These papers were presented at the Energy Research Roundtable, hosted in partnership with the Lincoln Institute of Land Policy. We thank the Lincoln Institute for their commitment to fostering and sustaining collaborations that contribute to a prosperous and sustainable region.

We also thank Siemens for supporting RPA’s efforts to advance innovation in cities.

It was a pleasure to work with the authors of the three papers enclosed in this briefing book, including: Ed Krapels, Clarke Bruno, Adam Friedberg, Fiona Cousins, Chris Brosz, Alexan Stulc, James Fine and Michael Roos.

We are thankful to Ben Oldenberg for designing this briefing book.
Executive Summary

Today, the energy industry is in a period of disruption. The industry is faced with an urgent need to resolve questions about energy security, reliability, decarbonization, and price stability. Massive investments on the scale of $80 billion per year will need to be invested. These investments must be made at a time when demand growth is slowing and energy efficient technologies are proliferating. These market conditions challenge utilities, which must be responsive to shareholders, regulators, and customers.

Cities and states are capitalizing on—if not facilitating—this disruption. Absent federal climate policies, planners and decision-makers are taking steps to create cleaner, greener, and economically competitive cities and states. Cities are experimenting with building codes, point-of-sale agreements, electric vehicle infrastructure, special energy improvement districts, and other ways to gain greater control over future emissions while spurring innovation and economic growth.

All of these changes will require us to think critically about how we can create an energy infrastructure that is at once reliable, efficient, affordable, secure and resilient. Though the challenge is daunting, inaction is not an option.

There are opportunities to intervene at the regional scale. New federal policies will require inter-regional cooperation and give states leverage in pursuing projects that meet public policy objectives. New York, New Jersey, and Connecticut have pioneered innovative policy and regulatory standards, financing tools and authorities, and the development and deployment of renewables. Now there is an opportunity to knit together the disparate activities of the Pennsylvania Jersey Maryland Power Pool (PJM), the New York Independent System Operator (NYISO), and Independent System Operator-New England (ISO-NE) in pursuit of new infrastructure that can meet the region’s needs. Furthermore, state and local efforts to reduce carbon emissions will change the way we interact with our homes, our neighborhoods, and our cities. The efforts will transform our buildings, transportation systems, and other parts of our daily lives. Regional planning will bring these changes to scale in a way that benefits rate-payers and helps us meet our carbon goals.

RPA hopes to advance an energy infrastructure that is at once reliable, efficient, affordable, secure, and resilient. The purpose of the Energy Research Roundtable is to bring together a small group of experts to discuss emerging trends, challenges, and opportunities that could be considered in upcoming Fourth Regional Plan. This multiyear initiative is the fourth such effort led by RPA in its 90 year history, and the first in a generation. The Fourth Regional Plan focuses on the strategic government and business decisions that will shape the region’s overall well-being for the next generation. The Plan creates a vision of future success and a roadmap for the major government and business decisions required to achieve it. The Fourth Regional Plan will address three distinctive challenges: governance, economic opportunity, and climate change. For the first time, the Regional Plan will address energy, which touches on all three issues.

To advance this discussion, RPA has commissioned three white papers on critical challenges and opportunities. These papers address emerging technology, financing, and regulatory trends that can help advance a decentralized, distributed model of infrastructure. The first paper, written by Edward Krapels and Clarke Bruno of Anbaric Transmission, makes a case for greater competition in the electricity industry, which will spur innovation and transform the New York metropolitan region from a load pocket to an energy hub. This paper focuses on opportunities to advance competition and innovation in transmission and distributed generation. The second paper, authored by James Fine of Environmental Defense Fund (EDF), proposes On-Bill Repayment as a long-term solution for expanding energy efficiency programs. This paper presents the results of a detailed quantitative analysis that explains the environmental and economic benefits of On-Bill Repayment. EDF proposes this financing tool as a way to overcome the challenges in scaling up energy efficient technologies and bringing renewables to market in the region. The third paper is authored by Adam Friedberg, Chris Brosz, and Fiona Cousins of Arup. This paper describes key technologies that are enabling a shift to a distributed, decentralized grid and identifies opportunities to deploy these technologies in the region.

Using these papers as a touchstone, we invite discussion for the key factors that will shape the region’s energy future. From these discussions, we will tease out priorities for the Fourth Regional Plan and identify planning, policy, and research issues to which RPA can contribute.

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Transforming Metropolitan New York Into An Energy Hub For The 21st Century:
Transmission Infrastructure And Microgrids To Increase Reliability, Spur Innovation, And Stimulate Regional Growth

Authors
Edward Krapels
Clarke Bruno

Introduction
Since the Dutch founded New York almost four centuries ago, the state has been a center of commerce and competition. The New York metropolitan region has become a successful emblem of innovation, competition, and the myriad benefits of commerce. It is no coincidence that Thomas Edison – with a lab in New Jersey -- created the electricity industry in lower Manhattan.

While the electricity industry has succeeded in transforming our world in ways Edison never could have imagined, the industry has lost much of its innovative and competitive character. In recent years, innovation has largely come from outside of the regulated sectors of the industry, including project developers who are expanding the renewable power sector; aggregators who are delivering demand response to wholesale power markets; and the appliance manufacturers, HVAC designers, and system controllers who have enabled energy efficiency to temper our society’s ever-increasing need for power. As these innovations have entered the market, the absence of competition and the attachment to the status quo in large sections of the electricity industry have become apparent. The deployment of innovative infrastructure and technologies is encumbered by a system with high barriers to entry. As new technology promises to usher in a new era of prosperity in the power sector—and the region—in the coming decades. Energy policy-makers should expand the vision and opportunity to advance competition in this critical part of the economy.

What makes the electric situation so unique is that transmission is deemed to be an interstate activity, hence is regulated by FERC. But federal energy policy is made in discrete orders; there is no integrated vision for the nation’s energy infrastructure.

The New York metropolitan region should embrace innovation, competition, and increased commerce as the fastest and most cost-effective way to meet the challenges of building a modern model of electricity transmission and delivery. This approach offers the greatest likelihood of a new era of prosperity in the power sector—and the region—in the coming decades. Energy policy-makers should expand the vision and opportunity to advance competition in this critical part of the economy.

The New York metropolitan region should embrace innovation, competition, and increased commerce as the fastest and most cost-effective way to meet the challenges of building a modern model of electricity transmission and delivery. There are two strategies that can improve the region’s electric grid through competition:

Build the transmission infrastructure required to meet the region’s energy needs and advance clean energy. Building more transmission infrastructure is a long-term strategy that will eliminate “load pockets” and enable a regional energy trading hub with robust links integrating downstate and upstate New York, New England, and the Mid-Atlantic. More transmission infrastructure will put all energy fuels on an equal footing. This strategy will prepare the region for the coming era of renewable energy and use today’s low natural gas prices to enable-- not destroy-- wind from western and northern New York.

Advance decentralized, distributed generation through microgrid technologies. Decentralized, distributed generation and accompanying technologies can advance sustainability goals—especially if the reactors at Indian Point are retired. In Long Island, new models of utility ownership and operations will need to correct years of mismanagement and deliver more reliable energy. Each of these issues is symptomatic of the disruptive trends that are shaping tomorrow’s electric power industry.

Public and private sector decision-makers responsible for operating the power grid in the New York metropolitan region should embrace innovation, competition, and increased commerce as the fastest and most cost-effective way to meet the challenges of building a modern model of electricity transmission and delivery. This approach offers the greatest likelihood of a new era of prosperity in the power sector—and the region—in the coming decades. Energy policy-makers should expand the vision and opportunity to advance competition in this critical part of the economy.
the region’s economic competitiveness and energy reliability. Although microgrid innovation is expanding rapidly, the current regulatory frameworks in the New York metropolitan region do not allow customers to capitalize on the potential. Regulatory frameworks and technology should enable the deployment of microgrids — an umbrella term for an array of distributed energy, combined heat and power (CHP), and “behind the meter” supply and demand technologies — embed smaller distributed energy resources and demand-management systems. Some of the region’s universities and real estate developers have begun to invest in this technology, but regulatory and financing changes will be required to reap the benefits of microgrid technologies more broadly.

To remain a competitive and attractive place for world-class businesses, research institutions, and talent long into the future, the New York metropolitan region must transform its energy infrastructure. Investments in transmission and decentralized generation will help transform the region into an energy hub, in which the region can take advantage of new technologies in generation, demand response, efficiency, and renewables.

Background

Superstorm Sandy’s high winds and severe flooding revealed both the fragility of our electricity infrastructure and the limits of reliability in the regulated utility model. The storm’s impacts revealed shortfalls in key assumptions that underpin the century-old model of regulated electricity monopolies:

- a one-size-fits-all standard of reliability imposed on a 21st century society; and
- a state-centric electricity regulatory model that fails to recognize that the tri-State area constitutes a single electricity region.

The New York Metropolitan region must plan for an unpredictable future. The northeast will experience climate change impacts such as sea level rise, extreme storms, increased precipitation, and drought. We cannot plan for the proverbial “last war”, and instead must focus on building a model for electric power that is robust across multiple futures.

As we envision the grid of the future, we should start with the recognition that our tri-State area is a single, interconnected region. In light of the political, regulatory, and administrative divisions that balkanize the region’s energy, how can we create a grid that is a platform for innovation?  

Transmission: Strengthening the Grid, Spurring Economic Growth

Since the Northeast Blackout of August 14, 2003, regional energy transmission planners have puzzled over where and how to invest in transmission. Without sufficient transmission infrastructure, the region will face pricing pressures, reliability issues, and difficulties bringing renewables to market.

In New York, only three major transmission projects have been commissioned and constructed since 2003. In Connecticut, $16 billion were invested, but no new funds have been invested in transmission since 2008.

Each state has experienced differing levels of investment in transmission since the Northeast Blackout. These differing transmission outcomes can be attributed to two factors that make the New York Metropolitan region unique. First, New York is the only city whose broader metro area is largely located in other states. Second, each state in the region belongs to a different regional transmission organization (RTO), independent system operator (ISO), or “control area”. Each has its own regulatory and political processes that govern transmission planning and investment. Connecticut’s grid is governed by the Independent System Operator of New England (ISO-NE). New Jersey’s power grid is administered by the Pennsylvania- New Jersey-Maryland Interconnection (or PJM). New York City and Long Island’s transmission systems are administered by the New York Independent System Operator (NYISO).

The Federal Energy Regulatory Commission (FERC) created these entities in the late 1980s and 1990s. The federal effort was motivated by the reality that electricity trade is inevitably an interstate activity, and therefore requires both regional and federal oversight. Consistent with their federal mandate, these regional transmission organizations quite naturally focused

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1 From a Columbia University published in 2007. "Despite the benefits of CHP, there are many opportunities for projects to become sidetracked in New York City. As this report repeatedly noted, interconnection is a major hurdle, and other issues – from air permitting to fluctuations in gas prices – have the potential to inhibit deployment as well. Given that current small-scale CHP deployment levels represent just 118 MW of generation capacity150 – despite nearly 3,200 MW of aggregate CHP deployment potential within Con Edison’s service territory151 – PlaNYC’s goal of 800 MW of CHP by 2030 must be seen as rather optimistic, absent a CHP policy paradigm shift. Over the next several years, until fuel current limiters enter the market, over duty circuit breakers at feeders and substations are replaced, and the use of power electronics becomes commonplace, there will likely be a significant increase in overall CHP deployment levels around New York City. Longer-term prospects, however, are contingent on policy changes made in the near future. Laying CHP friendly policy groundwork now will allow CHP deployment to increase rapidly once technological upgrades are in place. Achieving the Mayor’s goal should therefore follow a two-track approach, in which the City works with state officials and key market stakeholders to improve both the short and long-term outlook for CHP technologies," Columbia University. Center for Energy, Marine Transportation and Public Policy, CHP in NYC: A Viability Assessment. 2007.

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inwards. They have spent the vast majority of their time managing the complex system of connections between electricity generation, transmission, distribution, and consumption within their service areas, not between service areas. Thus, neither PJM nor ISO-NE nor NYISO have transmission projects that are interregional and cover the tri-state area and, consequently, there are few transmission connections between Connecticut, New Jersey and New York.

To the extent there are interregional projects, however, New York has led the way. New York’s electric authorities that have pioneered interconnections between the different electrical grids that serve the New York metro area. LIPA commissioned the Cross Sound cable that connects New Haven Connecticut to Shoreham, Long Island; LIPA commissioned the Neptune cable that connects Sayerville, New Jersey to New Cassel, Long Island; and NYPA commissioned the Hudson cable from Ridgefield, NJ to mid-town Manhattan.

These projects have been developed by independent transmission authorities, not the established electric utilities. As such, these independents are an important part of the changing structure of the transmission business. Even before the Northeast Blackout of 2003, it was widely agreed that hundreds of billions of dollars needed to be invested in the transmission sector. The Federal Energy Regulatory Commission (FERC) made it clear in Order Nos. 888, 890, and 1000 that it wanted to encourage private capital to make this investment voluntarily, instead of relying on mandatory payments from the captive ratepayers of the utilities. New York, New Jersey and Connecticut state political leaders share this priority. In fact, New York Governor Andrew Cuomo launched a New York “Energy Highway Initiative” in 2012 that holds particularly great promise.

What makes the electric situation so unique is that transmission is deemed to be an interstate activity, hence is regulated by FERC. But federal energy policy – aside from its environmental aspirations – lacks an integrated vision for the nation’s energy infrastructure. The United States does not have a national electricity policy. The only federal guidance is expressed in a series of discrete Orders issued by FERC over the last several decades.

The FERC aims to attract private investment in transmission as part of its long-standing campaign to restructure the electricity industry. Twenty years later, however, FERC’s goals have not yet been accomplished. Construction of new transmission has been modest. All of the transmission projects commissioned in New York since 2003 – a total of 1,635MW in a 35,000MW system – have been HVDC and VFT (an alternative form of controlled transmission) projects. Of that, 990MW were commissioned by New York’s authorities for both reliability and economic purposes. There has been almost no new AC transmission built since 2000. In Connecticut, Northeast Utilities completed $1.6 billion in transmission upgrades in 2008, spanning more than 109 miles of the electric grid including the counties that are part of the New York City metro area. The “southwest Connecticut solution” consisted of four transmission projects: Bethel-Norwalk, Long Island Replacement Cable, Glenbrook Cables and Middletown-Norwalk. In New Jersey, the New York metro area is served by Jersey Central Power & Light and by Public Service Electric and Gas (PSEG). PSEG is developing three projects that will increase the transmission service into the New York metro area: the North Central Project ($390 million), the Northeast Grid ($895 million), and the Susquehanna-Roseland Project ($1.5 billion).

Part of the challenge of constructing new transmission in the tri-state region is that it is already highly developed. In New York, Consolidated Edison maintains the extraordinarily complex urban transmission and distribution systems that serve Westchester County and the five boroughs of New York City. Due to the density of the population, most of ConEd’s wires are considered part of a massive distribution system, not part of a transmission grid. ConEd’s largest transmission project, M29, is routed through city streets. When the project was first proposed in 2006, ConEd estimated the cost of this 10-mile project to be

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2 Mr. Krapels was a principal in the companies that developed the Neptune and Hudson projects.
3 From the U.S. Department of Energy’s National Transmission Grid Study: “There is growing evidence that the U.S. transmission system is in urgent need of modernization. The system has become congested because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities. Transmission problems have been compounded by the incomplete transition to fair and efficient competitive wholesale electricity markets. Because the existing transmission system was not designed to meet present demand, daily transmission constraints or “bottlenecks” increase electricity costs to consumers and increase the risk of blackouts.”
4 http://www.nyenergyhighway.com/
5 The electricity sector remains heavily regulated so, unlike the airline industry, the government retains a significant role in monitoring pricing, for example. It has been restructured to allow a greater degree of competition than was previously allowed and to vary the roles of the entities within the market. With those structural changes, it remains heavily regulated.
6 See http://www.transmission-nu.com/residential/projects.asp
7 See http://www.pseg.com/family/pseandg/powerline/reliability_projects/projects.jsp
8 Typically, the distinction between transmission and distribution is defined by voltage levels: anything below 69kV is considered distribution.
$214 million. In 2011, the cost was estimated at $468 million.\(^9\)

While each of these projects will help improve the amount of transmission within the geographic boundaries of New York metropolitan region, none of the projects help build inter-regional connections between the three control areas. Thus, New York, and Long Island, New Jersey, and Connecticut remain disconnected. From an electric service standpoint, the metropolitan region is balkanized.

