usually during peak load times)

Standby rates in New York do not distinguish between these three situations in the rates charged to participating customers (PECC).

For most customers, who are entirely dependent on electricity purchased from the electric grid (often termed full requirements customers), rates are entirely determined by their electricity consumption. For customers with large loads, such rates will include two components reflecting on-site electricity use: an energy charge for the actual kilowatt-hours used during a billing period, and a capacity charge that is tied to the site's maximum electricity demand during some period of time.

The standby rates paid by partial requirements customers are likewise comprised of energy and capacity charges, but in any given month these rates may include much larger capacity charges than are charged to full requirements customers. The standby rate includes a contract demand charge that is paid in all months of the year, regardless of the actual level of peak demand reached in that month. This disparity is the focus of continuing debate. The debate centers around what energy and capacity based charges will fairly allocate the costs created by standby service customers.

To provide standby service, the utility must invest in sufficient distribution capacity to provide power when called for by the customer. This is also the case for full requirements customers; the rate design debate focuses on the differences between the costs imposed by standby service customers and those imposed by full requirements customers whose loads also vary over time. If assets are in place solely to serve a partial requirements customer, then the distribution utility may argue that allocating that asset to the customer is justified, even if it is only used on a very infrequent basis.

System Costs

The deployment of DG on the interconnected electric system is changing grid management in important ways. Only a few years ago the interconnected grid system was largely comprised of a limited number of big central station generating plants that delivered electricity service via the high voltage transmission grid connected to local distribution networks. Today, a growing number of DG facilities of various types are being located on distribution networks in a variety of settings, some close to load centers, others at the end of distribution lines that have only modest scale loads, and yet others on distribution networks containing a diverse mix of loads and other DG facilities.

This section addresses additional costs that increasing deployment of DG may impose on grid operations. Understanding these potential additional costs, as well as the additional benefits that can be provided by DG, is key to achieving the most economical and efficient deployment of DG, and to deciding fair compensation for DG benefits.

The system costs of integrating DG are in significant measure determined by the equipment, controls, communication schemes and network protection devices and protocols employed by the NY ISO and the distribution utilities. New York has made a significant commitment to expanding the usage of clean and renewable DG. Utilities continue to invest in the distribution and transmission system. In assessing the investments made, one important criteria ought to be the extent to which new distribution and transmission capital expenditures are making the grid more amenable to higher penetration levels of DG. If future investments are made in the absence of consideration of expected future increased DG penetration and of the need to incorporate DG as an active, rather than a passive, agent on the grid, then additional costs will be incurred that need not have been.

The increasing penetration of DG on interconnected systems offers the opportunity for DG to make a growing contribution to grid management by providing backup energy and capacity to address emergency capacity shortages and by providing several types of non-energy services here described broadly as ancillary services. However, the interaction of a growing number of small DG facilities with diverse performance characteristics also adds complexity to the task of managing the transmission grid and the many distribution networks. For example, intermittent generators, such as solar and wind powered DG, may pose problems for grid managers when their power output varies in response to changes in available wind and solar energy. DG may also pose an operation risk for distribution networks when sited in a relatively isolated network location where its impacts may be large relative to the effects of comparatively small nearby loads and distribution capacity (Lopes, 2007). These effects are not new to grid managers, having been addressed by evolving operating standards and extensive research. The impact of intermittent resources in particular has been studied extensively due to concerns that the varying electric output of intermittent generators may impose significant costs on the grid.

The distribution and transmission capital investment planning process should consider increasing accommodation of DG as a part of the benefit/cost analysis when assessing the functionality and design of systems. The analysis should consider future benefits that might accrue from incorporating some proportion of future DG as an actively managed asset on the grid. Conversely, investments that do not improve the amenability of the system to accepting higher penetration levels of DG ought to consider the costs of that result.

Intermittent Generation

The impacts of wind and solar PV, particularly large utility scale units, has been the focus of extensive research. These intermittent generation technologies are considered potentially problematic because the output from individual units may vary widely in response to variation in available wind and solar energy, which can only be predicted to a moderate degree of accuracy.

> *All users of the bulk power system—generators and users alike – contribute to the amount of ancillary services that must be procured and delivered by the control area operators. For wind generation, the major question is by what amount they require more of these services on a per MW basis than conventional generators or loads (UWIG, 2003a).*

Concerns about the impact of high penetration of wind generation on the electric grid have received attention for more than a decade. The Utility Wind Energy Integration Group (UWIG), formerly the Utility Wind Energy Interest Group, was organized in 1989 to address the impacts of wind energy generation on utility grids. Their 2003 analysis and literature review (UWIG, 2003*b*) focused specifically on the cost of ancillary services necessary to accommodate a wind plant on a utility system. This analysis focused on three types of impacts that add costs to grid operation:

1. Regulation reserves - the cost of additional capacity reserves that may be required to accommodate wind with its varying output on the system.
2. Load following - the cost of following the intra-hour ramping and fluctuation of wind generation.

3. Unit commitment - the additional costs incurred to re-schedule other generation on the system because of inaccuracy in the wind generation forecasts used in day-ahead scheduling.

The available analysis indicates that costs increase with increasing penetrations of wind on the grid, with the total incremental cost ranging from 1.47 to $5.50 per MWh of output (UWIG, 2003). The UWIG has continued to investigate the technical and cost implications of integrating wind powered generation into interconnected electricity grids, supporting continuing analysis aimed at accelerating "the development and application of good engineering and operational practices supporting the appropriate integration of wind power into the electric system."[29]

Attention to the impacts of solar PV generation on the grid has also increased with increasing deployment of solar technology. In 2010 the National Renewable Energy Laboratory, with support from and active participation of the UWIG and others, conducted several workshops to address specifically the technical challenges and costs posed by high penetrations of solar PV in interconnected grid systems.[30] These workshops addressed challenges facing utilities accommodating growing penetration of distributed PV on their distribution networks. For example, Southern California Edison describes how some attributes of PV, including fluctuations in power output, its low capacity factor, and the potential for reverse power flow, pose issues that impose resource costs on grid operations (Neal, 2010). Current investigations addressed in these workshops consider not only the additional operating costs caused by PV technology, but also the potential contributions this technology can make as contributor to grid operation management. The workshop presentations indicate that while the ways PV systems impact the grid is understood, there is much yet to learn about how to optimize the integration of intermittent PV resources on distribution networks and overall grid operations.[31]

Recently the National Renewable Energy Laboratory commissioned two studies that examined the impact of high penetrations of wind and solar resources on the electric grid, one focused on the western United States (GE Energy, 2010) and one on the eastern states. The Eastern Wind Integration and Transmission Study (NREL, 2011) addresses the impact on grid operations and costs of four wind deployment scenarios, three that consider wind amounting to 20% of installed capacity and one reaching 30% by 2024. The analysis describes the need to make a number of changes in the operation of the interconnected grids across the eastern United States, but

[29] Mission statement of the Utility Wind Integration Group. Available on their Internet web site: http://www.uwig.org/

[30] The NREL program addressing the integration of increasing solar photovoltaic generation on interconnected electric grids, including the several recent workshop proceedings is described on the NREL Internet web site at: http://www.nrel.gov/eis/renewable_energy_integration.html These workshops include the NREL High Penetration Photovoltaics Workshop. May 10, 2010 Proceedings available in the Internet at: http://www.nrel.gov/eis/high_penetration_pv_wkshp_2010.html

[31] See for example: Vladimir Chadliev. Integration of Solar Resources in Southern Nevada. Nevada Energy. October 15, 2010 slide presentation. Available on the Internet at: http://www.nrel.gov/eis/pdfs/solar_power_high_penetration_chadliev.pdf

concludes that the total additional grid operating cost would amount to less than 10% of the bus-bar cost of the wind energy produced (NREL, 2011, p. 45).

It is important to note that DG comes in many shapes and sizes, and the system costs imposed by DG interconnection, if any, will vary depending on many factors. Dispatchable generators, such as fuel cells, turbines and engines, may not impose costs related to intermittency, but may still require distribution system upgrades to accommodate two-way power flows. Small intermittent generators operating alone may not contribute enough electricity to the grid to require backup units, but this can change when many small interconnected generators are operating in proximity, such as in a city. These costs will also depend to a significant degree on the equipment local distribution utilities choose to invest in. Thus, a one-size-fits-all approach to the system costs of integrated DG is unlikely to result in a fair allocation of costs.

Component costs for DG systems

Customized Power Electronics

Power electronics encompass the full spectrum of control and conversion devices required to move power from generating and storage sources to end-user loads. These range from power conversion and inverter technologies to static compensators and automated switches. The field of power electronics is developing the technologies needed to integrate DG systems safely into the electric distribution grid.

However, to date the high cost of these devices has prevented DG developers from leveraging the potential of power electronics as an enabling platform. This is in part because the lack of standardized components has forced the power electronics industry to design specific solutions to each power conversion situation, to accommodate specific power levels and minimize the losses resulting from inefficient electrical design (Piff, 2003). Power electronics devices are typically designed for complete systems; as a result, DG projects often require extensive engineering and design customization related to power electronics devices. This case-by-case customization has prevented significant cost-reduction in power electronics.

At this writing, there are no utility scale, high power, off-the-shelf invertors and power converters on the market.

> *Even the energy storage manufacturers have not made inroads in the development of power electronics and control systems dedicated to their own energy storage system as most delivered systems are one-of-a-kind with little or no opportunity to mass produce the electronics necessary for their device. The most important near-term development that needs to be realized in power electronics and controls is to motivate the system integrators to begin packaging their systems in a turn-key*

manner so that costs for their systems can be driven down to more reasonable levels (EPRI, 2008).

The lack of standardized components among the system integrators developing new energy storage applications suggests that this customization is likely to remain a significant barrier for years to come.

The development and integration of cost effective, efficient, and reliable standardized power converters would substantially increase the penetration of DG on the distribution grid by reducing the costs of DG systems.

In 2004, Navigant Consulting reported that the expense of power electronics accounts for as much as 40% of the total cost associated with DG systems. In addition, Navigant found that power electronics continue to suffer from performance problems (Treanton et al. 2006).

Table 4

	DG Capital Cost $/kW	Power Electronics % of DG Cost
Microturbine	$900-$1,800	35%-45%
Wind Turbine	$1,000-$4000	25%-40%
Fuel Cell	$3,000-$6,000	10%-30%
Photovoltaics	$6,000-$10,000	10%-25%

Source: NREL

Navigant identified the following three factors as the most critical challenges impeding the development of low-cost, high-reliability power electronics for DG:

- A lack of standardization and inter- and intra-operability of power electronic systems, components and the grid
- A need for improvements in power electronic system packages
- A need for power electronic devices that are modular and scalable[32]

In 2003, the U.S. Office of Naval Research began the Power Electronics Building Blocks (PEBB) program to pioneer interoperability standards for power electronics devices.

The PEBB concept was to convert from complete system designs for each application—the clean sheet of paper approach—to a system design achieved by

[32] See id.

selecting from a small set of standard modules, i.e., a modular design approach. A PEBB was defined as a universal power processor that changes any electrical power input into any desired form of voltage, current, and frequency output. Considering the wide range of power handling requirements, a family of de- vices was expected (Piff, 2003).

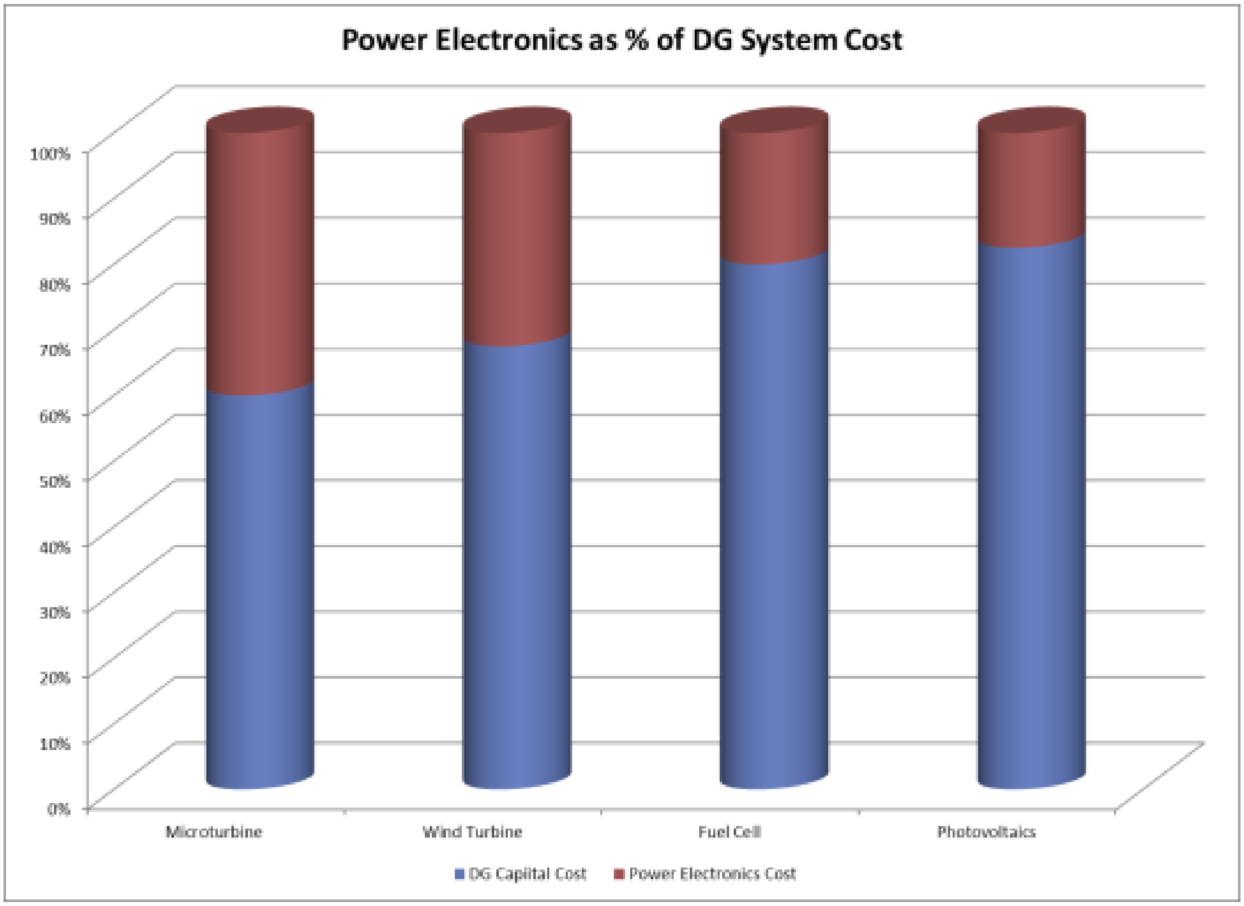

Figure 2

In 2008, the U.S. Department of Energy's National Renewable Laboratory (NREL) launched a similar initiative focused on developing a modular power converter/controller for renewable applications, primarily photovoltaics. The goal of this effort is to create a cost effective power converter/controller based on a common topology that can scale from small to large power applications.

2. Knowledge Deficits

The deployment of DG is increasing in New York State, although it has slowed. With this progress, however, has come the growing recognition that increased deployment of DG poses both an opportunity and a challenge:

- The opportunity to capture the many environmental, efficiency and service quality benefits DG can provide; and

- The challenge of integrating large numbers of diverse types of DG installations into the distribution networks of the interconnected grid without decreasing service quality and/or increasing grid operating costs.

While there is widespread recognition of these potential benefits and costs, there is little practical operating experience with such impacts, and the cost/benefit equation for various types of DG in various applications is not well understood. This lack of knowledge and experience is an extremely important barrier to DG utilization. It causes those responsible for the management and operation of all aspects of the New York's integrated grid to approach with caution many decisions that could facilitate DG deployment. This includes, for example, the NYISO, utility distribution system operators, and state energy policy leaders such as the Public Service Commission, NYSERDA, and the state legislature.

A key feature of the DG knowledge deficit is that the costs and benefits of various types of DG, in various applications, placed in various positions on the grid, are not well understood. In general, grid operators and utilities acknowledge that there are both costs and benefits potentially associated with DG deployment on the grid; however, it is difficult to conduct a meaningful and thorough cost/benefit calculation for a specific proposed DG project or class of projects, because of the large number of unknowns on both sides of the equation. Under these conditions, use of better-understood resources, such as "wires" solutions rather than DG to address T&D upgrade needs, is often seen as the less risky path.

To a significant degree, the benefits conferred by DG will depend on the manner in which the barriers to DG deployment are addressed. It is therefore essential to clearly understand the DG cost/benefit equation, so that a coordinated strategy to address DG barriers may be developed, such that the greatest benefits may be realized at the lowest cost.

3. Market development

Like the electricity grid, New York's electricity markets were designed around big, centrally-located generators. This is beginning to change, with the inclusion of energy efficiency, demand response, energy storage, net metering and DG in some markets. However, the development of effective markets for these services is still in the initial stages, and DG is still not an active participant in many markets where it could provide valuable services. Policies and incentives may encourage DG development, but without viable, predictable markets in which to participate, governed by rules that account for DG's specific attributes, DG developers are unlikely to make the additional investments necessary to provide services to the grid.

Likewise, there are few environmental markets in which small DG can participate, and none that promise a significant return. Small DG cannot directly participate in RGGI, or in the emissions allowance market (formerly under CAIR, now presumably under CATR). If accepting support from NYSERDA under the RPS CST program, DG units must give up ownership of any RECs produced, and thus cannot sell the environmental attributes produced.[33] Some DG types can produce ERCs, but the ERC market in New York is moribund, prices are low, and aggregation would be necessary to generate enough ERCs to interest a buyer. CO_2 reduction credits can be sold into private markets, such as CCX, but again prices are low, and a single small DG project is unlikely to produce enough credits to interest buyers.

The ability to sell a diverse array of products into markets is extremely important for investment decision making. In the absence of viable markets that recognize and account for the unique attributes of various types of DG technologies, it becomes difficult to justify the added costs associated with grid interconnection; furthermore, some potential benefits of DG are lost when there are no viable markets into which attributes can be sold.

[33] There are a few exceptions, for example, attributes associated with methane capture and storage at manure management facilities are not included in the RECs that pass to NYSERDA, and may be marketed separately by the DG operator.

IV. Existing Policies, Programs and Markets Supporting DG Deployment

New York State and the federal government have established a variety of policies, programs and markets aimed at supporting and incentivizing the development of various types of DG. Individually, these initiatives have met with varying degrees of success; however, coordination of initiatives among diverse agencies and programs with different primary and secondary objectives has been uneven at best. Just as the development of the smart grid will require a coordinated effort, so too the development of programs and policies to support DG development and lower barriers should be coordinated between the various agents working on different aspects of the problem. For example, incentives may support DG financing, but in the absence of viable markets, projected revenue may not justify the initial investment. Similarly, programs that have successfully supported the development of utility-scale renewables do not necessarily transfer successfully to small DG. This includes tax credits, which offer little incentive to smaller developers who may not have the tax appetite to take advantage of them.

This section reviews the existing policies, programs and markets supporting DG development in New York State.

1. Existing Interconnection Standards

Recognizing the importance of interconnected DG as an energy choice for consumers in increasingly competitive electricity service markets, in 1998 the PSC convened proceedings to investigate, and eventually to standardize, the procedures for accomplishing interconnections between DG projects for partial requirements customers (NY PSC, 1999). These standards aim to ensure that interconnections meet standards for safety and reliability while also minimizing the costs imposed on DG system owners. The PSC established interconnection standards initially in 1999 and has revised these standards repeatedly, most recently in 2010 (NY PSC December, 2010). The policy standardized and simplified the technical requirements for interconnection and established a standardized application process and simplified contract for interconnecting new DG projects with the grid (NY PSC 1999).

Current interconnection standards are set forth in the "New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less Connected in Parallel with Utility Distribution Systems" (NY PSC, 2010). These standards offer a six-step process for DG systems with a nameplate rating of 25 kW or less, and an eleven-step process for systems larger than 25 kW, up to a maximum capacity of 2 MW. Projects with capacity greater than 2 MW must meet the distribution interconnection requirements established by individual utilities, requirements that often follow the practices mandated for projects with capacity under 2 MW. The PSC has not established interconnection standards for generators above 2 MW, but provides for case by case review if disputes arise (Pause, 2011).

The NY ISO administers the interconnection process with the active participation of the utilities that own the affected transmission. For interconnections subject to Federal Energy Regulatory Commission jurisdiction, the NY ISO has established Small Generator Interconnection Procedures (SGIP) that are applicable to generators no larger than 20 MW.[34]

Nationwide, the Interstate Renewable Energy Council (IREC), through the North Carolina Solar Energy Center, monitors interconnection issues and emerging technology trends. The IREC publishes a periodically updated Guide to Distributed Generation Interconnection Issues (IREC, 2009*b*). IREC also sponsors a review of state interconnection policies and practices, assigning grades that evaluate these practices compared to their best practice standards (Network for New Energy Choices, 2010). The 2010 ratings give New York State interconnection practices a "B" rating, defined in the report as, "Good interconnection rules that incorporate many best practices adopted by states. Few or no customers will be blocked by interconnection barriers. There may be some defects in the standards, such as a lack of standardized interconnection agreements and expedited interconnection to networks."

The Regulatory Assistance Project (RAP) is conducting a nationwide assessment of the interconnection of DG to utility systems. The RAP assessment focuses on policies and practices addressing DG systems with capacity of 10 MW to 20 MW, and on emerging issues associated with high penetration of DG on transmission and distribution grids. The RAP analysis observes that state interconnection guidelines often give little attention to the larger capacity DG facilities. The New York Standard Interconnection Requirements do not specifically address interconnection with DG above 2 MW. RAP also observes that existing interconnection guidelines often reference the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547. That standard currently does not address facilities above 10 MW, but is being revised to do so in a new Subsection 1547.8 standard.

The RAP study also draws attention to interconnection issues that arise as the number of DG facilities on a distribution network increases, suggesting that these conditions may bog down interconnection decision making, imposing new barriers to DG deployment (Scheaffer, 2011). This report notes elsewhere the growing concern about the interactive effects of multiple DG facilities on a local network, effects that can complicate interconnections of incremental DG facilities. RAP notes that IEEE Standard 1547, which includes technical specifications and requirements for interconnections, does not address impacts of high DG penetration levels on

[34] New York Independent System Operator. FERC Electric Tariff Number 1, Attachment Z. Available on the Internet at:
http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2005/12/Attchmnt_I_SGIP_Clean.pdf The NY ISO process for administering these procedures is set for the summary table, "Steps in the Small Generator Interconnection Process." Available on the Internet at:
http://www.nyiso.com/public/webdocs/services/planning/other_nyiso_interconnection_documents/NYISO_Summary_of_SGIP.pdf

local and area distribution and transmission planning and operation. Similarly, the existing IEEE standard does not yet consider how emerging smart grid technology may effectively strengthen the capacity of the grid to utilize DG effectively.

2. Existing Standby Tariff Policy

A study of effective standby rate design, conducted for the United States Environmental Protection Agency (US EPA) by ICF International and the Regulatory Assistance Project, described effective rate design:

> *. . . they are designed to give customers a strong incentive to use electric service most efficiently, to minimize the costs they impose on the [grid] system, and to avoid charges when service is not taken. This means that they reward customers for maintaining and operating their onsite generation (US EPA, 2009b).*

The New York Public Service Commission (PSC) has over the last decade focused very careful attention on providing fair and reasonable rates for backup and supplemental power services for customers who have or are contemplating installing on site generation (OSG) to meet a significant portion of their regular electric power supply needs. The following outlines how this policy has evolved in response to a growing awareness that OSG offers significant benefits both for host customers and for the grid system. PSC policy aims to reduce barriers to cost-effective OSG while also ensuring that related costs are born by those who benefit.

The following short history describes the policy foundation that supports the PSC approach to changing conditions that are the focus of this project.

The PSC policy has pursued two goals: first, to provide fair and reasonable rates that neither subsidize nor penalize customers who choose to install OSG (PSC, 2001); and second, to support the New York State energy policy commitment to becoming a national leader in the deployment of clean distributed generation technology and to develop the potential of renewable energy as a means to reduce air emissions, increase the reliability of the State's electric system, and improve energy security (PSC, August 2003).

In 2000 the PSC initiated a proceeding (Case 99-E-1470) to consider an appropriate framework for the rates charged standby customers, including customers who install DG/OSG to meet a significant portion of their electricity needs and accordingly only depend upon utility grid service for a part of their regular electricity supply. The investigation sought to ensure that customers using DG/OSG paid a fair share of the grid system costs. In October 2001, after a process of collaborative deliberations followed by public comments on remaining unresolved issues, the PSC adopted guidelines for standby rates (PSC, 2001).

Recognizing that the required standby service rates in some circumstances may pose an economic barrier, the PSC has offered qualifying customers the option of a permanent exemption from the standard standby rate. These exemptions are available only for a limited number of facilities. However, the PSC has indicated that it will revise the standby rate policy if new information indicates that changes are required to conform to the overarching commitment to fair and reasonable rates (NY PSC, 2009).

The following subsections describe the PSC standby rate framework, the current exemption offered to qualifying clean DG technologies, and the steps the PSC has taken to standardize interconnection requirements for DG.

Standby Rate Policy

The October 26, 2001 NY PSC Opinion and Order Approving Guidelines for the Design of Standby Service Rates (Opinion 01-04) reflects an overarching commitment to fair and reasonable rates: "Cost-based standby delivery rates should provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of DG or OSG" (PSC, 2001 at page 11). All new initiatives are screened against this principle.

The PSC holds that the commitment to cost-based rates for standby electric service will serve the public's interest "in creating a more efficient, equitable, and competitive energy market" (NYS PSC October 2003 Con Edison at p. 25). Toward that end, the guidelines state that standby rates should enable utilities serving partial requirements customers to recover the costs these customers impose on the electric system. The standby rates do not address the energy component of partial requirements service. The standby rate guidelines also specifically avoid recovering the cost of "delivery service" in energy cost charges, i.e., charges for kWh consumption. The NY PSC observed that this distinguishes standby service rates from full service rates in which a large proportion of distribution delivery service costs are recovered in the kWh energy charges. The guidelines focus on the delivery service costs such customers impose on the grid, recognizing differences in the service requirements for partial requirements customers as opposed to full requirements customers.

The standby rate guidelines address three categories of delivery service cost:

1. The routine costs of serving such customers, i.e., account management, that are to be recovered in a monthly fixed customer charge;
2. The local distribution system costs incurred mostly to serve a particular customer that are to be recovered in a fixed *contract demand charge* that is linked to the customer's maximum demand (in kW); and
3. The share of general distribution system costs incurred to meet peak loads that are to be recovered in a *daily as used demand charge* that is linked to the customer's daily maximum load during the utility's system peak load period.

The PSC noted evidence from these standby rate proceedings indicating that for two thirds of existing partial requirements customers depending on DG systems to meet a major share of their electricity needs, the new standby rate framework would either lower the cost of delivery services, or would be cost neutral (PSC, October 2003 – Con Edison). Because some existing customers could be expected to experience increased costs under the new cost-based standby rate structure, the PSC offered existing customers the option of adopting the new rates immediately or phasing them in over an eight-year period.

Significantly, the guidelines recognize that individual customers subject to the general provisions of standby rates may also be subject to additional charges or credits directly attributable to the customer's delivery service. The Commission cites interconnection charges as an example of such customer specific costs (PSC, 2003 at page 6). One may surmise that the standby rate policy would allow, through general tariff provisions or contracts with individual customers, justified credits for specific system benefits an individual customer may provide the distribution system. These benefits might include ancillary services such as those outlined earlier in this report.

These standby rate guidelines, set forth initially in the October 2001 Opinion and Order and refined in implementation proceedings, serve as the reference framework for utility standby rates in New York.

The PSC noted evidence from these standby rate proceedings indicating that for two thirds of existing partial requirements customers depending on DG systems to meet a major share of their electricity needs, the new standby rate framework would either lower the cost of delivery services, or would be cost neutral (NY PSC October 2003 – Con Edison). Because some existing customers could be expected to experience increased costs under the new cost based standby rate structure, the PSC offered existing customers the option of adopting the new rates immediately or phasing them in over an eight-year period.

Standby Tariff Exemption for Clean Technologies

In 2003 the PSC introduced an exemption from standby rates for new DG systems eligible for participation in the then-new state RPS or meeting the definition of clean DG[35] (NY PSC 2003). Qualifying DG technologies were offered the choice of adopting standby rates or opting to pay for grid service under the rates that would apply to full requirements customers in their rate class.

Qualifying DG/OSG projects include DG with a maximum electricity generating capacity of 1 MW produced by the following technologies: fuel cells; wind; solar thermal; photovoltaic; sustainably-managed biomass; tidal; geothermal; methane waste; and qualifying[36] combined heat and power (CHP) generation (NYS PSC October 2004). In 2009 the PSC increased the

[35] For combustion based systems, qualifying DG was defined to be systems of 1 MW or less, operating at or greater than 60% average annual total system efficiency and having NOX emissions < 1.6 lbs/MWH.

[36] Qualifying CHP generation includes CHP receiving funding assistance from the NYS Energy Research and Development Authority (NYSERDA) and CHP that meet a minimum total efficiency standard of 60% and emissions levels <1.6 lbs NO_X/MWH. See NY PSC October 2004.

maximum capacity for qualifying solar generation from 1 MW to 2 MW, to align the exemption policy with current DG interconnection regulations, and to recognize the benefit that solar DG provides by supplying a large proportion of its output at the time of system peak demands, on sunny summer afternoons (NY PSC, 2009).

Customers installing new qualifying DG/OSG projects would be offered the choice of adopting the standby rates, phasing these rates in over several years,[37] or opting to permanently obtain grid service under the rates that apply to full service customers. This new exemption recognized that some proportion of the customers otherwise subject to the standby tariff would always experience higher costs under the standby rates than they would under rates charged full requirements customers.

This permanent exemption option was offered initially for only three years, from 2002 to 2006, but has been extended to May 31, 2015. The PSC indicated that it will at that time evaluate the necessity and impact of this exemption along with "success of the State's policies for achieving the '45 by 15' and '15 by 15' renewable-fueled generation and energy efficiency goals by that year" (NY PSC, May 2009).

Although the PSC has repeatedly extended the option available to "designated DG technologies" to choose the rates normally available to full requirements customers, which recover most of the delivery costs in energy charges, in place of standby rates, which recover these costs in demand charges, the PSC has articulated its long term commitment to cost based rates. For example, when the PSC considered the latest exemption extension it did so by "… balancing of the interests of the DG developers, in promoting DG development, and the interests of other ratepayers, who might face increased costs if DG customers avoid the standby rates intended to accurately charge them for the costs of electric service" (NY PSC 2009 at page 2). Thus, any new policy or program must serve two objectives, both capturing the full potential of DG, and ensuring that rates reflect the fair allocation of costs.

The PSC has also indicated that it may discontinue the exemption policy if the balance of costs and benefits change, stating, "Utilities or other parties, however, may petition to shorten the six-year term if it can be shown that the DG industry has matured and retaining the exemption would cause other ratepayers to bear excessive costs" (NY PSC 2009 at page 9).

Participation in Standby Rates and the Exemption for Qualifying Technologies

The Commission directed the utilities to provide annual updates on customer participation in the standby rate program beginning in August, 2010.[38] New York State Department of Public

[37] In 2009 the NYS PSC decided to end the standby tariff phase-in option for qualifying technologies because the availability of standby tariffs and the standby exemption were sufficient to meet their needs (NYS PSC, 2009).

[38] "To track the growth of the DG industry, we direct the electric utilities that tariff the exemption to file an annual report, by August 1 of each year. The report shall list: 1) each DG customer that availed itself of the exemption and its size; 2) each DG customer that was eligible for the exemption but selected standby rates instead, and its size; 3) each DG customer, sized from more than 1 MW to up to 5 MW that would have qualified for the exemption but for its size, and each such customer's size; and, 4) cumulating, for each DG customer category, the total number of DG

Service staff report that as of January, 2009, about 157 customers were being billed under standby rates. All had opted for the phase-in. Only 16 customers had qualified for and selected the exemption for clean technologies (Rieder, 2010). Details of the reports from the various utilities may be found in Appendix E.

A recent study by the Regulatory Assistance Project and ICF International for the U.S. Environmental Protection Agency surveyed standby tariff policies nationwide to identify approaches that provide both appropriate savings to DG owners, and appropriate cost recovery to the utilities, taking into account the benefits of clean DG (US EPA, 2009*b*). The analysis cited several New York utilities as examples of utilities that had successfully addressed key elements of model tariff policy objectives.

New York's standby tariff policies and the specific tariffs of the distribution utilities express an affirmative commitment to support the deployment of clean DG while ensuring that all electricity consumers pay fair and equitable rates. They also appear to provide an effective platform for adapting to changing grid conditions associated with increasing deployment of DG on the transmission grid and with the introduction of smart grid technology.

3. Existing Targeted Incentives

States and the federal government support the development of markets for DG technologies through a variety of different mechanisms. Each has a set of attributes that make it more or less attractive from the perspective of the grantor (giver of the grant/incentive) and the grantee (recipient). The grantor is an agent for the ratepayer or the taxpayer, the ultimate source of the resources that underwrite the incentive. A third perspective that deserves consideration is that of the ratepayer/taxpayer.

There are a number of reasons given by policymakers and regulatory authorities for promoting DG. These include the contribution of DG to reducing criteria pollutants, lowering greenhouse gas emissions, reducing reliance on imported fuels, increasing electricity supply diversity, lowering energy costs, improving local/regional economic competitiveness, creating jobs, nurturing the development of infant industries and creating future "green" economic clusters.

However, the term "distributed generation" refers to a number of different technologies; some are more effective at meeting some objectives than others, and some may in fact support some objectives while hindering others. For example, non-polluting renewable DG ranks quite well as a resource that lowers emissions of CO_2 and criteria pollutants, but may conflict with the objective of lowering energy costs. High efficiency natural gas based CHP, particularly when strategically located for distribution system benefits, may improve economic competitiveness

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customers and magnitude of DG installations over the annual period and since inception of the exemption" (NY PSC 2009 at page 9).

and lower energy costs, but it does not represent an infant industry and, although highly efficient, it does combust natural gas and therefore creates air emissions.

For these reasons, regulatory incentive programs typically are open to some, but not all forms of DG. For example, under the NYS RPS, some forms of biomass are recognized as a qualifying resource whereas other forms are not.[39] Under the RPS Customer Sited Tier (CST), fuel cells running on natural gas have been categorized as renewable, but microturbines, gas combustion turbines or reciprocating engines using natural gas have not (NYSERDA, 2010*a*).

Frequently, distinctions are made even within those resources categorized as qualifying. For example, state incentives often include "carve-outs" for certain renewable resources, which guarantee a certain share of the benefits will be allotted to particular technologies.

Figure 5 lists many types of incentive mechanisms that have been put in place to stimulate investment in smaller-scale DG. Some of these are briefly discussed in the following pages.

Figure 3: Examples of DG Incentive Mechanisms

Installed Capacity Payments ($/kW) – fixed payments per nameplate capacity rating, sometimes including a performance component (e.g., number of run hours during peak summer periods). These payments are typically capped on a dollar or a total capacity basis. For example the incentive may be available up to $4 Million per project, or for the first 2,000 KW of installed capacity.

Project Grants (XX% of project costs, capped at $X Million) – an important variation of capacity payments, which may incorporate technology or application type, innovative features, strategic geographic location, or other goals.

Peer Reviewed Project Grants – grant payments offsetting total system cost, up to a certain percentage of total project cost. Awarded following a request for proposal (RFP) process and review by a technical committee that selects grantees subject to certain goals and program standards.

Investment Tax Credits (ITC) – A reduction in the tax liability of a project owner based on the initial capital cost of the installed DG project. For example, the federal 30% ITC for Solar, Fuel Cells.

Production Tax Credits (PTC) – provides an offset to the taxable income of the project owner based upon the volume (kWh) of energy produced.

Renewable Portfolio Standards (RPS) / Utility Purchase Obligations – obligations on utilities or energy service companies to procure a set percentage of delivered power from certain types of generation resources. For example, New York has established an RPS standard that requires 30% of total power delivered by 2015 come from "qualifying renewable resources."

Net Metering Payments – ongoing payments to project owners for electricity produced in excess of on-site consumption (may use a variety of pricing models). Net suppliers of electricity to the grid may be paid at the full retail electricity rate, rather than at the wholesale power rate, or at some lesser rate.

Low-Interest Loan Programs – provides financing assistance to reduce the interest expense for funds borrowed to purchase and install the DG system.

[39] The definitions of what qualifies as eligible biomass for New York can be found in the NY RPS Biomass Guidebook (http://www.nyserda.org/rps/RPS_Biomass_Guide.pdf).

Special Gas Purchase Rates (Fuel Discount) – this incentive provides discounted natural gas distribution charges to DG/CHP users meeting certain criteria.

Locational Payments or Time Specific Payments – payments to relieve congestion, lower peak demands, or both, on specified networks and at particular times of the day and seasons of the year.

Carbon Cap and Trade [RGGI, CA AB 32] – Monetizes the value of avoided carbon emissions by setting hard caps on carbon emissions for *affected facilities*. Sites that can't meet their cap must either invest in new technologies, or buy carbon emission allowances from sites that have excess allowances.

Carbon Tax – a price on emitted carbon that differentially assists no- or low-carbon emitters.

Feed in Tariff / Off Take Tariff – guarantees a fixed price for electricity produced by qualifying technologies over a specified time period (more experience in Europe than in the U.S.).

Tax Incentives

Tax incentives can be based on capacity or on production. Capacity based incentives are preferable to the host site (grantee) as they receive their payments earlier in the process and shift some of the production risks to the grantor. Capacity incentives can be delivered through the tax system as a reduction to tax liability (an investment tax credit, or ITC), or they can be offered as "Capacity Grants" which are one-time payments that reduce the installed capital costs at a qualifying facility. Capacity grants are a more expansive mechanism as noted below.

There is currently a 30% federal ITC for qualifying renewable DG investments and a 10% ITC for qualifying CHP investments. The real value of a tax credit is often less than its face value because the potential recipient may not have sufficient tax liability to benefit from all, or even part of the incentive. If the DG owner is not a taxpayer, the project will be unable to capture the ITC either in whole or in part.[40] This was addressed by a provision of the ARRA that temporarily allowed for conversion of the ITC to a cash grant. In the absence of such a provision, financial structures have sometimes been created to allow third parties with sufficient tax appetite to capture the full value of tax credits and pass some of the benefit back to the DG owner. However, there is a cost, at times quite significant, in bringing a 3rd party into the transaction. The benefit to the host site may be significantly diluted when the buyer of the credit requires a high rate of return for taking the allowance.

Production based incentives have historically been favored by grantors, as they reward electricity delivered rather than capacity building. Certain renewable energy projects may qualify for a federal Production Tax Credit (PTC). The PTC pays 2.2 cents/kWH sold to an unrelated third party during the taxable year. Because the PTC requires a sale of power, "behind the meter" projects are typically not eligible for the PTC.

NYSERDA and other grantors have created some structures that incorporate both production based incentives as well as capacity based incentives. A grantor is likely to favor a production incentive that insures that "clean energy" is actually being produced by the facilities in which they have taken a stake. Production incentives, properly designed, may also have certain

[40] This is true for any tax credit program, ITC, PTC, or any other tax benefit provision such as modified accelerated cost recovery (MACRS).

efficiency advantages. A project that is compensated on the volume of production will look to design an operation that extracts the maximum production from the facility. to further increase efficiency, incentive structures can be tied to production at times when energy is most valuable. For example, an incentive may be based upon the volume of production occurring at "peak periods" for the electric system as a whole, or the zonal (transmission) or network peak (distribution).

Details of the various tax incentives currently available appear in Appendix B.

Renewable Portfolio Standard (RPS) / Renewable Energy Credits (RECs)

A well-established version of the DG incentive is the RPS. This approach creates a purchase obligation that requires the distribution utility to acquire a specified percentage of qualifying resources. The compliance instrument is the renewable energy credit (REC); the distribution utility, or more generally the "load serving entity" (LSE), will be obliged to purchase and surrender a certain number of RECs, determined by the fraction (percent) of the load that renewable resources represent, at the end of a compliance period. If the LSE has not purchased enough RECs to cover its obligations, it is required to make an "alternative compliance payment" (ACP). The ACP sets the ceiling on the value of the RECs.

Some states include a carve-out for specific resources while others do not. A carve-out is likely to imply a divergent stream of payments for specific resources. For example, if there is a mandate to achieve a certain amount of solar PV in the retail sales mix, then a solar REC is separate and distinct from a general "renewable" credit. This will separate the solar REC market from the market for other qualifying renewables. Compliance payments will be specific to the solar resource.

RECs and the NYS RPS

The New York State Renewable Portfolio Standard (RPS), established by the state Public Service Commission (PSC) in 2004 and expanded in 2009, requires that the state increase the percentage of its electricity generated from renewable sources from 19.3% to 30% by 2015. NYSERDA, which administers the RPS, operates two programs to achieve this goal: its Main Tier program supports development of larger scale renewable energy projects through a competitive central procurement process, while the much smaller Customer Sited Tier (CST) program offers incentives for smaller scale DG projects, including solar PV, anaerobic digester systems at farms and wastewater treatment facilities, fuel cells, and small wind turbines.

Under NYSERDA'S central procurement model, any renewable energy credits (RECs) produced by renewable projects funded through the RPS Main Tier belong to NYSERDA and are retired. A similar rule applies to RECs generated under the RPS CST; NYSERDA owns all environmental attributes created by the portion of electrical systems installed with CST funding (with the exception of those associated with biogas methane destruction) for the duration of performance payments or for the first three years of operation, whichever is greater.[41]

A REC in New York is not defined in terms of emissions reduction, but instead represents one MWh of renewable energy that has been sold into the NYS grid. In other states RECs may be traded privately for a limited time before they must be retired, but in New York RECs are not traded by private brokers.[42] Because New York RECs carry with them the rights to all

[41] NYSERDA does allow DG operators receiving $/kWh incentives to terminate CST performance-based incentives, after which they may sell their green attributes in other markets in New York State.

[42] The PSC has requested, as part of NYSERDA's 2009 Review, a plan to transition the program to a more market-based model. It is not clear at this writing whether this would include any future provision to allow the private trading of RECs.

reductions in pollutants resulting from the CST-supported production of electricity, participating DG operators cannot simultaneously participate in other emissions reduction markets. Pollutants potentially affected by this policy include emissions to air, soil or water, as well as greenhouse gases. Specific pollutants affected include, but are not limited to, SO_x, NO_x, CO, Hg, CO_2, CH_4, and N_2O.

The overlap between the RPS and other market-based programs can be problematic for some developers of DG projects. For example, certain biomass projects that qualify under the RPS may also qualify as offsets under RGGI.[43] However, carbon credits and/or offsets can only be counted once. This can present biomass developers with a dilemma, in that they must decide which program will most benefit their project.

New York State RPS Customer Sited Tier

A central mechanism for promoting smaller-scale distributed generation in New York is the RPS Customer Sited Tier (CST) suite of incentives implemented via NYSERDA Program Opportunity Notices (PONs).

The RPS CST generally applies to specific DG technologies of limited size installed on the customer's side of the electric meter. Fundable capacities are generally limited to the customer's peak load, although recent changes to the program appear to open the door to systems of capacity larger than the host's peak load, in cases where public benefit can be shown; and, for the first time, the new "geographic balancing" program allows projects in excess of 50 kW and coordinates with electricity distribution companies to "assess and account for the electric grid and location-based value of installations."

The Geographic Balancing Program seems designed to begin to address certain categories of benefits potentially conferred by DG, such as load pocket relief and critical infrastructure support, that were not previously valued under the RPS CS-T. According to the Program Goals and Funding Plan, "In advance of issuing the competitive solicitations, NYSERDA will work with the utilities and other stakeholders to identify strategic locations to install the eligible technologies to realize possible environmental, load reduction and economic development benefits and to analyze system performance and the impact of any installations on their respective distribution systems. The solicitations will include evaluation criteria, or some other means, to signal preference for these strategic locations, but the strategic locations will not be used to establish the eligibility of an installation" (NYSERDA, 2010*a*). Eligible technologies include solar PV and renewable biogas-to-electricity projects where the electricity generation is geographically separated from the biogas production (as long as both biogas producer and end-user are within the same NYISO zone group). The program is designed to support larger projects (above 50 kW), and to "assess and account for the electric grid and location-based value of installations (NYSERDA, 2010*a*)." The program description states that "Examples of non-

[43] Projects that can qualify under both the RPS and RGGI include landfill gas capture and manure management operations that result in both GHG destruction and renewable electricity generation.

price variables may include, but are not limited to: the potential for measurable value to the utility electric power distribution system; the potential for additional public benefit (installations that can operate during a disruption in the electric grid); quality of the implementation plan; qualifications of the proposer; quality control and performance measurement and verification plan; and, the expected installation schedule" (NYSERDA, 2010*a*). This opens the door, for the first time, to compensation for DG-provided ancillary services under the NYS RPS, although these services are not defined in the program and would be evaluated on a case-by-case basis.

Funding will be awarded on a competitive basis and, initially, is available only to non-utility market participants. Payments will be both capacity- and performance-based, and the selection process will include consideration of such non-price variables as "potential for measurable value to the utility electric power distribution system" and "the potential for additional public benefit (installations that can operate during a disruption in the electric grid)." However, funding for biogas programs will be limited to $3 million per installation.

At this writing, the New York RPS CST program includes the following components:

- Solar PV Incentive Program NYSERDA PON 2112
- Geographic Balancing PON 2156
- Fuel Cell Program PON 2157
- Customer Sited Wind Turbine Incentive Program PON 2097

These PONs are described in greater detail in Appendix B.

The total budget set by the NY PSC for the CST incentive programs from 2011 through 2015 is set at $429.1 million. Of that total, solar PV has received $144 million, Geographic Balancing $150 Million, Fuel Cells $21.6 Million, Anaerobic Digester Systems $70.6 Million, On-Site Wind $18.2 Million, and Solar Thermal $24.7 Million. This is shown graphically in Figure 6.

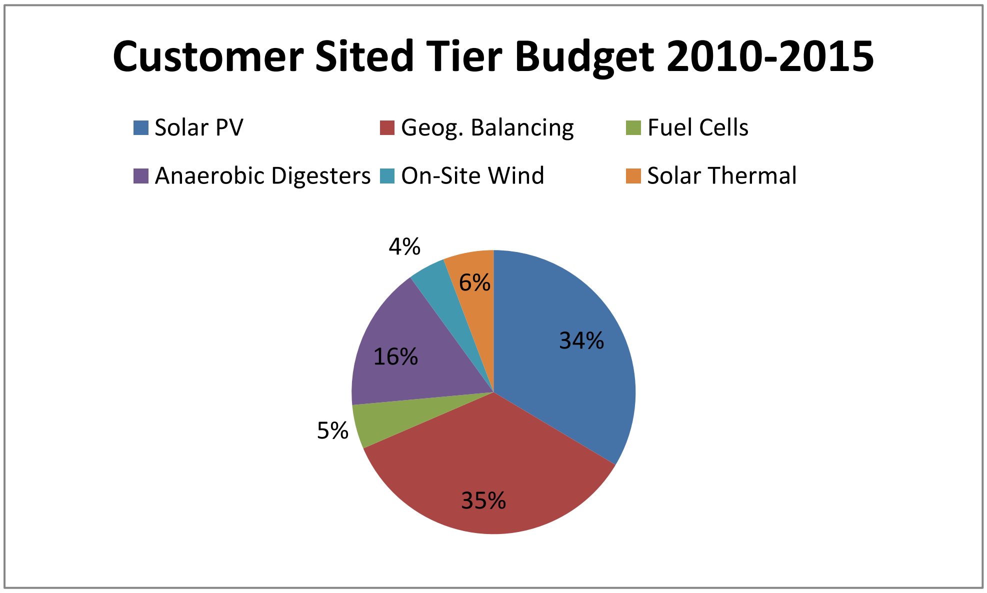

Figure 4

Feed in Tariffs

Feed in tariffs, sometimes referred to as standard offer contract programs, are designed to encourage the development of clean renewable electricity generation by offering eligible generators guaranteed payments over a set period of time. Although not widely adopted in the United States, feed in tariffs are the most widely used policy framework for encouraging the deployment of renewable energy generation worldwide. By 2010, 50 countries and 25 states/provinces had enacted feed-in tariffs, more than half of which were put in place since 2005 (REN21, 2010). Deutsche Bank estimates that by 2008, feed in tariff programs accounted for 75% of worldwide installed solar capacity and 50% of worldwide installed wind capacity (Deutsche Bank, 2010). In the US, limited feed in tariff programs have been adopted in California, Hawaii, Vermont and Washington State, and the cities of Gainesville, Florida and Sacramento, California (REN21, 2010).

The goal of a feed in tariff is to provide DG developers with predictable revenues upon which they may build an effective business plan. Feed in tariff programs often provide different payment amounts for different DG technologies. They generally include three key elements (NREL, 2010):

1. Payments for electricity output based on the cost of generation
2. Long term contracts for the purchase of electricity
3. A guarantee that participating plants will have access to the grid.

The key to designing an effective feed in tariff program is to set the guaranteed payment correctly for each DG technology. Payments must be high enough to attract the interest of developers, but if the price is too high, the result will be large amounts of capacity at a cost that exceeds what competitive bidding solicitations would have obtained. A recent NREL survey of feed in tariff program experience observes that effective program design should give careful attention to cost containment (NREL, 2010),

A 2010 NREL technical report describing feed in tariff policies and related issues (NREL, 2010) observed four main approaches to setting feed-in tariff prices:

1. A cost of production based approach that sets prices at the levelized cost of electricity production, aiming to assure that prices be high enough to attract developers to invest in DG projects.
2. A value based approach that sets prices at the value DG produced electricity provides to utilities and society, considering avoided costs of electricity production and such societal benefits as climate change mitigation, health and air quality impacts, and/or effects on energy security.
3. An auction based approach.
4. A simple fixed price incentive.

Feed in tariffs can also be designed to serve specific policy goals by offering a menu of prices tied to such objectives as technology type, project capacity, resource quality, and project location (NREL, 2010).

Net Metering

Many states offer net metering for qualified sites. Energy generated by the customer is credited against energy purchased at the full retail rate. If there is generation in excess of on-site energy consumption, that excess may be carried over to a future period, or sold to the distribution utility at an avoided cost rate. There are a number of ways of crediting net energy balances that accrue over a month or a year.

Net metering is a benefit to the DG host site insofar as they are able to reduce their electricity bill, in theory down to zero, based upon their local generation. Oftentimes the net metering qualifications restrict a qualifying site to a cap that does not exceed their historical energy consumption. Some states are experimenting with virtual net metering and other constructs that could let sites benefit from renewables absent having the physical equipment located on their premises.

In New York State, net metering is available to qualifying DG technologies up to 2 MW in capacity. A qualifying facility can use net metering to reduce its electricity bill by offsetting electricity purchased and electricity generated at the same retail rate. Generation in excess of onsite usage is purchased at the distribution utility's avoided cost, a much lower figure than the retail rate.