**Economic Transmission Projects**

There are two types of transmission investments: reliability projects and economic projects. Reliability projects are needed to maintain a certain technical standard of service. Economic projects are used to accomplish most other objectives, such as narrowing price disparities between regions or bringing a new class of generators or renewable energy sources into the grid. While reliability investments maintain or incrementally enhance the grid, they are not transformative. Economic investments

\(^9\) The transmission line will be installed primarily within the curb-to-curb portion of the right-of-way of public roadways. The preferred route for the transmission line begins at Con Edison’s Spuyten Duyvil Substation, generally located between Lakeview Avenue and Tuckahoe Road in Yonkers, and heads southwest along Con Edison’s Sprain Brook Substation access road for a distance of 1,500 feet to the intersection with Tuckahoe Road. The route turns west along Tuckahoe Road for a distance of approximately 5,000 feet to the intersection with Saw Mill River Road. Along Tuckahoe Road, the transmission line would cross under the New York State Thruway (Interstate 87) and cross over the New York City New Croton Aqueduct. For the quadriax crossing, the transmission line would be mounted on the underside of the Tuckahoe Road Bridge, which also crosses an abandoned railroad right-of-way. At the intersection of Tuckahoe Road and the Saw Mill River Road (State Route 9A), the line will travel 700 feet southwest along Saw Mill River Road until the intersection with Old Nepperhan Avenue, where it would turn west. At Old Nepperhan Avenue, the route veers north/northwest for 500 feet, surfacing for a segment that would be mounted under the Old Nepperhan Bridge, where the roadway crosses the Saw Mill River. The line then turns southwest to the intersection with Nepperhan Avenue. At Nepperhan Avenue, the line continues south for 6,400 feet to the intersection with Ashburton Avenue, and then travels another 1,500 feet to the Nepperhan Avenue Bridge, where it will be installed within the bridge's roadway to again cross the Saw Mill River and the New York City Croton Aqueduct. At this crossing, the transmission line would be installed within the existing bridge roadway. From the Nepperhan Avenue Bridge the route travels another 3,500 feet southwest to the intersection of Nepperhan Avenue and Broadway (State Route 9). The transmission line crosses Broadway where Nepperhan Avenue becomes Prospect Street. The feeder continues west on Prospect Street for approximately 400 feet to the intersection with Riverdale Avenue. The route turns south on Riverdale Avenue, traveling 6,800 feet to the City of Yonkers/City of New York (Bronx County) boundary. The total distance of the proposed route through the City of Yonkers is approximately five miles. In the Bronx, the transmission line would continue along Riverdale Avenue for another 4,200 feet and enter the Henry Hudson Parkway western service road. The line continues on the western service road for approximately 1,000 feet and turns east on West 252nd Street, crossing the Henry Hudson Parkway via the West 252nd Street Bridge. At this location the transmission line will be mounted to the underside of the bridge. The line would then travel south on Riverdale Avenue, parallel to the main Henry Hudson Parkway for 3,600 feet, and continue southeast on Riverdale Avenue for another 4,000 feet to West 230th Street, continuing southeast on West 230th Street for approximately 1,800 feet to the intersection with Broadway. At this point the line turns south, crosses the boundary between Bronx and New York Counties, and then continues along Broadway for approximately 1,350 feet onto Kingsbridge Associates property south of West 225th Street. The total distance of the preferred route through the Bronx is approximately 2.7 miles. The tunnel shaft on the north side of the Harlem River crossing is located on Kingsbridge Associates property approximately 200 feet south of West 225th Street. The feeder will pass under the MTA railroad before crossing beneath the Harlem River, and, on the Manhattan side of the river, pass under property between Ninth Avenue and the river owned by New York Presbyterian Hospital (NYPH). A tunnel shaft will be constructed within the New York/Presbyterian Hospital parking lot to facilitate the tunnel construction activities. South of the tunnel, the line would then continue south on Ninth Avenue for approximately 500 feet where it turns due east on West 219th Street. At the intersection with Broadway, the line turns south again, following Broadway for approximately 3,500 feet to the intersection of West 20th Street. The route turns southeast to follow West 20th Street for 2,000 feet to the intersection of Tenth Avenue, where the line turns south for 800 feet to the intersection with West 20th Street. At West 20th Street the feeder continues south for approximately 1,600 feet to its terminus at the new Academy Substation. The total distance of the preferred route through New York County (including 750 feet for the Harlem River crossing) is approximately 1.8 miles. From http://www.comed.com/publicissues/M29_PDF/Text/Exhibit2Location_Facilities.pdf [ConEd’s Article VII permit application].

Changes to the governance of the power markets will provide an opportunity for the dynamic economic growth that the New York metropolitan region needs and that technology makes possible. Under the auspices of FERC’s effort to restructure the power industry, NYISO has developed a set of rules codified as the open access transmission tariff (OATT), which influences whether the New York metropolitan area will experience growth in transmission – and hence greater connectivity in the tri-state region – or whether the region is tilted towards more investment in electric generation.

Investments in transmission and generation are a trade-off: the more generation in the metropolitan area, the less transmission infrastructure is required, and vice-versa. NYISO’s activities have primarily focused on generation. In large part, that is because its central mission – to keep the lights on – depends most critically on maintaining a designated amount of electricity generating capacity in the New York market area. There is no such requirement for transmission.

To outsiders, it seems at first odd that the federal or state governments seek to ensure sufficient electricity generation capacity in a given area. After all, there is no particular require-
ment for capacity in petroleum refining or even natural gas supply. However, two factors necessitate government intervention in the electric industry. First, modern society relies on electricity for provision of basic services that cannot be replaced, at least in the short-term. A disruption in electricity services, therefore, has far-reaching consequences beyond loss of revenue to the immediate power buyer and seller. Second, all electric assets in the three primary U.S. electric interties are essentially parts of a single, enormous machine. The integrity and reliability of that machine cannot be put into jeopardy. A reserve margin is required to ensure that periodic failures of its component parts (generators, groups of generators, and transmission facilities) do not bring the entire machine to a halt. While it is clear why reserve margins are required, it is unclear how to ensure that these margins are maintained. In the early years of the deregulation process, a market paradigm reigned. ISO-NE, PJM, and NYISO all experimented with regulating capacity markets. Fifteen years later, many believe that these markets are ineffective.11

It is critical to understand this capacity market experience because it remains one of the most problematic aspects of FERC’s market rules. The rules stipulate that load-serving entities—entities responsible for delivering power to wholesale and end-user customers—will be responsible for ensuring that there is enough capacity to meet their projected peak loads plus the designated reserve margin. This makes load serving entities (LSEs) the locomotive of electric asset development. There are stiff penalties imposed on LSEs that do not meet their obligations. LSEs can meet this capacity requirement either by contracting for it in bilateral transactions or by purchasing the capacity in the ISO-administered capacity markets. These capacity markets were never designed to handle all of the capacity transactions. To the contrary, they were contemplated as classic “spot” marketplaces, complementing larger and longer-term bilateral transactions between principals.

FERC’s capacity market rules envision that the RTO/ISO would continuously study their respective power markets. These studies would forecast both load and new generation and transmission projects; identify areas where investment is needed in either generation or transmission investment; encourage the placement of that investment and, if the investment is not forthcoming, identify a “backstop” process whereby the needed investment would be made anyway but presumably financed using rate-payer (as opposed to investor) money. This model is the central planning model that restructuring aimed to minimize. It is not the wide-open investment climate of real markets, and it will have many of the well-documented drawbacks of centralized decision-making. In New York, one of the surprising directions in which the ISO has gone is a doctrine that appears to favor the construction of generation in load pockets, at the expense of transmission. This will make it difficult to overcome New York’s load pocket.

FERC’s market rules have created load pockets in urban areas. In the early days of restructured power markets, there was a boom in generation development but not in transmission development. Generators were typically sited where there was access to input fuels. Thus, many new power plants were built in rural areas and very few new plants in urban areas. However, little transmission was built to deliver power to high-demand urban areas.

As a result of the disparity in generation and transmission infrastructure, New York City has become a load pocket. This could have been prevented by building the transmission required to meet the City’s energy demands alongside generation capacity. The NYISO further perpetuated the load pocket by requiring that a minimum percentage of the constrained area’s load be met by local generation. In New York City, a 1996 study by Stone and Webster noted that the “in-city capacity requirement is a function of transmission cable import capability into the City relative to in-City load.” Since the existing AC cable transmission system can only satisfy 50 percent of New York City’s load, the minimum in-city generation requirement has to be 50 percent. Stone and Webster’s study then goes through a logical progression of events that affect the reliability of either the in-city generators of the AC cables into the City to arrive at the view that reliability concerns require that New York City have an 80 percent “locational generation capacity requirement.”12 However, as transmission capacity increases, the locational generation capacity requirement can be relaxed. The 330MW DC transmission line into from Connecticut to Long Island reduced the Long Island’s locational requirement in that market from 93 to 87 percent.13

The Economic Argument for Transmission

A decision made long ago to impose an in-city and an on-island generation requirement on New York City and Long Island respectively has become a permanent part of the regulatory landscape. However, conditions have changed and require a new regulatory landscape.

Because New York City and Long Island are heavily populated and developed areas, building a generator in these areas is likely to cost much more than in rural areas. A power plant in these areas is likely to cost well over $2,500 per KW of capacity, while the same facility located outside the urban or suburban area is likely to cost under $1,000 per KW. The comparison is even more compelling when considering transmission is infrastructure typically has a much longer useful life than generation facilities. Thus, the urban/rural generation cost difference is essentially a “capacity spread.” A difference of $1,000 per KW in capital cost sets a target for an acceptable cost of a DC transmission line. In other words, for the transmission project to make economic and business sense, the combined transmission and rural generation capacity cost should ideally be no greater than the in-city generation capital cost. If the transmission costs are lower than or equal to the urban generator, the urban load-serving entity with the obligation to procure capacity should choose to import rather than build, especially if the urban-generator-via-cable alternative provides additional benefits such as lower noise and cleaner air.

The capacity spread made the Cross Sound Cable and the Neptune project feasible options for improving transmission into highly developed areas. The Cross Sound Cable and the

11 For example, “Over the last twenty years, the electric industry has see-sawed as regulators seek to strike the right balance between using competitive forces and regulation to establish just and reasonable rates. Nowhere is this tension more evident than in regulation of capacity markets in organized wholesale markets administered by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). Indeed, the degree of litigation that has taken place at the Federal Energy Regulatory Commission (FERC) over the administration of capacity markets has served to impede the smooth functioning of those markets. This litigation has involved many aspects of the capacity markets. One issue that has been particularly contentious recently involves buyer-side mitigation. Buyer-side mitigation refers to offers floors that have been put in place by the FERC to deter large net buyers and local governments from subsidizing new entry and artificially depressing capacity market prices.” From Richard B. Miller, Neil H. Butterfield, and Margaret Combs, “Buyer-Side Mitigation In Organized Capacity Markets: Time For A Change?”, Energy Bar Association, Energy Law Journal, 2012.


project were selected in the early 2000s through a competitive process: they were cheaper and cleaner alternatives than on-island generation. The Cross Sound Cable, installed in 2003, was the first project to demonstrate the advantage of controllable DC transmission between the New York and neighboring control areas. Around the same time, the New York ISO adopted regulations that allowed the locational capacity obligation to be satisfied either by generation located in the load pocket or by a controllable transmission line combined with contractually committed generation located outside of the New York control area. This would enable New York City and Long Island to be fully integrated into the NYISO, the PJM, and the New England markets, allowing the metropolitan region to become a hub of electric trade.

Generators and In-City Mitigation Policies

NYISO capacity regulations pushed back against the advances that would have allowed New York City and Long Island to be integrated into regional power markets. Under FERC rules, the NYISO can propose amendments and refinements to its foundational document (the OATT), but FERC disposes approvals and denials. In 2010, the NYISO put forth the outlines of a series of rules that would ultimately be called “market power mitigation measures applicable to the New York City (in-City) Installed Capacity (ICAP) market.”

The original New York ISO capacity (ICAP) regulations designed a periodic auction of the existing and proposed capacity, with minimum and maximum bid prices. The intent was to protect consumers against market power and predatory pricing (hence the ceiling), and to protect generators against monopoly power in the form of efforts by utilities and Authorities to subsidize new generation and thus drive the price down (hence the floor). To qualify as capacity resources and earn capacity revenues, new projects were required to meet a painstakingly negotiated definition of what would be regarded as a “competitive entrant” (the language selected for this assignment was “NET CONE” with CONE as acronym for Cost of New Entry). The effect of these regulations on New York capacity prices is shown in Figure 1. In New York City, the higher price of capacity is reflected on the vertical axis. At equilibrium, when capacity equals requirements, the payments to generators in the upstate market (NYCA) in 2011 were $8.86 per kilowatt (kw) per month. In New York City; however, the payment at equilibrium was nearly double that price at $16.91 per kw per month.

As usually happens in these types of regulatory constructs, the devil is in the details. The key parameters are: (1) the definition of what constitutes a competitive entrant; (2) how the price floor is calculated; and (3) how the ceiling is calculated. As shown in Figure 2, these constructs were embedded into a demand curve for capacity that allows the capacity price to fluctuate between the floor and ceiling in response to the changes in the balance between supply and demand for capacity. The floor and the ceiling are determined in reference to the cost of a theoretical new generation unit, constructed in the City of New York, Net CONE. The floor was set to protect generators against subsidized competitors at 75% of Net CONE. One effect of this construct was to protect in-city generation against transmission projects that might remedy the load pocket. This formula treats the new DC transmission projects as if they were merely a part of a generator plant located out-of-city (or off-island). In other words, the regulations assume that transmission—even the ultra-sophisticated DC variety—is akin to generation. As a result, the rules practically forbid New York City to take steps to cease being a load pocket. Subsequently, New York City ratepayers will continue to pay high costs for electricity.

The Category Error

The NYISO’s capacity rule will be detrimental to the New York metropolitan region and to the formation of a competitive, innovative electric power market. We argue that this new capacity market rule is founded upon a category error, which should be corrected before the rule is institutionalized at the federal level. The rule is intended to attract needed infrastructure and to prevent “uneconomic entry” that suppresses prices in the New York City capacity market below a justifiable level. In practice, the rule equates transmission with generation, a logical error without federal precedent or economic basis. A review of the Hudson Transmission Project reveals the error and the potential implications it can have on improving transmission in the region.

Barriers to Transmission Development: The Hudson Transmission Project’s Treatment as if It Were Generation

The Hudson Transmission Project (HTP) is a 660MW HVDC transmission project selected by NYPA through a competitive process in 2006; it was constructed between 2011-2013. In 2012, the NYISO ruled that HTP was “uneconomic”—meaning that its capacity clearing prices would be higher than 75 percent of Net CONE—and therefore would be subject to the Mitigation Exemption Test (MET). HTP subsequently lodged a complaint with FERC arguing against this application on grounds pertaining to timing and the exact figures to use in the MET. HTP’s Complaint did not raise the larger issue of whether the MET should be applied to a new transmission line at all. In our view, there is no basis in logical basis, FERC precedent, or economic theory that allows for the treatment of transmission as if it were generation. And the application of this highly technical NYISO rule—designed to prevent exercise of monopoly or market power by utilities in the generation of electricity—has the perverse outcome of preventing competition, preserving market power of generators, and maintaining high electricity prices in New York City. We now turn to the misapplication of this generation rule to a transmission line.

The HTP should not have been subject to the mitigation rule for reasons of timing alone. The HTP won the request for proposals prior to the enactment of NYISO’s buyer market power mitigation rules and before the MET had been proposed. After the rules were enacted in 2008, the NYISO proposed to apply the MET to controllable transmission lines without justifying the proposal or providing guidance on applying the MET to transmission. Hudson Transmission objected to the NYISO’s proposal. The FERC order that accepted the NYISO’s proposal to apply the MET to transmission included only a cursory discussion of the proposal, and did not address the fundamental objections to the NYISO’s proposal raised by Hudson Transmission.