Under Section 66-J of the Public Service Law, New York offers net metering for eligible technologies, subject to a cap that is set at 1.3% of a utility's 2005 demand. [44] The eligible technologies are:

- PV, Residential up to 25 kW
- PV, non residential up to 2,000 kW
- Wind, residential up to 25 kW
- Wind, farm up to 500 kW
- Wind, non residential up to 2,000 kW
- Biogas, farm sector only, up to 1,000 kW
- Fuel Cells, residential only up to 10 kW
- Micro-CHP, residential only up to 10 kW

Demand and non-demand customers are treated differently with respect to net excess generation and fuel cell and micro-CHP is treated as distinct from PV, wind and farm biogas. For non-demand customers using PV, wind and biogas in any given month the excess is carried over to the following month at the full retail rate. Fuel cells and micro-CHP are treated differently with net excess generation in any month being credited to the customer at the utility's avoided cost rate. On an annual basis, any residential net excess generation for PV, wind and biogas is credited at the utility's avoided cost rate. Non-residential PV, wind and biogas excess generation are carried over to the next year and credited at the retail rate.[45]

The net metering rules and the schedule of compensation for net metering systems are summarized in Appendix B.

Combined Heat and Power (CHP) Incentive Programs

NYSERDA has long been a leader among the states in offering incentives to qualifying CHP projects. Through December 2010, there were two programs in place supporting high efficiency, low emissions CHP projects in New York. The CHP Demonstration Program closed at the end of 2010, but will return in some form in 2012. The Existing Facilities program is open through June 30, 2011.

The CHP Demonstration Program was open to new and existing industrial, commercial, institutional and multifamily building sites who are served by distribution utilities that contribute

[44] The cap is 1.0% for eligible PV, fuel cells, on-farm biogas systems and micro-CHP combined, plus 0.3% for qualifying wind.
[45] For more details on this program, see https://www.nationalgridus.com/niagaramohawk/business/energyeff/4_net-mtrg.asp

to the System Benefits Charge. This program was run by means of a competitive selection process (PON) on an occasional basis. Incentive payments ranged from 30% to 50% of the CHP system's capital cost, but capped at $2 million for any one project. There was an additional category for "Fleet Projects" where the incentive cap was raised to $4 million for the "fleet." This category was reserved for multiple CHP projects at sites that had common electric and thermal load profiles and were under common ownership. Examples of such sites include a chain of supermarkets, a chain of hotels, or similar multifamily buildings on a residential campus.

The base level of incentive was set at 30% but with certain conditions met, projects had the opportunity to increase the reward to a maximum of 50% of total project cost. Fleet projects were eligible for up to 50% of total project costs with a cap of $4 million rather than the cap of $2 million that pertained to the single demonstration project.

Additional details of the CHP Demonstration Program may be found in Appendix B.

Existing Facilities Program: CHP Component

Until June 30, 2011, combined heat and power systems were eligible to receive performance based incentives under NYSERDA's Existing Facilities Program. Performance based incentives are based upon engineering analysis, and are subject to reporting and measurement and verification to secure payments.

The program was targeted to mature CHP technologies, including reciprocating engines and natural gas combustion turbines. Payments were made based on verified capacity reductions during summer peak hours for each of three years. The minimum system size for participation was 250 kW. In order to receive payments the CHP system was required to operate at 60% annual fuel conversion efficiency based on a higher heating value (HHV), including parasitic losses. At least 75% of the generated electricity was required to be used onsite. The emissions rate of the CHP system was required to be less than 1.6 .lbs/MWH of NO_X.

The schedule of payments is presented in the table below.

Table 5

BASE INCENTIVE	Upstate	Downstate
Combined Heat & Power	$.10/kWH + $600/kW of summer peak demand reduction	$.10/kWh + $750/kW of summer peak demand reduction

Combined Heat and Power will no longer be part of the Existing Facilities Program after June 30, 2011.

Existing Utility Programs

Utility DG incentive programs address two types of benefits:

- Emergency load relief (ameliorating emergency electricity supply shortages by providing increases in electricity supply or net load reductions); and
- T&D investment Deferral (deferring the need for investments in distribution or transmission system capacity such as substation and substation feeder upgrades, and transformer upgrades).

Utility Incentives for DG Providing Emergency Load Relief

Utility load management programs have been designed to address electricity shortages when demand exceeds the available supply, or when the cost of electricity rises during periods of peak demand. These programs have focused primarily on encouraging large electricity consumers to reduce consumption, but the programs also offer incentives to customers with on-site generation who may be able to increase output to meet grid needs. For operating DG facilities, the host load must often be curtailed in order for the DG unit to increase output to the grid, a requirement that may pose significant costs for the DG host facility.

While the details of the load curtailment programs vary from utility to utility, these programs do offer DG operators a potential revenue stream. Customer owned DG can obtain incentives for providing electricity output directly (in the case of larger units) or through an aggregator, a third party that bundles the combined capacities of several smaller DG units. Participating DG facilities or aggregators will be called upon to meet minimum load delivery requirements, delivery response time requirements and energy delivery duration requirements.

The emergency load relief programs offer two types of incentives: an incentive payment tied to the net electricity actually provided during a load relief event, and a continuing incentive paid for the promise to deliver when called upon, subject to stiff penalties if the commitment is not kept. Accordingly, utilities offer both voluntary and contract programs. Voluntary programs pay only for energy supplied but do not threaten penalties if the customer chooses not to contribute when called. Contract programs offer continuing payments for the commitment to provide specified amounts of supply accompanied by stiff penalties for failing to meet delivery commitments.

In New York load relief programs are designed and managed by individual distribution utilities but coordinated by the New York ISO, which has responsibility for planning and operation of the state's transmission grid. The ISO sets forth the details of the voluntary load curtailment program, the Emergency Demand Response Program (EDRP), and the contract curtailment program, the Installed Capacity (ICAP) Special Resources Program (SRP), in its Demand Response Program Manual. The ISO will call on customers participating in the voluntary and contract load relief programs to address emergency supply shortages affecting the transmission grid. The ISO compensates the individual utilities for the load reductions that their programs produce. The individual distribution utilities may also initiate such load curtailment calls to address local distribution network needs.

New York's load relief programs are discussed further in the subsection titled "Ancillary Services Market," below.

Property Assessed Clean Energy Bonds (PACE)

Property Assessed Clean Energy Bonds (PACE) are a relatively new mechanism for supporting distributed generation development. PACE enabling legislation has been adopted by 17 states including New York, although New York's PACE enabling law is flawed in that it requires that municipalities receive federal funding in order to implement PACE. In addition, the residential portion of the PACE program was derailed when the Federal Housing Finance Agency advised Fannie Mae and Freddie Mac to avoid PACE-involved residential properties, due to concerns about the seniority of PACE liens relative to other liens on mortgages. However, New York State could enable PACE as a financing mechanism for clean energy development in the commercial and industrial building sectors, which are not as impacted by the FHFA decision.

Typically, municipalities electing to use PACE establish a special improvement district, similar to a lighting or sewer district, declaring energy efficiency and pollution reduction to be public benefits. The municipality then issues a municipal bond to fund projects within that district. Interested property owners can apply for PACE loans of up to 10% of the value of their property, which they repay over 20 years through an annual add-on to their property tax bill. The PACE property tax lien is senior to other liens, and since property taxes are rarely subject to default, investors typically see municipal bonds as a very safe investment. In case of a property sale, the lien passes to the new owner.

A well-planned and installed PACE project can generate a positive cash flow for the property owner from year one. There should be no cost to either the property owner or the municipality. Municipalities typically set stringent standards for eligibility, based on tax payment history and project viability, so that PACE municipal bonds are viewed as low-risk investments. Any environmental attributes created (in the case of community or commercial/industrial scale projects) would be retained by the project owner, unless the municipal ordinance establishing the program stated otherwise, and could be sold on the open market.

The PACE mechanism dovetails with existing programs administered by NYSERDA, such as the Home Performance with Energy Star and Multifamily Performance Programs. NYSDERDA also offers accredited installer lists to help municipalities and property owners find trustworthy contractors for PACE projects. Typically, PACE legislation requires an energy audit and often requires energy efficiency improvements be completed prior to renewable energy installations on a property. These are also areas where PACE participants could take advantage of NYSERDA's existing programs.

Under New York's PACE enabling legislation, eligible technologies include solar thermal, solar PV, small wind, geothermal, anaerobic digester electricity production, fuel cells, and "other technologies approved by NYSERDA." This gives NYSERDA the ability to approve additional energy efficiency technologies such as CHP, which has wide applicability in both urban and rural environments.

4. Existing Market-Based Mechanisms

The markets that currently allow DG participation are poorly integrated. As a result of this patchwork coverage, many services that could be provided by DG remain uncompensated or undercompensated. Moreover, many market-based programs suffer from problems of scale; that is, markets that work well to support utility-scale renewable development often do not work well when expanded to include smaller DG projects. From the developer's perspective, many barriers remain.

Ancillary Services Market

Investments in DG, particularly the smaller scale DG systems considered in this report, are made primarily to obtain electricity for on-site use. However, there is growing interest in the technical and economic feasibility of employing small scale DG facilities to provide ancillary services to the local grid. Earlier sections of this report describe the importance of ancillary services and the specific ways DG may deliver such services, based on a number of studies (ORNL, 2005; Kirby, 2007; Mutale, 2005; DG-GRID, 2007).

The NYISO administers a demand-side ancillary services program that is nominally open to participation by small DG units (with the exception of the spinning reserves credit, which is not available to DG participants due to reliability concerns). However, at this writing, no small DG units are participating (Ahrens, 2011). As discussed below, a number of issues and barriers need to be resolved before it would be reasonable to expect significant DG participation in this program.

> *The policies that will best support the long-term deployment of distributed resources are the ones that enable the resources to be put to their most highly valued uses. In the main, this means that approaches that expose the value of the resources, and reward the resource owners for providing that value, should be implemented.*
> *(R. Weston et al NREL 2002 at p. 8)*

The NYISO also operates the Emergency Demand Response Program, which "allows wholesale electricity market participants to subscribe retail end users able to provide Load Reduction (Demand Side Resources) when called upon during emergency conditions" (NYISO, 2010). The demand side resources may be called upon during both system wide and local zonal emergency conditions. The ISO's Emergency Demand Response Program specifically indicates that owners of on-site and emergency generators may participate in this program, along with end use customers reducing or disconnecting load, if the generators meet program requirements. These requirements include the ability to respond within two hours' notice, the availability of specified metering and communications equipment, and limits on how generated power is used at the customer site during an emergency (Section 2.4). Plants are compensated for the electric generation provided during emergencies, benchmarked against baseline generation records for the unit (Section 5.24).

At this writing, several DG units are participating in this program. Payments vary by zone and are adjusted annually. Currently, the Zone J price is $12.50/kW-month. For a 3,000 kW generator, this amounts to an annual payment of $245,000. Prices vary annually, so this figure is not necessarily reflective of a long-term expected annual average value. However, to put this into context, under the following set of assumptions this level of payment reduces the payback period by 0.6 years and increases the annual savings by 13.6%

Table 6

kW of capacity	3,000
Installed cost	$2,750/kW
Total System Cost	$8,250,000
Annual savings (5 year payback)	$1,650,000
Annual ICAP Payment at $12.50/kW-month	$245,000
Increase in annual savings (Annual ICAP/Annual Savings)	13.6%
Payback period including assumed annual ICAP savings	4.4 years

Participation in this program involves voluntary contributions during emergency conditions, with no penalties for not participating, but also no payment beyond the compensation for energy actually delivered.

The NYISO Emergency Demand Response Program also includes the Special Cases Resource (SCR) program that offers end-use loads and on-site generators incentives to commit capacity during system emergencies. The NYISO describes special case resources as "end-use loads capable of being interrupted upon demand, and distributed generators, both of which must be rated 100 kW or higher and are invisible to the ISO's Market Information System."[46] Participating resources receive capacity payments for pledging to deliver capacity during system emergencies, and additional compensation for the energy delivered when such an emergency request is executed. SCR resources bid minimum payment terms that they will require when called to contribute, the amount of which is used by the ISO to prioritize the use of these resources. SCR program participants are penalized if they fail to provide the promised capacity during SCR events. Emergency generators that routinely operate only infrequently are the most common participants; partial requirements generators are eligible to participate but are limited to the net additional contributions they offer above their regular generation patterns (NYISO 2010, Section 4.12).

Individual utilities also administer load management programs that address short term emergency capacity shortages on their distribution networks. Con Edison, for example, administers its Distribution Load Relief - Tariff Rider U Program, that offers financial payments for load reductions during critical demand periods ("load relief periods"). This is achieved by use of on-site generators or by reducing customer electricity use (Nexant, 2008).

NYISO has developed detailed Ancillary Service compensation policies and practices that adhere to guidance from the Federal Energy Regulation Commission under the milestone Open Access Transmission Tariff (OATT) policy mandated by FERC Order 888. As spelled out in the NYISO's Ancillary Services Manual,[47] DG units with capacity of least 1 MW can participate in the NYISO Ancillary Service market (aggregation of smaller resources is not permitted); however, so far, no DG systems in the range of 1 to 10 MW have done so (Ahrens, 2011).

Similarly, the New York State Renewable Portfolio standard Customer-Sited Tier program has very recently introduced a new "geographic balancing" program, described earlier, that offers incentive payments to locate new RPS qualifying DG in strategic locations that will strengthen local grid reliability and performance. The electric utilities have identified "strategic locations" within their service territories "…where installation of new PV and/or Renewable Biogas fueled electric power generation systems will provide benefits to the electric distribution system" (NYSERDA, 2011). Although the primary impetus for this program appears to have been an effort to balance the distribution of RPS-qualifying new generation between upstate New York and downstate locations (NYS PSC, 2010*a*), the program offers utilities the opportunity to identify, for extra incentives, those grid locations where the addition of new DG capacity could not only serve energy generation needs, but ancillary service purposes as well. However, this

[46] The SCR program allows smaller capacity resources to participate if aggregated to the 100kW minimum resource requirement.
[47] The New York ISO's regularly updated Ancillary Services Manual is available on the Internet at: http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf

opportunity is not spelled out in the CST manual. It remains to be seen whether utilities and DG developers will take advantage of this opportunity.

Environmental Markets

Many types of DG will emit fewer criteria air pollutants and CO_2 per kWh, as compared with emissions from the current average mix of generator types feeding New York's electric grid. This is an important social benefit of DG deployment; however, in order to be compensated for this benefit, operators of small DG units would have to be able to participate in markets for criteria air pollutant and carbon dioxide emissions reductions. For the most part, at this writing, such markets do not exist in New York State. Even if they did exist, they would only be relevant to the decision to make a capital investment in clean DG if they offered the DG developer/owner the prospect of significant financial gain. In other words, in order to effectively compensate and thus incentivize DG deployment, environmental markets must facilitate a fair monetization of the benefits of DG, and the costs of participating must not be greater than the benefits available to small-scale generators.

Currently in New York State, there is no market in which to certify and claim certain environmental benefits. This is especially true for small capacity units of the type discussed in this report. Where markets do exist, they are frequently characterized by poor liquidity, high transaction costs for small units, limited coverage, and other attributes that have made them, thus far, largely irrelevant to the decision to invest in, operate and maintain clean DG units.

The following markets for creating, certifying and trading emissions reductions currently exist in New York State:

- Emission Reduction Credits (ERCs)
- Emission Allowances (Formerly administered under the NO_x State Budget Program, now under CAIR, and presumably soon to be under CATR)
- Regional Greenhouse Gas Initiative (RGGI)
- Renewable Energy Credits (RECs)
- Greenhouse Gas Reductions sold in the voluntary market (e.g. Carbon Offsets)

Each of these markets is briefly described below. For more detail on these markets, see Appendix A.

Emission Reduction Credits

Emission Reduction Credits (ERCs) are credits for on-site emissions reductions, measured against representative baseline emissions levels, within a geographically defined non-attainment area. These reductions must be permanent, substantiated in the facility's air emissions operating permit (which must be federally enforceable), and in excess of any reductions required by federal, state, or local law.

ERCs can be created as a result of facility shutdown, the shutdown of an emissions unit at a site, curtailed hours of operation of an emissions unit, or a process change that results in significant reductions in onsite emissions of criteria pollutants (NO_x, SO_2, PM_{10}, VOCs and CO). ERCs may also be created by, for example, replacing boilers combusting residual oils or natural gas with low emissions, high efficiency DG systems, such as gas combustion turbines, microturbines, fuel cells or internal combustion engines that capture and utilize waste heat (CHP). ERCs are not usually available for renewable DG types such as wind and PV, since these do not typically replace onsite sources of emissions.

Once created, ERCs can be sold to emissions sources covered under the New Source Performance Standards (NSPS). Buyers are developers seeking to establish a new facility that will create a new source of emissions, or a major modification at an existing site that triggers the requirement to obtain emission offsets (ERCs). The certification, registration and use of ERCs is governed by 6 NYCRR §231-2.6, and the NYSDEC maintains an online registry of ERCs available for offsets (NYSERDA, 2006).[48]

At this writing, the markets for ERCs are highly illiquid in New York State, with very little trading activity occurring. There are a number of reasons for this:

[48] The simplest way to ascertain whether there will be buyers for ERCs to be created by a specific project may be by consulting an emission broker who is familiar with the market. This is addressed in a 2006 report prepared for NYSERDA by Pace, titled Guidebook for Small Combined Heat and Power Systems Seeking to Obtain Emissions Reduction Credits in New York State.

- Demand for ERCs is low, due to the decrease in manufacturing and other emissions-intensive industry in the Northeast; and,
- The scope of ERC markets is constrained:
    - By law an ERC is only valid if it is being sold into an area of equal or lesser non-attainment severity. Thus, an ERC created in an area of severe non-attainment is salable into a severe non-attainment area (equal level) or into a moderate non-attainment area (lesser level of non-attainment). However, an ERC created in a moderate non-attainment area is not salable into a severe non-attainment area.
    - Markets are established on a state-by-state basis. Trading may take place among states, but doing so requires the states to enter into a formal agreement – typically via a Memorandum of Understanding (MOU) between the participating states. New York has MOUs with Pennsylvania[49] and Connecticut, but information on these MOUs is difficult to find; it is unclear how generally applicable these agreements are, and unlikely that a developer would be cognizant of their existence.

In addition to the general lack of ERC market liquidity, prior analyses of these markets indicates that there are transaction costs and aggregation issues that discourage their use by smaller-scale DG owners:

[49] The text of the NY-PA MOU can be read online at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/erc/rec_ny.pdf

- Many of the costs of certifying ERCs are fixed. Thus, small projects cost significantly more per ton to certify than larger projects.
- The creation and certification of ERCs requires the site to enter into an ERC quantification process with NYSDEC.[50] This process can take an unreasonably long time to complete.
- Purchasers of ERCs generally need larger blocks of credits than will be available from a single small DG project, meaning that the value of small ERC lots is diminished. For example, if a buyer requires 100 tons of NO_x ERCs, it would prefer to execute a single contract with one seller for 100 tons, rather than 20 contracts with 20 sellers for five tons each. This problem could be addressed via aggregation and transfer of the rights to the emission reduction from the site's owner to the project developer. In that case, if a project developer installs 20 CHP projects each resulting in five tons of credits, he or she would then hold title to 100 credits. However, this would still require the developer to go through 20 separate certification processes with NYSDEC. For these reasons, DG developers may need to rely on third party ERC aggregators to bring their credits to the marketplace.
- Different states use different processes to quantify and certify ERCs, and frequently these processes are neither simple, nor well-documented. The criteria for ERC creation and use also vary from state to state. For example, ERCs are bankable in some states, but not in others; in some states, banked ERCs decline in value over time. Rules regulating ERC creation and use would have to be standardized if cross-state ERC trading were to be established.

While in theory clean DG can capture onsite emission reduction benefits via the ERC program, for these and other reasons ERCs have not proven to be a viable revenue stream for clean DG projects to date.

Emission Allowances

Emissions allowances have been created in New York State under the federal NO_x State Budget Program (NBP) and the Clean Air Interstate Rule (CAIR). Currently, CAIR is being supplanted by the new Clean Air Transport Rule (CATR); it is not clear at this writing whether DG units will receive any benefits under CATR.

The former NBP was created by the U.S. EPA to reduce the regional transport of NO_x. Although it was a federal program, it was placed under the administration of the participating states—in 2008, the final year of the program, 20 eastern states plus the District of Columbia. In effect, it was a regional cap and trade system for NO_x. A regional budget was established, and each participating state was allocated a share. New York established a set-aside for energy efficiency and renewable energy project, so that developers of these projects could apply for allowances

[50] This process has been described in detail in an ERC Guidebook prepared by Pace Energy and Climate Center on behalf of NYSERDA

that they could subsequently sell on the open market.[51] However, according to NYSDEC, few facilities applied for allowances. NYSDEC has stated that this was due to two problems. First, it was very difficult for a small project to demonstrate enough avoided emissions to qualify for a single NBP allowance; and second, selling NO_x avoidance allowances could reduce or eliminate the ability of these projects to sell their other environmental attributes (New York State Department of Environmental Conservation, Proposed CAIR Regulatory Impact Statement). It is instructive to note that our neighboring state of Massachusetts has operated a renewable energy/energy efficiency set-aside for several years – the Public Benefit Set Aside (PBSA). In contrast to the New York program the allowance requests have outstripped those available in the PBSA. The program has generated enough interest that it has been over-subscribed in several years of operation.

The NBP was supplanted by CAIR. Created by the EPA, CAIR covers 28 states and the District of Columbia. NYSDEC promulgated three rules to establish New York State's Cap and Trade programs under CAIR: 6 NYCRR Part 243, implementing the CAIR NO_x ozone season program; 6 NYCRR Part 244, which governs the implementation of the NO_x annual trading program; and 6 NYCRR Part 245, which establishes the CAIR sulfur dioxide (SO_2) trading program. CAIR was vacated by the D.C. District Court in July 2008, but the court then remanded the rule to EPA for rewriting. CAIR remains in effect as originally written while EPA considers how to remedy deficiencies in the rule.

Under New York's CAIR program, 10% of the state's annual NO_x allowances are set aside for the benefit of EE/RE projects. These allowances are deposited into the Energy Efficiency and Renewable Energy Technology Account (EERET), operated and administered by NYSERDA, which uses the money to fund energy efficiency and renewable energy projects (New York State Department of Environmental Conservation, *CAIR Summary of Express Terms*). The rationale for this system was that if NYSERDA disbursed EERET account funds to qualifying EE/RE projects, these projects would no longer need to rely on aggregation strategies to qualify for funds, and would retain their ability to sell any environmental attributes they were able to generate in the market. Theoretically, the list of qualifying projects would include electricity-producing DG using eligible fuels and technologies (biogas, biomass, hydrogen, LFG, municipal solid waste, natural gas, tire-derived fuel, waste heat recovery, and other fuels/technologies approved by NYSERDA). However, in actual practice, the EERET account funds have been allocated to battery energy storage development efforts and are not being disbursed to electricity-producing EE/RE projects at this time (Saintcross, 2010).

It is not certain at this writing whether the state's application of the new CATR will include a similar set-aside for EE/RE projects.

Although the EERET approach addresses the problems with the NBP set-aside identified by NYSDEC, such an approach might not accurately value the environmental benefits of DG

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[51] *See* NYCRR Parts 204 (NO_x Budget Trading Program) and 237 (Acid Deposition Reduction NO_x Budget Trading Program) for complete regulations covering the previous NO_x SIP Call Trading Programs. Previously, § 204-5.3 authorized a set-aside of 3% of NY's allowance trading budget for energy efficiency and renewable energy projects.

projects, since compensation to project developers would be set by policymakers and not directly tied to market mechanisms. Under such a program, developers would not receive market-based price signals; they would also not receive an ongoing revenue stream, and this could make it difficult to incorporate the value of environmental benefits into a pro forma to successfully finance a project.

It is unclear how a set-aside program, if used to support DG projects, would interact with other state programs such as the RPS and RGGI. For example, if a DG project received CATR set-aside funds, would it still be eligible to receive RPS funds, or to qualify as a RGGI offset? These details would need to be decided if the state wished to use an EERET-type program to encourage DG project development.

RGGI

The Regional Greenhouse Gas Initiative (RGGI) creates a carbon cap and trade market for 10 Northeast and Mid-Atlantic states.[52] It caps the total annual CO_2 emissions from generators 25 MWs or larger at 188 million tons through 2014. The cap will decrease 2.5% each year from 2015 through 2018 for a total reduction of 10%. New York will cap CO_2 emissions at approximately 64 million tons through 2014. New York's CO_2 Budget Trading Program was established by NYSDEC through a new rule, 6 NYCRR Part 242, and revisions to an existing rule, 6 NYCRR Part 200, General Provisions. The RGGI allowances, which permit the holder to emit one ton of CO_2, are auctioned by NYSERDA under regulations established in 21 NYCRR Part 507 - CO_2 Allowance Auction Program. Allowances are auctioned off on a quarterly basis in lot sizes of 1,000 allowances.

The first auction occurred on September 25, 2008. All of the 12,565,387 CO2 allowances offered for sale were sold, at a clearing price of $3.07/ton. The price for RGGI allowances has declined, as evidenced by the most recent RGGI auction held on June 8, 2011. Yields from this auction were $25.5 million, the lowest yield seen from the 12 quarterly RGGI auctions. Purchasers bought 12,537,000 (or 30%) of the 42,034,184 current control period (2009-2011) CO2 allowances. In addition, 943,000 (or 51%) of the 1,864,952 future control period (2012-2014) allowances were sold. Both current and future control period allowances sold at $1.89 per ton, the floor price for the auction (RGGI, Inc., 2011).

Although not covered under the RGGI allowance program, DG systems of less than 25MW may benefit from RGGI in two ways:

- Offsets: Some biomass-fed DG systems may qualify as offsets. This would include systems associated with landfill gas capture and farm waste/manure management.

[52] At this writing, it appears that New Jersey will withdraw from RGGI.

- Investment projects: Some DG projects may be eligible to receive funding from the investment of RGGI funds. According to the RGGI operating plan, eligible DG projects could include solar PV, under the Statewide Photovoltaic Initiative; CHP, under the Advanced Building Systems and Industrial Process Improvements program; and biomass, tidal energy and offshore wind energy systems under the Advanced Power Technology Program (NYSERDA, 2009*a*). However, aside from a one-time infusion of RGGI cash for the Statewide Photovoltaic Initiative, RGGI funds have not thus far been allocated to DG investment.

Other CO_2 Offset Programs

In addition to RGGI, several state and private programs allow the creation and sale of CO_2 emission offsets from CHP facilities. These include:

- Oregon CO_2 Emission Standards, administered by The Climate Trust
- Washington State Carbon CO_2 Offset Program
- Massachusetts CO_2 Reductions from New Plants (now superseded by RGGI)
- California Cap and Trade Program
- Chicago Climate Exchange (CCX)

Oregon

The Oregon Energy Facility Siting Council established CO_2 emission standards for new baseload gas plants, non-baseload power plants, and industrial boilers (Oregon Energy Facility Siting). Based on current technologies, baseload gas plants and non-baseload power plants are not able to meet the regulated emissions rate through efficiency alone. Thus, regulated facilities have two options for meeting the CO_2 limits:

- Implement offset projects directly or through a third party; or
- Implement offset projects through a "monetary path" (payment into a separate fund that is ultimately used to fund offset projects).

Offsets must be new projects that avoid, sequester, or displace CO_2 emissions. The only organization approved to generate offsets is a nonprofit organization, The Climate Trust;[53] however, there are no geographic or technology-specific limitations on eligible types of CO_2 offsets. Thus, DG projects in New York should qualify so long as they satisfy the criteria for offset projects. These criteria include an additionality requirement which requires showing that the Climate Trust funding is necessary to allow the project to go forward.

[53] For more information, see www.climatetrust.org.

In practice, power plant developers pay a fixed fee to the Climate Trust, which issues a request for proposals (RFP) for projects that can provide offsets and pays a fee per ton of CO_2 offset produced. The fee is based on the specific projects received during each separate RFP. As of May 2007, the average fee across The Climate Trust's entire portfolio of offsets was $3.30 per metric ton of CO_2 (The Climate Trust). The 2005 RFP paid $4.80/tonne of reductions. The trust has invested $8.9 million in offset projects, which will offset a predicted 2.7 million metric tons of CO_2 (Ibid.).

Washington

Washington limits CO_2 emissions from new plants 25 MW or larger, in addition to modified facilities that increase production by either 15% or 25 MW or more. These regulated facilities must submit a mitigation plan with CO_2 offsets to cover 20% of their new CO_2 emissions.

Affected generating facilities have several different compliance options. They can make payments to a third party to implement offsets, purchase carbon credits, or directly invest in CO_2 offset projects. For parties that choose to make payments to a third-party organization, the initial payment is set at $1.60 per ton of CO_2. The actual cost of the reductions acquired by the third party could be higher than $1.60/tonne, as for example through the Oregon Climate Trust.

Eligible offset-generating projects include, but are not limited to, alternative energy resources, demand-side management, carbon sequestration, energy efficiency measures, and clean and efficient transportation measures. DG projects are eligible if they create verified carbon credits traded by a recognized trading authority or exchange, or enforceable and permanent reductions in CO_2 or a CO_2 equivalent through operational changes, equipment shutdown, or other approved activities. The program administrator—either the Department of Ecology or Energy Facility Site Evaluation Council—must approve all offsets proposed by affected facility owners/operators. Direct investment projects must provide reasonable certainty that the performance requirements of the mitigation project will be achieved.

Massachusetts

The Massachusetts Energy Facilities Siting Board, an administrative board within the Department of Telecommunications and Energy, established CO_2 offset requirements in 1997. The Board required new power plants with a capacity of more than 100 MW to offset 1% of their CO_2 emissions for 20 years. The requirement provided some cost assurance to plant owners by establishing a cost limit of $1.50 per short ton of CO_2, which could have been adjusted upwards in the future to account for inflation. This program has been superseded by RGGI; however, it does provide an example and precedent for this type of offset program.

California

Although California's greenhouse gas emissions cap and trade program is not expected to be finalized until the Fall of 2011, proposed regulations indicate that offsets will be allowed for up to 8% of a company's compliance obligations. Other provisions would allow California's cap and trade market to link to other markets, as long as the external greenhouse gas emissions trading market and compliance instruments have been approved by the California Air Resources Board. Proposed regulation includes four offset protocols: Ozone Depleting Substances Projects, Livestock Manure Projects, Urban Forest Projects, and U.S. Forest Projects. Farm-based DG systems incorporating methane capture may be eligible.

Chicago Climate Exchange

The Chicago Climate Exchange (CCX) was established in 2003 as the first voluntary trading platform for greenhouse gas reduction and offsets. CCX operated as a cap and trade program with roughly 450 members until 2010, when it was acquired by IntercontinentalExchange (ICE). Although CCX no longer operates the cap and trade program, it does maintain a carbon offsets program and will continue to operate the Chicago Climate Futures Exchange (CCFE). In 2011, CCX launched the Chicago Climate Exchange Offsets Registry Program, which established rules and verification requirements for registered offsets. DG units should qualify for CCX offsets so long as they meet CCX requirements.

5. Impact of existing market-based environmental resource streams on CHP project finances (a case study)

In work previously completed for NYSERDA, Pace Energy and Climate Center assessed the financial impact of existing environmental resource streams (ERSs) on CHP project economics, modeling the impact of three types of market-based programs—emissions cap and allowance trading, CO_2 offsets, and new source emission offsets (ERCs)—on project economics (NYSERDA, 2010*b*).[54] It is important to note that the results obtained are valid specifically for gas-fired CHP projects replacing boilers burning heavy oils (#6 or #4 oil) in urban settings, where such boilers contribute disproportionately to air pollution. These results rely on specific assumptions regarding fuel prices, electricity prices, the market prices of environmental

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[54] The material in this section is from *Expanding Small-Scale CHP Opportunities Through the More Efficient Use of Trading Programs: An Analysis of Market Opportunities and Regulatory Issues*, a report prepared for NYSERDA by Pace Energy and Climate Center.

attributes, etc. Furthermore, the same results would not apply to other forms of DG, such as wind, solar, or fuel cells, which have different characteristics, efficiencies, and applications. However, it is likely that the example CHP systems used in this modeling exercise would benefit as much or more than these other DG types from the ERSs analyzed, for the following reasons:

1. CHP systems can potentially benefit from both Emission Allowance (EA) and Emissions Reduction Credit (ERC) programs simultaneously, because they offer emissions reductions related to both electricity and on-site thermal energy production.

2. Natural gas CHP systems benefit not only from high rates of efficiency, but also from historically low fuel prices. While natural gas is not a free fuel, as are solar and wind energy, CHP systems offer the added benefit of being able to replace on-site oil-burning boilers as well as the majority of electricity purchases from the grid.

3. Reliable, off-the-shelf component systems are commercially available and easily integrated into existing host facility systems.

4. CHP systems are dispatchable and thus not subject to the intermittency issues faced by wind and solar generators; as such, they can offer additional power quality and critical infrastructure resiliency benefits, and have a relatively high capacity factor.

Two example projects were used for this case study: a 3 MW engine CHP system, and a 10 MW gas turbine CHP system, both burning natural gas. Each was evaluated both with and without emissions after-treatment (in the Northeast, emissions treatment for NO_X would likely be needed to meet permitting requirements).

The case study assumptions and results are summarized below.

Baseline System Economics

Baseline economics for both systems are shown in Table 7, along with key performance and cost parameters and the annual NO_X and CO_2 emissions of each system.

Table 7: Summary of Performance, Emission, and Cost Parameters

System/Parameters	IC Engine	IC Engine w/SCR	GT Base	GT w/SCR and CO
Capacity, MW	3	3	10	10
Capital Cost, $/kW	$1,264	$1,469	$1,298	$1,434

O&M Cost, $/kWh	$0.014	$0.022	$0.008	$0.013
Heat Rate, Btu/kWh HHV	9,492	9,492	11,765	11,765
Thermal Recoverable, Btu/kWh	3,510	3,510	4,674	4,674
Annual Emissions				
NOx, Tons/year	27.1	2.7	27.0	5.4
CO2, Metric Tons/year	7,348	7,348	28,752	28,752
Revenue Requirements				
Capital Recovery, $/kWh	$0.020	$0.023	$0.021	$0.023
O&M Cost, $/kWh	$0.014	$0.022	$0.008	$0.013
Fuel Cost, $/kWh	$0.058	$0.058	$0.072	$0.072
Avoided Boiler Fuel, $/kWh	($0.024)	($0.024)	($0.032)	($0.032)
Total, $/kWh	$0.068	$0.079	$0.068	$0.075
Economic Value Measures at Assumed Electric and Fuel Prices				
Project Basis	Avoided retail electric and gas purchases			
Payback, years	3.9	5.7	4.0	5.0
IRR, %	24.7%	15.5%	24.3%	18.4%
Net Present Value, $/kW	$1,088.69	$442.21	$1,091.18	$679.41

Notes: * Capacity factor assumed at 95%.
**Thermal utilization factor of 90%.
***Avoided boiler efficiency assumed at 80%.
****Based on a 15-year project life with a cost of capital assumed at 10%. Calculations assume a CHP avoided retail electric price of $0.087/kWh and gas purchase price of $6.15/MMBtu.

Environmental Resource Streams

New Source Offset (ERC) Programs

Market prices for ERCs generally depend on how much development is taking place in the region that requires offsets, especially development in the manufacturing and non-renewable energy sectors. Due to the lack of activity in these sectors, demand for ERCs in New York at this writing is quite low. However, prices have historically been much higher in areas where supply is tight. For example, NO_X ERCs in California have at times cost upwards of $120,000/ton (Evolution markets, 2002). More common prices are in the range of $3,000 - $7,000/ton. Markets also exist for PM, VOC, CO, and reactive organic gas (ROG) ERCs.

Two model runs were conducted based on ERC prices of \$4,500/ton and \$10,000/ton. For comparison to the other programs described in this report, the one-time ERC payment, which occurs at the beginning of the project, is converted to an annual payment at the developer's cost of capital. Estimates of the resulting economic impact on the modeled projects are based on the following assumptions:

- The installation of the new CHP system contributes to the retirement of a 53-MMBtu/hour residual (#6) fuel oil boiler that emits NO_X at 0.367 lb/MMBtu.[55]
- The annual boiler capacity factor is 85.5%, equivalent to a CHP system with a 95% electric capacity factor and 90% utilization of recovered thermal energy.
- The annual boiler NO_X offset is equal to 91 tons of NO_X per year. This value is adjusted by subtracting the much lower NO_X emissions of the gas turbine.
- The CHP developer's transaction costs amount to \$7,500 (based on typical permitting costs for a small project).

Allowance Trading Programs

Potential benefits to the two example CHP projects are modeled for existing allowance trading programs, as well as several programs still under development. The modeled programs are:

- The Clean Air Interstate Rule (CAIR) NO_X emission cap and trade program (now superseded by CATR). A number of states had planned to provide allocations to CHP under this program.
- The Regional Greenhouse Gas Initiative (RGGI). Some participating states (e.g., Maine and, formerly, New Jersey) use RGGI proceeds to promote CHP project development. The New York State Operating Plan lists micro-CHP for residential applications, but not larger commercial/industrial CHP systems, among the types of technologies that may benefit from RGGI proceeds.
- Carbon dioxide trading programs, such as the one recently adopted in California, that could include CHP.

Assumptions about the modeled programs are discussed below.

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[55] Emissions rate based on EPA *AP-42, Vol. 1, Section 1-3, Fuel Oil Combustion*, Number 6 oil-fired boiler less than 100 million Btu/hour.

CAIR

CAIR is being replaced by CATR, but at this writing, CATR has not yet taken effect. Due to market uncertainty created by this situation, the economic value of CAIR allowances has been ambiguous for some time. For the purposes of this case study, their potential value was estimated based on Argus Air Daily projections, which place the value of CAIR NO_X allowances at approximately $500/ton. In New York, CHP generators could earn allowances in both the annual and ozone season NO_X programs (i.e., both five-month payments and annual payments for NO_X avoidance). Total annual NO_X allocation would therefore be 17/12ths of the allowed 1.5 lbs/MWh.

Because current CAIR allowance prices are quite low relative to historic prices, and because many analysts expect prices to rise again once CATR takes effect, a second model run was conducted using historic allowance prices from early 2006, when the value of NO_X allowances under CAIR was about $2,725/ton.

RGGI

The economic value of RGGI allowances is based on the outcome of the quarterly allowance auction. At the time of this study (in September, 2009), allocation year 2009 allowances sold for $2.19/ton, and allocation year 2012 allowances sold for $1.87/ton (RGGI, Inc., 2009 Argus Air Daily projected the current value of RGGI allowances to be approximately $2.50/ton (Argus Air Daily).[56]

A second model run was conducted at a RGGI allowance price of $25/ton, an extremely optimistic scenario.

At this writing, smaller-scale DG projects do not participate in the RGGI program as affected sources. Several DG types are eligible to participate as offsets or to receive RGGI investment funding, but with the exception of a one-time funding of solar PV projects, this has not occurred in New York State. Thus, the inclusion of RGGI prices in the model runs is based on an assumption that small DG will, at some future date, be included in the program.

CO_2 Offset Programs

[56] Prices have changed little since that time. At the most recent auction (in June, 2011), both allocation year 2009 allowances and allocation year 2012 allowances sold for $1.89/ton (http://www.rggi.org/docs/Auction_12_Release_Report.pdf), and Argus Air Daily projects the current value of RGGI allowances to be approximately $1.92/ton (Argus Air Daily, March 2011).

The economic value of CO_2 offsets was modeled using the requirements of an ongoing (no fixed deadline) solicitation by The Climate Trust. The potential economic impacts for the two modeled CHP projects are based on two hypothetical offset payments valued at $5/ton and $10/ton. These payment values are intended to represent a fair approximation of the economic impact on a project from any of the several existing CO_2 offset programs.

Conclusions

The potential impact of the studied ERS programs on the economics of the modeled CHP projects is mostly small to moderate. The most promising type of ERS is the CO_2 offset type, which can increase the NPV of a qualifying DG project by almost $2 million (see Figure 7).

The RGGI program, if it allowed small DG projects to participate, could add half a million dollars to the net present value of such projects, and this value could increase as the program continues. However, at this writing there is no mechanism for most smaller-scale DG to participate in RGGI (specific types of biomass-based DG can participate as offset projects based on methane reduction).

The NO_x CAIR programs do not provide as much value as the CO_2 programs because the present uncertainty about the future of these markets is keeping the value of emissions reductions low; but for particular project sites, especially those displacing high-emitting boilers, they might be the most applicable.

Note that the estimated annual value of the various ERSs varies widely, and these values can change with fluctuations in market prices and changes in policy. Some programs have seen wide price fluctuations that can provide opportunities to capture a higher—or lower—value than shown. The uncertainty of these markets represents risk to investors, with the result that ERSs may not be viewed as a positively as more reliable revenue streams, such as a power purchase agreement.

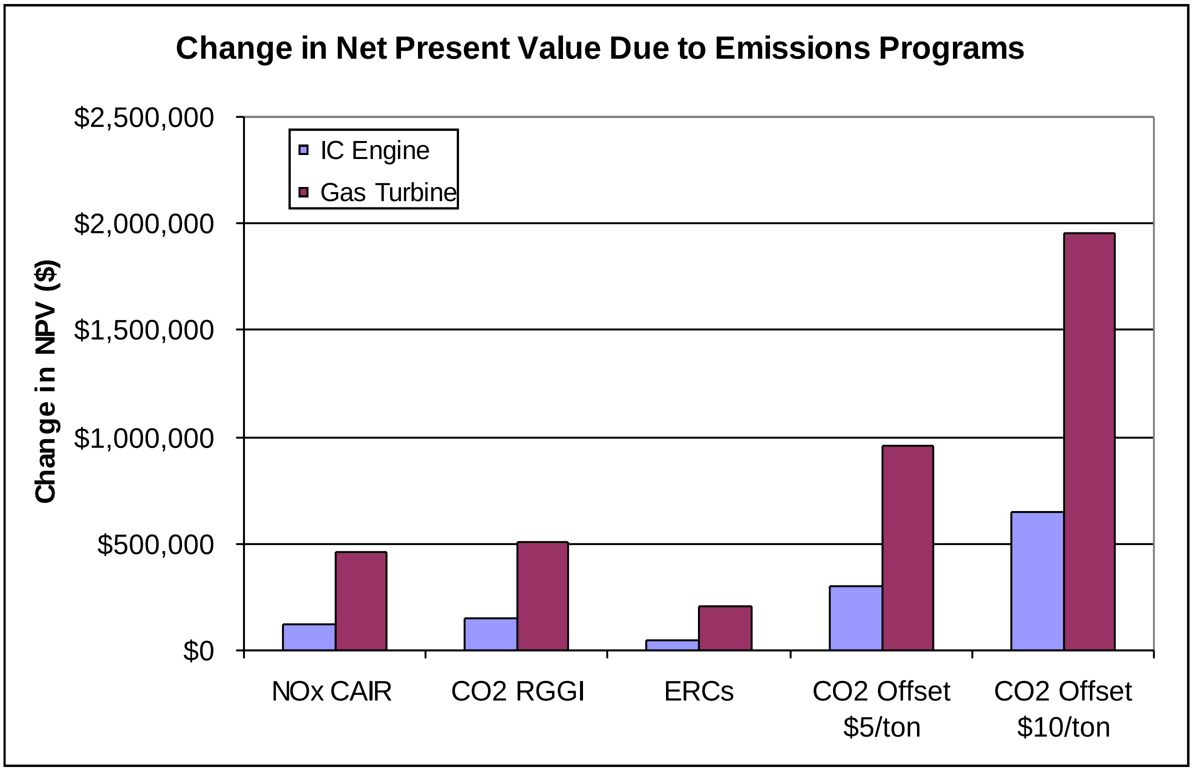


Figure 5: Net Present Value of ERS Programs for Two Example Projects

Table 8 provides a summary of the annual revenue impact and the improvement in IRR that is created by each of the ERS programs discussed in this report.

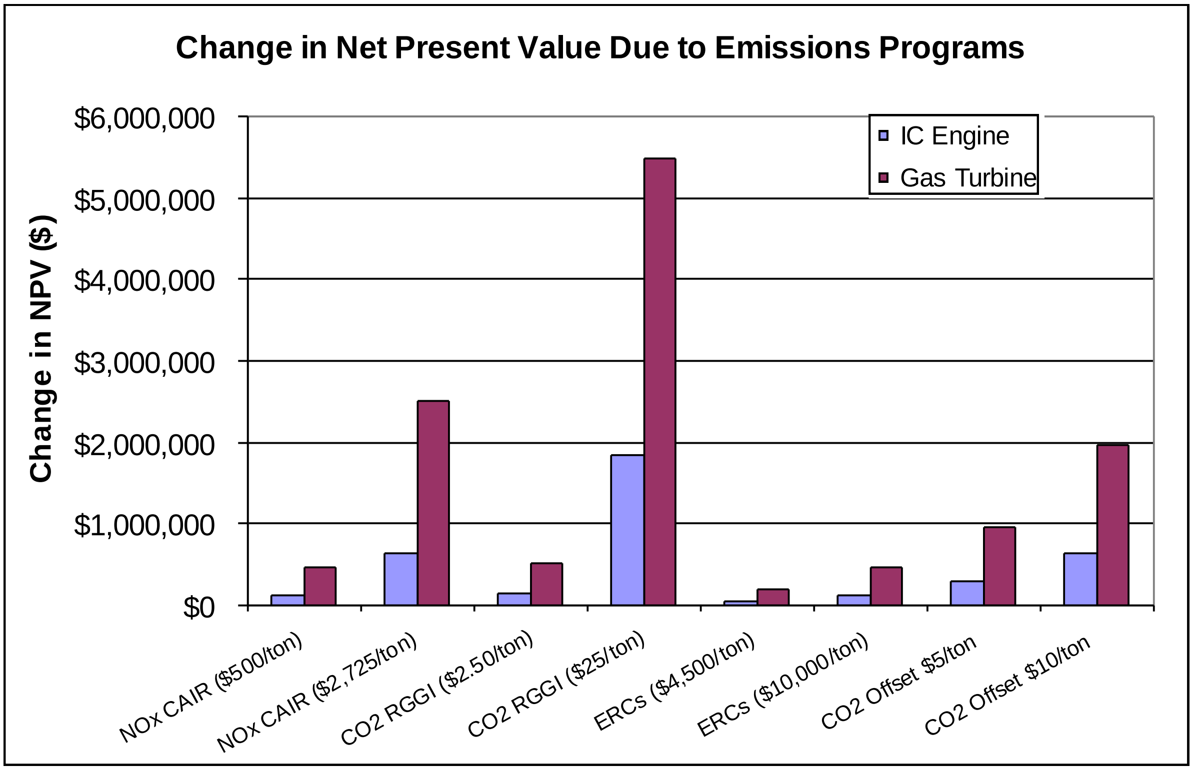
Table 8: Summary of Annual Revenue Impact and IRR Improvements from ERS Programs

ERS Programs	IC Engine	IC Engine w/SCR	Gas Turbine	Gas Turbine w/SCR and CO
Capacity, MW	3.0	3.0	10.0	10.0
Annual Revenue Impact, $/year				
NO_x CAIR Allocation	$11	$17,280	$51,435	$66,733
CO_2 RGGI	$27,462	$27,462	$79,807	$79,807
Emission Reduction Credits (ERC)	$0	$7,128	$29,563	$42,340
CO_2 Emissions Offset $5/ton	$49,819	$49,819	$144,774	$144,774
CO_2 Emissions Offset $10/ton	$99,637	$99,637	$289,549	$289,549
Improvement in IRR, percentage points increase				
NO_x CAIR Allocation	0.00%	0.47%	0.43%	0.53%
CO_2 RGGI	0.61%	0.57%	0.62%	0.59%
Emission Reduction Credits (ERC)	0.00%	0.19%	0.25%	0.34%
CO_2 Emissions Offset $5/ton	1.24%	1.18%	1.16%	1.11%
CO2 Emissions Offset $10/ton	2.65%	2.50%	2.36%	2.25%

Because history shows that NO_x emissions reductions have been more valuable in the past (EPA, 2009*a*), and forecasts show that CO_2 reductions may be more valuable in the future,[57] a second model run was conducted with higher ERS values in these categories. Figure 8 shows the impact of the following projected ERS price scenarios: NO_X CAIR allowances at $2,725/ton, RGGI CO_2 allowances at $25/ton, and NO_x ERCs at $10,000/ton.

[57] Pace Global Energy Services CO2 Allowance Price Forecast, www.paceglobal.com/paceglobal/pdfs/company/unique-market-analysis/CO2%20allowance%20price%20forecast%20080607.pdf

Figure 6: Net Present Value of ERS Programs Including Historic and Future Price Scenarios



As illustrated in Figure 8, the major increase in net present value to a CHP project was delivered by a projected increase CO_2 price per ton through the RGGI program. As carbon cap-and-trade legislation progresses and regional programs ramp up, the future value of carbon reductions has the potential to significantly change project financing options for low- and no-carbon DG projects. NO_X CAIR prices at $2,725/ton have the second best impact on the project economics of the gas combustion turbine; an increase in prices to 2006:Q1 levels could result in an increase of 2% to 2.88% on project IRR and a 6 to 8 month decrease in payback periods.

Note that in some markets, multiple ERSs can be pursued for a single project. For example, a project may be able to pursue both NO_x and CO_2 credits, or both ERCs and emissions allowances. However, the interactions between multiple ERSs are not well defined; in some markets, only one ERS can be used for a particular project. If this is the case, a DG developer or owner must analyze what programs could be applicable to a given project, and the potential value of those programs, on a project-by-project basis to determine which ERS to pursue.

6. *Barriers to DG participation in existing markets and programs*

New York State DG projects wishing to participate in existing markets may encounter a number of barriers. These may be regulatory, economic, logistical or informational in nature. In many cases, these barriers could be addressed at little or no cost to the state. The major barriers are discussed below.

Barriers: Environmental markets and programs

CAIR Allowances

Proceeds from the CAIR allowance program were not made available to EE/RE developers, despite a 10% set-aside program nominally dedicated to this purpose.

New York allocated 10% of its CAIR emission allowances to the Energy Efficiency and Renewable Energy Technology (EERET) Account, administered by NYSERDA. This account was intended to support renewable energy and energy efficiency programs. Eligible technologies included backpressure turbines, boilers, combustion turbines, condensing turbines, extracting turbines, fuel cells, microturbines, reciprocating engines, heat recovery generators, stirling engines, and other similar technologies. Eligible fuels included #2 and #6 fuel oils, biogas, biomass, coal, hydrogen, LFG, municipal solid waste, natural gas, tire-derived fuel, and other fuels, along with waste heat recovery. All project sizes were eligible.

The EERET account was established by NYSDEC because few EE/RE developers had applied for credits under the previous program. It was thought that credits were too difficult to qualify for, and not worth the investment of time and effort for small project developers (even when aggregated). For example, a savings of approximately 1,333 MWh of electricity (at a reward rate of 1.5 lbs/MWh) was required to yield one NOx allowance, valued at approximately $2,000. In addition, it was thought that developers were reluctant to apply for NO_x allowances because this would restrict their ability to sell environmental attributes into other markets (effectively, awarded credits reduced or eliminated the value of RECs created by project developers). For these reasons, the NO_x program was undersubscribed in New York State, and eventually was replaced by the EERET set-aside account.[58] However, at this writing, EERET account funds have not been made available for DG project support.

New Source Offset Emissions Reduction Credits (ERCs)

[58] By contrast, a similar program in Massachusetts was oversubscribed, perhaps due to clear application instructions and a relatively transparent approval process, despite low allowance prices.