14 An AC transmission line regulated by a phase angle regulator was built by PSEG and ConEd in the 1980s, but did not serve as a model for additional projects.
15 The seminal FERC Order was issued on November 26, 2010. See FERC Docket No. ER10-30-000.
16 The percentages on the horizontal axis are defined levels of surpluses, with 100% being exactly the amount required.
17 See “Complaint Of Hudson Transmission Partners, LLC,” Attachment 7, FERC Docket EL12-98.
18 See FERC Docket No. EL07-39.
19 New York Independent System Operator, Inc., 122 FERC ¶ 61,211 (the “March 2008 EL07-39 Order”), on
**Figure 1:** NYCA Demand Curves


**Figure 2:** NYC Demand Curves
But there’s a much deeper problem than timing: the HTP should not have been subject to the mitigation rule because HTP is a transmission line and the mitigation rule is to apply to generation, what philosophers call a “Category Error.” By treating a transmission line as if it were a generator, the NYISO fails to recognize the fundamental differences between generation and transmission.

The NYISO’s treatment of HTP as a generator was mistaken for at least four reasons. First, generators create electricity; transmission lines convey electricity from one point to another. A generator is a market participant and a producer and supplier of electric energy and capacity. To compound the error, the NYISO treated the Hudson Transmission Project as a “generator lead line” that provides electric energy, capacity and ancillary services from one specific generator to a specific point on the NYISO system. The Hudson Transmission Project is not a generator lead. It is a high-tech, controllable, system-to-system connection between the entire PJM system and the NYISO system. It will continue to operate whether or not any particular generator is on or off.

Second, the concept of “uneconomic entry,” as defined in the NYISO’s current rules, cannot be meaningfully applied to transmission lines. Generation and transmission earn revenues from different sources. Transmission infrastructure earns revenue from providing transmission service. Costs are based on the cost of construction, rather than the marginal costs of fuel. Thus, the revenue streams for new generation and new transmission projects are fundamentally different.

Third, transmission provides different reliability benefits to the system than generators. If a transmission project cannot clear the ICAP auction, and returns the associated unforced capacity deliverability rights (UDRs) to the NYISO, the line can be used to reduce the Installed Reserve Margin (IRM) for NYISO and the Minimum Locational Capacity Requirement (MLCR). By contrast, if a generator in NYISO Zone J is unable to clear the capacity markets, it is not available to be used by NYISO to reduce the IRM or MLCR.

Fourth, federal precedent treats transmission and generation differently. The Commission recognizes fundamental differences between generation and transmission, which is reflected in different standards for evaluating and mitigating generation and transmission market power, respectively. The Commission assesses generation market power through market share, pivotal supplier, and/or delivered price tests that are based on the amount of generation owned or controlled by a generator and its affiliates in a given market. Generators that fail those tests are mitigated by applying cost-based offer caps or similar mitigation. In contrast, the Commission normally assumes that a regulated transmission provider with a franchised service territory (i.e., a non-merchant transmission line) has market power by virtue of the fact that transmission is assumed to be a natural monopoly. Consequently, the Commission addresses this by requiring such transmission providers to provide service under an open access transmission tariff (OATT) and/or through transferring operational control to an ISO/RTO (as Hudson Transmission did). Service over the Hudson Transmission line will be provided under the terms of an ISO/RTO OATT; consequently, it is inappropriate to impose additional mitigation on Hudson Transmission.

Moreover, the Commission itself even hinted that application of the mitigation rule to HTP would be misplaced in its own review of HPT. For merchant transmission providers such as HTP, the Commission applies a four-prong test to evaluate requests for negotiated rate authority. To pass this test, the merchant transmission provider must demonstrate to the Commission, among other things, that the line will not be located in the footprint of another franchised service territory, that it will not have the ability to exercise market power (by turning operational control over to an ISO/RTO), and that it cannot engage in undue discrimination or affiliate abuse. In addition, Hudson Transmission agreed that it would not sell energy or capacity in the NYISO market. The Commission determined that Hudson Transmission satisfied these requirements. The Commission’s decision therefore stands in some tension with the NYISO’s determination that Hudson Transmission should be subject to additional mitigation as if it were a generator.

The NYISO compounded its category error by committing a Composition Fallacy, which occurs when the conclusion of an argument depends on an erroneous characteristic from parts of something to the whole or vice versa. By assuming that Hudson Transmission is, in effect, part of a generator, it attributes to Hudson Transmission only the attributes of a generator. But Hudson Transmission is a controllable transmission line that conveys the products of multiple generators across the Hudson River to New York City.

There is no basis in FERC precedent or economic theory for the presumption that building new merchant transmission lines is a means of exercising buyer market power. The Commission has required ISOs/RTOs to adopt rules to prevent the exercise of buyer market power through sponsoring or subsidizing uneconomic entry because it recognizes that buyer and seller market power are “mirror images” of each other. In other words, suppliers could withhold generation to artificially increase prices, whereas buyers may exercise market power by flooding the market with uneconomic entry to artificially decrease prices. This analogy does not apply to new transmission infrastructure.

This regulation, while highly technical, has enormous implications for the New York metropolitan area. If applied in the future, it will prevent economic transmission projects from being built or it will render existing projects uneconomic by eliminating significant revenue streams. This will make it difficult to improve interregional connectivity and transform the tri-state area into an energy hub.

To remedy this problem, FERC should not only grant relief requested in the HTP Complaint, the Commission should direct the NYISO to eliminate the provisions authorizing the NYISO to apply the MET to new controllable transmission lines and to subject such new projects to Offer Floor mitigation in the event that they fail the MET. Once these remedies are enacted, new transmission lines will be better able to serve New York City and connect the metropolitan region’s disparate ISOs into an energy hub.

Remedying Load Pockets with Transmission Investments

Once the regulations are repaired, utilities can construct transmission projects to eliminate the New York City and Long Island load pockets. FERC’s Order 1000 provides an opportunity to coordinate regionally and to give states more control over
transmission decisions. This will provide states with a competitive structure to push their transmission sectors from the 20th to the 21st century.

FERC Order 1000

FERC Order 1000 requires public utility transmission providers to participate in regional transmission planning processes within the ISO/RTO framework. They are also required to coordinate with neighboring transmission planning regions to determine more cost-effective solutions are available. This interregional planning process will open the door to competition from neighboring transmission providers. This rule opens the door to competition by removing the rights of first refusal (ROFR) to build transmission that utilities have held for decades. This encourages both small and large utilities to move out from their service areas.

Selecting Future Projects

The region can capitalize on FERC Order 1000 by codifying public policy goals in wherein the electric grid is a central component of state economic and environmental policy goals. This is the starting point whereby states can compel companies to invest in transmission to meet policy objectives—such as reliability, affordability, or carbon reductions. For instance, the New York State Energy Highway initiative launched in 2012 can take advantage of the Order by implementing a more progressive transmission development system that advances state goals. Centralized procurements will allow New York to procure renewable energy, energy efficiency technologies, and transmission infrastructure on a large scale in order to decrease the per-MWh cost.

To reach these economies of scale, New York needs to expand the proven and competitive transmission infrastructure procurement mechanism used to select Cross Sound Cable, Neptune and Hudson transmission projects. In the spirit of FERC Order 1000, these competitive projects should be open to new and existing utilities and transmission providers. Independent companies or utilities from another regional transmission planning jurisdiction may build them cheaper, better, and smarter. Competition will open the projects up to the best equipment vendors, the best developers, and the most efficient investors. In transmission, competition ultimately will be a better system than oligarchy, and has a much better chance to bring down the price of renewable energy.

State policy, in other words, can put FERC Order 1000 into practice: a large scale and efficient procurement, coupled with a competitive process for selecting the best transmission project, will assure that New York, New Jersey, and Connecticut can achieve their progressive energy goals while enhancing economic competitiveness.

Harnessing Private Sector Investment

Under Order 1000, state laws can direct transmission development to meet policy objectives. Depending on how a state operates, it can compel or incentivize companies to build out the grid for any state policy purpose. Whether it is to connect renewables, stimulate state economic development, or get access to cheap energy generated elsewhere, for example, Vermont and northern New York share a common border, and lots of commerce and movement along that border, yet practically no electric trade. This lack of electric trade results from a series of transmission decisions made over the decades, in which no connections between Vermont and New York were made. The one line operating today, a 115-kV uncontrolled AC tie, was built decades ago. A high voltage connection between Burlington and Plattsburg across or under Lake Champlain would provide a valuable anchor for both states’ electric infrastructure and would provide steady energy and electric capacity between the states. With Order 1000, Vermont and New York, separately or together, could enable transmission companies to build a better transmission line to reach such a policy objective.

21 Much of the argument in the following pages was originally published in the author’s “Busting the Transmission Trusts: Creative Destruction Is Coming, And It Can’t Be Stopped,” Public Utilities Fortnightly Magazine, February 2013, available at http://www.fortnightly.com/fortnightly/2013/02/busting-transmission-trusts?authkey=e672aa500a99495d1c22728dcd884d93cc8be65015be504d148594189ba.
become direct owners of a greater portion of America’s infrastructure. This can transform transmission from the closed industry it is today, to an inclusive and competitive industry.

Direct investment by institutional investors is a smart way to finance energy infrastructure.22 Direct investors have the capital, and need long-term, predictable returns to pay their pension and insurance benefits. Their investments will expand the breadth of stakeholders in our electric infrastructure to be greater than ever.

In recent years, America’s institutional investors have shown signs that they are gearing up for leaner years ahead. The days of consistent double-digit returns in conventional investment classes are over. While many investment managers have come of age believing the asset bubbles of the 2000s were the norm, others know that it is possible to have a prolonged period of low returns in conventional equity markets. Indeed, looking ahead, turmoil in the sovereign and municipal bond markets suggest that even capital preservation might be a non-trivial task.

This uncertainty makes investments in infrastructure especially valuable. In the past 10 years, almost $100 billion has been invested in U.S. electric transmission development. Most new transmission has been financed by utilities, providing them with the relatively safe, regulated returns allowed by state and federal regulators. Some new transmission is project-financed. Under FERC Order 1000, both established and nonincumbent transmission companies can compete in RFPs and bid market-based or regulated tariffs that are designed to win a competitive procurement. In this emerging competitive transmission sector, developers have to design project returns that are low enough so that capital costs keep the bids competitive, but high enough to satisfy the investment thresholds of the financiers and developers.

The fit between infrastructure projects that need investors and investors who need infrastructure-type investments is clear. Transmission infrastructure assets last for decades and, properly designed, can provide annuity-like returns for investors who want stable returns amidst the volatility in typical equity investment. In the coming decades, there will continue to be an urgent need for infrastructure investment in the United States and abroad. Electricity infrastructure assets, thus far, are mostly in the hands of utilities. Thus, an institutional investor seeking infrastructure exposure in that industry could, until recently, only buy utility stock. The problem with that is that utility management might, or might not, be content to be an infrastructure player. Utilities in search of growth buy or merge with others. Investors and regulators have become increasingly skeptical about the benefits to the public from these ventures, and they are making M&A more difficult to execute.23

Slowly but surely, a transmission asset class is emerging that institutional investors can buy directly, with little or no danger of utility management surprises. Four major independent transmission projects have been developed, three of them in New York, and one transmission company has been set up as a real estate investment trust (REIT). Interestingly, they are all direct current (DC) projects, and all are under the sea. Collectively, they total almost $3 billion of capital invested. The equity has come from pioneering private equity firms, while the debt has been eagerly subscribed by institutional investors—notably, public and private institutions, and Taft-Hartley pension plans and insurance companies.

In each case, the initial development was carried out by a new class of developers, some of them from the oil and gas business, others from the power plant development boom of the 1990s. After paving the way, development capital began to flow from U.S.-based private equity firms into projects, in large part because the private equity (PE) firms saw how attractive the electric power transmission asset class was to their limited partners. In exchange for the capital for early development, the PE firms obtained the right to buy equity and influence the placement of debt in the projects.

The Force of Financial Gravity

This innovative transmission investment terrain is promising, both for New York and for institutional investors. There is ample capital that can be deployed by institutional investors to build much-needed electric infrastructure. With access to capital, developers will have lower capital costs and will perform strongly in a competitive arena. Moreover, companies representing institutional investors willing to buy and hold will have an advantage over those who need to flip the asset a few years. Cross Sound Cable and Neptune interests have already been sold in secondary markets, and the buyers were firms that had comparatively low cost of capital.24 For institutional investors, transmission projects are prized assets; they are long-lasting, low maintenance, critical to their customers, and they typically have a material residual value at the end of the initial financing period. Additionally, transmission projects can be liquid assets. After the transmission projects are built, many of them will wind up in Real Estate Investment Trusts (REITs). In a private letter ruling issued in 2007, the U.S. Internal Revenue Service ruled that electric power transmission assets qualify as “real property” and can therefore be held in REITs.25 Just as master limited partnerships are good institutional homes for oil and gas pipelines, REITs are good homes for electric transmission lines.

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22 There is a growing recognition by pension and insurance funds that investment in infrastructure aligns well with their long-dated return profiles. See Ashley Monk, “Institutional Investors Need to Stop Abdicating Their Responsibilities,” Institutional Investor, May 8, 2013.
23 For example, see “S&P Cuts Duke Energy, Citing Abrupt Leadership Changes,” Wall Street Journal, July 25, 2012. “The ratings firm said as a result of the sudden leadership shift, the company may not be able to realize regulatory goals in two of its biggest jurisdictions.”
24 Most recently, Calpers, the California retirement fund, acquired a majority interest in the Neptune project in 2012.
25 Sharyland Utilities, L.P. was the party requesting the private letter ruling. Subsequently, Sharyland created a REIT that includes as participants Hunt Transmission (a Sharyland affiliate), along with John Hancock, TIAA-CREF, Marubeni, and the Canadian Op.
Transforming the Grid into a Platform for Innovation and Competition

It will take some time to transform the region’s transmission infrastructure and overcome the legacies of the New York metropolitan load pocket. While this change is underway, the region should also pursue distributed generation to meet energy demand, reduce carbon emissions, and improve resilience to external shocks and stressors. The region can become a place of electricity exchange—states can become net electricity exporters, not just importers. The platform for this growth is the grid—intelligently expanded, responsive to state government-led policy aspirations, controlled by a technology-neutral ISO, and open to the emergence of new players. As we wait for increased competition and innovation to transform the region’s transmission infrastructure, the region should also pursue distributed, decentralized generation.

The Appeal of Microgrids – Embracing Innovation and Fortifying the Power Grid

Transmission integrates electricity markets and expands their reach from local markets to fully regional ones, increasing the efficiency and driving down the costs of the central station model. Microgrids complement the central station model by generating electricity where it is consumed, reducing the need for transmission and distribution, and making the current transmission and distribution system more efficient and more durable. Together, increased deployment of transmission and microgrids will yield a more efficient, reliable, and lower-cost grid generating fewer emissions.

Since Superstorm Sandy hit the tri-State area and cut off power to over 8 million customers, public officials and private sector executives have been looking for ways to improve reliability. Specifically, they have been looking at microgrids to prevent or reduce the duration of power outages. Advocates argue that technological advances can transform how our cities, suburbs, and surrounding areas generate, convey, and use electricity, thereby transforming the grid’s reliability and the ability of the grid to withstand external shocks and stressors. Traditionalists claim that the current electricity grid, the so-called central station model, is the greatest technological achievement of the 20th century and has demonstrated the ability to provide electricity on demand, all day, all year, to all users, at an affordable price. They argue that this system should not be rejected because it was found wanting during an anomalous event.

Each of these views has merit, but is incomplete. Microgrid advocates are right to point to the transformative power of technology and competition and the efficiency of many on-site distributed generation systems, but often fail to appreciate the efficiencies of the bulk power grid and the costs of moving away from the central station model. Advocates for the current grid are right to emphasize the efficiencies and economies of scale offered by the current grid, but often fail to grasp what technology can now accomplish.

To strengthen the grid and increase reliability in a region that is likely to face more frequent and powerful extreme weather events and with a society that is ever more dependent on secure, reliable power, the region should capitalize on technological innovations that make distributed, decentralized technologies possible. To do so, state policy should ease the regulatory requirements governing deployment of microgrids and eliminating the sometimes-adversarial relationship between grid owners and those seeking to deploy microgrids. The greatest barriers to the use of microgrids are regulatory, such as interconnections and cost uncertainties. These barriers can be reduced by creating clear standards and timetables, financial incentives for utilities to connect microgrids, and by making information available to large energy users so that they can readily determine if a microgrid is feasible and economic. State policy should also embrace the value of microgrids as a way of making the existing grid more efficient by delaying transmission, distribution, and substation upgrades and by matching customer loads more closely to distribution systems.