Theoretically, DG projects can generate and sell ERCs if they lower emissions levels from facilities in non-attainment areas. In practice, however, the ERC markets are moribund in New York and the surrounding states, largely due to a lack of demand. Additionally, DG project developers wishing to certify ERCs face transactional barriers; the ERC certification process in New York is not well documented or publicized, forms are unnecessarily burdensome to complete, and the certification process can take months or even years. Furthermore, DG projects face barriers of scale, since potential ERC buyers frequently want larger quantities of ERCs, making aggregation necessary for small producers. Due to fixed transactional costs, smaller quantities of ERCs are also more expensive per unit to produce.

RGGI

DG projects cannot directly participate in RGGI at this time. Notably, some biomass DG types may qualify as offsets under RGGI. DG technologies eligible as RGGI offsets are those using landfill gas or agricultural methane (manure management projects). The offset is awarded for methane emissions reduction. There is also a provision allowing micro-CHP for residential applications to benefit from RGGI proceeds (but not larger commercial/industrial CHP systems). RGGI proceeds may also be invested in several types of DG projects, including solar PV, under the Statewide Photovoltaic Initiative; CHP, under the Advanced Building Systems and Industrial Process Improvements program; and biomass, tidal energy and offshore wind energy systems under the Advanced Power Technology Program (NYSERDA, 2009*a*). However, of all these eligible DG types, only solar PV appears to have received any RGGI funds. The Statewide Photovoltaic Initiative was allotted $11.8 million in RGGI funding through March, 2011, but that was a one-time allocation made as a stopgap measure because the solar PV funding under the RPS CST had been oversubscribed. Proposed allocations of RGGI funds through 2014 do not include any additional money for solar PV (NYSERDA, 2011*b*).

Other CO_2 Offset Programs

Some DG projects may qualify as offsets for CO_2 reduction programs, including state programs, such as those in Oregon, Washington and California, and voluntary markets, such as CCX. Eligibility will depend on the type of project and the requirements of the offset program. Note that NYS projects accepting funding under the RPS CST cannot sell credits into these markets for at least the first three years of project operation.

Barriers: Ancillary Services Markets

As explained previously, this investigation finds little evidence that DG is currently contributing ancillary services on any significant scale. Virtually all studies that examine this observe two types of barriers:

1) The small total contribution that can be made by the relatively few small DG systems on the grid, and
2) The availability of other, lower cost methods of obtaining ancillary services that are already in use (ORNL, 2005, DG-GRID, 2007, Lopes et al., 2007).

The first barrier is due to the fact that existing DG plants of the types addressed in this analysis are small both in number and capacity, meaning their potential contribution does not achieve the scale required by system operators. This limits their practical value to what has been described as "niche applications," in network locations where environmental, planning, terrain related or other constraints limit development (Mutale, 2005). A related problem has to do with the relatively large transactional costs of rewarding relatively small service contributions. If the net potential value an individual DG facility may offer is very small, the cost to grid managers of capturing that value and providing fair compensation may render any payment impractical (similarly, if the potential reward is small, there is little incentive for DG operators to seek to participate in programs, especially if participation requires additional investment for communications and control equipment). Aggregation of small DG units shifts some of the cost to the aggregator, but reduces the value to participating DG units by introducing a middleman into the transaction; and, as noted above, some existing programs prohibit the participation of aggregated resources. For these reasons, there may be little interest by grid managers or public regulators in providing a role for DG in meeting ancillary service needs, until DG capacity represents a significant component of the interconnected electric system. In this setting, time and trouble alone create a formidable barrier.

It is also important to note that increasing the number of interconnected DG units on the grid not only increases the potential contribution of DG; it also increases the potential costs (Lopes et al., 2007; DG-GRID, 2007; ORNL, 2005). While DG units can provide ancillary services, increasing the number of DG units, especially intermittent generator types such as wind and solar PV, also increases the need for ancillary services. This cost/benefit equation is poorly understood at this writing, although studies are currently underway to better quantify the net impact of adding various DG types to the grid.

The second barrier cited above refers to the existence of well-developed practices and resources that can meet ancillary service needs without the contributions potentially obtainable from DG. Coupled with this is the paucity of available knowledge and experience with using DG to provide these services. Absent such knowledge and experience, and absent a compelling need, grid operators have little incentive to develop new policies and programs to obtain ancillary services from DG units, and to compensate DG owners for providing these services.

Thus, the use of interconnected small DG to provide ancillary services is hindered by a chicken/egg problem. Small DG could make a significant contribution to improving the overall reliability of the interconnected electric system; but this promise awaits the day when large quantities of small DG are deployed throughout the grid. However, there is a risk that if large scale deployment of DG is poorly managed, it will reduce system performance and increase costs. At the same time, until DG offers significant benefits for the interconnected electric system, grid managers and regulators have little reason to modify existing methods of obtaining these services or to compensate DG for providing such services.

From the DG owner's point of view, committing to providing ancillary services is not simply a question of obtaining incremental revenue that may improve DG plant economics. It is also a question of the net effect of modifying the plant operations and equipment that would otherwise be optimized to serve the needs of a specific local load. Because most DG systems are installed to provide capacity and energy for the owner's purposes, few existing units have been designed with the communications and control equipment necessary to allow the DG unit to serve grid operational needs. Such equipment may include governors, automatic voltage regulators, resynchronization facilities, and protection, monitoring and communication facilities (Lopes et al., 2007; Kirby, 2011).

For a small DG plant, the required additional equipment can be prohibitively expensive. For example, DG units providing ancillary services must install telemetry equipment, which provides communication between the DG asset and the transmission operator. This equipment includes redundant relays and communication lines. One anecdotal estimate of the incremental cost of these relays and lines is $60,000 for a 5 MW DG asset (Ahrens, 2011). If aggregated smaller assets were allowed to enter the market, each individual unit would be required to invest in the telemetry equipment. This cost, in combination with the added cost imposed by the aggregator, would likely overwhelm the potential benefits that a small unit might expect to receive from participation.[59]

The need for such additional equipment, and associated changes in plant operations, implies a trade-off between anticipated incremental income from, and the associated costs of, providing service(s) to the grid. Since markets for DG ancillary service contributions are not mature and revenues are not predictable, there is significant risk in making capital investments based on these anticipated revenue streams. Providing spinning reserve capacity could, for example, require that the DG unit set aside production capacity that would otherwise serve on-site needs for the duration of the spinning reserve commitment. If they cannot be confident that the incremental costs required to deliver ancillary services will earn a significant, predictable and reliable economic return, few DG plant owners will pursue this.

Furthermore, there are issues of control, risk and liability that need to be resolved. For example, utilities are responsible for providing reliable electric service within a narrow range of acceptable voltages. Relying on a third party (the DG owner) for voltage regulation services puts utilities in the untenable position of being responsible to provide services they cannot directly control. If voltages are not well regulated and damage to customers' property results, the utility may be

[59] Anecdotal evidence suggests that the NE ISO and PJM have simpler and cheaper telemetry requirements, which perhaps could be adopted by NYISO to lower the cost of entry into the NY ancillary services markets (Ahrens, 2011).

liable for this damage. Thus, to manage risk and liability, and to ensure delivery of important services, utilities will prefer to use generation units they can directly control.

DG unit owners, for their part, are unlikely to want to cede control of their systems to the utility, because the utility may make demands on the DG unit at times when the DG owner needs to devote the unit's full capacity to serving the local load. This conflict of interest is inherent in the system so long as the DG unit is owned and operated by an entity whose core business is not the sale of electricity and related services. Because small DG units are often owned by entities for whom the provision of such services falls well outside their core business, there is considerable inertia on the provider side as well.

This is the status quo. However, it is likely that the status quo will shift due to technological advances and regulatory initiatives. Emerging smart grid technology promises to improve the ability of grid managers to monitor and control conditions throughout the grid. At the same time, public policy commitments to renewable energy deployment and highly efficient natural gas-fueled combined heat and power (CHP) and fuel cell systems continue to increase the number of distributed generators throughout the electric power system. And new tools, such as the RPI test bed, are giving researchers the ability to better evaluate the balance of costs and benefits presented by expanded DG development and grid penetration.

Barriers: Regulatory and Targeted Incentive Programs

RPS CST

The New York State RPS Customer Sited Tier (CST) is the primary mechanism by which the state supports development of clean DG. Although the program has met with some success, barriers remain to participation in the RPS CST program for many DG types and applications.

A common complaint of participants in the RPS Main Tier is the requirement that environmental attributes (RECs) associated with renewable electricity generation become the property of NYSERDA. As with the Main Tier, to prevent double counting of RECs, participants in the CST give up all environmental attributes created by the generation of renewable fuel-based electricity to NYSERDA for three years or the duration of production payments, whichever is greater (except for attributes associated with biogas methane destruction). This applies to the first 700 kW capacity of any system receiving capacity incentive payments, and the first 10,000,000 kW generated by any system receiving performance incentive payments. Participation in the CST therefore precludes participation in other emissions markets for all projects other than some anaerobic digesters. This means, for example, that an industrial-scale, on-site wind project supported by the RPS CST cannot sell carbon credits into the Chicago Carbon Exchange until at least year four of project operations. This may make it difficult for developers to include environmental attribute-related revenue streams in a project pro-forma, since these revenues will not be available in the earliest years of the payback period, and because uncertainty related to their value increases as the possibility of monetizing these attributes is pushed farther into the future.

Another barrier to DG participation in the RPS CST is that not all DG types are eligible. Eligible technologies include solar PV, thermal PV (valued according to displaced electric water heating), anaerobic digesters, fuel cells and on-site wind. Notably, CHP technologies not associated with ADG at farms, food processing facilities, or methane capture from municipal wastewater treatment are not eligible under the CS-T. This excludes biomass-fired boilers, biomass gasifiers, natural gas-fired engines or microturbines, and landfill gas (LFG) recovery and combustion systems.

Furthermore, the geographic scope of New York's C-ST program is strictly limited. Eligible projects must be located within the state (unlike the Main Tier program, which allows out-of-state projects to participate if they sell power into the NYS grid). By comparison, RPS programs in some other states accept RECs from a multi-state region or even nationwide to satisfy their RPS quotas.

In addition, funding is generally limited to installations scaled to meet the customer's peak load, although installations scaled to exceed the customer's peak load may sometimes be approved due to practical considerations or "where there are recognized public benefits." However, these exceptions are subject to technology-specific size restrictions; for example, on-site wind turbine funding is capped at a capacity rating of 600 kW, while solar PV is capped at 7 kW for residential, 25 KW for not-for-profits, and 50 kW for commercial systems.

Net Metering

Historically, New York State's net metering program has been subject to individual project capacity caps and overall kWh caps, which limit participation in the program. Current New York State net metering law limits systems to a maximum capacity of 2 MW for non-residential applications, and less for residential and farm applications. The overall net metering limit for utilities is capped at 1.3% of the utility's 2005 demand. In addition, participants have cited interconnection issues as a barrier to participation, although some of these have been addressed.

These barriers have been lowered somewhat in recent years with the liberalization of the state's net metering law. The Interstate Renewable Energy Council (IREC), which monitors net metering issues and practices nationwide, publishes a periodically updated Model Net Metering Rules that tracks best practices among state programs (IREC, 2009*b*). IREC also sponsors a review of state net metering policies and assigns grades that evaluate these practices compared to its best practice standards (Network for New Energy Choices, 2010). The most recent ratings, published in 2010, give New York net metering policies a "B" rating, defined in the report as "Generally good net metering policies with full retail credit, but there could be certain fees or costs that detract from full retail equivalent value. There may be some obstacles to net metering."

The 2010 rating is a significant improvement over the "D" rating the New York policies received in 2009. This reflects changes in the maximum size of participating DG facilities authorized by statute and implemented in PSC regulation. The 2010 evaluation recommended that New York raise the caps further. Specifically, the evaluation recommended that the state increase the limit on overall enrollment to 5% of a utility's peak demand, and allow community net metering and meter aggregation. The evaluation also noted that the current 1.3% cap, while it poses no immediate limits on net metering in New York State, should be revisited before it becomes a barrier to program participation.

In June, 2011, the New York State Legislature adopted virtual net metering, which allows some customers to net meter from DG remotely located from the point of electricity use. The amended statute allows qualifying agricultural customers to combine the meters on properties they lease or own for net metering, and allows non-residential customers who operate wind generating systems to engage in remote net metering.[60]

Barriers: Existing Utility Programs

<u>Emergency Load Relief Programs</u>

Although there are well established programs that the NYISO and distribution utilities use to address supply shortages, customer owned DG has so far made only very limited contributions. Most of the capacity provided comes from load curtailment rather than from the operation of customer owned DG; and almost all of the limited contributions from customer owned DG come from emergency standby generators rather than partial requirements DG systems that operate regularly.

In New York, Con Edison's Distribution Load Relief (Tariff Rider U) Program provides an important example. The Con Edison program offers customers two options, a mandatory and a voluntary load relief program. The former provides continuing payments for customers who can guarantee load reductions, and the latter provides payments only for the load reductions made during emergencies. While this program has been successful in obtaining load relief, virtually all of the load relief so far has been provided by demand reduction measures rather than additional supply from participating DG facilities (NYS PSC, 2010*c*).

<u>Distribution Grid Investment Deferral Programs</u>

Previous sections of this report have considered the general role customer-owned DG may play in deferring the need for utility investments in the distribution grid. The New York Public Service Commission (PSC) has taken several steps over the last decade to encourage distribution

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[60] Assembly Bill A.6270b. Amending Subdivision 3 of section 66-j of the Public Service Law adding a new paragraph (e).

utilities to offer incentives for DG capacity installed in locations where it can help defer otherwise-needed distribution system upgrades. In 2005, following a plan developed by a multi-party working group, the PSC directed New York's investor-owned distribution companies to carry out a three-year pilot program aimed at testing whether DG could cost-effectively defer the need for significant investment in distribution system infrastructure (Opinion No. 01-5). The pilot program required each distribution utility to identify distribution systems in need of major reinforcement and to issue a series of Requests for Proposals (RFPs) for DG capacity at these locations. This would allow the utilities to defer planned "wires" investments in these areas. The six utilities issued 24 RFPs over a three year period, and received 14 proposals; however, the utilities selected none for implementation, because the proposed projects did not prove to be cost-effective compared to the distribution upgrades they were intended to defer. Pace collaborated with Synapse Energy Economics, Inc., to conduct an evaluation of the pilot project experience (NYSERDA, 2006*a*). The evaluation concluded that several factors contributed to the failure of the pilot RPFs to provide cost-effective alternatives to the candidate distribution system upgrades, including:

- Incongruence between the utility distribution system need and DG "best fit"
- Limited time available for proposal development
- Inability to secure developable site
- Non-disclosure of the cost of the utility build option
- High transaction costs to participate
- Economics did not often support project development
- Short contract period
- Risk of incurring significant financial penalties for non-performance
- Reliability/redundancy requirements

In March 2010, the PSC adopted a joint proposal from collaborating parties in a Con Edison rate proceeding that included, among other things, a proposal to create a Distributed Generation Collaborative to address various aspects of DG, including the value of using DG to defer infrastructure investments. The PSC approved plan included a collaborative effort to:

1. "Develop protocols to guide the Con Edison evaluation process for incorporating the use of DG as a load relief option within the [Transmission and Distribution] T&D planning process and submit proposed protocols to the [Department of Public Service] Staff for its review; such protocols are to consider all attributes of DG on a comparable basis with other measures;" and
2. "Explore potential mechanisms that can be tested in the market to attract and fund DG facilities in lieu of T&D investments where such facilities are economically and Case 09-E-0428 2 technically feasible and appropriate."

A few months later, in November 2010, a collaborative working group submitted a proposed plan of action (NYS PSC, 2010*c*). The recommended actions included efforts by Con Edison to address the needs of DG project developers with incentives and contract terms intended to reduce the barriers to DG participation. The target distribution and transmission upgrades include, for example, distribution system feeders, transformers and mains and transmission substations and substation feeders. The plan sets forth a number of steps designed to address the barriers to effectively enlisting DG investments to defer transmission and distribution upgrades. The November 2010 collaborative report describes changes in grid planning and in individual upgrade decision making aimed at placing DG and demand side management on an equal footing with other methods of maintaining grid reliability.

While it is too early to assess the impact of this effort, the collaborative provides a productive pathway to remove persistent barriers posed by past planning and investment decision making practices.

In a recent Niagara Mohawk rate case decision the PSC accepted a plan proposed by Niagara Mohawk and the Pace Energy and Climate Center to develop “non-wires alternatives (demand side management and distributed resources) to avoiding and delaying transmission and distribution system investments.” The PSC approved plan will “. . . entail collaborative discussions between the Company and Pace/NRDC, resulting in a draft proposal for Staff’s input, followed by comment from a larger group of interested parties, leading to a proposal to the Commission. The plan would be oriented toward the development of pilot projects.” (NYS PSC, 2011). The Con Edison and Niagara Mohawk collaborative initiatives, engaging New York State’s two largest distribution utilities, offer a platform for identifying and implementing the changes needed to open the way for integrating customer owned DG into grid planning and management.

V. Recommendations

This report focuses on the opportunities and challenges posed by the prospect for growing penetration levels of smaller scale DG on New York State's integrated electric power grid, and the adequacy of existing policies, programs, markets and targeted incentives for achieving the level of DG development envisioned by state energy planners. New York, like many other states, has committed to achieving significant renewable energy targets in the near future. Meeting these targets implies that the penetration level of smaller-scale distributed generation is inevitably going to increase markedly over the next decade or two.

Earlier sections of this report addressed the benefits and costs associated with DG deployment, reviewed how existing policies and programs support or pose barriers to this deployment, and identified gaps in knowledge and experience that hinder accurate calculations of the true costs and benefits of different DG types in various applications. This final section pulls together the findings from the previous analysis and offers recommendations aimed at minimizing the costs and maximizing the benefits associated with the large scale deployment of small DG on New York's electric system.

The following recommendations consider the steps required to significantly increase the number of grid-integrated small DG systems in New York State, and to change DG from a modest contributor, perhaps best described as a "marginal contributor," to a significant contributor of electricity services. The four key recommendations represent broad policy areas where decision maker should focus. These are followed by lists of specific recommendations. A summary narrative concludes this section by relating the recommendations to the existing policy and program framework examined in earlier sections of this report.

Four key recommendations

This assessment concludes that four core changes are needed to enable the existing public policy and program framework to build an effective pathway to optimizing the role DG plays in electric service delivery:

1. More study of the true costs and potential benefits of large numbers of small interconnected DG units on the state's electric grid. Closing the knowledge gap is essential because it lowers barriers to development, informs effective policy, allows for more efficient markets and establishes a basis for fair and efficient tariffs and incentives. This recommendation lays the groundwork for all following recommendations.
2. Better coordination of programs, policies and market rules at the state level. A piecemeal approach to promoting and incorporating DG is not effective. Policy, incentives, markets and regulatory structures must work in concert, and these efforts should be based on a much more complete understanding of DG's unique attributes and the technical challenges posed by the incorporation of these attributes into the existing electric grid.

3. Lowering barriers to DG development, interconnection, and market participation. These barriers reflect a poor understanding of DG's technical requirements, and of the true costs and benefits of different DG types in various locations and applications. Given the state's commitment to renewable energy and to the implementation of a smart grid, and the rate of technical innovation in this sector, grid operators and utilities can no longer afford to view DG as a useless and potentially dangerous novelty.
4. Developing markets in which DG can participate, and adjusting market rules to take account of DG's unique attributes. Currently, most DG is developed to serve an on-site load. Bringing DG into a productive and efficient relationship with the grid, where DG's highest potential value can be realized, will require markets to become much more inclusive of DG resources.

Specific recommendations

Below are two concise lists of appropriate policy and public program steps that address these four overarching recommendations, drawn from this study's assessment of DG potential, barriers and public policy drivers. The action recommendations are steps New York should take to capture the important benefits offered by DG, address costs associated with DG development and grid integration, and incentivize DG deployment by fairly and effectively compensating DG for its contributions. The recommendations for further consideration are initiatives that may merit further investigation; these initiatives offer promise for reducing barriers to DG deployment, for providing new policy tools, or for significantly improving the support existing programs provide to DG, but may require more analysis and in some cases testing to evaluate their efficacy.

ACTION RECOMMENDATIONS

1. Address knowledge gaps

- Continue and expand efforts to align utility grid investments with the state's objectives to increase the proportion of electric energy requirements met by renewable energy and clean, high efficiency CHP and District Energy Systems. The introduction of smart grid technology offers opportunities to strengthen the capacity to integrate DG effectively, but the choices made now may determine whether or when improvements affecting DG integration will happen. Monitor and periodically report on the progress being made in making the New York grid more amenable to higher penetration levels of DG. Include DG contributions of benefits and costs affirmatively in grid planning and management (e.g., related Con Edison settlement plan).

- Develop a better understanding of the potential costs and benefits of various types of DG in various applications and locations on the grid. The test bed being developed by RPI CFES offers the opportunity to estimate the physical impacts of DG on the grid and to assess its costs and benefits. Interconnection policies, standby rate design and other regulatory mechanisms can be better informed with tools of this sort. This will allow the NY PSC to improve the rate and contract policies it uses to ensure that benefits and costs are fairly assigned to responsible parties and to appropriate beneficiaries.

- Create an expert working group to advise state energy planners on the regulatory, legal, financial and market structure considerations that might further the deployment of more highly efficient multiple building systems. Multiple building systems with complimentary electric and thermal profiles and a set of assets (CHP, EE, RE, DR, storage) operating in a coordinated fashion may provide a large impacts with significant savings, and at a much lower total cost than single building approaches.

<u>2. Coordinate existing programs</u>

- Continue and expand efforts to align existing state DG incentives with the objective of maximizing system benefits, to the extent feasible.

- When evaluating T&D capital equipment expenditures, consider the incremental value that an investment offers when it creates a platform for or otherwise enables greater utilization of DG resources as an asset on the T&D system. The goal should be to improve opportunities for DG to contribute benefits and avoid adding costs to grid operation.

- Examine means of "stacking" DG benefit streams and the resulting potential revenue streams. DG benefits are "stackable" when a DG operator can simultaneously provide several different benefits, e.g. ancillary services, environmental services, and energy services, and thereby create several different revenue streams that will support project development. This is often essential for units of smaller capacity that may not be able to secure financing based on a single revenue stream and on-site economic benefits. Public policy can support benefit stacking through the more conscious design of programs that work synergistically to enable the highest and most efficient contributions from DG units, and of markets that reward the same. Capture the ability of aggregated DG resources to provide firm capacity by quantifying with statistical measures the low risk of outages associated with coordinated DG resources. This knowledge is essential to the widespread acceptance of aggregated DG resources in supporting grid operations.

- Continue support for high efficiency, low emissions Combined Heat and Power and District Energy Systems in the operating budget for SBC IV, 2012 – 2016, with a particular emphasis on facilities that maximize system benefits, particularly in those locations and time periods where the value of avoided system costs is greatest.

<u>3. Lower barriers</u>

- Prioritize investments in the grid that enable two way communications, controls that can react to system conditions in real time, and open source communications protocols that are accessible to a wide range of assets. These investments will enable greater numbers of interconnected DG units offering greater benefits. Investments in "smart grid" technologies should include due consideration of how they will impact the expanded deployment of interconnected DG, and the ability of DG to offer greater and more varied benefits to the grid and to society.

- Provide incentives and regulatory guidance to utilities to more thoroughly consider DG alternatives in system planning, bringing it more into the mainstream of the process.

- Encourage utilities to standardize protocols and streamline processes to use DG resources to displace distribution system capital investment where economically viable.

- New York City is phasing out the use of residual oil (#4 and #6) in buildings. Policymakers should explicitly address the role that CHP might play in accomplishing this objective at a lower total cost. Because gas infrastructure is constrained in some of these areas and gas infrastructure investments are required to enable the use of gas-fired CHP, policymakers should consider the aggregation of sites in an underserved area as a means of making the infrastructure build-out more cost effective.

<u>4. Develop and open markets</u>

- Work towards the development of broader market access for services that can be provided by DG at the transmission and distribution levels (e.g., NY ISO markets for Ancillary Services, Installed Capacity, and Emergency Demand Response).

- Future market based environmental mechanisms (MBEMs) should consider the role that smaller-scale clean DG might play in reducing the social cost of meeting environmental goals and objectives, and consider how revenue from MBEMs may affect DG project economics. Best practices in MBEM designs incorporating clean DG should be a part of consideration in any future program.

RECOMMENDATIONS FOR FURTHER CONSIDERATION

- Where applicable, consistently develop air and energy regulations that consider the load and time-of-day weighted T&D benefits of DG (e.g. air quality and energy benefits of avoided line losses of 6-8%, and at peak, perhaps up to 20% in some locations).

- Explore policy options to support the financing of power electronics, telemetry and storage technologies that could enable DG operators to better support the grid. One bottleneck for expanding the deployment of grid-beneficial small DG is the incremental cost of components and systems.

- Consider and evaluate opportunities to effectively integrate feed in tariff program designs in the context of continuing evaluation of RPS program performance. Feed in tariffs have proven successful in fostering rapid renewable energy growth in other contexts worldwide, by providing potential DG developers with the promise of a predictable and consistent revenue stream over a significant period of time.

- As estimates of the value of specific benefits and costs that DG contributes to distribution grids become more accurate, policymakers should consider, as an offset to costs allocated to partial requirements customers, credits for specific net system benefits an individual customer may provide the distribution system. Standby rate guidelines recognize that individual customers subject to the general provisions of standby rates may also be subject to additional charges or credits directly attributable to the customer's delivery service. The NYS PSC cites interconnection charges as an example of such customer specific costs (NY PSC 2003 at page 6).

- Consider increasing the limit on overall net metering enrollment from the current cap of 1.3% of a utility's peak demand; raising the current 2 MW cap on individual system capacity size for net metering; and allowing community net metering and meter aggregation.

- Extend New York's Standardized Interconnection Requirements (SIR) to address the interconnection process for DG with capacity in the range of 2 MW to 20 MW, and relate these requirements to the existing FERC/NYISO interconnection process.