Governor Malloy has made the development of microgrids an Administration priority to prevent a repeat of blackouts that resulted from Hurricane Irene, the Halloween snowstorm of 2011, and Hurricane Sandy. Governor Cuomo recently announced that $40 million will be made available for entities developing microgrids larger than 1 MW. Governor Christie’s Board of Public Utilities is re-examining the role of distributed generation as one of its many initiatives following Sandy.

The current central station model has demonstrated its ability to provide electricity on demand, all day, all year, to all users. This model rests on massive economies of scale and has yielded formidable benefits.

First, this system generates electricity at a reasonably low cost. For at least for the next several decades, the central station model—large power plants burning fuel to transform water into steam that will spin turbines that will generate electricity—will remain the principal source of the region’s electricity. Power plants have become more efficient in recent years. As aging, high emission power plants retire, they will be replaced by power plants that are considerably more efficient. Thus, the region’s basic energy infrastructure will become more efficient and, all other factors being equal will continue to generate electricity efficiently and at a low cost.

Trust.

27 “Microgrids are integrated energy systems consisting of distributed energy resources and multiple electrical loads operating as a single, autonomous grid either in parallel to or islanded from the existing utility power grid. In many ways, a microgrid is really just a small-scale version of the traditional power grid that the vast majority of electricity consumers in the developed world rely on for power service today. Yet the smaller scale of microgrids results in far fewer line losses, a lower demand for transmission infrastructure, and the ability to rely on more localized sources of power generation.” “Microgrids Pike Research.” 2009. 14 Jan. 2013. http://www.pikeresearch.com/research/microgrids.
Second, the current system is large and has sufficient redundancies and fail-safe mechanisms to protect its users and itself under all but the most extreme conditions. When plants halt operations for maintenance, electricity is generated by other plants. When there is a very high demand for power, typically on a hot, humid summer afternoon, the system has the capacity to expand to supply power to all who need it without interruption. When a large transmission line is lost, electricity flows through other lines. And when lightning or other disruptions damage power quality, a properly maintained system corrects itself.

The Value of Microgrids

Even against the background of the achievements of the central station model, microgrids are becoming a compelling option for their reliability, efficiency—and for certain users—lower costs. Microgrids are tailor-made for certain institutions with particular electricity, heating and cooling needs where the institution has the capacity either to manage its own use of power or to contract with another entity to do so. Under the right conditions, microgrids can compete against the central station model on reliability and efficiency and deliver power to the institutions that require uninterrupted service. When situated properly within the distribution network, microgrids can complement the operations of the central station grid and deliver gains for all users that are tied into centralized grid.

Reliability

The central station model provides a high, uniform degree of reliability to all users: hospitals and hotels, police stations and restaurants, water treatment plants and private homes. But as society becomes more technologically sophisticated and more businesses and services depend on uninterrupted power, a uniform degree of reliability is inadequate for a growing number of users. Microgrids provide reliability by eliminating the distance between the point of generation and the point of use, and by operating off the grid when the central system is compromised.

In the private sector, some have taken the steps required to obtain increased reliability with on-site electricity generation facilities that can be deployed when the central station grid falters. Often, this on-site electricity generation is deployed with sophisticated building and HVAC controls, energy efficiency and demand response technologies, and energy optimization hardware and software to reduce costs. Across the US, large financial institutions, energy intensive manufacturers, data centers, military bases, hospitals, and college campuses are adopting these technologies. Microgrids bring generation in close proximity to the businesses that need electricity, thereby increasing the reliability of power by virtually eliminating the distance between the point of generating electricity and the point of use.

The public policy choice is clear: when the human and economic costs of power outages are stark, should public funds be deployed to obtain the reliability benefits of microgrids? A uniform standard of reliability is antiquated in a modern, complex society where certain institutions and services are more critical than others. Treating all end-users equally yields hospitals without power, critical infrastructure inoperable, and water unavailable. Decision-makers must assure that critical needs are met first. A democratic process will guarantee that priorities are established in a transparent, non-discriminatory way that will yield increased reliability.

Efficiency

Industry experts have long noted the benefit of microgrids, especially when backed by combined heat and power generation units, known as CHP29 or cogeneration units. These include increased efficiency, lowered costs, and a reduced emission profile.29

CHP Generation

In the central station model, heat created by burning fuel is lost into the atmosphere. CHP units, however, use the heat generated during power generation to supply heating or cooling to the host institution. As a result, CHP improves the efficiency of generation; the amount of fuel to achieve a given output of energy, whether electrical or thermal, can increase by 50% or more in comparison to the central station generation model.31

The key to designing an optimal CHP unit is to match the host institution’s need for electricity and its need for thermal energy, whether for heating or cooling. A CHP unit can be inefficient where there is not a mismatch between the unit’s electrical and thermal output and the host institution’s electrical or thermal load. Assuming that output and need match, CHP’s energy, economic, and environmental benefits are formidable. CHP units also incur no line losses because CHP units are typically deployed close to load, resulting in 6% to 8% additional savings from the line losses inherent in the central station model.

Load Management Technologies

Load management technologies can also deliver energy, economic, and environmental savings, but the impacts are optimized when used in conjunction with CHP. The most common technologies to reduce load include high efficiency lighting, high efficiency HVAC units, building controls, and optimization technologies as well as demand response and peak shaving technologies. The benefits of each technology are building and location-specific and depend on factors including the systems now in place, their remaining life, and whether there is physical space for upgrade. Each technology offers different electrical and financial advantages. The first four can be deployed in conjunction with implementation of a CHP upgrade and will add significant value to any CHP unit. The final two, demand response and peak shaving, are programs offered by third parties or utilities that may or may not be available to institutions that deploy a CHP unit.

29 Combined heat and power generation allows the heat that is usually lost as waste heat in the generation process to be captured and used to provide heating or cooling to nearby homes, offices, or businesses. CHP units are usually installed in large campuses, hospitals, military bases, hotels, and other large institutions where there is both a significant electrical load and a year-round need for heating and/or cooling.

30 See, e.g. the 2011 update to New York City’s PlaNYC, noting the City’s commitment to “Clean distributed generation (clean DG) enables properties to create their own power with higher efficiencies and less environmental impact than central plants. For example, cogeneration systems can achieve high efficiencies by capturing the heat by-product of electricity production and reusing it for heating and cooling, thus reducing GHG emissions. Clean DG systems also help lower peak demand for electricity and improve the reliability of our electrical grid. We will seek to develop 800 megawatts (MW) of clean DG” PlaNYC 2030.7 2007. 14 Jan. 2013. http://www.nyc.gov/planyc.

31 The efficiency of generation is a concept that is simple to describe but has layers of complexity. Measuring the efficiency of CHP compared to the central station model would require comparison of the best of each technology, with appropriate siting, fuel supply, and a host of other variables – a technical operation beyond the scope of this paper. Regardless of the precise increase in efficiency, most industry experts would agree that the increased efficiency is substantial, in the neighborhood of 50% in most circumstances, as the chart on the next page demonstrates.
High efficiency lighting and heating, ventilation, and air conditioning (HVAC) systems provide substantial cost savings to an entity considering CHP. High efficiency lighting is often regarded as the easiest way to achieve substantial savings with minimal pay-back periods, provided that lighting systems have not been upgraded in the last five years. Similarly, high efficiency HVAC units, which are almost always needed for either heating or cooling in New York metropolitan region, offer very considerable savings as well, again provided that the current HVAC systems are at the end of their useful lives.

Building controls refer to a package of technologies that reduce a building’s electricity usage and enhance efficient lighting and HVAC systems. Optimization management systems extend beyond building controls and seek to match the energy usage of the most efficiently designed buildings with the highest efficiency systems, using electricity generated on-site, and purchasing additional power (or selling surplus power) at the most advantageous times. These sophisticated and ever-evolving technologies will monitor and balance the technical features of a micro-grid to insure reliable flow of high-quality power in the same way that the grid operator balances the technical operation of the centralized grid. These technologies together lead to “increasingly affordable microgrids – because the more efficiently you can manage the system, the less capacity you’ll need to build, and the less fuel you’ll need to burn.”

The next two efficiency savings, demand response and peak shaving, focus not on systemic savings year-around or building or campus wide but instead address a different need: the imperative to reduce electricity use when the demand for electricity is at its greatest. Demand response programs are efforts managed by third parties; peak shaving programs are efforts run by utilities. Each is available to potential customers of microgrids. Demand response is a growing business in parts of the United States with robust wholesale electricity markets, including each of the states in the tri-state region. Demand response pays large electricity users to reduce their demand for electricity at certain days and certain times of the year. The entity providing demand response services helps the grid operator to operate at its maximum efficiency by aggregating the reduced demand for electricity across its customer base and guaranteeing that it will be able to reduce demand by a specified level. In the PJM, NYISO, and ISO-NE wholesale markets, demand response programs have grown enormously over the last decade and now represent significant capacity within each region. Large electricity users can derive significant revenue from participating in demand response programs. However, the extent to which demand response can be deployed in connection with microgrids to reduce a user’s overall electric load—not just during peak load—is unclear. Peak shaving programs resemble demand response programs: they are utility-managed efforts to reduce the load of the electricity grid at its peak. Again, as important as the effort to reduce a grid’s peak demand, it is unclear whether an institution that has already reduced its demand for baseload power would be eligible to receive payments for shaving its peak as well.

Microgrids will achieve the same goals as demand response or peak shaving programs but will do so by reducing the overall demand on the electricity system year-around, not just during times of peak demand.

### Developing Microgrids To Complement the Distribution Network

The discussion of the costs and benefits of microgrids should not only focus on the host institution, but also on the broader grid. Microgrids relieve the transmission and distribution network of significant demand, thereby preventing the need for upgrading a transmission line, a significant distribution line, or a transformer. This represents a significant cost savings to the ratepayer in the form of deferred upgrades. The advantages of a microgrid only increase if its deployment avoids expenditure of ratepayer funds. However, utilities are often reluctant to share this degree of information about the status of their distribution system with other, outside entities, and even if they did, it’s not clear how such savings to ratepayers could be monetized and shared between microgrid owners and the ratepayers.

### Barriers

Microgrids have immense potential, but there are many barriers to their widespread deployment. These include regulatory barriers; the perceived threat that microgrids can pose to incumbents’ business models, franchise rights, and revenue stream; the hybrid nature of microgrids and the consequent difficulties of monetizing their benefits and apportioning their costs; and the logistical and operational challenges of a non-utility entity entering the complex electricity market.

To remedy these challenges, FERC can enact a rule to eliminate the perceived tension between the developments of microgrids and utility franchise rights and business models. It is now in utilities’ self-interest to oppose microgrids because their implementation will result in reduced kWh sold. For microgrids to flourish, this disincentive to their development must be eliminated. Utilities and their franchise rights are creatures of state statutory law; therefore, laws governing franchise rights must be modified to reward utilities, rather than penalize them, for microgrid development.

Additionally, states can facilitate transparency and certainty in regulations. The development of a microgrid brings great regulatory uncertainty because the interconnection process has few standards and no timing guidelines. It is sometimes easier to develop larger and more costly projects where interconnection, permitting, and siting rules are established, relatively transparent and have a relatively clear timetable. State regulators should establish a uniform siting and permitting process, much like New York State’s Article VII for transmission projects and Article X for generation projects. Connecticut is moving in this direction.

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Federal agencies, states, industry groups, and non-profits can improve access to information about microgrids. The parts of the distribution system that most need upgrades are the parts that could most benefit from microgrids. Large energy users should be informed of how a microgrid might help their local grid operate more effectively by delaying the need for substantial upgrades.

Microgrids in the New York Metropolitan Region

The New York metropolitan region, with its vulnerability to extreme weather and high energy prices, is primed for microgrid development. It has savvy property owners, world class universities, and unrivaled commercial real estate developers who understand the promise of deploying green technologies. The metropolitan area has hundreds of entities that are suitable candidates for on-site generation and progressive utilities that are willing to explore alternative business modes.

The region is already deploying these technologies. Princeton University lost power shortly after Sandy arrived in central New Jersey. However, within thirty minutes, campus engineers were able to restart the university’s CHP units and provided nearly the entire campus with power. Cornell University in Ithaca also has a microgrid, which provides most but not all of the power for the University and provides a greater-than-utility scale of reliability for critical research operations. Cornell is also capable of operating in islanded mode.

New York State also offers models of microgrids in different contexts: luxury apartments and an urban hospital complex. The Rudin Family, one of New York City’s largest residential developers, launched its first luxury condominium project 130 West 12th Street, in a completed renovated pre-war apartment building with an onsite CHP facility. The building is marketed as a smart green building, noting the efficiency of the cogeneration facilitating and the individualized benefits made possible by optimization controls. Montefiore Medical Center, located off Gun Hill Road in the Bronx, is served by a microgrid. The microgrid provides Montefiore considerable savings compared to purchasing power directly from the utility and offers above-utility grade reliability. Montefiore can operate in islanded mode and continue its core mission of caring for patients during a blackout.

Next steps

Microgrid host institutions and developers have proven microgrids’ potential; it is now time for system planners and policy makers to capture that potential across the region. The region’s decision-makers can fortify our electricity – and social – infrastructure by deploying microgrids at scale.

First and most importantly, microgrids can be deployed to fortify electricity infrastructure and eliminate the loss of power during extreme weather events. Second, microgrids can be deployed across the distribution system to delay the need for costly transmission, distribution, and substation upgrades. The deployment of microgrids and the local distributed generation that is inherent in them can reduce the capital costs of operating the transmission and distribution elements of the power grid. Simply stated, when substantial local generation is made available via a micro-grid, transmission and distribution system planners can obtain years or even decades more service from existing infrastructure. Until recently, these benefits of microgrids have been virtually ignored by most regulators, legislators, and regulated monopolies. 33

Third, microgrids can be deployed to increase the overall efficiency of the entire generation, transmission, and distribution grid system by matching more closely generation to electricity demand or load. For example, New York State is required to have available generation capacity of 16% above its peak load in order to be able to meet demand on the highest days of electricity usage – and its average load is just 57% of its peak load. 34 But this excess capacity needed to meet demand on highest usage days is virtually unused the rest of the year and represents an extraordinarily expensive investment that ratepayers must pay for – as does the difference between average and peak loads. Microgrids can increase the efficiency of the bulk system in two ways: first, by reducing the demand for power from the system on days of highest use by providing generation to meet that use themselves; and second, by deploying energy efficiency at scale, in the way only comprehensive efficiency planning can, and thereby driving down electricity demand throughout the year, and reducing the strain on the grid every day of the year, and the average/peak difference. Energy efficiency at scale includes both engineering and control systems designed to reduce a building’s demand for power and to match that demand to with the availability of local generation, and financial and technological measures, such as purchasing power at night to use it later during the daytime, designed to reduce user costs which bring with them increased efficiencies to the bulk grid.

Finally, microgrids can be deployed to maximize the benefits of renewables by insuring that solar power, in particular, is employed both as a means of emission and carbon-free generation and to delay the need for transmission upgrades and increase the efficiency of the bulk power grid.

Deploying Microgrids at Scale

To achieve reliability goals, microgrids must be distributed relatively evenly distributed across the geography. This will require government action to facilitate deployment in the private sector. First, governmental actions should facilitate the development of microgrids at critical facilities. Interconnection processes must become standardized and regulated monopolies must be incentivized, i.e. compensated, to interconnect and maximize the value of microgrids. Second, regulations can also ensure that microgrids that are partially or wholly funded by public dollars provide public benefits, such powering a shelter or adjacent facilities at no cost during emergencies. Codes and are also necessary to ensure that microgrids work the way they should, especially in an emergency. For instance, seismic codes in are required to ensure that critical infrastructure operate during earthquakes in California. Third, distribution utilities and grid operators must be required to allow microgrids to compete against conventional methods of renovating the grid. Every time a transmission or distribution line above a certain level needs to be upgraded, a microgrid alternative should be examined to see if similar results can be reached at a lower cost. 35 Every time demand response, energy efficiency, or peak shaving project is funded by ratepayers, an RFP should be conducted to identify the most cost-effective solution and allow technologies to compete on price and results.

33 Maine Power RFP for non-transmission alternatives to eliminate need for $18 million upgrade of a radial 34.3kV transmission line.

34 New York State has a maximum of 43,686 megawatts of available resources to meet an anticipated 2012 summer peak demand of 33,295 megawatts and resulting reserve margin requirements totaling 38,622 megawatts. New York ISO, Power Trends 2012: State of the Grid.

35 Some have proposed adoption of a resiliency portfolio standard, that is, a mandate that utilities be required to purchase a particular portion of their electricity from generation sources that are defined as “resilient.” While this policy innovation needs some fleshing out, it would appear that wholesale approach would fail to create the incentives that capture the location-specific benefits of microgrids.
Together, these changes will enable private entities to invest in microgrids at the scale required to deliver greater efficiency and reliability.

**Competition and Commerce Will Enable the New York Metropolitan Region’s Electricity Sector to Flourish**

The electric industry is in a state of disruption. Recent extreme weather and disruptive trends illustrate that the electric industry is in need of competition and innovation to meet the challenges it faces. Policy-makers at all levels of government should introduce competition and innovation into the industry to capitalize on the transformations underway.

Competition reinvents and improves business. Schumpeter’s 1942 declaration still rings true, and more so in New York than elsewhere:

> Capitalism [...] is by nature a form or method of economic change and not only never is but never can be stationary. [...] The fundamental impulse that sets and keeps the capitalist engine in motion comes from the new consumers’ goods, the new methods of production or transportation, the new markets, the new forms of industrial organization that capitalist enterprise creates. [...] The opening up of new markets, foreign or domestic, and the organizational development from the craft shop and factory to such concerns as U.S. Steel illustrate the same process of industrial mutation [...] that incessantly revolutionizes the economic structure from within, incessantly destroying the old one, incessantly creating a new one. This process of Creative Destruction is the essential fact about capitalism. It is what capitalism consists in and what every capitalist concern has got to live in.\(^\text{36}\)

Daren Acemoglu and James Robinson are modern scholars looking for the secrets to economic growth. Their seminal work, *Why Nations Fail*, argues that new ideas and new products will drive economic growth:

> The success and failure of specific groups notwithstanding, one lesson is clear; powerful groups often move against economic progress and against the engines of prosperity. Economic growth is not just a process of more and better machines, and more and better educated people, but also a transformative and destabilizing process associated with widespread creative destruction.\(^\text{37}\)

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Moving toward a distributed, decentralized, and diverse energy infrastructure in the New York Metropolitan Region

Technological changes that are enabling a shift toward a distributed, decentralized and diverse model of energy generation and distribution

Authors
Adam Friedberg
Fiona Cousins
Chris Brosz

Introduction

As the world’s largest man-made machine, the traditional power system relies on centralized generation and transmission with power flowing from large, central-station power plants, connected by a high-voltage grid, to local distribution systems, and from there to customers. Using central-station power plants is inherently vulnerable: any natural or man-made disruption to the plant, fuel system or to key parts of the network can have major and wide-reaching consequences for the cities and regions served. Central-station power plants are also vulnerable to new, energy consuming technologies (e.g., plug-in electric vehicles, or electronics) that were not imagined when the grid was created. This vulnerability is reduced in part by the use of a grid that connects multiple power plants together but can be reduced further by the addition of “microgrids” – smaller, distributed generation systems coupled with energy storage, management and control systems. Microgrids can augment centralized power generation during peak demand periods but can also disconnect and operate independently, “islanding” during a failure of the central grid. The ability of the microgrid to “self-heal” – detect problems with the power grid and isolate the microgrid from the main, or primary grid in the event of a disturbance – increases the overall resilience of the power system. Microgrids can also facilitate cleaner energy production through the use of renewables or by coupling them with heat-distribution networks that use waste heat from the power production process. The communication, command and control capabilities are a key and overarching requirement and element of microgrids. The ability to exchange multiple sets of operational information in real-time via internet, will be a crucial characteristic of all modern grid operations.

Definitions

- **Distributed Generation (DG)** – energy supplied by small generators that are close to the demand
- **Microgrids** – small power systems composed of one or more DG units that can be operated independently from the central power system (Barker 2002)

Making the transition from a centralized grid to a distributed arrangement incorporating generation from a variety of power sources will require a systematic approach in the Metropolitan Region. Interventions must be dynamic and flexible to accommodate legacy infrastructure, changing technology and increasing proportions of renewable generators with unpredictable and varying power output. Infrastructure planners must avoid technological “lock-in” – using outdated technologies or non-adaptable equipment which could become obsolete – and allow a graceful transition from the traditional system.

The technology solutions that will be addressed in the paper are broken down into the following components: generation, transmission and development, and storage.

It will be necessary to integrate generation, transmission and distribution, and storage components with each other and the existing energy infrastructure and supply chain. Although this may complicate ownership, communication and regulation, it will increase efficiency and the overall value at both the site and system level.

The NY Metropolitan Region is in a deregulated energy market where there is conflict between energy generation and energy distribution (Howard 2012). This complicates governance and ownership since utilities that own T&D resources can potentially leverage advantages against generators, and utilities cannot own DG resources unless they can prove “substantial public benefit, [that ownership] does not harm competition and provides measure to mitigate market power” (NYSERDA 2011).
The next steps in implementing DG and other technological solutions requires changes in governance and ownership models, regulations, planning policy, design standards, financial models, technical expertise and communicating the benefits. These next steps for the Region may include:

**Governance and Ownership:** Reduce the ‘silo’ approach and encourage intra and inter organizational coordination; developing ownership models and selecting responsible parties for running and maintaining the infrastructure.

**Regulation/Legislation:** Without regulatory changes, newer, cleaner and more resilient technologies may not be implemented. Examples of this type of regulations are: those that may prohibit non-utilities from running power lines to serve local networks of microgrid customers; those that prohibit utilities from owning generation assets (vertical integrated utility). A standard regulatory definition of a ‘microgrid’ is also needed.

**Standards:** New standards will be required to balance grid supply and demand as penetration levels of non-dispatchable1 technologies (e.g. solar and wind) reach higher and higher levels; drafting uniform standards which can eliminate uncertainty in the product design; flexible protocols that allow variation in technologies.

**Economics:** Developing economic models that compensate utilities and address capital cost recovery for installing these technologies; developing business models for those who may be subject to “electric poverty” – distributed generation may increase electricity prices for those receiving.

**Planning:** Streamlining the lengthy permit processes for siting generation, transmission and distribution assets is needed (currently there is a long application and approval process for design and construction); providing rebates, incentives or loans to reduce high cost of real-estate.

**Technology:** Bringing new technologies to market; increasing guidance and awareness in connecting to an already complex grid.

**Communication:** Seeding demand for improvements to the power system by improving the understanding of the benefits of the technologies within the community and governing institutions. This will require education and experience in implementation, communication of the benefits of smart meters, distributed generation and microgrids, and coordinated action to ease adoption.

**Drivers**

Early electricity generation was done at a local scale, with generators capable of powering a single building such as a factory or a cluster of buildings. Economies of scale and a desire to retire polluting generators from population centers led to the development of a centralized generation system. Over time the increase in population and energy demand required more electricity to be transmitted over higher voltage transmission lines. Continued growth in demand has caused transmission congestion issues due to lack of capacity and losses in the lines due over long distances. For instance, large power demand in New York City and Long Island results in congestion issues such as decreased reliability and high electricity prices from upstate New York generators and in New Jersey. Congestion can be mitigated through distributed generation resources closer to the demand, aggressive demand response programs, and energy efficiency programs (USDOE 2009).

New England has significantly increased their demand resources since the 2008 adoption of its Forward Capacity Market (FCM) auction process, established to procure adequate capacity to meet forecasted installed capacity requirements three years into the future. Under the program, ISO New England projects power needs three years in advance and holds a reverse auction to purchase the resources necessary to meet these requirements. The auctions are open to a variety of bidders, and the entity that can provide the lowest cost power gains the right to supply that capacity. This means that capacity providers other than traditional utility companies may enter the market. Moreover, ISO New England has established rules for qualifying resources that include International Performance Measurement and Verification Protocol (IPMVP)-based protocols to quantify reductions and requirements within specific capacity zones. The use of location-specific pricing concentrates new generation capacity in zones that offer the highest future capacity payments, which reflects areas where demand is expected to be highest (USDOE 2009) (ISO New England, Inc. 2013).

Recent developments are leading to the evolution of a more decentralized, distributed system. Drivers for this include:

- **Favorable economics**
  - Decreasing cost of distributed generation technologies
  - Increasing cost of grid-supplied electricity
  - Wish to avoid costs for new or upgraded transmission and generation assets
  - Rebates and other incentive programs, typically offered by utilities or state agencies to reduce peak demand and thus avoid the need for new generation assets

- **Regulatory changes**
  - Federal regulation, specifically related to emissions combustion
  - Enforcement of state-legislated renewable portfolio standards (RPS)
  - Minimum Installed Capacity (ICAP) requirements in New York City and Long Island

- **Environmental**
  - Increased interest in environmental and social justice issues
  - Desire for more efficient generation and load optimization offered by DG to reduce overall energy use

- **Resilience**
  - Increased interest in the reliability and resilience of electricity supply in the light of uncertainty over fossil fuel supply issues and costs and recent failures of the grid

- **Technological changes**

---

1 Electricity sources that cannot be dispatched at the request of the grid operator
• Improved microgrid technologies including advances in power electronics or converters that can switch power from DC to AC and an increased number of charge/discharge cycles that increase battery lifetime and improve cost-benefit analysis (NYSERDA 2010)
• Increased smart grid technology piloting and deployment such as energy management systems, smart meters, plug-in electric vehicles, automated switches, etc.

Technical solutions

Enabling a shift from a centralized system to a decentralized system will require a multipronged, sophisticated strategy that benefits both customers and utilities. The shift will require a diverse “mix” of power generation – fossil-fuel based and renewable based – and incentives for both users and generators. There will not be one, “fix-all” technology that will rebuild the grid, nor could the region wait for such a technology. The electric grid will transition to a dynamic and flexible system that allows for future technologies, additional clean energy integration, increased reliability and resilience and improved efficiencies. New designs should not be dependent on specific technologies and should instead be flexible to incorporate new devices as products are developed.

This section discusses both the existing technologies and anticipated near term technological advances that will further enable the shift from the existing electrical supply model dependent on large, centralized power stations to a new model of distributed, decentralized and diverse energy generation.

Generation Technologies

Distributed generation includes a variety of technologies that provide power locally to an area of demand, and are distributed across the grid. DG can be a more energy-efficient solution than centralized power since energy is generated and distributed close to the loads, so transmission and transformation losses are minimized and opportunities such as heat reclaim can be realized because transmission distances are not too long. System size varies but DG technologies can be broken into either hydrocarbon-based technologies that require a fuel supply, or renewable energy technologies. An appropriate mix of DG technologies reduces the impacts of fuel supply-chain disruptions and the exposure of the power price to fuel price volatility.

Figure 1: Mix DG Technologies and Fuel Sources to Introduce Resilience into the Grid

<table>
<thead>
<tr>
<th>Imported fuels</th>
<th>Renewables</th>
</tr>
</thead>
<tbody>
<tr>
<td>Internal combustion</td>
<td>Solar</td>
</tr>
<tr>
<td>engines</td>
<td>Photovoltaics</td>
</tr>
<tr>
<td>Gas turbines</td>
<td>Solar thermal</td>
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<tr>
<td>Microturbines</td>
<td>Wind</td>
</tr>
<tr>
<td>Fuel cells</td>
<td>Small</td>
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<tr>
<td></td>
<td>hydroelectric</td>
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<tr>
<td></td>
<td>Geothermal</td>
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<tr>
<td></td>
<td>Ocean energy</td>
</tr>
<tr>
<td>Biogas, biomass &amp;</td>
<td>Solar</td>
</tr>
<tr>
<td>biofuels</td>
<td>Photovoltaics</td>
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<tr>
<td></td>
<td>Solar thermal</td>
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<td></td>
<td>Wind</td>
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<td></td>
<td>Small</td>
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<td></td>
<td>hydroelectric</td>
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<td></td>
<td>Geothermal</td>
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<td></td>
<td>Ocean energy</td>
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</table>

Hydrocarbon-based technologies require a reliable supply of hydrocarbon fuel, which could be either fossil or renewable in nature. For instance, both a solid-oxide fuel cell (SOFC) and a combined heat-and-power (CHP) plant will operate with nearly the same efficiency using fossil natural gas methane as they do using renewable biogas methane. Renewable electricity-generating technologies also operate using “fuels”; however their “fuels” vary greatly between technologies. For example, solar PV uses incident sunlight energy to fuel its electricity production, whereas bioenergy facilities use various forms of biomass for their feedstock.

Figure 2: Global Solar Potential Compared to Other Sources and Global Consumption (Arup)

Renewable energy potential dwarfs both fossil and nuclear energy potential by orders of magnitude; Stanford University states that “the amount of solar energy reaching the surface of the planet is so vast that in one year it is about twice as much as will ever be obtained from all of the Earth’s non-renewable resources of coal, oil, natural gas, and mined uranium combined” (GCEP 2013).

While renewable energy is plentiful globally, siting of renewable energy plants is most effective when it is driven by the local abundance of the resource fuel, for example solar PV systems should be placed in areas with abundant sunshine, and wind turbines sited in areas with steady winds. This dependence on site-specific conditions means that while one technology might be ideal in one area, a different technology may be preferred in another area with different climatic and demand conditions.

The Bayonne Municipal Utilities Authority (BMUA) completed installation of its Oak Street Pumping Station wind turbine in early 2012 (Steadman 2013). The 262 foot gearless turbine has a nominal power of 1.5 MW; its blades are 252 feet in diameter. Once operational, it is expected to produce 3.3 GWh of electricity per year, resulting in an energy cost savings of approximately $175,000 annually (North American Clean Energy 2011). The authority expects to save an estimated $7 million over the next 20 years through a combination of reduced costs and revenue from the sale of renewable energy credits (RECs) to the local utility, PSE&G (Kowsh 2012). Electricity generated by the turbine will be used on-site to help power Bayonne’s Oak Street and Fifth Street pumping stations; excess power will be returned to the local grid through a distribution interconnection (Bayonne Municipal Utilities Authority 2012).
Table 1: Technology assessment of CHP

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
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<tbody>
<tr>
<td>Regulations and Standards</td>
<td>• Low carbon technology helps reduce greenhouse gases (GHGs)</td>
</tr>
<tr>
<td></td>
<td>• Reduction on fossil fuels</td>
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<tr>
<td></td>
<td>• Low carbon technology helps reduce greenhouse gases (GHGs)</td>
</tr>
<tr>
<td>Economic</td>
<td>• Reducing the amount of fossil fuels used</td>
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<td></td>
<td>• Value of the waste heat (hot water, heating, cooling)</td>
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<tr>
<td></td>
<td>• Sale of excess electricity to grid</td>
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<tr>
<td></td>
<td>• As domestic production increases, natural gas prices have dropped relative to electricity prices</td>
</tr>
<tr>
<td>Technological</td>
<td>• Increased energy efficiency</td>
</tr>
<tr>
<td></td>
<td>• Local source of power and heating/cooling</td>
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<tr>
<td></td>
<td>• Diversity of fuel sources (natural gas can be replaced with biogas)</td>
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<tr>
<td></td>
<td>• Improved resilience through diversity of supply paths</td>
</tr>
<tr>
<td>Environmental</td>
<td>• Low carbon technology</td>
</tr>
<tr>
<td>Planning</td>
<td>• Locations with CHP can be safe havens during power outages</td>
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</table>

Opportunities in New York City Metropolitan Region

The advantage of ‘islanded’ CHP systems was proven during Superstorm Sandy. These systems have the capability of powering buildings using the natural gas supply instead of using grid electricity. CHP works best in buildings with 24-hour load and concurrent heat and power demands such as hospitals, mixed-use developments with an anchor load, university campuses, industry centers, and assisted living centers. NYC’s goal is to increase the amount of distributed generation using CHP (and other DG technologies) by 800MW (City of New York 2011). Connecticut has Energy Improvement Districts to allow multiple participants to form an entity to finance and generate its own energy, which allows shared costs and benefits, issuing bonds and installing wires. New Jersey provides for interconnection of CHP systems up to 2MW.

Figure 3: Efficiency of CHP Generation

CHP reduces primary energy consumption in comparison to methods involved in the separate generation of space-heating, domestic hot water and electricity (Arup)
The College of New Jersey installed a 5.2 MW gas-turbine CHP system in 1999 to serve the 39 major buildings located on its 340 acre campus. The system meets approximately 90% of the college’s energy needs and uses natural gas as a fuel source. It runs continuously except during routine maintenance; remaining power demand is met by the local utility PSE&G. The system achieves fuel savings of 13% compared to the gas turbine consumption prior to CHP installation; the system provides approximately 47% of the campus’s annual electricity needs and saves the college an estimated $3.5 million per year (ICF 2013). During Superstorm Sandy, the College was able to island their central plant and operate off the grid after the 26 kV line feeding power to the campus was severed (IDEA 2012). The CHP system enabled the College to maintain electricity throughout the next week while grid infrastructure was repaired. Although it was unable to provide power for off-campus facilities during the storm, the college was able to use its dual-feed substation equipment to back-feed one of PSE&G’s power lines to restore service after the storm (ICF 2013).