- Provide cost recovery to utilities for costs incurred in the design of new and innovative programs to capture grid system benefits of DG (these costs might include new software, outreach and target sector programs, and other costs associated with new program development); and consider offering incentives to utilities for the development of such programs.

Further Discussion

Addressing the Knowledge Gap

Improving knowledge and experience of potential DG benefits and costs—both at present and prospectively given anticipated technological advances—and of the potential impact of various types of interconnected DG on distribution network performance, may be the single most important next step that can be taken to advance the deployment of DG over the next few years. Steps to address this knowledge gap should focus on determining the actual costs and benefits associated with DG on distribution networks, and identifying grid management practices that will minimize costs while capturing the greatest potential benefits. Progress also needs to be made in assigning these costs and benefits real dollar values.

The need to close this knowledge gap comes at a time when the electricity infrastructure is about to change in fundamental ways. New York's interconnected electric power system is poised to undergo a transformation precipitated by the introduction of new technologies, information systems and grid controls. This transformation is often described as the development of a "smart grid." But, within the wide range of meanings attached to the phrase "smart grid," certain investments in transmission and distribution network technology will significantly improve the ability of system operators to monitor and control grid performance (while others will not). The smart grid transformation will yield larger benefits if informed by DG integration scenarios, with the objective being a grid that is better able not only to accommodate DG, but to fully incorporate and value the benefits DG can offer. In this context, the test bed tools RPI has developed in this project represent a significant new opportunity to investigate DG-grid interactions and to formulate new approaches to managing the deployment of DG technology.

Coordinating Existing Programs

New York State policy and programs already address many of the critical issues widely recognized as hurdles impeding more robust market penetration. For example, the PSC has taken steps to reduce barriers to DG in standby tariff design; implemented renewable portfolio standard-based generation resource acquisition programs that provide a market for DG electricity production; simplified DG-to-grid interconnection practices; recognized the opportunities clean DG technology provides to improve the environmental quality of grid service; and encouraged the use of DG to serve load management needs during emergency capacity shortages. These and other existing policies provide a foundation for the significant new investments in DG that must occur to reach high DG penetration levels.

However, in many cases, existing programs are not well coordinated, and do not work in concert to significantly improve the financial outlook for potential DG investors. For example, some markets are not open to small DG participation. Where markets are open, high transaction costs, low potential returns, and significant uncertainty may create barriers to participation by small DG. Measures intended to lower barriers may address only certain types or sizes of small DG units.

These obstacles are not insurmountable, but addressing them effectively will require a proactive, coordinated approach.

Lowering Barriers

Utility standby tariffs and interconnection policies have historically acted as barriers to DG development, though significant progress has been made recently in both areas. Further progress requires improved knowledge of the actual benefits and costs of increasing DG penetration on the interconnected grid system.

While public policy and programs aim to increase deployment of DG to serve environmental and other goals, the planning and management of the interconnected grid remains tied to a past where interconnected DG is (sometimes) accommodated rather than treated as valued contributor to grid service objectives.

This view is changing, albeit slowly; many stakeholders now recognize that DG offers benefits as well as costs. However, until quantified, the benefits offered by DG will remain largely theoretical. The relationship of costs to benefits has not been analyzed and well understood.

Minimizing DG costs and maximizing benefits will require an affirmative effort to integrate DG deployment into grid investment planning and operating practices. The effective use of DG to serve grid objectives also may require significant changes in the role and technology design of DG project development. New technology designs that include, for example, subsidiary investments – such as energy storage – can enable DG's role as a dynamic and important asset supporting the grid.

Developing and Opening Markets

During the last decade the NYISO, NYSERDA, and the PSC have introduced market based solicitations to acquire the clean, alternative energy resources needed to meet the State's environmental, climate change, and renewable energy goals. However, DG is still not an active participant in many markets where it could provide valuable services. Needed market changes may include:

- Changing existing codes and standards for interconnection of smaller scale DG, permitting new services and functionality where feasible (e.g. IEEE 1547.8).
- Altering DG's interface with existing distribution system protection schemes.
- Innovations in product design that will permit the DG asset to provide certain services at a competitive cost (e.g. inverters with greater functionality).
- Expanding existing markets for ancillary services at the transmission level to incorporate smaller-scale DG (including aggregation of resources).
- Developing new markets for distribution services currently self-supplied by the distribution utilities.
- Extending existing markets, or creating new ones, that allow DG sites to capture currently uncompensated environmental or electric system benefits.
- Aligning DG incentive schemes more closely with a broader set of societal and energy system benefits.
- Designing more effective market based environmental mechanisms.
- Where markets cannot easily be leveled, sustaining or improving direct incentives that remedy market barriers inhibiting widespread deployment of economic DG technology.

More specific discussion of potential market policy initiatives follow:

Net Metering

Participants in the past have identified onerous interconnection processes as a barrier to participating in net metering. While the SIR rules have effectively lowered many barriers, additional steps remain to be addressed.

The <u>Freeing the Grid 2010</u> evaluation sponsored by the IREC and others recommends that New York State increase the limit on overall enrollment from the current cap of 1.3% to 5% of a utility's peak demand, raise the current 2 MW cap on individual system capacity size, and allow community net metering and meter aggregation.

This report elsewhere recommends continuing study to obtain better information on the benefits and costs DG offers in the context of DG's ability to achieve grid service goals. This analysis should inform continuing management of net metering policies and programs.

Standby Tariffs

Standby tariffs play a very important role in determining the economic feasibility and long-term viability of DG projects. DG project costs must be recovered largely in electricity bill savings (and, in the case of CHP systems, on-site heating). If the costs for standby service remain high even when the consumer obtains very little energy from the grid, the economic benefits provided by the DG system tend to be low. At the same time, if the DG-equipped facility pays very little for its grid connection but imposes costs on the grid for infrequently needed additional capacity, it will not be paying its fair share of grid costs. The challenge is to design standby service charges that encourage the customer to maintain and operate the DG unit in such a way that value for the customer is maximized, while costs to the grid are minimized.

Current PSC policy embraces this objective. The standby tariff guidelines specifically aim to provide cost based rates and to increase deployment of clean DG capacity on New York's electric power supply system.

The earlier summary of standby tariff policy indicates that current policy reflects current knowledge of the costs DG imposes on the electric system and the benefits it provides. It is also clear that the current tally of costs and benefits focuses largely on capital equipment costs that new DG facilities impose on different parts of the interconnected electric grid, separately considering very site specific costs incurred to serve a specific facility located on a specific distribution network location, and the network wide transmission and generation capacity costs associated with DG. It does not appear that the opportunities for DG to provide ancillary services benefits, or the ancillary service costs that DG may impose, are addressed in standby tariff designs or the specific standby tariffs of each utility. The PSC has indicated that such benefits and costs may be addressed in tariff design proceedings or in revisions to standby tariff guidelines when evidence is presented to the PSC supporting specific valuation for such benefits and costs. Current policy reflects current knowledge of the costs and benefits of DG.

Other sections of this report indicate that the value of the benefits and costs associated with DG is not well documented, and in many ways not well understood. Further research and demonstration projects would be very helpful in addressing this issue.

In designing the standby tariffs, the PSC considered arguments that the charges should be adjusted to reflect the benefits DG provides for utility distribution grids. The PSC concluded that stand-by tariff charges are not the place to address such benefits, observing that no one had yet offered specific estimates of the value of such benefits, that such benefits may be very site specific, and that existing contracting procedures offer a means by which DG may be compensated for such services when justified (NYS PSC 2003).

The test bed being developed by RPI offers the opportunity to estimate the physical impacts of DG on the grid and to assess its costs and benefits. This will allow the PSC to improve the rate and contract policies it uses to ensure that benefits and costs are fairly assigned to responsible parties and to appropriate beneficiaries.

Support for CHP as part of the 2012-2016 System Benefits Charge IV (SBC IV)

As indicated throughout this report, CHP and district energy systems (DES) can provide substantial system benefits in addition to those private benefits provided to the end-user who invests in the system. New York State is deciding at this time how to allocate funds so as to "test, develop, and introduce new technologies, strategies and practices that build the statewide infrastructure to reliably deliver clean energy to New Yorkers."[61] These Technology and Market Development (T&MD) programs are provided for customers served by the investor-owned distribution utilities under the jurisdiction of the PSC.

NYSERDA has proposed an Operating Plan that includes $15 million in funding annually for CHP and district energy systems. Continued support of high efficiency CHP and DES, particularly targeted systems that maximize benefits during summer peak demand periods, strategically targeted to focus on the New York City load center and other areas facing transmission capacity constraints, may offer substantial system wide benefits.

Incentives can be used as a mechanism to direct investment in DG to areas of highest value for the utility grid. Recently, New York State has begun to create new innovative incentives that are designed for this purpose. In a proposed T&MD plan NYSERDA has proposed directing performance-based payments for CHP and DES to projects that maximize benefits during summer peak demand periods, focusing on the New York City load center.[62]

Encouraging Strategically Sited DG as an Alternative to Distribution System Capital Expenditures

DG siting decisions could be improved if there were price signals indicating which sites created the greatest level of social (or system) benefits. Presently, DG/CHP development takes place absent information about the most desirable siting decisions from the perspective of lowering utility system costs.[63] Consider two potential projects of equal economic value to the two end

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[61] Mission of the T&MD Portolio. Pg. ES-1.

[62] T&MD Plan, page ES-5

[63] NYSERDA's new CST geographic balancing program (PON 2256) does support some cooperation between utilities and DG developers to site DG units in advantageous locations. However this promising program is very new, and of limited scope.

users operating on a distribution utility system. If location at one site is on a severely constrained network it likely has far greater value to the utility and the ratepayers than does an identical project in an area with plenty of excess distribution system capacity. Local price signals, rewarding owners for locating their DG projects in the highly constrained areas, the locations with the greatest system benefits, could lead to better DG investment decisions.

Operation and control issues can be solved by the development of contracts, incentives and penalties. Utilities have commonly required "physical assurance" requirements that DG owners considered to be onerous. For example, a utility may require a site providing a compensated load reduction to demonstrate that they can shed that amount of load, and make that requirement binding over all 8,760 hours of the year. The utility may not account for the reliability of multiple DG/DG assets serving a need when setting reliability requirements and the associated value. Sites that have multiple DR sources should be evaluated on the basis of the aggregated reliability of the joint set of sources at meeting a local need, recognizing that the likelihood of all generators failing simultaneously will be very small.

Tapping DG Potential to Provide Ancillary Services

The NYISO has established a market solicitation process to acquire many needed ancillary services. This is a market that could offer potentially valuable revenues to DG operators. Small DG, however, is not yet participating in this market. Interviews with DG developers and owners indicate that opportunities to participate are constrained in part by the incremental costs of equipment required for participation, size thresholds (1 MW) and barriers to aggregating DG assets (Ahrens, 2011).

Historically, ancillary services have been managed and delivered by tapping large central station generators or by installing utility-owned equipment (such as capacitor banks) to provide such services. The new ISO market is designed to obtain these services economically from the now independently owned central station generators and other sources.

As a practical matter, the DG resources considered here, small capacity generators installed primarily to provide for the energy requirements of a specific facility, have not generally offered the level of ancillary services ISO transmission and utility distribution grid operators require to maintain network performance. While there are a number of studies that describe how DG can contribute such services, there is little experience with actually obtaining ancillary services from DG systems serving partial requirements electricity consumers. It is apparent that there are a number of barriers keeping small DG from participating in this market. For example:

- There are significant costs associated with the communication and control equipment that DG facilities must have to provide ancillary services
- Participating DG owners may face the prospect of having to divert capacity from on-site needs to meet ancillary service commitments

- Utilities may face the prospect of having to meet power reliability commitments using customer-owned equipment
- Dealing with small DG units for the provision of ancillary services is more costly than obtaining such services from fewer, larger sources

Developing commercially viable practices to tap small DG for specific ancillary services will require design and demonstration efforts to increase the level of knowledge and experience among stakeholders.

The earlier cited concerns of grid planners confronting the impacts of rapid growth in DG facilities on their networks also requires attention. Recent utility reports suggest that these impacts vary widely with DG technology type and design and with local distribution network conditions. The costs and operating impacts in some cases may be significant.

Obtaining ancillary service benefits from DG, while avoiding new costs to distribution networks, is both an opportunity and a challenge. Meeting this challenge will require significantly increased attention from grid planners and operators. Trials that encourage the deployment of DG as a means to achieve grid performance objectives – as an active rather than a passive agent on the grid—may be a useful strategy to advance knowledge and experience in this area.

It may be productive to initiate in New York a collaborative working group of DG, utility, ISO, and regulatory stakeholders to plan and implement the analysis, design, testing, and demonstration that is required to provide effective market pathways for the economic use of DG to serve grid performance goals. The PSC has previously used such collaborative working groups effectively to design interconnection standard policy, standby tariff guidelines, and the program implementation strategy to achieve the Energy Efficiency Portfolio Standard goals.

Effective integration of DG into grid planning and operations will require the active participation of a diverse group of stakeholders to ensure that the needs of DG developers/owners, grid managers, and consumers are reconciled. In order to ensure that new market designs support science-based goals, the work of such a collaborative group should be informed by the results of grid integration modeling and testing. The test bed tools being developed by RPI CFES may provide new, relatively low-cost, low-risk methods to demonstrate effective grid management practices that integrate DG into networks, minimizing costs and maximizing value. Such innovation is needed to overcome the potential high transaction and set up costs associated with the procurement of services from many small, distributed providers.

Designing Direct Incentives to Remedy DG Market Barriers

Direct incentives for qualifying DG[64] may be needed to help overcome barriers related to project scale, location, and the newness of some DG technologies, which can make them less attractive

[64] DG systems may be required to meet certain efficiency and environmental performance prerequisites for some incentives.

to financiers and permitting agencies. Incentives, including grant programs, investment or production tax credits, improved interconnection standards, etc., can be implemented in parallel with market programs. This report has described a broad range of incentives that are designed to remove barriers to and provide support for DG that serves important energy policy objectives. This report recommends steps to improve knowledge of the costs and benefits DG may produce, knowledge that should also inform the design and implementation of effective DG incentives.

Tapping Market Based Environmental Mechanisms

At this writing, there are very few market based environmental mechanisms where smaller-scale DG can participate. The recommendations below address opportunities to improve DG access to existing market based environmental programs.

Integrating DG into market-based mechanisms can present challenges to both policymakers and project developers. Issues include problems of scale and associated higher transactions costs for incorporating numerous small agents.

EERET Account

After a few years of experimentation with a set-aside open to EE/RE projects, New York has chosen a different vehicle, an Energy Efficiency and Renewable Energy Technology account (EERET) retained by NYSERDA. The EERET account was created to address a failure to distribute set-aside allowances to eligible DG projects under the previous NOx SIP Call. The NYSDEC noted, “Few sponsors of EE/RE projects have sought the award of EE/RE allowances…. due to the difficulty in demonstrating enough avoided emissions, even when aggregating projects, to qualify for a single EE/RE allowance.”[65] It is also true that the state may not have dedicated sufficient resources to promoting the set-aside program, developing outreach materials and creating standardized web-based application procedures. Potential participants may not have known of the program’s existence, and those that knew of it may not have been aware of how to participate.

At this writing, New York’s EERET account has been set up to receive the proceeds of set-aside allowance sales for use in promoting EE/RE efforts in the state, but so far funds in the account have been used to support R&D efforts rather than DG project development.

Emission Reduction Credits (ERCs)

Aside from private and state-based CO2 emissions trading programs, the ERC market is the only existing environmental market in which DG can directly participate. ERCs are a good fit for

[65] CAIR Summary of Express Terms, http://www.dec.ny.gov/regulations/38561.html

some types of DG, particularly those, such as gas-fired CHP, that can replace aged, inefficient heavy oil (#4 or #6) boilers. The market should be particularly active in New York State, since consumption of fuel oil for process and comfort heating is concentrated in the Northeast and Mid-Atlantic states. However, at this writing the ERC market is moribund, for various reasons.

Even if the ERC market were to return to its former vigor in New York, taking advantage of the opportunity to certify and sell ERCs is not easy. Developers face significant impediments, including high transaction costs and the need to aggregate ERCs:

- High Transaction Costs. This is due to the fact that many of the costs of certifying ERCs are fixed, meaning that small projects cost significantly more per ton to certify than larger projects. Small, independent developers may not have the ability to easily pay these costs.
- Lack of Process Familiarity. The application processes can be daunting, particularly for smaller entities. Documentation, guidance and ease of access are important.
- Long Wait Periods for Certification. Long certification processing times are reported in many states, where the time required for ERC approval can range from several months to several years.
- The Need to Aggregate. The need for smaller generators to aggregate to produce marketable ERCs is due to the fact that purchasers of ERCs generally seek larger blocks of credits than will be available from a single small DG project. However, aggregation imposes costs that reduce the ultimate value of ERCs to the individual DG projects that create them.
- Market Illiquidity. Illiquidity, while due in part to external economic factors, is exacerbated by geographically constricted markets, both within and between states.

These problems are not intractable, and several remedies are available:[66]

- A small outreach investment could increase the general level of knowledge regarding the opportunity to certify ERCs.
- The opportunity for creating ERCs is concentrated in a few economic sectors, and is greatest where there is the greatest difference between prior period (baseline) and future period emissions. This occurs primarily at sites with the oldest, least efficient boilers using the most polluting fuels. Therefore, ERC certification information should be targeted to those economic sectors most likely to generate substantial quantities of ERCs.[67] The state should proactively review minor source database records and conduct

[66] Recommendations are from Expanding Small-Scale CHP Opportunities Through the More Efficient Use of Trading Programs: An Analysis of Market Opportunities and Regulatory Issues (PECC, 2010).
[67] For more information on the highest value target sectors for ERC creation, see PECC, 2010.

outreach to these sites, informing them of the opportunity that exists to participate in the ERC program.

- Each stage in the process of obtaining ERCs could be streamlined by the use of standardized procedures, resulting in reduced time and transaction costs for developers.
- Self-calculating spreadsheet templates could be provided to simplify the applicant's demonstration of actual pre-reduction emissions, based on input data such as monthly fuel usage and equipment type. Applicants claiming special circumstances would be provided the opportunity to demonstrate that the standard form and assumptions should not apply.
- The determination of future emission levels could be simplified by using pre-certified emissions from reliable sources. For example, the California Air Resources Board (CARB) pre-certifies emission rates of distributed generation technologies.
- The development of ERC reciprocity agreements among the states would increase the liquidity of the currently moribund ERC markets, and should increase the value of ERCs. All else being equal, larger markets should function more efficiently than smaller markets. Broadening the market by allowing cross-state trading would expand the set of potentially affected sites.

It is important to note that ERC processes are affected by numerous market-based factors, many of which are external to these processes. Establishing interstate trade in ERCs may improve the market at the margins, and other practical steps could also be taken to reduce barriers to participation. However, the impact of these efforts, though positive, is likely to be small in relation to the broader factors determining the state of the market. The fundamental lack of demand for ERCs is the predominant factor determining the state of the Northeastern ERC markets; addressing this lack of demand will mean addressing larger market forces affecting the economies of the northeastern states.

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Appendix A: Details of Market-Based Environmental Protection Mechanisms

Emission Reduction Credits

Emission Reduction Credits (ERCs) are credits for on-site emissions reductions, measured against representative baseline emissions levels, within a geographically defined non-attainment area.

Frequently, ERCs are confused with Emissions Allowances (EAs). Although both ERCs and EAs may be bought and sold on the open market, there are important differences between the two:

- ERCs are created at a source level by discrete emission reductions; EAs are established under a budget (cap) and distributed to sources to cover the allowable emissions from a source.
- An ERC can be created in any non-attainment area, and does not have to be part of a cap and trade program.
- Each ERC represents one ton per year of reductions in perpetuity, which is different from an allowance, which represents one ton used in one year or program period.
- ERCs are created by the shutdown, upgrade or replacement of an existing emissions source, and are a one-time creation; EAs are created and distributed periodically by a governmental authority.

In many cases, a single DG project may be able to qualify for both ERCs and EAs.

The rationale behind ERCs is to ensure that development does not worsen air quality in areas that are already in "non-attainment" status for certain criteria pollutants. New activities that will increase emissions of criteria pollutants must more than offset their contribution as a means of demonstrating "reasonable further progress" towards attainment in these areas. The offset ratio varies depending on the degree of non-attainment. For example, in severe non-attainment areas, a site subject to NSPS must offset its emissions at a ratio of 1.3 to 1. If the region in which the new activity is to be located is designated as a moderate non-attainment area, the offset ratio that would apply is 1.15 to 1.

Emissions Allowances

The former NO_x State Budget Program (NBP) was created by the U.S. EPA and placed under the administration of the participating states. The NBP covers most of the states in the Eastern part of the United States. As of 2008, the final year of the program, there were 20 participating states plus the District of Columbia.

The objective of the NBP was to reduce the regional transport of NO_x. Emissions of NO_x contribute to ozone non-attainment in the Eastern United States. States came together to form an agreement to limit emissions of NO_x on a regional basis. A budget was established, and each participating state was allocated a share.

The NBP is in effect a cap and trade system for NO_x. For units covered by the program, an annual budget is set. At the end of the designated period, units must surrender allowances equal in number to their allotted budget. An allowance gives the holder the right to emit one ton of NO_x during the period specified. If units find that they have insufficient allowances, they must purchase them on the market.

The federal NO_x Budget program was established as a seasonal program, covering the ozone season – the months of May through September. New York State established three cap and trade systems covering large industrial emitters and electricity generating facilities; one for NO_x emitted during the ozone season (May-September), one for non-ozone season NO_x emissions, and one for year-round emissions of sulfur dioxide (SO_2). The regulations establishing these programs are found at 6 NYCRR Parts 204, 237 and 238.

Clean DG units were able to participate in the NBP by means of the "Energy Efficiency Renewable Energy Set-Aside" (EERE set aside). The EPA encouraged states to reserve a certain portion of their allowances for energy efficiency and renewable or other clean energy facilities. Several states opted to create an EERE set aside. New York created a set aside of 3% of the total number of allowances, and Massachusetts created a 5% set aside.

The demand side of this market was composed of units that are covered under the cap and trade programs. In the case of the NBP, there were 2,594 units covered across the 20 participating states. Unlike the ERC program, if a clean DG unit certified emission allowances in New York, it could sell them to any interested buyer across all participating states. The scope of this market was far wider, and its liquidity far greater, than that of the ERC market.

It is important to note that NBP emissions allowances (EAs) were defined as displaced emissions; that is, a DG unit could receive NBP EAs for displacing emissions that would otherwise occur off-site. By contrast, ERCs, as noted above, are credited on the basis of a net reduction in on-site emissions. Therefore, there is no double counting involved if a DG unit were to certify both EAs and ERCs. The EA is defined with respect to a net decrease in emissions as a result of the formula

*[DISPLACED EMISSIONS = [(OFFSITE RATE – ONSITE RATE) * MWHs generated]*

While the ERC is defined as a net reduction at the site, using the formula

($EMISSIONS_{PRE}$ – $EMISSIONS_{POST}$).

An illustrative example of the calculation of NBP EAs is given by the following scenario: Suppose that the offsite rate is 1.5 lbs/NOx per MWH, and new microturbines have been installed at the site. The microturbines have been certified to operate at 0.5 lbs NO_x per MWH. Therefore, for every MWH hour that the microturbines run, they generate 1 lb of NO_x reductions. If the site has 0.5 MWs of microturbine capacity that runs 4,000 hours per year, generating 2,000 MWHs per year at the site, then they will accumulate 1 ton (2,000 lbs) of creditable NO_x emission reductions.

Although in theory the New York NBP encouraged the development of clean DG, due to a number of factors, it provided few to no surplus revenues to support clean DG projects.

NYS RPS CST

Unlike the Main Tier program, the CS-T program makes funding available on a per-project or per-capacity basis, rather than a per-REC basis. For example, funding is available up to $1 million per anaerobic digester system; up to $1 million per large fuel cell system, and up to $50,000 for small systems (25 kW or less); $2 - $5 per watt for solar PV[68]; and up to $150,000 per small wind installation (funding amounts for wind systems are based on the lesser of $4,000 per meter of rotor diameter or $4,000 per rated kW, with adjustments for tower height; higher incentives are available for farms, schools, not-for-profits, municipalities, and counties). Among these eligible technologies, solar PV and anaerobic digester projects have received the greatest number of applications; and in fact, the budgets for these two technologies have been oversubscribed.

Table A1, from The Renewable Portfolio Standard: Mid Course Report, shows the expenditures to date by technology for the CS-T (NYS DPS, 2009).

[68] A one-time incentive payment for PV installations follows the following schedule: for residential systems, $3 per watt up to the first 4 kW and $2 per watt after the first 4 kW up to a maximum of 8 kW per site/meter; for commercial systems, $3 per watt up to the first 40 kW and $2 per watt after the first 40 kW up to a maximum of 80 kW per site/meter; and for not-for-profit installations, $5 per watt up to the first 25 kW up to a maximum of 25 kW per site/meter. All incentives are capped at 50% of total installed cost.

Table A1: CST Production and Expenditures

	2008	2009	Total
MWs			
Solar Photovoltaic	5.99	13.86	19.85
Anaerobic Digester	6.69	4.43	11.12
Fuel Cell	0.52	0.00	0.52
Small Wind	0.17	0.19	0.36
Solar Thermal	0.00	0.00	0.00
Total	**13.37**	**18.48**	**31.85**
MWhs			
Solar Photovoltaic	7,770	17,963	25,733
Anaerobic Digester	46,912	30,996	77,908
Fuel Cell	4,045	0	4,045
Small Wind	207	403	610
Solar Thermal	0	0	0
Total	**58,934**	**49,362**	**108,296**
Expenditures			
Solar Photovoltaic	$22,251,730	$58,776,113	$81,027,843
Anaerobic Digester	$14,812,926	$4,461,824	$19,274,750
Fuel Cell	$2,032,210	$0	$2,032,210
Small Wind	$518,283	$446,914	$965,197
Solar Thermal	$0	$0	$0
Total	**$39,615,149**	**$63,684,851**	**$103,300,000**

This table reflects the fact that solar PV costs approximately two times as much as the other supported technologies per megawatt, but is also much more amenable to installation in a virtually unlimited number of locations across the state. By comparison, anaerobic digesters are the least expensive technology on a per-megawatt basis, but are largely tied to farms; small wind turbines are also very limited in where they can be sited.

The RPS mid-course report notes that solar PV, while it is the most expensive option, offers a number of advantages, especially if sited in New York City, where locally-produced electricity is more valuable than that produced by a baseload plant upstate, by virtue of being closer to the load. The report also notes that solar PV offers avoided distribution costs and that its output rises and falls in a close approximation of the demand curve – thus, PV produces most when demand and rates are highest. The combination of these advantages confers a 115% premium on a megawatt hour produced by a behind-the-meter solar PV system in New York City, relative to a megawatt hour produced by a baseload plant upstate. However, even taking all its advantages into account, solar PV remains more expensive than all other C-ST technologies.

Table A2 (RPS mid-course report, 2009) shows the proposed funding levels and targets for the various C-ST eligible technologies through 2015:

Table A2

Proposed CST Production and Budget

	2010	2011	2012	2013	2014	2015	Total
MWs							
Solar Photovoltaic	8.00	8.28	8.57	8.89	9.23	9.60	52.57
Anaerobic Digesters	4.40	4.90	4.40	3.60	3.45	3.45	24.20
Fuel	2.45	2.45	2.45	2.45	2.45	2.45	14.70
Small Wind	0.72	1.77	1.77	1.84	2.23	2.30	10.63
Solar Thermal	7.92	7.92	7.92	7.92	7.92	7.92	47.52
Total	23.49	25.32	25.11	24.70	25.28	25.72	149.61
MWhs							
Solar Photovoltaic	9,120	9,434	9,771	10,133	10,523	10,944	59,926
Anaerobic Digesters	30,625	33,883	31,290	25,544	24,633	24,633	170,607
Fuel	19,030	19,030	19,030	19,030	19,030	19,030	114,180
Small Wind	1,264	3,045	3,108	3,178	3,944	4,028	18,567
Solar Thermal	9,030	9,030	9,030	9,030	9,030	9,030	54,180
Total	69,069	74,423	72,230	66,915	67,159	67,664	417,460
Budget (Millions)							
Solar Photovoltaic	$24.0	$24.0	$24.0	$24.0	$24.0	$24.0	$144.0
Anaerobic Digesters	13.7	13.3	12.0	11.6	10.2	10.2	71.0
Fuel	6.1	6.1	6.1	6.1	6.1	6.1	36.6
Small Wind	1.9	2.8	2.9	3.1	3.8	4.0	18.5
Solar Thermal	4.3	4.3	4.3	4.3	4.3	4.3	25.8
Total	$50.0	$50.5	$49.3	$49.1	$48.4	$48.6	$295.9

Appendix B: Details of Targeted Incentive Programs

Details of current NYSERDA CST PONs are discussed below:

Solar PV Incentive Program (NYSERDA PON 2112)

This is an open enrollment program offered on a first come, first served basis. Incentive levels will be adjusted based upon an evaluation of the rolling two month average program applications. If applications materially exceed available funding in two consecutive months, incentive levels will be adjusted downward. Conversely, if applications for the prior two months fall short of available funds, NYSERDA may increase the incentive levels.

As of February 2011, incentive levels for the PV incentive program are set at $1.75/watt. The incentive is capped at different levels for different types of customers:

- Residential, up to 7 kW maximum
- Non-Profit, up to 25 kW maximum
- Commercial, up to 50 kW maximum

In general, program incentives are set at a scale that is limited to energy capacity or production that satisfies the peak load of the customer. In no instance will this program pay more than 40% of total installed system costs.[69] There are added incentives of $0.50/watt available for building integrated PV systems and for certified NY EnergySTAR homes.

All environmental attributes associated with the NYSERDA funded portion of the project will be retained by NYSERDA for the benefit of all ratepayers. For example, if 40% of a project was funded by NYSERDA, then only 60% of all environmental attributes associated with a project are available for use by the end user.

GEOGRAPHIC BALANCING PON 2156

The Geographic Balancing program, newly created in 2011, is designed to develop larger scale renewable projects in the New York City area and the lower Hudson Valley. The program is confined to NY ISO zones G, H, I and J. Zones G/H are eligible for $5 million per year and projects in zones I/J are eligible for up to $25 million per year. Table B1 describes the geographic location of these zones:

[69] The cap is considered *after* the application of all other tax credits

Table B1

Zone G	Hudson Valley (Orange, Ulster, Dutchess, Putnam)
Zone H	Millwood (Southeast corner of the Hudson Valley including Northern Westchester, parts of Dutchess, Orange and Putnam)
Zone I	Dunwoodie (Southern Westchester)
Zone J	New York City (all 5 boroughs)

The minimum project size for participation is 50 kW. There is no maximum size limit, but there is a cap on the total payment that can be made to any project. Eligible technologies include grid connected solar photovoltaic (PV) projects and renewable biogas[70] fueled electric power generation applications. The renewable biogas fuel can either be provided at the site of the generator, or may contracted for delivery through a natural gas distribution pipeline. However, the renewable biogas must originate from a location in the same zone group where the electric generation equipment is located. For example, pipeline-directed renewable biogas serving electric generating equipment in Zone I, must originate from Zone I or J.

Applicants can propose a single installation or multiple installations, but the minimum installation size is 50 kW. The total capacity block for which an applicant can request a payment cannot exceed $3 million, or 50% of the total project cost.

Applicants propose an incentive bid, in $/kWh. Payments are made on a schedule that incorporates both up-front payments as well as production payments. There are two up-front payments made prior to the commencement of production and three performance period payments made upon review of production data from years 1, 2 and 3. The first is made at the time that all equipment has been procured and delivered to the site, all permits have been received, and a request for utility interconnection has been made. The second up-front payment is made after the system has been interconnected to the grid and has demonstrated capability to deliver the required data to the website that NYSERDA has specified. This is shown in Table B2.

[70] Renewable biogas is defined as fuel from the anaerobic digestion of farm, food or wastewater treatment materials that is currently not being used for the production of heat, power, or steam.

Table B2

UPFRONT PAYMENT 1 & 2 SCHEDULE BASED ON AREA OF LOCATION		
	Upfront Payment 1: After delivery of all equipment and permits	Upfront Payment 2: After utility interconnection and proof of data transmittal
Strategic Location	.15 * (Incentive Bid * 1.15) * estimated annual energy production	.15 * (Incentive Bid * 1.15) * estimated annual energy production
Non-Strategic Location	.15 * (Incentive Bid) * estimated annual energy production	.15 * (Incentive Bid) * estimated annual energy production

Source: NYSERDA

Performance payments will be made at the conclusion of years 1, 2 and 3 of operation, based upon the level of energy production relative to the estimated annual energy production proposed by the applicant, as shown in Table B3.

Table B3

PERFORMANCE PAYMENT SCHEDULE BASED ON AREA OF LOCATION AND ENERGY PRODUCTION		
	Year 1 Production >= 80% of estimated annual energy production	Year 1 Production <80% of estimated annual energy production
Strategic Location	.70 * (Incentive Bid * 1.15) * Year 1 actual energy production	.35 * (Incentive Bid * 1.15) * Year 1 actual energy production
Non-Strategic Location	.70 * (Incentive Bid) * Year 1 actual energy production	.35 * (Incentive Bid) * Year 1 actual energy production

Source: NYSERDA

This DG PON incorporates specific “Strategic Locations” in zones G, H, I, J. These are areas that distribution utilities have identified as being locations where operation of a renewable biogas based generator or PV will have significant benefits for the distribution system. In offering an additional 15% performance incentive for these locations, the utilities and NYSERDA are attempting to direct DG investments into areas of greater value for the distribution system.

FUEL CELL PROGRAM (PON 2157)

The CST Fuel Cell program is NYSERDA's primary vehicle for providing incentives to end-user fuel cell capital installation projects in New York. There are two tracks; one for fuel cell systems less than 25kW in capacity, and the other for fuel cell systems 25 kW and greater.

The Large Fuel Cell program will award up to $3.5 million per calendar year, from 2010 to 2015, with total program funding of $21 million available. The Small fuel cell program will award up to $100,000 per calendar year over the period 2010 through 2015.

Large fuel cell systems may qualify for an incentive payment up to $1 Million

Fuel cell systems are eligible for both capacity payments and performance based incentives. Capacity payments are now set at $1,000/kW, and capped at $200,000 for any given project. A bonus capacity incentive of $500/kW, capped at $100,000 for any given project, is available for secure power and standalone operation capability at sites of "essential public services,"[71] or where the system provides for continuity of power services at a *documented and approved* "facility of refuge."[72] Therefore, a project site qualifying for the bonus capacity payment may obtain a capacity based incentive up to $300,000. The capacity based payments are shown in Table B3.

Table B4

CAPACITY BASED PAYMENTS 1 & 2		
	Payment 1: After delivery of all equipment and permits	Payment 2: After utility interconnection and proof of data transmittal
Basic Capacity Payment	[.50 * Nameplate Capacity Rating * $1,000/kW][A]	[.50 * Nameplate Capacity Rating * $1,000/kW][A]
Bonus Capacity Payment	[.50 * Nameplate Capacity Rating * $500/kW][B]	[.50 * Nameplate Capacity Rating * $500/kW][B]

A. Capacity Payment capped at $200,000 per project site.

[71] Examples of such sites are hospitals, police stations

[72] A facility of refuge is a site providing shelter for a local population during a time of an emergency in coordination with state, regional or local emergency management officials

B. Bonus payment for secure power/standalone capability at sites of Essential Public Services or for serving a documented facility of refuge. Bonus capacity payment capped at $100,000 per project site.

In addition to capacity payments, large fuel cell projects are eligible to receive performance based incentives based on annual net energy production for up to three years. Performance incentives are paid at a rate of $0.15/kWh of net energy production[73] but only for project sites with an annual capacity factor of at least 50% during the year for which the performance payment is requested. Payments are capped at $300,000 per year and can be paid for up to three years, provided that total payments to the site do not exceed $1 million (including capacity and performance payments). The annual capacity factor (ACF), which is the basis of determining eligibility for the performance payment, is defined as ACF = Actual Net Annual Output / (Nameplate Rating * 8760) where Actual Net Annual Output is the total verified electrical energy delivered by the fuel cell system to the site per year (i.e., fuel cell stack production minus parasitic consumption). The performance incentives are shown in Table B5.

Table B5

Performance Incentives (three consecutive annual payments)	
Annual capacity factor >= 50%	$0.15 * annual net kWh capped at $300,000/year
Annual capacity factor < 50%	No payment

Customer Sited Wind Turbine Incentive Program PON 2097

The Customer Sited Wind Turbine Incentive Program can provide up to 50% of the total installed system cost for wind turbine projects up to 600 kW in size. The total payment will not exceed $400,000 per turbine and the incentives are paid to eligible installers.[74]

The allocation for this PON is an amount up to $3.2 million.

Incentives are paid based upon estimated production, referred to as the “annual energy output” (AEO), and incentive structures vary by the volume of output.

[73] The portion of verified fuel cell electricity generation, which exceeds the fuel cell system’s parasitic consumption.
[74] Installers must be approved by NYSERDA in order to submit an application for incentives on behalf of a customer.

For sites with AEO <10,000 kWhs the incentive is $3.50/kWh. If the AEO is >10,000 but <125,000 kWhs the payment is $35,000 plus $1.00/kWh for all kWhs generated in excess of 10,000 kWhs in a year. If the AEO exceeds 125,000/kWhs than the payment structure is $150,000 plus $0.30/kWh for all generation that is in excess of 125,000 kWhs.

The proposed projects will not receive payments for AEO that is greater than 110% of historical energy consumption of the site (kWhs). As noted above, other restrictions apply including a cap on total payments of $400,000 for a turbine at a site, wind turbine projects greater than 600 kW in size are in-eligible and incentive payments must be no more than 50% of total installed system costs.

Table B6

New York – Solar, Farm Waste and Wind Net Metering Rules As of December 28, 2010						
Eligible Renewable/Other Technologies:	**Solar (PSL 66-j)**		**Farm Waste (PSL 66-j)**	**Micro CHP/Fuel Cells (PSL 66-j)**	**Wind (PSL 66-l)**	
Applicable Sectors:	**Residential**	**Non-Demand / Demand Commercial**	**Farm-Based Residential / Non-Residential Farms**	**Residential Up to 10kW**	**Residential / Farm-Based**	**Non-Demand / Demand Commercial**
Limit on System Size:	**25 kW Residential**	**Up to 2,000 kW (2MW)**	**1000 kW (1MW)**		**25 kW Residential/ 500 kW Farm-Based**	**Up to 2,000 kW (2MW)**
Limit on Overall Enrollment[1]	**1.0% of 2005 Demand per IOU (65,360 kW for NMPC)**				**0.3% of 2005 Demand per IOU (19,608 kW for NMPC)**	

Treatment of Net Excess:	Residential - net excess will roll over monthly. At the end of 12 month period, any excess will be converted to a cash value and paid to the customer at SC6 avoided cost rates. Non-Demand Commercial customer's net excess will roll over monthly on an ongoing basis. Demand Commercial customer's excess is converted to its equivalent value and applied as a direct credit to the customer's current utility bill for outstanding energy, customer, demand and other charges on an ongoing basis. [2]	Residential/Non-Demand – net excess will roll over monthly. Demand customer's excess is converted to its equivalent value and applied as autility bill direct credit to the customer's next utility bill for outstanding energy, customer, demand and other charges. For both demand and non-demand customers, at the end of the net metering year, any excess will be converted to a cash value and paid to the customer at SC6 avoided cost rates.	Net excess will be converted to a cash value calculated at SC6 avoided cost rates and applied as a direct credit to the customer's next bill for service. This dollar credit will be applied on the bill as a separate line item.	Residential/Farm-based – net excess will roll over monthly. At the end of 12 month period, any excess will be converted to a cash value and paid to the customer at SC6 avoided cost rates. Non-Demand Commercial customer's net excess will roll over monthly on an ongoing basis. Demand Commercial customer's excess is converted to its equivalent value and applied as a direct credit to the customer's current utility bill for outstanding energy, customer, demand and other charges on an ongoing basis. [2]

(1) Net Metering is available on a "first come, first serve" basis determined by the date the utility notifies the DG Customer that it has received a complete project application.

(2) Demand customers will be subject to applicable actual metered demand charges consumed in that billing period. The Company will not adjust the demand charge to reflect demand ratchets or monthly demand minimums that might be applied to a standard tariff for net metering.

Source: National Grid

Table B7: Summary Table of Incentives by Technology/Application

Technology/Application	Size Range	Capacity Payment	Bonus	Performance
SOLAR PV: Residential	0 - 7 kW	$1.75/Watt, up to 40% of capital cost	Incentives capped at 110% of demonstrated usage or expected load	Incentives reduced in proportion to losses when >20% of loss is caused by sub-optimal PV placement
SOLAR PV: Non-Profit	0 - 25 kW	$1.75/Watt, up to 40% of capital cost		
SOLAR PV: Commercial	0 - 50 kW	$1.75/Watt, up to 40% of capital cost		
Geographic Balancing	Above 50kW	-	$3 million budget cap per applicant per round; Incentive[B] not to exceed 50% of capital cost	Paid annually for 3 consecutive years based on performance[C]
Fuel Cell Systems Large (modules >25 kW)	Above 25kW	$1,000/kW, up to $200,000	$500/kW up to additional $100,000[a]	**Qualifying**[D] systems receive $.15/kW for 3 years, capped at $300,000/year
Fuel Cell Systems Small (Modules <= 25kW)	0 to 25 kW	-	-	**Qualifying**[E] systems receive $.15/kW for 3 years, capped at $20,000/year
Anaerobic Digesters	-	$1,000/kWh, up to the lesser of $850,000 or 50% of the Total Eligible Capital Expenses[F]	Maximum incentive is $1 million per site	Performance incentives will be the lesser sum of the two provided formulas[G]
On-Site Wind: AEO[H] <10,000kWh	0-600kW	$3.50/kWh, up to 50% of capital cost	Maximum incentive is $400,000 per turbine; AEO may not exceed 110% historic annual electric needs at the site (meter)	-
On-Site Wind: AEO[H] 10,000-125,000kWh	0-600kW	$35,000 + $1.00/kWh above 10,000kWh, up to 50% of capital cost	Maximum incentive is $400,000 per turbine; AEO may not exceed 110% historic annual	-

			electric needs	
On-Site Wind: AEO[H] >125,000kWh	0-600kW	$150,000 + $0.30/kWh above 125,000kWh, up to 50% of capital cost	Maximum incentive is $400,000 per turbine; AEO may not exceed 110% historic annual electric needs	-
Solar Thermal	Displaced kWh cannot exceed 80% of total calculated existing thermal load	$1.50/kWh, adjusted as necessary to meet program goals (not to exceed the incentive cap)	Incentives capped at $4,000 for residential sites and $25,000 for nonresidential sites; NYSERDA reserves right to limit incentives per site /customer/meter	Incentives not approved when losses caused by sub-optimal placement exceed 25% of ideal system in that location w/o site losses

NOTES:

A. Bonus for providing secure/standalone power to sites of "essential public services (e.g. hospitals, police stations) or to certified "centers of refuge:" locations providing shelter during emergency situations

B. Qualifying systems must have a documented capacity factor of at least 50%, net of power to parasitic loads. The sum of all payments (base payments, bonus payment, performance payment) can not exceed $1 Mil per site.

C. Payments will be calculated and paid based on performance, as follows:
   a. For any given year of the three year Performance Period, a performance payment equal to 70% of the Applicant's Incentive Bid ($/kWh) multiplied by the Site Actual Annual Energy Production (kWh) (if installation is in a Strategic Location, the Incentive Bid will be multiplied by 1.15) will be made to those installations producing at least 80% of the Site Estimated Annual Energy Production.
   b. For any given year of the three year Performance Period, a reduced performance payment equal to 35% of the Applicant's Incentive Bid ($/kWh) multiplied by the Site Actual Annual Energy Production (kWh) (if installation is in a Strategic Location, the Incentive Bid will be multiplied by 1.15) will be made to those installations producing less than 80% of the Site Estimated Annual Energy Production.

D. Qualifying systems must have a documented capacity factor of at least 50% net of power to parasitic loads. The sum of all payments (base payments, bonus payment, performance payment) cannot exceed $1 Mil per site.

E. Qualifying systems must have a documented capacity factor of at least 50% net of power to parasitic loads. The sum of all payments (base payments, bonus payment, performance payment) cannot exceed $50k per site.

F. If funding has been received by the Host Site from NYSERDA under a contract that included the purchase and/or installation of the New Equipment, the equipment is not eligible for Capacity Incentives through this solicitation.

G. Performance Incentives are also calculated based on the Contracted Capacity of the New Equipment. The Total Performance Incentive is calculated using one of the following two (2) methods; the method producing the lowest Total Performance Incentive will be used in calculating the Total Contracted Project Incentive:
   a. Multiply the Contracted Capacity (kW) by 8760 hours/year by five (5) years by $0.07/kWh by 80% (capacity factor);
   b. Subtract the Total Capacity Incentive from $1 million.

H. Expected Annual Energy Output of proposed system, as calculated by the *Wind Professional Wind Resource Report*.

NYSERDA CHP Demonstration Program Details

In general, each project may be awarded up to 30% of total project cost. A project may be able to increase the award to a maximum of 50% of total project cost if the project has certain characteristics. Each of the following characteristics can increase the award by 10 percentage points:

• The project is located in Consolidated Edison (Con Edison) service territory,

• The project is connected to a "spot network" (as opposed to "radial grid") outside of Con Edison service territory. A facility is connected to a spot network when it is connected to multiple high-voltage feeds which serve a common bus and/or circuit,

• The project is directly powered by a renewable or opportunity fuel, or waste heat, and not eligible under any NYSERDA Customer Sited Tier Renewable Portfolio Standard (CST-RPS) program,

• The DG-CHP system will be an integral part of a documented and verifiable "facility of refuge". A facility of refuge is a structure or facility capable of providing shelter for a significant portion of the local population during times of man-made or natural disaster, and is cooperating and coordinated with county or city emergency management officials, as appropriate,

• The project is designed to provide a seamless, flicker free transition between normal and backup power operation using the DG-CHP prime mover to serve priority loads during periods of grid outage, and

• The project utilizes a pre-engineered, pre-packaged, factory tested, DG-CHP system(s) that integrates electric generation and thermal systems.

For example, a project that will provide seamless transition to grid-independent operation could receive up to 40% of total project cost if located outside of Con Edison service territory, and up to 50% of total project costs if located within Con Edison service territory.

Source: Distributed Generation as Combined Heat and Power (DG-CHP) Program Opportunity Notice (PON) 1931, proposals due December 23, 2010. Page 2

Tax Incentives

Federal Capacity Incentives

There is currently a 30% federal ITC for qualifying renewable DG investments and a 10% ITC for qualifying CHP investments. The real value of a tax credit is often less than its face value because the potential recipient may not have sufficient tax liability to benefit from all, or even part of the incentive. If the DG owner is not a taxpayer, the project will be unable to capture the ITC either in whole or in part.[1] This was addressed by a provision of the ARRA that temporarily allowed for conversion of the ITC to a cash grant. In the absence of such a provision, financial structures have sometimes been created to allow third parties with sufficient tax appetite to capture the full value of tax credits and pass some of the benefit back to the DG owner. However, there is a cost, at times quite significant, in bringing a 3rd party into the transaction. The benefit to the host site may be significantly diluted when the buyer of the credit requires a high rate of return for taking the allowance.

New York State Capacity Incentives

New York Real Property Tax Exemption.[75,76] This 15-year real property tax exemption applies to residential, commercial, and municipal properties installing solar, wind, or farm waste energy systems. All installations existing before July 1, 1988 qualify for the exemption, while improvements made between January 1, 1991 and December 31, 2014 can qualify subject to a local option. If unaffected by the exercise of the local option, property owners can take a municipal and school district tax exemption on the increase in property value attributable to the installation of the solar, wind, or farm waste energy system.

Under the local option, counties, cities, villages, and towns may pass laws to disallow the exemption. School districts may also enact ordinances proscribing the exemption. If a local government or school district declines to exercise the local option, it may instead require the property owner to enter into a contract for payment in lieu of taxation.

New York City Real Property Tax Exemption.[77,78] New York City property owners qualify for a real property tax incentive for solar photovoltaic installations that operates independently of the state property tax exemption. The grantee may be eligible for an annual tax abatement of up to 5% of eligible expenditures over a period of four years. The maximum abatement is $62,500, or 100% of a grantee's real property tax owed in a given year.

The incentive applies to systems which were put into service between January 1, 2011 and December 31, 2012. A grantee wishing to use the abatement for costs incurred in a given tax year must submit an application by March 15 of that year.

New York Residential Solar Tax Credit.[79] This credit applies to personal income for taxpayers installing solar equipment on residential properties. PV installations (installed no earlier than January 1, 1998) and solar-thermal installations (installed no earlier than January 1, 2006) can qualify the taxpayer for a credit equal to 25% of the cost of the equipment and installation. There is a $3,750 cap on the credit for solar-thermal installations put into service prior to September 1, 2006 and a $5,000 for systems put into service on or after September 1, 2006.

Systems are subject to the state's 10 kW capacity limit for net-metered residential solar systems. Condominium groups and cooperative associations are permitted to install systems as large as 50 kW.

[75] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY07F&state=NY&CurrentPageID=1&RE=1&EE=1

[76] http://www.orps.state.ny.us/assessor/manuals/vol4/part1/section4.01/sec487.htm

[77] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY52F&state=NY&CurrentPageID=1&RE=1&EE=1

[78] http://www.nyc.gov/html/dob/html/sustainability/solar_panels.shtml

[79] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03F&re=1&ee=1

Federal Capacity Incentives

Federal Residential Renewable Energy Tax Credit.[80,81] The Federal Residential Renewable Energy Tax Credit provides homeowners with up to a 30% tax credit for expenditures made in the installation of solar-electric, fuel cell, small-scale wind energy, or geothermal heat pumps on existing structures or new construction. Expenditures only qualify for the tax credit after the installation has been fully completed. As of 2008, there is no longer a maximum credit, except for fuel cell systems, which are eligible for credit up to $500 per half-kilowatt. The improved residential building must be the taxpayer's residence but must be the taxpayer's primary residence only in the case of fuel cell installations. Qualified installations are those put into service no earlier than January 1, 2006 (for solar-electric and fuel cells) or January 1, 2008 (for wind energy and geothermal pumps), and no later than December 31, 2016.

Federal Business Energy Investment Tax Credit.[82] Businesses that are eligible for a Production Tax Credit (PTC) may opt instead to take the Federal Business Energy Investment Tax Credit. The credit applies to various maximum percentages of total expenditures for a number of DG installations. Solar installations, fuel cells, and small wind turbines qualify for a credit valued at 30% of expenditures, while geothermal systems, microturbines, and CHP installations qualify for a credit up to 10% of expenditures. Qualified systems must be placed in service on or before December 31, 2016.

Production Based Incentives

Certain renewable energy projects may qualify for a Production Tax Credit (PTC). The PTC pays 2.2 cents/kWH sold to an unrelated third party during the taxable year. Because the PTC requires a sale of power, "behind the meter" projects are typically not eligible for the PTC.

NYSERDA and other grantors have created some structures that incorporate both production based incentives as well as capacity based incentives. A grantor is likely to favor a production incentive that insures that "clean energy" is actually being produced by the facilities in which they have taken a stake. Production incentives, properly designed, may also have certain efficiency advantages. A project that is compensated on the volume of production will look to design an operation that extracts the maximum production from the facility. to further increase efficiency, incentive structures can be tied to production at times when energy is most valuable. For example, an incentive may be based upon the volume of production occurring at "peak periods" for the electric system as a whole, or the zonal (transmission) or network peak (distribution).