**Hydrocarbon-based Technologies**

**Combined heat and power (CHP)**

The location of central power plants in remote areas creates inefficiency in the energy system due to the inability to use waste heat from power stations and the line losses incurred during transmission. Combined heat and power (CHP) is a technology that converts a primary fuel (typically natural gas) into electricity and recovers the ‘waste heat’ by-product and uses it for heating, domestic hot water, and/or cooling (via absorption chiller) for buildings or industrial processes (Howard 2012).

CHP accounts for approximately seven percent of United States electricity generation (EIA 2012). The main driver of CHP growth was the enactment of Public Utility Regulatory Policies Act (PURPA) in 1978 resulting in 340 percent increase in deployment in the following 15 years (Chittum 2011). Recently, the enactment of American Recovery and Reinvestment Act (ARRA) in 2009 and the increase in domestic natural gas production promise future growth (Chittum 2011). CHP systems can range in size but are typically sized for meeting the daily and annual electrical or thermal base load rather than the peak demand. In order for the CHP to be most cost effective the buildings being served should have coincident electric and thermal loads, or thermal storage to allow for heat use at a later time.

New York City has also increased CHP (and PV capacity) over the past six years (Figure 5) (Con Edison, 2012).

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2  Peak demand – Maximum load during a specified period of time
Renewable Technologies

Anaerobic Digestion

Diverse fuel sources for generation will improve the resilience of the region during hazard events and economic change. Most of the electrical generation capacity that has been added in the United States since 2000 has been natural gas fired generation and this will likely continue for the next decade (EIA 2011) (NERC 2011). Since the mid-2000s, natural gas prices in the United States have been low compared to historical figures due to increased inexpensive domestic production from shale formations but they are projected to grow as gas recovery becomes more difficult (EIA 2013).

In addition, natural gas delivered to the region relies on aging infrastructure that extends beyond the metropolitan region into the US and Canada. An alternative, renewable fuel that can complement natural gas is biogas. The organic portion of solid waste, sewage and plant material can be converted into biogas through anaerobic digestion. Anaerobic Digestion (AD) is a carbon-neutral biological process that uses bacteria to break organic waste into biogas (approximately 60% to 80% methane and 20% to 40% carbon dioxide with traces of hydrogen sulfide, hydrogen and nitrogen) in the absence of oxygen. The biogas can also be “upgraded” to remove the balance gases and impurities, which increase its energy value and reduces corrosion and damage to equipment. The biogas can be used to generate electricity and heat, or be converted into compressed natural gas (CNG) and used as transportation fuel.

The process also produces byproducts such as nutrient-rich compost and fertilizer.

An advantage of using organic waste is that the availability of these materials coincides with the population, i.e., the higher the population, the higher availability of organics, enabling more biogas to be generated.
Solar Photovoltaics

Solar Photovoltaics (PV) is anticipated by many to eventually become the most cost-effective and widespread technology for DG (WSJ 2013). Solar PV converts incident electromagnetic energy into electric direct current (DC) electricity via the photovoltaic effect. PV systems are comprised of solar PV cells, which are linked to create solar PV modules. There are two available technologies: thin film and crystalline modules, although commercial PV technology is currently dominated by crystalline modules, which typically have 60 to 72 PV cells arranged in series. Modules are connected together in series and parallel to get the voltages and currents needed to feed an inverter, which converts the DC electricity into alternating current (AC) electricity for consumption.

Solar energy is the most abundant energy source available. In any given hour, more solar energy reaches the surface of the earth than humans use over an entire year (Nocera 2006). Thus, for solar PV to become a more prominent energy generation source, it is simply a matter of placing PV modules over enough surface area to collect incident photon energy for our energy needs. Incident solar energy varies by location but while the southwestern United States has more solar resource than the East Coast, all locations in the United States have ample solar resource to make PV an effective technology (Figure 10).

A principal disadvantage of PV with respect to technologies that use a fuel feedstock (e.g. diesel generators) is that the solar modules only generate power when they are exposed to incident light energy, i.e., when the sun is shining. In order for PV systems to be able to provide reliable power at all times, day and night, energy storage is required. Energy storage can be provided either on-site (typically in the form of electrochemical batteries), or if there is a grid connection, it can be via a process known as Net Energy Metering (NEM). NEM allows the electric grid to serve as the battery that both receives excess power from the solar system when there is surplus and supplies loads when the solar PV system cannot meet them (e.g. at night).

As the amount of solar power on the grid increases, the use of NEM has the potential to disrupt the grid. The use of microgrids with storage in conjunction with PV minimizes this risk and is a major advantage of using this type of system.

Over the past decade, as PV manufacturing companies have scaled up their manufacturing plants to increase throughput, economies of scale have resulted in dramatic reductions in the cost of solar. For instance, the leading Chinese crystalline PV
manufacturers reduced their module costs by more than 50% (Lacy 2013). This steady and rapid reduction of costs is projected to continue with an additional 30% reduction in costs by 2015, resulting in PV module costs of only $0.42/W (Lacy 2013). Similar cost reductions are taking place with components of a solar PV system, such as inverters, mounting hardware and design and installation costs. Simultaneously, as solar PV is becoming less and less capital intensive, the technology itself is improving. Solar cells and inverters are becoming more efficient, and with the advent of microinverters and DC-to-DC optimizers, systems are more optimized and thus generate increased energy. The result of all of these innovations and cost reductions is that solar PV is becoming more economical, with grid parity already reached in some areas and being rapidly approached in others.

For nearly all grid-connected solar PV systems installed in the United States in DG applications, their current grid-direct inverters are required by codes and are designed to disconnect from the grid in the event of a grid fault or outage. This means that if the grid is out, PV systems will not be able to supply power to the loads, even if the sun is shining.

Microgrids allow “islanding” operation, whereby loads can continue to be served in the event of a grid outage without putting line workers at risk of electrocution. They do this by adding two additional components: the battery storage and the bi-directional inverter, to the PV system, thus making it a grid-tie battery backup (GTBB) system. The battery storage system comprises electrochemical storage batteries – deep-cycle lead acid batteries are most common, although Li-ion batteries are likely to become more economical in coming years (discussed in the Storage section). The bi-directional inverter provides DC/AC conversion and allows the battery to charge. These systems are becoming more popular and there has been a large upswing in interest after the power outages resulting from Superstorm Sandy rendered hundreds of conventional grid-tied PV systems useless (Harvey 2012). As the cost of PV and these additional components continues to decrease (particularly batteries), we expect GTBB systems to become more common.

Germany, for example, has inferior solar resource to nearly all 50 states in the United States but is the world’s leader in installed PV capacity, with over 32 GW. On Saturday May 26, 2012, solar energy provided nearly half of the peak electric demands in Germany. Contrast this with the US, which installed 3.3 GW in 2012 to reach a total capacity of 7.7 GW (Kaften 2013). The important takeaway is that nearly all places in the United States can utilize solar PV technology for their energy needs.
Grid parity is a term used to describe the point at which the levelized cost of energy (LCOE) for a particular technology is less than or equal to the price of electricity of the centralized grid. For areas with higher grid electricity costs, and assuming equal incentives, grid parity will occur sooner. Figure 11 shows the grid parity line of solar PV as a function of both solar resource (on the x-axis) and LCOE (on the y-axis), overlaid on various electricity markets around the world. Solar PV in Hawaii reached grid parity several years ago due to electricity rates approaching $0.30/kWh. It is currently a significantly cheaper source of energy than the grid.
Table 2: Technology assessment of Solar Photovoltaics

<table>
<thead>
<tr>
<th>Regulatory and Standards</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Net metering credits generators</td>
<td>• Currently public sector buildings in New York do not have net metering opportunities</td>
</tr>
<tr>
<td></td>
<td>• There are numerous government sponsored incentives and grants available</td>
<td>• Fire code issues (smoke ventilation and impediments) specifically on multi-family residential</td>
</tr>
<tr>
<td></td>
<td>• Interconnection standardized by Standard Interconnection Requirement’s (SiR) in NYS by PSC</td>
<td></td>
</tr>
<tr>
<td>Economic</td>
<td>• Cost of PVs have decreased</td>
<td>• Currently PV generation is more expensive than conventional power generation</td>
</tr>
<tr>
<td></td>
<td>• Incentives are available for customers</td>
<td>• Lack of incentives for rental buildings</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• High costs of storage</td>
</tr>
<tr>
<td>Technological</td>
<td>• Can provide on-grid and off-grid power</td>
<td>• Output degrades over time</td>
</tr>
<tr>
<td></td>
<td>• Available anywhere</td>
<td>• Intermittent energy source without energy storage (in its infancy)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Requires storage or grid connection for continuous use</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Requires inverter to convert into AC</td>
</tr>
<tr>
<td>Environmental</td>
<td>• Low carbon technology (no GHGs)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Renewable supply</td>
<td></td>
</tr>
<tr>
<td>Planning</td>
<td>• Potential revenue source for urban renewal projects</td>
<td>• Potentially tedious permitting and incentive application process</td>
</tr>
<tr>
<td></td>
<td>• Opportunity to review and revise land-use policies</td>
<td></td>
</tr>
</tbody>
</table>

Opportunities in New York City Metropolitan Region

Solar power generation has been successful in the metropolitan area. For example, New York City has increased its PV capacity to approximately 5.65 MW and is projected to increase up to 75MW by 2015 (Meister Consultants Group Inc. 2011). This is due in large part to the improvement in interconnection and incentives. A solar map has been created in NYC (CUNY 2013). In addition, the public sector utilities should work with local government to create a net metering tariff at parity with the investor-owned utilities located in the metropolitan region (Meister Consultants Group Inc. 2011). New Jersey, which has installed over 1GW of capacity, has had success with solar power due to its renewable portfolio standard (RPS), solar renewable energy credits (SRECs) and locating PV’s on buildings, landfills, parking lots, and utility poles (NJBPU 2013).

Increased opportunities in the Metropolitan region exist through microinverters and AC modules, which simplify installations and designs, DC-to-DC optimizers increasing system performance, improved inverters that can provide ancillary services for the grid, control ramp rates to facilitate central station needs, etc., which will enable a higher penetration of solar PV on the grid, continued improvements in solar cell efficiencies, continued cost reductions in both equipment hard costs as well as installation and other soft costs, improved economics resulting in grid parity, and continued development and adoption of alternate financing methods.

Since solar PV systems have no moving parts and consequently minimal maintenance costs; nearly all of the life-cycle costs of a solar system are capital costs. One way to think about solar PV systems (and other renewables), is that the owner is pre-paying for the energy that will be generated over the entirety of the system’s life. While on a life cycle basis solar PV may be the more economical choice, coming up with the capital for the first costs in order to purchase and install a solar PV system remains a barrier for many, a problem that will likely continue going forward as well.

There are several financing methods that help deal with this issue, which can result in increased adoption of solar PV systems (and other DG systems). These include:

- **3rd party financing** – Immediate savings in energy with no upfront cost. Companies own and maintain a system installed on the customer’s property (e.g. roof), selling the generated electricity to the customer at a discount to their utility as either a solar lease or solar Public-Private Partnership (PPA). In some markets, up to 80% of commercial and residential systems are currently financed this way (SEIA 2013).

- **PACE financing** – Property Assessed Clean Energy (PACE) financing is an alternative to a loan whereby system owners can borrow money from a local government, repaying this debt in increased property taxes, or another locally-collected tax or bill, such as a utility bill. Connecticut has state-wide commercial PACE financing in every municipality, while federal mortgage agencies have effectively blocked PACE funding in New York (DSIRE 2013). While PACE financing does not reduce the total price tag of a solar-energy system, it helps make a system more affordable by spreading the cost of the system over a long time period (DSIRE 2013).

- **Crowd-sourced funding** and other innovative funding mechanisms – New financing method using crowd-sourcing to provide low-interest debt or equity financing for medium to large solar PV projects.

Demand reduction

The most effective and cheapest solution to a decentralized system is increasing energy efficiency and conservation to reduce consumption and demand. There are numerous building and infrastructure technologies that improve energy conservation and efficiency for new buildings and major renovations; however, it is difficult to transition the existing building stock to low-energy use due to the high cost and disruption involved in doing so. Organizations such as the New York State Energy Research and Development Authority (NYSERDA) and the New Jersey Clean Energy Program (NJCEP) have helped reduce electricity demand and continue to increase energy efficiency by providing guidance, grants and incentives.
Figure 13: US Electricity Demand Growth from 1950 (Historical) to 2040 (Projected) (EIA 2013)

This paper will not focus on these demand reduction technologies and strategies, however the quantity and cost of the technologies discussed in the paper will be reduced due to energy efficiency and conservation.

Transmission and distribution

The future electric power system should be dynamic and flexible enough to draw from a diverse suite of power sources. The transition from a centralized system to a distributed generation system with storage will require the increased use of the distribution system without heavily relying on the high-voltage transmission system. High-voltage transmission is an issue for the region due to losses from aging transmission lines and increased congestion, and siting new transmission lines is difficult.

Creating a smarter grid requires an array of sensors and electronic devices throughout the T&D system to monitor real-time conditions on the grid and from the customers, enhance situational awareness and control, improve the grid’s “self-healing” ability, and allow two way communications between the generators and consumers of electricity thus integrating operations technologies with information technologies. Communications technology is the key enabler for improving the T&D component of the grid.

Understanding and controlling the state of the grid

Distribution automation technologies integrate the systems discussed below to monitor and control the grid and optimize system performance. Some of the key technologies are discussed below:

- **Distribution management system (DMS)** - a decision support system for utilities to assist control room and field operating personnel to monitor, control and optimize the electric distribution system without compromising safety and assets (EPRI 2011). These systems can utilize geographic information systems (GIS) to track and monitor assets across the grid.

- **Distribution supervisory control and data acquisition (D-SCADA)** - collects and reports voltage levels, real-time demand, apparent power, reactive power, equipment state, operational state, and event logging allowing operators to remotely control capacitor banks, breakers and voltage regulation (NYS 2013).

- **Phasor Measurement Units (PMUs)** – measure current and voltage on the grid at a more frequent rate than existing sensors to determine the “health” of the grid and identify any stresses or vulnerabilities of the grid. PMUs are beginning to be implemented across the region and they will also help enable the integration of renewable energy resources.

- **Voltage and Volt Ampere Reactive (VAR) control on feeders** - help distribution feeders\(^3\) to maintain acceptable voltage at all points and help maintain power. A basic requirement for all electric distribution feeders to maintain acceptable voltage at all points along the feeder and to maintain a high power factor. Recent efforts by utilities to improve efficiency, reduce demand, reduce GHGs, and achieve better asset utilization, have shown the importance of voltage/VAR control and optimization (E. Reinfurt 2013). Utilities continue to face system losses from reactive load, such as washing machines, air conditioners and by optimizing voltage/VAR control great efficiencies can be realized.

- **Intelligent Electronic Devices (IEDs)** - receive data from sensors and power equipment and issue control commands. Smart and automated switches can be installed on distribution feeders to quickly isolate a fault and reduce outages to customers. These technologies use distributed intelligence and use peer-to-peer communications to isolate faults and restore power quickly without the need for field crews in some cases. Other IEDs include Intelligent head-end feeder reclosers and relays, intelligent reclosers and Short-Circuit Current Limiters (SCCL), which allow not only greater fault protection but flexible conversion between different frequencies, phasing, and voltages while still producing a proper AC voltage to the end user.

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\(^3\) A feeder circuit carries a large amount of electric power to a sub-feeder or a branch of a circuit or to a point at which the block power is broken into smaller circuits (NYSERDA 2010).
Communication between generators and consumers

The transmission and distribution components of the grid form the bridge from the generators to the consumers. Bi-directional communication from one to the other through technology can improve the state of the grid. A secure communication system is important to ensure confidentiality of information and integrity of the grid (EPRI 2011), but the more information that can be passed back and forth across the grid, the better generators can meet consumers’ requirements. As noted above, all technology improvements need to provide benefits for both utility and consumer.

Advanced metering infrastructure (AMI) allows two-way communication across the grid through smart meters, customer and operational data bases. It can provide customers with the data that they need both to reduce electricity bills by timing the use of their equipment and to incentivize reductions in energy use. It provides utilities with the ability to operate the electricity system more robustly (EPRI 2011).

One of the main components of AMI is smart metering. Smart meters provide communication between the utility and customer; remotely programmable firmware and a remotely manageable service disconnect switch; consumption measurements; voltage measurements and alarms that can be integrated with distribution automation technologies to maximize benefits; and interval data to support dynamic pricing and demand response programs (EPRI 2011). Smart meters can help customers reduce electricity bills by using electricity more effectively and providing utilities the ability to operate the electricity system more robustly. For example, utilities envision the smart meters’ ability to communicate with devices and appliances to provide information and control to the customer.

The use of smart meters will particularly benefit customers who program the operation of appliances, heating systems, and other technologies based on electricity prices. Additionally, coupled with a DMS, the increased deployment of smart meters will assist utilities in determining which customers have lost service and inform restoration strategies.

Smart meters facilitate real-time or dynamic pricing, rate structures that capture the true cost of energy, by fluctuating throughout the day, based on the costs of generation and transmission at any given time. This is important because electricity can be several times its average cost at times of peak demand, and reducing peak demand can reduce the need for investment in both generation and transmission assets. Typical electric utility rate structures include a basic fee to cover overhead costs (e.g. billing, meters, and equipment), an energy charge based on the number of kilowatt-hours used by a customer over a period of time and a demand charge based on peak power used, typically based on the customer’s peak demand for a given month (some commercial and industrial). Standard residential rates (without an additional demand charge) use a block rate structure, which is tiered based on monthly consumption. Although this system discourages excessive consumption, its ability to accurately reflect true energy costs are limited. In addition, those consumers that have little to no peak demand during the day are subsidizing those who have many peaks during the day. This “cross-subsidy” has been calculated at about $3 Billion annual in the United States (The Brattle Group 2011). An alternative rate structure is time-of-use (TOU), which is designed to encourage customers to shift loads from peak demand times by increasing electricity charges during specific periods such as summer afternoons when air conditioner use is high. A TOU rate structure increases electricity rates during these periods to reflect the cost of greater demand, and decrease rates during off-peak times when capacity is idle. However, it is difficult to determine if a TOU rate structures provide customers with greater value compared to standard rate schedules. Through smart meters utilities can offer real time, or dynamic pricing. This provides customers with price information and allows them to implement measures to shift or reduce usage in response to increased costs. Accurately representing the real cost of electricity incentives customers to reduce consumption during peak periods and can encourage more efficient demand management (Masters 2005).

Once real-time pricing is in place it is much simpler to encourage people to participate in demand response programs that enable grid operators to more effectively manage the balance between supply and demand. Large power demands, such as large lighting areas, motors, equipment, etc. are purposefully curtailed. This “load shedding” can be done to avoid costly peak demand energy or in emergency situations to prevent brown-outs due to inadequacy of supply. Typically demand response programs are done through voluntary load reduction programs initiated by the utility communicating with the consumer, however smart meters and a building’s Energy Management System (EMS) can create an automated demand response system using the internet or other signal (EPRI 2008).

For most grids, peak demands are growing faster than baseload demands, and thus utilities have to procure additional peaking capacity in order to meet seasonal worst-case peak demands. For utilities and grid operators, peaking capacity is generally both expensive and environmentally destructive.

Utility customers are typically given financial incentives in exchange for agreeing to yield some control to the grid operator for temporary shut-off of large power demands. There are some residential demand response programs available that disconnect power to air conditioning compressors of participating customers in a large area (e.g. an entire neighborhood) for a short amount of time (e.g. 15 min), before power is reconnected. If the grid operator has enough residential load shedding capacity due to demand response, he or she may be able to curtail significant amounts of power from the overall demand.

As a result of demand response programs, the term “negawatts” has been coined to describe the grid operator’s ability to subtract megawatts of power from the demand through active demand response management. 4

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4 Peaking capacity is typically provided with single cycle gas turbine plants, which are much less efficient than most thermal plants designed to meet more than peak demands, such as combined cycle plants.
The Long Island Power Authority (LIPA), Stony Brook University and Farmingdale State College secured funding from the US DOE’s American Recovery and Reinvestment Smart Grid program to create a Smart Energy Corridor along Route 110 in Long Island. The demonstration project (in its third year) integrates advanced metering infrastructure (AMI) technology with automated substation and distribution systems to monitor demand and identify outages.

The project is assessing the impact of a range of variables on customer behaviors, including alternative rate structures, information and analytics, and energy automation. Demonstration projects at the Farmingdale campus are evaluating the integration of intelligent devices and renewable energy distributed generation. (Long Island Power Authority: Long Island Smart Energy Corridor 2010)
Storage

As fundamental as the other technologies are to creating a decentralized and resilient grid, energy storage technologies are the game changing component. Electricity supply and demand must match. As such, the electricity infrastructure must be equipped (and capable of forecasting) from its generation facilities to high voltage to low voltage transmission and distribution lines. This is considerably challenging – peak demand changes seasonally, during time-of-day and from customer preferences, and expensive – the addition of power stations or upgrades to transmission and distribution infrastructure). Optimally, the first goal is to reduce power demand from customers thereby reducing the need for transmission and distribution upgrades, generation stations, or purchasing electricity at very high price during these demand periods. However, the costs can be nearly eliminated and the system can be more resilient by adopting new and emerging storage technologies which may include advanced batteries, flywheels, compressed air energy storage (CAES), plug-in electric vehicles (PEVs) and thermal storage (ice or heat storage).

These technologies range in size (kW to MW) and application from transmission to distribution to the customer site. In addition, these technologies can be used for various purposes and timeframes such as shifting generated energy from off-peak to when it’s needed, increasing efficiency of thermal generation, reconciling momentary difference between supply and demand, reserve capacity, maintaining voltage and frequency in the grid, mitigating investment in new transmission assets, and providing energy in the event of failure.

Storage system can complement renewable energy systems and smart grid investments (advanced communications and automatic controls of customer loads), add redundancy during a power outage, add flexibility during peak demand periods when electricity costs are high and ultimately make the grid more robust. Without key technologic advances in energy storage in the coming years, DG penetration will be constrained.

The Bank of America Tower in midtown Manhattan uses thermal energy storage to shift a portion of its cooling electricity demand to nighttime off-peak hours. The technology uses large insulating tanks to store ice produced at night from the buildings CHP system to help cool the building during hot summer afternoons when the cost of electricity is highest. The 44, 8 1/2 foot tall tanks occupy the building’s basement and help chill air circulating through the 2.1 million square foot tower. Each of the 44 tanks holds 167 ton-hours (570 kWh) of cooling capacity, enough to provide cooling for up to 12,000 square feet of office space (Wilson 2009).

The system takes advantage of differential electricity pricing in New York by producing ice at night when the building is unoccupied and utility rates can be up to 75% lower than peak daytime hours. When daytime temperatures increase and the building becomes occupied the ice is used to supplement the buildings HVAC system and reduce electrical loads used for cooling. Although energy reductions are based on outdoor temperature and occupancy, it is estimated that the system can meet between 40-60% of the building’s cooling needs (Gronewold 2011).
Electro-chemical battery energy storage

Electrochemical batteries are energy storage devices capable of converting between chemical energy and electrical energy. The battery technology discussed, i.e. used for electrical energy storage, reverse the chemical reaction and can both charge and discharge. Common rechargeable batteries include lead-acid, nickel-cadmium (NiCd), sodium sulfur (NaS) and lithium-ion (Li-ion).

Batteries can provide energy storage for both small and large systems and can serve to provide on-site dispatchability and firmness to an otherwise intermittent generation facility (e.g. a wind farm with a battery bank facility) or can be used through an electric T&D system to balance supply and demand. From a resilience perspective, stationary systems such as back-up battery banks provide the best support for off-grid power.

Currently, lead-acid batteries are the most common battery technology in battery backup solar systems, but all of the aforementioned technologies have been employed on projects. For example, a NiCd bank in Alaska can provide up to 46 MW of power, NaS batteries have been applied to over 300 grid applications mostly in Japan (34 MW of NaS batteries have been integrated to the Futamata wind farm in Japan) and a 1MW NaS battery system is currently being tested in a Long Island Bus Depot, and a 20MW Li-ion installation has been commissioned in Johnson City NY to provide regulation services to the grid.

Lithium ion batteries are the fastest growing batteries in portable and mobile applications (Battery University 2013). Lithium ion batteries are typically used in smaller applications and will need to be more cost effective at the utility scale.

The selection of the battery is typically based on life-cycle economics, which balances capital costs with other variables such as depth of discharge, maintenance and cycle life, however capital cost is typically the most important factor considered. Energy storage in the form of electrochemical batteries remains an expensive technology but costs continue to decrease with time. For example, in 1999 the price for a Li-ion 18650 cell (the most common and mass produced Li-ion model) was $2,600/kWh and in 2011 the price had reduced to $240 $/kWh (Element Energy Limited 2012). Further, cost reductions are projected to decrease rapidly – automotive lithium-ion battery packs are projected to fall 60 to 70 percent by 2020 and 75% by 2025 (McKinsey 2012).

As the need for electric vehicles, renewable energy penetration, and reliable DG has grown, energy storage has become an area of concentrated interest, research and development. Many, in fact, refer to energy storage as the “holy grail” of renewable integration, due to its anticipated importance in balancing the future energy system and meeting both customer and utility needs.

There are myriad different chemistries and architectures that are being researched and developed both domestically and abroad, with some highlights described briefly below:

- Nickel-zinc (NiZn)
- Flow batteries
- Metal air batteries
- Zinc-bromide

Energy storage will become an ever increasingly critical component in our future electric system, not only enabling massive amounts of renewable energy penetration, but also holding the key to reliable, self-sufficient micro-grids that can operate completely independent of a centralized grid.
### Table 4: Technology assessment of battery storage technologies

<table>
<thead>
<tr>
<th>Advantages of battery technologies</th>
<th>Disadvantages of battery technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulations and Standards</td>
<td>Complicated ownership structures due to multi-functional characteristics</td>
</tr>
<tr>
<td>Requires development of pricing arrangements</td>
<td>Potential bi-directional energy flows create tariff and billing issues</td>
</tr>
<tr>
<td>Integration of battery technology into traditional regulatory classifications</td>
<td>Some Federal Energy Regulatory Commission (FERC) rules prohibit storage from competing with traditional resources</td>
</tr>
<tr>
<td>Resale of electricity beyond RECs</td>
<td></td>
</tr>
<tr>
<td>Economic</td>
<td></td>
</tr>
<tr>
<td>More economical to purchase power during off-peak periods</td>
<td>High capital costs and long return on investment</td>
</tr>
<tr>
<td>Funding available for product development and commercialization in NY and NJ</td>
<td>Difficult to monetize multiple stakeholder benefits</td>
</tr>
<tr>
<td>Technological</td>
<td>Bi-directional energy flow issues (tariffs, metering and billing)</td>
</tr>
<tr>
<td>Numerous benefits depending on technology</td>
<td></td>
</tr>
<tr>
<td>Research and development projects supported by NYSERDA and CAIR funding</td>
<td>Rapidly changing technologies</td>
</tr>
<tr>
<td>Modular and scalable technology</td>
<td>Limited deployment of emerging technologies (Li-ion, flow, etc.)</td>
</tr>
<tr>
<td>Environmental</td>
<td>Battery durability</td>
</tr>
<tr>
<td>Reduction in emissions by using energy that would otherwise be wasted</td>
<td>Commercial maturity</td>
</tr>
<tr>
<td>Increases effectiveness of renewable sources</td>
<td></td>
</tr>
<tr>
<td>Planning</td>
<td></td>
</tr>
<tr>
<td>Provides opportunities for other renewable sources to be used</td>
<td>Wide variety of storage options will likely be needed</td>
</tr>
<tr>
<td>Increases value in areas where power supply is frequently interrupted</td>
<td>Space for battery storage in buildings will reduce leasable area</td>
</tr>
</tbody>
</table>

**Opportunities in New York City Metropolitan Region**

During Superstorm Sandy, critical facilities such as New York University Langone Medical Center and Bellevue Hospital Center lost their backup power due to essential equipment for the diesel generators located on lower levels. These facilities may have benefited from battery power systems (as opposed to mechanical diesel generation systems). However, the cost of battery systems compared to diesel systems is significantly higher.

Organizations such as the New York Battery and Energy Storage Technology (NY-BEST) Consortium were created to stimulate growth in the energy storage industry by utilizing its diverse group of members from different industries and providing a forum for communication and interaction. It also provides funding and grant opportunities and advocates energy storage policies.

In New Jersey, the Office of Clean Energy at the New Jersey Board of Public Utilities has proposed to reduce the renewable energy budget to provide more funding for energy storage ($10 million over four years) (NJSpotlight 2013).
Plug-in electric vehicles

Plug-in electric vehicles (PEV) are battery powered vehicles charged through the grid. Battery swapping and fast charging as well as other infrastructure technologies are evolving. However, PEVs can help balance the grid during off-peak periods and can be used as storage devices to provide a reverse flow power capability such as vehicle-to-grid (V2G). The benefit of V2G is that it also enhances the value of a PEV. PEVs can reduce reliance on volatile fuels such as gasoline and reduce the associated emissions with combustion fuels, specifically as grid emission factors decrease over time (due to renewable portfolio standards). Larger batteries and the implementation of smart grid technologies (discussed in Transmission and distribution) will enable DG in the form of vehicle-to-grid operation.

Table 5: Technology assessment of plug-in electric vehicles/vehicle-to-grid

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulations and Standards</td>
<td>Requires regulatory reform</td>
</tr>
<tr>
<td>• Existing state and local government support</td>
<td>• Will need electricity grid investment to support technology and accelerate deployment</td>
</tr>
<tr>
<td>• Grid power is less volatile and faces less escalation compared to gasoline costs</td>
<td>• ISO/RTO market will need to evolve to include DG resources</td>
</tr>
<tr>
<td>• Increased vehicle efficiency and decreased fuel costs</td>
<td>• Development of business models for the utility and the consumer</td>
</tr>
<tr>
<td>• Higher up-front costs for owners</td>
<td>• Capital costs of fast-charging stations must be significantly reduced to make immediate investment in public EV infrastructure more economically viable</td>
</tr>
<tr>
<td>Economic</td>
<td>Increased power demand on grid</td>
</tr>
<tr>
<td>• Provides load-balancing for electric grid</td>
<td>• V2G requires capability for bi-directional power flow (very few examples)</td>
</tr>
<tr>
<td>• Acts as distributed storage</td>
<td>• Increased emissions from generation facilities</td>
</tr>
<tr>
<td>• Can act as localized backup power</td>
<td>• Requires expansion of public charging stations</td>
</tr>
<tr>
<td>• Higher capital expenditures of electric vehicles are offset with greatly reduced operating expenditures over time.</td>
<td>• Locating charging stations in dense areas</td>
</tr>
<tr>
<td>Environmental</td>
<td>Planning</td>
</tr>
<tr>
<td>• Reduced vehicle emissions (as grid emission factors decrease) and increased public health</td>
<td>• Requires expansion of public charging stations</td>
</tr>
<tr>
<td>• Reduced pressure on petroleum supply networks by decreasing transportation demand</td>
<td>• Locating charging stations in dense areas</td>
</tr>
<tr>
<td>Technological</td>
<td>Incentivized adoption with EV-specific lanes and parking</td>
</tr>
<tr>
<td>• Provides load-balancing for electric grid</td>
<td>• Incentivized adoption with EV-specific lanes and parking</td>
</tr>
<tr>
<td>• Acts as distributed storage</td>
<td>• Incentivized adoption with EV-specific lanes and parking</td>
</tr>
<tr>
<td>• Can act as localized backup power</td>
<td>• Incentivized adoption with EV-specific lanes and parking</td>
</tr>
<tr>
<td>• Higher capital expenditures of electric vehicles are offset with greatly reduced operating expenditures over time.</td>
<td>• Incentivized adoption with EV-specific lanes and parking</td>
</tr>
<tr>
<td>• Increased power demand on grid</td>
<td>• Incentivized adoption with EV-specific lanes and parking</td>
</tr>
<tr>
<td>• V2G requires capability for bi-directional power flow (very few examples)</td>
<td>• Incentivized adoption with EV-specific lanes and parking</td>
</tr>
</tbody>
</table>

Opportunities in New York City Metropolitan Region

Developing an electric vehicle storage program will provide an alternative option for energy storage in the region. The Region, through State’s Department of Transportation and private businesses, can increase its electric vehicle readiness by installing more public charging stations in areas where PEV users drive including municipal and private parking lots, transit stations, tourist destinations and workplaces. In the short-term, PEV can take advantage of already-existing electrical infrastructure and region’s utilities can offer PEV customers with cost saving measures to reduce their rates for vehicle charging. In the long term, larger batteries will enable DG in the form of V2G and as PEV penetration increases utilities can use PEVs for energy storage and V2G programs, specifically during peak hours.