[80] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F
[81] http://www.energystar.gov/index.cfm?c=tax_credits.tx_index
[82] http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1

Appendix C: Details of Utility Curtailment Programs

The following curtailment (load relief) programs are in place at this writing.

National Grid

Through the Company and other Enrolling Participants, the Independent System Operator – New England (“*ISO-NE*”) is offering a Real-Time Demand Response Program (“*Demand Response Program*” or “*Program*”) in order to ensure reliability when capacity is tight on the electric grid, particularly during the summer months.

During the term of this Agreement, Customer commits to mandatory energy use reductions on a 30-minute notice from ISO-NE. Customer receives credits for participating in the Program and receives additional credits for the energy actually saved when requested by ISO-NE to curtail. All program requirements and the methods for establishing baselines and calculating performance are governed

by the ISO-NE Load Response Manual (“Load Response Manual”). (National Grid, Load Response Program Agreement Real-Time Demand Response Program – 30 Minute Notice, 2009)

NYSEG

Under the C.A.$.H. BACK program, eligible customers can choose to curtail load in either or both of two scenarios: in response to an emergency signal from the New York Independent System Operator (NYISO) indicating that statewide demand is approaching utilities' capacity to supply electricity; or in response to rising wholesale electricity prices. The NYISO monitors the statewide power grid, and coordinates electricity purchases with utility companies to ensure adequate supplies. When curtailment is deemed necessary, customers that curtail are paid a fair-market price by the NYISO for each curtailment. (NYSERDA Press Release, NYSERDA and NYSEG Team up on Innovative Load-Curtailment Initiative, September 11, 2001)

LIPA

LIPA Commercial Voluntary Curtailment Program - a traditionally designed program aimed at commercial customers who offer a minimum

50kw voluntary curtailment when called upon to do so on non-holiday weekdays between 2pm and 6pm from June 1 to September 30. All program participants are notified at least four (4) hours before being asked to shed load. LIPA agrees to pay the customers $6.43 per kw per occurrence for the actual load shed up to the amount agreed upon with LIPA in advance. The program is administered in-house with notifications and curtailments done manually. (Long Island Power Authority, Background and C Three Observances, 2001)

NYPA

The New York Power Authority contracts with qualifying customers to reduce load upon request from the NYISO and/or Con Ed (where applicable). Participants will be contacted to curtail their load either by operating their on-site generation or by curtailing their discretionary electricity usage. Monetary compensation is paid to customers enrolled in this program when they participate in curtailment events. This program is strictly voluntary and there is no penalty for non-compliance. The program also gives customers the opportunity to review and effectively revise emergency plans. (New York Power Authority, Peak Load Management, 2011)

RG&E

RG&E's CA$HBACK and CA$HBACK plus are two Emergency Demand Response Programs (EDRP) that reward businesses for reducing their electrical load during specific curtailment periods. The New York Independent System Operator (NYISO) is responsible for balancing statewide electricity supply and demand. On occasion, the NYISO determines that it's necessary for consumers to reduce electricity use in order to ensure the continued reliability of the statewide power grid. By participating in CA$HBACK or CA$HBACK plus, you reduce your electricity use upon request and help ensure there is sufficient electricity supply during times of particularly high demand. CA$HBACK offers you the opportunity to voluntarily reduce your electricity load; you only receive payment when you reduce your use.

CA$HBACK plus requires you to reduce electricity load and gives you a guaranteed payment. (RG&E, Your Business Cashback Programs, 2011)

Appendix D: Utility Standby Tariff Participation Reports Summary

Summary of August 2010 Utility Reports Under Case 09-E-0109

Total number of customers: 67

Total capacity: 354,270.7 kW

Chose exception: 63

Capacity: 227,920.7 kW

Chose standby rates: 4

Capacity: 126,350 kW

Customers sized out of eligibility for exception: 7

Capacity: 15,317 kW

Individual Reports:

Consolidated Edison

Chose Exception: 6725.7 kW, 45 customers

Chose standby: 1350 kW, 3 customers

Sized out: 15317 kW, 7 customers

Orange and Rockland

Chose Exception: 75 kW, 1 customer

Chose standby: 0

Central Hudson

Chose Exception: 100 kW, 7 customers

Chose standby: 0

New York State Electric & Gas

Chose Exception: 220.82 MW, 9 customers

Chose standby: 125 MW, 1 customer

Rochester Gas & Electric

Chose Exception: .2 MW, 1 customer

Chose standby: 0

Appendix E: Environmental Market Recommendations

Integrating DG Into Market-Based Systems

Integrating DG into market-based mechanisms can present challenges to both policymakers and project developers. Issues include problems of scale and of location. Various types of DG can have technology-specific issues, and these are not always appropriately addressed by market-based mechanisms.

Emissions Measurement Methodologies

When integrating DG into market-based systems, it is important to use appropriate emissions measurement methodologies and protocols to ensure that emissions reductions from low- and no-emissions technologies are accurately calculated. For example, a recent study shows that many states and organizations misapply the most commonly used methodology, the eGRID system average methodology, to calculate emissions reductions due to EE and RE installations. This method was found to underestimate the CO_2 and NO_x emission reduction benefits of five EE/RE technologies[83] by 65% to 165% in the two power markets included in the study (the PJM Interconnection and the Upstate New York power markets) as compared with the TMM, an hourly methodology (Jacobson and High, 2010). An example of the wide range of results obtained from different avoided emissions methodologies is shown in Table GGG, below.

Table 9: Avoided CO_2 emissions from 10,000 MWh of wind energy generation from a hypothetical wind farm in upstate New York, based on 2005 data, and calculated using three different methodologies

[83] The technologies studied are high-efficiency commercial lighting, high-efficiency commercial air conditioning, LED traffic lights, solar PV, and wind energy.

Avoided Emissions Methodology	Avoided CO_2 Emissions (Tons per Year)	Organization Using Methodology
eGRID System Average	3,600	Climate Registry[l]
eGRID Non-Baseload Average	7,571	EPA Green Power Partnership
Time-Matched Marginal (TMM)	9,160	DOE Loan Guarantee Program, Metro Washington COG

Source: Jacobson and High, 2010

The study's authors recommend that states use the eGRID non-baseload emissions methodology as an interim measure until the eGRID system average methodology is enhanced with additional data and a more accurate TMM-like (hourly) methodology.

Integrating DG Into Cap and Trade Systems

Cap and trade systems have proven their ability to harness market forces to achieve significant emissions reductions with high efficiency and at low cost. However, for various reasons, DG is not easily incorporated into such trading schemes. Some problems are related to the small scale of DG, which can make it difficult for project developers and owners to monetize their environmental assets. Allowances are not usually allocated to DG facilities because they are simply too small to warrant regulation; when set-aside allowances are awarded, aggregation is frequently necessary to amass sufficient allowances to meet the minimum requirements of buyers. Also, due to inefficiencies of scale, transactional costs and other fixed costs can mean that small system owners pay more per unit to participate than their larger counterparts.

Regulating DG under a cap and trade program can be complicated, and policies must be carefully crafted to ensure that the benefits of DG are properly valued. The varying applications and characteristics of DG, and the change in point of emissions, may necessitate that DG facilities be regulated differently than centralized power stations. For example, although overall fuel efficiency is higher and total emissions lower for CHP than for grid-purchased power coupled with an on-site oil-burning furnace, onsite emissions can increase relative to onsite generation of thermal energy only (International Energy Agency). If the emissions benefits of electricity displacement are not recognized, the environmental benefits of CHP will not be properly valued.

Common methods to incorporate DG into cap and trade systems include set-asides and offset credits. Set-asides did not work well in New York State under the NO_x SIP Call, but the comparable program in Massachusetts was oversubscribed; the difference was at least in part due to the fact that New York provided little or no information on the program to potential participants, while Massachusetts achieved a high degree of transparency with clear and easily obtainable application materials. Offsets can work but tend to apply only to certain types of DG, for example, to certain biomass-based projects under RGGI.

One difficulty in incorporating DG into market-based mechanisms is that most market-based programs reward either electricity production or on-site emissions reductions, but many DG facilities are CHP systems, which replace both on-site thermal systems (such as fuel oil boilers) and electricity supplied by the electric grid. Such systems are not typically well-compensated by market-based mechanisms. For example, ERCs compensate CHP projects for their thermal displacement, but not for their electricity displacement. If CHP projects were eligible for CAIR allowances, they could be compensated under CAIR for certain emissions reductions in the electricity sector, but not for the reductions due to their thermal displacement.

It is possible in some states for CHP systems to simultaneously benefit from two market-based programs, which separately reward the different types of benefits conferred by CHP. For example, under the NOx SIP Call, a CHP system could have applied for both ERCs and EAs. However, this is not now possible in New York, because the EERET account administered by NYSERDA replaced the prior system of set-aside allowances, and at this time EERET funds are not being used to support DG projects.

It is likely that in the near future, DG projects will be eligible to directly participate in carbon markets now under development.[84] Under an allowance-based cap and trade system, allowance allocation should to be designed such that CHP systems do not have to pay greater compliance costs for their increased on-site emissions (due to the shifting of electricity generation from a central generator to the on-site CHP system), and/or such that they receive recognition for their overall reductions. This could be achieved through an allowance set-aside based on output. If allowances are distributed freely, allowance allocations to CHP should be output-based with thermal credit.

[84] DG projects cannot directly participate under RGGI, although some biomass-based projects may qualify as RGGI offsets, and other specific types of DG may be eligible for RGGI investment program funds.

The most common approach to account for the thermal energy output associated with CHP is to measure the thermal energy in Btus, and then use the conversion factor of 3.413 MMBtu/MWh. If a pure auction approach is used then it is important to give bonus allowances to CHP to account for its greater efficiency. Otherwise, CHP receives no recognition of its net reduction in GHG emissions, and is disadvantaged under an auction allowance approach.

For example, Connecticut's RGGI regulations include two separate set-asides for CHP, one for CHP units that enter into long-term power purchase agreements, and another that gives thermal credit to CHP applications (CONN. AGENCIES REGS. § 22a-174-31). North Carolina's recent Renewable Portfolio Standard (RPS) regulations give thermal credit for CHP, stipulating that "Renewable energy certificates shall be earned based on one megawatt-hour for every 3,412,000 British thermal units of useful thermal energy produced" (In the Matter of Rulemaking Proceeding to Implement Session Law 2007-397, Docket No. E-100, Sub. 113).

Another approach within the cap and trade regulatory structure would be to provide bonus allowances to CHP systems. New Jersey provided bonus allocations to CHP under the NO_x SIP Call and several EU countries – the Czech Republic, Germany, and Poland – also give bonus allowances to CHP applications (International Energy Agency).

One fundamental problem for CHP systems is that they are frequently burn natural gas, and are therefore not included in renewable energy incentives; at the same time, they are not typically included in energy efficiency incentive programs. A holistic approach to energy regulation would help to ensure that such promising technologies do not "fall through the cracks" between programs.

DG Participation in Existing Markets

Emission Reduction Credits (ERCs)

ERCs are a good fit for some types of DG. However, taking advantage of the opportunity to certify and sell ERCs is not easy. Developers face significant impediments, including high transaction costs and the need to aggregate ERCs:

High transaction costs are due to the fact that many of the costs of certifying ERCs are fixed, meaning that small projects cost significantly more per ton to certify than larger projects. Small, independent developers may not have the ability to easily pay these costs.

Complicated and non-standardized application processes are exacerbated by poor documentation in many states.

Long wait periods for certification are reported in many states, where the time required for ERC approval can range from several months to several years.

The need to aggregate ERCs is due to the fact that purchasers of ERCs generally prefer to purchase larger blocks of credits than will be available from a single small DG project. Aggregation imposes costs that reduce the ultimate value of ERCs to the individual DG projects that create them.

Market illiquidity is exacerbated by geographically constricted markets, both within and between states.

These problems are not intractable, and several remedies are available:[85]

The state could, with a small outreach investment, increase the general level of knowledge regarding the opportunity to certify ERCs.

The opportunity for creating ERCs is concentrated in a few economic sectors, and is greatest where there is the greatest difference between prior period (baseline) and future period emissions. This occurs primarily at sites with the oldest, least efficient boilers using the most polluting fuels. Therefore, ERC certification information should be targeted to those economic sectors most likely to generate substantial quantities of ERCs.[86] The state should proactively review minor source database records and conduct outreach to these sites, informing them of the opportunity that exists to participate in the ERC program.

Each stage in the process of obtaining ERCs could be streamlined by the use of standardized procedures, resulting in reduced time and transaction costs for developers.

In order to simplify the applicant's demonstration of actual pre-reduction emissions, states could create a spreadsheet template requiring that the applicant fill in monthly fuel usage and equipment data from the site. The spreadsheet would calculate emissions based on the type of fuel used, the quantity of fuel used by month for each baseline period month, and the type and vintage of boilers and control equipment employed. Applicants claiming special circumstances would be provided the opportunity to demonstrate that the standard form and assumptions should not apply. The states could also adjust pre-reduction emissions calculations to account for new or pending rules, thus simplifying the assessment of whether proposed reductions would be surplus.

It may be advantageous for project developers, rather than the actual site owners, to hold title to the ERCs. In this way, the developer could aggregate ERCs from several projects and bring them to the market in larger lots.

[85] Recommendations are from the STAC report (PECC, 2010).
[86] For more information on the highest value target sectors for ERC creation, see the STAC report (PECC, 2010).

The determination of future emission levels can be simplified by using pre-certified emissions from reliable sources. For example, the California Air Resources Board (CARB) pre-certifies emission rates of distributed generation technologies. If CARB has already certified certain reciprocating engine-driven generators and microturbines, these test results should suffice for use in the ERC quantification process in New York, New Jersey, Connecticut and Massachusetts as well. The state, in consultation with equipment manufacturers and other key stakeholders, might inventory and post such emissions data for use by DG developers.

Certification costs could be reduced if each state were to establish and enforce timelines for ERC processing. Applicants should expect that the process for obtaining an ERC will occur within a reasonable time frame. Since processing delays are frequently the result of insufficient documentation provided by the applicant, states should be as specific and precise as possible when presenting requirements for review of an ERC proposal.

Certified ERCs available for use should be inventoried and displayed for public viewing on the certifying state's official website. States with MOUs for reciprocal trading should post ERCs available in the trading states as well. Postings should include all pertinent information, including states in which the ERC may be used, restrictions on usage within the certifying state and the trading states, and depreciation of ERC value over time.

Implicit in the design of the ERC program is the assumed continual growth of the manufacturing and energy industries, which provides demand for ERCs. However, these industries have not continued to grow, particularly in the Northeast, which has undergone a transition from a manufacturing- to a service-based economy. This transition has had a positive impact upon environmental quality, but has also undercut the ERC market. This is partly because demand for ERCs depends on the creation of new energy and manufacturing facilities. Another factor is a decline in the emissions intensity of manufacturing. Efforts to spur manufacturing activity in the Northeast, such as grant programs, tax incentive programs, technology and business incubators, and other efforts, could stimulate the demand for ERCs.

States can also spur demand for ERCs by taking a more rigorous stance in interpreting what triggers the need for offsets. There have been some indications from the states of an intent to tighten the interpretation of the need for NSR, and as a consequence widen the set of affected sites.

The development of ERC reciprocity agreements among the states would increase the liquidity of the currently moribund ERC markets, and should increase the value of ERCs. All else being equal, larger markets should function more efficiently than smaller markets. Broadening the market by allowing cross-state trading would expand the set of potentially affected sites on the demand side, and lower concentrations of holdings that might lead to price setting (not price taking) behavior on the supply side. Expanding the geographic scope of the market also widens the set of industries and emission-generating processes that can potentially supply ERCs. The greater the heterogeneity of process in the trading region, the more likely it is that parties can benefit from trade.

Creating a multi-state ERC trading program need not be expensive, but it would require some problem-solving. For example, an agreement to allow credits to be transferred from one state to another would require the participating states to agree on the relative value of ERCs from each state. In other words, the participants would have to decide whether a ton of NO_x in one state is equivalent to a ton of NO_x in the other. This might require the involvement of a non-state lead agency to help broker agreements; however, the idea is not without precedent.

The following measures may help to simplify the development of an interstate ERC trading agreement:

Select a lead organization to oversee the process. Candidates for this role might include EPA, NESCAUM, NACAA or a private institution. While EPA leadership may seem an obvious choice, direct federal participation may discourage state cooperation. On the other hand, a non-state agency such as EPA may be able to encourage middle ground solutions to intractable issues.

Mandate those states that share an interstate non-attainment national ambient air quality control region to develop a mutual interstate trading agreement, using identical ERC creation, validation, registry and use forms, and to participate in interstate ERC actions in the region without reservations. This, of course, would require enforcement by the EPA.

Assess the feasibility of instituting a quid pro quo process that eliminates the winner-loser concern. This concern arises because states view ERCs as a useful currency to assist in economic development efforts. For example, New Hampshire takes title to ERCs created as a result of unit shutdowns, if the site owner cannot use them, and holds them in a state operated account for economic development purposes.[87] Therefore, if through an interstate trading protocol credits generated in one state are repeatedly being transferred to a neighboring state, a mechanism is needed to assure that the receiving state in some way reciprocates to the generating state.

[87] "If the generator cannot use them, they become 'public ERCs' in a state-controlled account. The state can then use these ERCs for purposes of job retention (highest priority), economic development, and job creation" (New Hampshire DES, 2009).

Several states, following EPA guidance, have limited the distance between the ERC generator and ERC purchaser/user. Since this significantly limits interstate ERC trades, consideration should be given to eliminating this restriction under the premise that regional air quality is improved with a net emissions reduction. If this assertion is borne out by modeling, states should consider rescinding such restrictions.

Similarly, ERCs generated in an area of better ambient air quality may not be used in an area of lesser ambient air quality. Thus a New York State ERC generated north of lower Orange County may not be used for a project in New York City. While the rationale underlying this restriction is understandable, an empirical demonstration of its contribution to a greater environmental good may be warranted. A rigorous, consensus-based modeling process may demonstrate that the restriction could be loosened with no (or perhaps negligible) cost to environmental quality. Since the New York City NAAQCR also involves Connecticut and New Jersey, such a revision would involve all three states. EPA oversight and guidance will be needed to safeguard against abuses of any revised rule.

As noted above, states view a supply of reasonably priced ERCs as a component in their economic development strategies. Therefore, all administrative costs associated with the ERC process must be absorbed by the ERC receiving state and not passed on to the ERC generator or final user. Passing on the administrative costs to the ERC generator or the final user will inflate costs and lower the total return on ERCs. The receiving state should pay the administrative costs, since it benefits by an expanded pool of lower cost ERCs to promote economic development. Additionally, if the states bear the costs of program administration, they will have an economic incentive to exercise more vigilance in the areas of timeliness and cost control.

To successfully modify existing ERC programs, revisions may be required to current agency guidance and supporting regulations. States that are party to the development of a multi-state system should jointly conduct an inventory of regulations and administrative procedures that would require revision. Careful attention should be paid to the design of easily accessible, user friendly program forms and instructions.

It is important to note that ERC processes are affected by numerous market-based factors, many of which are external to these processes. Establishing interstate trade in ERCs may improve the market at the margins, and other practical steps could also be taken to reduce barriers to participation. However, the impact of these efforts, though positive, is likely to be small in relation to the broader factors determining the state of the market. The fundamental lack of demand for ERCs is the predominant factor determining the state of the Northeastern ERC markets; addressing this lack of demand will mean addressing larger market forces affecting the economies of the northeastern states.

Emission Allowances

At this writing, New York's EERET account has been set up to receive the proceeds of set-aside allowance sales, for use in promoting EE/RE efforts in the state. There is little information publicly available about the EERET account; according to sources at NYSERDA (Saintcross, 2010), funds in the account are not being used to support DG project development, but have instead been used to support R&D efforts. However, these funds could be used to promote DG project development if NYSERDA elected to use them for this purpose.

However, dedicating funds does not guarantee a successful program. The EERET account was created to address a failure to distribute set-aside allowances to eligible DG projects under the previous NOx SIP Call. Although it is true that the set-aside program offered too little value to incentivize individual DG projects—as noted by the NYSDEC, "Few sponsors of EE/RE projects have sought the award of EE/RE allowances…. due to the difficulty in demonstrating enough avoided emissions, even when aggregating projects, to qualify for a single EE/RE allowance"[88]—it is also true that the state did not sufficiently promote the set-aside program or provide a standardized application procedure. Potential participants were unlikely to know of the program's existence, and those that knew of it may have had no clear idea of how to participate.

Recommendations to regulators include:

Dedicate the EERET account, or some portion thereof, to the support of DG project development in the state. This could be accomplished in such a way that the account would not be continuously depleted, for example, by establishing a revolving loan fund.

Clearly describe program attributes and functioning in public documents, so that eligible participants would understand crucial aspects of the program. This would include how projects are chosen to receive funds, whether any environmental attributes created by projects are surrendered when program funds are accepted, how much money is available to a project, etc.

Create standardized application forms. The Massachusetts and Connecticut programs appear to be good models for other states in this regard. Massachusetts achieved a very high rate of participation in the prior NO_X Budget Program simply by making it easy for developers to understand and participate in the program. To achieve this, Massachusetts employed well-constructed application forms, clear procedures, examples, formulas and data requirements, all readily accessible to a potential applicant. In addition to increasing ease of participation, this approach made for a highly transparent process. The result is that the Massachusetts program was over-subscribed, with demand for certification of EAs outstripping the program budget.

[88] CAIR Summary of Express Terms, http://www.dec.ny.gov/regulations/38561.html

This was achieved through a modest investment in a well-defined process, and despite very little investment in publicizing the program.

It is important to note that regardless of how the state designs or promotes its EERET program, regional demand for EAs will likely be influenced by uncertainty in two areas:

CAIR was rewritten by US EPA, after being remanded to the agency for revision by a federal court. The EPA is in the process of promulgating the replacement Clean Air Transport Rule (CATR). At this writing, there is a great deal of uncertainty about the value of EAs under CATR. The drastic fluctuations in NO_x prices in response to these court decisions demonstrate the intricacies of the relationship between uncertainty and EA valuations (Burtraw and Szambelan, 2009). Such uncertainty could be addressed by the use of market mechanisms, such as price floor (Ibid.).

Some believe that a future federal carbon trading program may overshadow NO_x trading, EAs, and to a lesser extent ERCs. U.S. climate policy will also affect the amount of NO_x emitted since the number of coal-fired power plants may be reduced (Ibid.). Even if a climate change bill is not passed, EPA will likely regulate CO_2 emissions which would also have implications on coal-fired power plant emissions and hence NO_x markets. (Ibid.). However, it is possible that as trading firms devote greater resources to carbon trading, these same firms will also take an interest in NO_x programs and consequently stimulate market activity.

Tapping DG Potential to Provide Ancillary Services

By establishing a market for ancillary services, the NYSISO created a potentially valuable revenue stream for DG. Small DG, however, is not participating in this market. Interviews with DG developers and owners indicate that they do not see opportunities to participate because the market terms do not match well with the technical and operation characteristics of DG systems (Ahrens, 2011).

The mismatch between the emerging ancillary services market and small DG is understandable. Historically, ancillary services have been managed and delivered by tapping the large central station generators or by installing equipment (such as capacitor banks) in the transmission network to provide such services. The new ISO market was designed as a pathway to obtain these services economically from the fleet of now independently owned central station generators and other sources.

As practical matter, the DG resources considered here, small capacity generators installed to provide energy for a specific facility, have not provided ancillary services that ISO transmission and utility distribution grid operators require to maintain network performance. While there are a number of studies that describe how DG can contribute such services, there is little experience with actually obtaining ancillary services from DG systems serving partial requirements of electricity consumers. It is apparent that there are a number of barriers keeping small DG from participating in this market. For example, there are costs associated with the communication and control equipment that DG facilities must have to provide ancillary services; furthermore, there may be costs to the DG owner's core business related to the dedication of the unit's capacity to meet distribution system needs. There are also costs to grid managers dealing with small DG units for the provision of ancillary services. Developing commercially viable practices to tap small DG for specific ancillary services will require design and demonstration efforts to increase the level of knowledge and experience among stakeholders..

The earlier cited concerns of grid planners confronting the impacts of rapid growth in DG facilities on their networks also requires attention. Recent utility reports suggest that these impacts vary widely with DG technology type and design and with local distribution network conditions. The costs and operating impacts in some cases may be significant.

Obtaining ancillary services benefits from DG, while avoiding new costs to distribution networks, is both an opportunity and a challenge. Meeting this challenge will require significantly increased attention from grid planners and operators. What is needed is a trial that treats the deployment of DG not as a condition to be addressed protectively, but as tool to achieve grid performance objectives. The Test Bed tools this project is developing may provide new, relatively low-cost, low-risk methods to demonstrate effective grid management practices that integrate DG into networks, minimizing costs and maximizing value.

It may be productive to initiate in New York a collaborative working group of DG, utility, ISO, and regulatory stakeholders to plan and implement the analysis, design, testing, and demonstration that is required to provide effective market pathways for the economic use of DG to serve grid performance goals. The NY PSC has used such collaborative working groups effectively to design interconnection standard policy, to design standby tariff guidelines, and to design the program implementation strategy to carry out new programs to achieve the Energy Efficiency Portfolio Standard goals. Effective integration of DG into grid planning and operations will require the active participation of a diverse group of stakeholders to ensure that the needs of DG developers/owners, grid managers, and consumers are reconciled. In order to ensure that new market designs support science-based goals, the work of such a collaborative group should be informed by the results of grid integration modeling and testing using physical test beds, such as the one being developed by RPI. Innovation will be needed to overcome the potential high transaction and set up costs associated with the procurement of services from many small, distributed providers.