Plug-in electric vehicles

In September of 2009, Delaware’s Governor Jack Markell signed Senate Bill 153 into law. This legislation, the first of its kind in the United States, required electric utilities to compensate the owners of PEVs for energy sent back to the grid. Under its provisions, electric car owners are compensated at the same rate they pay for grid electricity (University of Delaware 2013). In late 2011, the University of Delaware and NRG Energy began working together to commercialize the technology that would enable a two-way interface between PEVs and the electricity grid. A pilot project was initiated to equip electric vehicles with two-way chargers, a feature that is generally not included in US electric car models, and aggregate individual cars into a larger power source to create greater storage capacity and provide load balancing capabilities. In April of 2014, the project was adopted as an official electricity resource by the regional transmission organization PJM Interconnection. The technology is expected to initially help large PEV fleet managers to add revenue, and will eventually include private PEV owners (News.Delaware.Gov 2013).
Thermal energy storage

An alternative storage mechanism is thermal energy storage (TES), which uses electricity to create heat or cooling during periods when electricity prices are low, or during periods of excess electricity, and stores heat for later heating and cooling uses. Two common technologies that can be deployed more frequently are ice storage – using chillers to create ice that can be used for cooling systems or chilled water system during peak daytime use – and hot water storage – using hot water tanks heated by electrodes or heat pumps to be used for domestic hot water or district hot water systems. TES can be valuable for DG systems that produce electricity during off-peak periods.

The Bonneville Power Administration (BPA) was facing balancing reserve issues due to the integration of wind power to the grid. BPA invested in installing electric water heaters, room heaters smart thermostats in a sample of residential homes and commercial buildings, and cold storage facilities in industrial buildings as part of a DOE pilot study. The water heaters act as battery storage that would start during surplus wind power generation. These devices contain two-way communication technologies and a network connection so that these systems can be utilized at the optimum time. Participating customers’ quality of life was not impacted by the project.

Table 6: Technology assessment of thermal storage

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulations and Standards</td>
<td>• Will compliment potential building energy efficiency regulations</td>
</tr>
<tr>
<td>Economic</td>
<td>• Operating cost savings when there is higher peak charges</td>
</tr>
<tr>
<td>Technological</td>
<td>• Long lifetime</td>
</tr>
<tr>
<td>Environmental</td>
<td>• Reduces carbon (replaces fuel-consuming peaking plants)</td>
</tr>
<tr>
<td>Planning</td>
<td>• Provides short-term resilience</td>
</tr>
</tbody>
</table>

Opportunities in New York City Metropolitan Region

There are many opportunities in the Metropolitan Region for thermal storage. For example, the price variability between nighttime off-peak rates and daytime summer on-peak rates creates an economic incentive for building owners to install ice storage systems. Chillers can be run at night, when electricity rates are low, and then have reduced operation during the day, when electric rates are higher. In cities such as Newark, New York and Stamford with a large amount of commercial office space and hot humid summers, there is a high demand for air conditioning services in the summer. This demand occurs at times when temperatures are the hottest. Ice storage provides a service to the grid by shifting energy usage from on-peak times to off-peak times during the summer. This energy time-shift benefits the electric grid by reducing the need for utilities to start-up the most inefficient and expensive forms of electricity generation, usually reserved for times when real-time electricity rates are highest and additional electricity is most-needed.

Thermal energy storage

An alternative storage mechanism is thermal energy storage (TES), which uses electricity to create heat or cooling during periods when electricity prices are low, or during periods of excess electricity, and stores heat for later heating and cooling uses. Two common technologies that can be deployed more frequently are ice storage – using chillers to create ice that can be used for cooling systems or chilled water system during peak daytime use – and hot water storage – using hot water tanks heated by electrodes or heat pumps to be used for domestic hot water or district hot water systems. TES can be valuable for DG systems that produce electricity during off-peak periods.
Pilot Opportunities

Regional advantages and disadvantages to implementation are identified for each of the technologies discussed in this paper. This information should be used as criteria for assessment when considering the feasibility of deployment, including potential barriers and opportunities for engagement. For each technology, pilot programs and case-study projects are identified as a reference for stakeholder groups to use when planning future initiatives. Additionally, a series of potential pilot programs is included for existing sites throughout the region. Knowledge gained from these projects should be published and communicated regularly to political figures, business leaders, professionals and community members to raise awareness and secure support for future opportunities.

<table>
<thead>
<tr>
<th>Generation</th>
<th>Challenges</th>
<th>Opportunities</th>
</tr>
</thead>
</table>
| Anaerobic digester in Staten Island (Fresh Kills or off Arthur Kill). | • Acquisition or use of the site  
• Community acceptance  
• Funding to finance and operate the facility | • The City (and Region) generates a substantial amount of organic waste  
• Export biogas to existing natural gas infrastructure  
• Reduce legal risks and transportation energy from exporting waste outside the region |

<table>
<thead>
<tr>
<th>T&amp;D</th>
<th>Challenges</th>
<th>Opportunities</th>
</tr>
</thead>
</table>
| Microgrid development with CHP and other Distributed Generation Resources in Stamford CBT using the CT Microgrid Grant and Loan Pilot Program | • Requires municipal, Connecticut Light & Power, private utility and local business support (financial and technical)  
• Local businesses interest in owning infrastructure (Energy Improvement District issue) and concern with sharing interconnection  
• Management, maintenance and operation of the microgrid | • Stamford is an Energy Improvement District (EID) (Connecticut Public Act 07-242)  
• High electricity prices and aging infrastructure in the area  
• EID board can play an active role in educating stakeholders |

<table>
<thead>
<tr>
<th>Storage</th>
<th>Challenges</th>
<th>Opportunities</th>
</tr>
</thead>
</table>
| Battery storage with DG integration | • Limited large-scale demonstration projects of battery storage and DG  
• Insufficient technical progress in battery technology  
• Lack of standards and/or models for battery and DG implementation  
• Limited understanding and awareness of battery technology | • Emergency generation (for critical facilities such as hospitals)  
• NYSERDA funding to develop advanced energy storage technology  
• Integration of DG sources into grid  
• Revenue from energy market |

<table>
<thead>
<tr>
<th>NYC Electric Vehicle fleet</th>
<th>Challenges</th>
<th>Opportunities</th>
</tr>
</thead>
</table>
| • PEV manufacturers are generally unwilling to permit battery discharge – battery life would not be tied to odometer (warranty liability), performance standards would not be compromised, general risk of allowing external control interfaces  
• Need for aggregation technology that can manage communication between individually connected PEVs and utilities  
• Standards needed for widespread adoption – a bi-directional charging protocol must include standards for physical components, communications and electricity quality | • Large vehicle fleet - the existing NYC fleet includes approximately 6,300 light and 8,100 heavy duty vehicles and 8,300 police vehicles  
• NREL has demonstrated V2G capacity with a battery converter that provides bi-directional power between PEV batteries and a 480V AC power grid |
Summary

This paper provides an outlook into future technologies that will enable a shift toward a distributed, decentralized and diverse model of energy generation and distribution. DG is a cost-effective way of augmenting the existing grid. The role of the centralized power grid in the New York Metropolitan Region will still be needed because of its advantages in cost and load management as well as its ability to move power over long distances. In addition, reducing energy consumption and demand will maximize the efficiency and reduce the cost of whichever new clean energy option is chosen, i.e., "negawatts" that aren't used can be just as important as the megawatts that are supplied by DG (NREL 2013).

There are many different technologies that can be adopted and it is likely that a diverse group will be selected, depending on local goals and conditions. Some of these technologies already exist, while others are being tested by regional utilities so that they can be easily introduced and integrated into the existing system without affecting customer reliability. To be the most cost-effective these strategies will need to deliver energy savings as well as increased reliability and resilience.

The three components of technical solutions suggested in this paper can be added to the Region individually, however the efficiency and resilience benefits will not be gained unless the components are integrated (Figure 16).

The key advantages of the technologies discussed in the paper are efficiency, reliability and resilience. They include diverse fuel and generation sources, smart technologies to make the grid more flexible and responsive during various climatic conditions. They also provide utilities and customers’ feedback to optimize energy efficiency, and technologies that provide redundancy during failures, as well as fuel flexibility and carbon emission reductions.

It is recommended that the transition to DG is accelerated and facilitated through changes to governance, legislation, regulation and incentives because of its many key advantages. It is expected that the transition will not happen at once and pilot projects are important – but this paper shows that most of the technologies are already proven locally. The transition will require leadership and a clear vision of where the Region needs to get to. As these actions occur and the technologies are added to the grid, the New York Metropolitan Region will move towards a more distributed, decentralized and diverse energy system.
Bibliography


NYS. *NYS 2100 Commission.* New York State, 2013.


(Footnotes)

1 Approximately 1,572,805 GJ (436,767 MWh) is consumed by streetlights and traffic lights (City of New York 2012)
ES.A. Executive Summary

Clean energy investing is a proven yet mostly untapped opportunity for improving America’s economic and environmental prospects. There is massive potential for profitable investment in energy efficiency (EE) and localized distributed generation (DG), but there are fundamental challenges. From the view of the building owner or occupant, access to information and capital are two key constraints. From the capital provider side, EE investments are seen as risky and DG is hampered by high costs and limited access to a niche of customers. EDF’s proposed solution - on-bill repayment – enables building owners and renters to repay clean energy investments on their monthly utility bills.

In this report, EDF describes how OBR can help the New York metropolitan region to achieve, and exceed, clean energy goals. OBR is an evolutionary step forward from inherently limited on-bill financing and thus will help to harvest the great reservoir of economically attractive energy efficiency and distributed energy resources, such as rooftop photovoltaic electricity generation. On-bill financing has proven successful, but it relies on ratepayer or taxpayer funds, which undermine its ability to achieve significant scale. Unlike OBF, OBR uses no public or ratepayer funds while providing a simple and scalable platform for private investment.

This paper lays out EDF’s proposal for OBR as a way to enhance investment in energy efficiency and localized distributed generation in order to meet regional goals for renewable energy, carbon reduction, and affordability. Chapter one introduces the OBR opportunity and lists on-bill programs around the country. Chapter two details barriers to clean energy investing and how OBR helps to overcome them. In the third chapter, we present OBR in context of the clean energy goals and financing programs in the New York metropolitan region. The fourth chapter presents the qualitative and quantitative benefits of OBR in terms of job generation, investment dollars, avoided energy costs and avoided pollution. EDF notes significant uncertainty in our estimates, and thus to arrive at the bounded estimates summarized in Table ES-1. Though uncertain, we are confident these are conservative. The upside could be much bigger. We conclude with a fifth chapter that identifies four key features for a successful OBR program. Several cornerstone program elements identified by EDF for a successful, scalable on-bill repayment program are provided in Table ES-2, below.
McKinsey & Co. ¹ estimate that $500 billion in efficiency investments through 2030 could net $700 billion in avoided energy costs nationally, and Aanesen (2012)² estimate that the $100 billion global rooftop solar industry will install up to 600 GW of new capacity within the next two decades even if the trends in declining production costs cannot be maintained. However, it takes money to make money, and a recent survey of business leaders by the PEW Center on Global Climate Change finds that access to financing is the largest barrier to clean energy investments.³

OBR investments are underwritten and financed by private, third-party capital providers, such as banks and credit unions. The program creates a marketplace for clean energy lending, allowing contractors to provide customers with an integrated package of building upgrades and financing. If done correctly, OBR can lower the financing and customer acquisition costs of clean energy projects, expand the pool of investors and economically attractive investments, and put people to work on good jobs that deliver real value.

### ES.B. How OBR Works

OBR involves several steps detailed here for a hypothetical project. These steps are shown in the following schematic; however, steps may differ in practice depending on specific program requirements.

First, certified contractors identify investments for a building, giving their client (the building owner or occupant) an estimate of the expected monthly energy savings and up-front project costs. If the customer is interested in proceeding, the contractor would help apply for a loan from an approved bank or other financial institution. Once financing investment capital is in hand, the contractor executes the project. After the project is installed, the program could require that the utility or other third party inspector confirm that the contractor properly installed the project and that savings estimates were calculated in accordance with program rules. The customer would ask the local utility to include repayment in future utility bills as part of the rate tariff attached to the meter.

To ensure that customers see a reduction in their monthly utility bill, an independent inspector (certified by the utility and/or a government agency) validates the contractor’s estimate of energy savings before the project starts. Specifically, the inspector determines whether the forecasted average energy savings are likely to exceed the average monthly loan repayment before the project starts. Finally, an independent expert inspector confirms that the contractor has installed energy-efficiency upgrades properly.

In repaying the investment for the project, homeowners pay their regular monthly energy bill, which charges for energy use and the clean energy investment. The energy savings should exceed the monthly payments, so customers see a reduction in their utility bills. However, some programs, such as the Oregon Clean Energy Works, do not require estimated energy savings to match or exceed repayments.

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### Table T.ES-2: Key Attributes of EDF OnBill Repayment

<table>
<thead>
<tr>
<th>Program Attributes</th>
<th>Why this is Important</th>
</tr>
</thead>
<tbody>
<tr>
<td>Private financing for qualifying Energy Efficiency and Renewable Energy projects</td>
<td>Private capital allows for capital at competitive rates of interest and with longer repayment schedules. This will provide substantially larger pools of capital than would be available through the public sector. Furthermore, the program does not use ratepayer or tax payer money.</td>
</tr>
<tr>
<td>Loan is repaid on utility bill</td>
<td>Default (i.e., nonpayment) rates on utility bills tend to be far lower than for other debts, such as mortgages and credit card balances. By utilizing this attribute of utility bills, lenders will be able to offer substantially lower rates, longer maturities and better terms for an OBR loan relative to conventional EE loans.</td>
</tr>
<tr>
<td>Repayment obligation becomes tariff on meter</td>
<td>The OBR program can be structured as a tariff that stays with the meter when the current owner or tenant moves. This program attribute overcomes an important barrier to investing in energy efficiency projects: that the project may have a useful life and payback period that exceeds the duration of the current ownership of the property. A tariff on the meter also enhances the quality of the loan because the obligation survives bankruptcy. Upgrades with long payback periods can be considered without worrying about sale or change in tenant.</td>
</tr>
<tr>
<td>Projects originated by contractors</td>
<td>Government certified, neutral third-party overseers would need to verify that expected energy savings exceed debt service and the total bill will likely decline from previous levels. The new tenant or owner would both benefit from the upgrade and be required to continue to make payments.</td>
</tr>
<tr>
<td>Projects required to produce net monthly savings</td>
<td>Customers will pay a single monthly bill for both energy and debt service that will be lower than their previous bill. This linkage should make it easier for customers to weigh the benefits of energy investments against anticipated savings.</td>
</tr>
<tr>
<td>Utilities follow standard collection procedures</td>
<td>Credit losses on utility bills have historically been quite low and existing programs have seen strong repayments, with default rates of less than 1%. Standard collection procedures further strengthen the credit of the loan, while also ensuring that the lender is removed from disconnection decisions.</td>
</tr>
<tr>
<td>Promote flexibility in allowing for range of eligible project types, property types, and financing structures</td>
<td>OBR is a network, not a prescriptive program. By maximizing program flexibility, OBR allows lenders, contractors, and property owners to choose the best go-to-market strategies, provides more choice for customers.</td>
</tr>
</tbody>
</table>
1. Introduction to On-Bill Repayment

1.A. Investment Opportunities in Clean Energy

The focus of this report is how to bring investment dollars to the table at scale and with attractive terms for clean energy investments. EDF’s solution is on-bill repayment (OBR), a mechanism to arrange repayment of private clean energy investments as tariffs on energy meters such that they show up as line items on utility bills.

OBR is an evolutionary step forward from well-tested successful on-bill financing (OBF). While on-bill financing has been wildly popular, it relies on ratepayer funds and is not available to residential customers. Although it uses the technique pioneered by OBF, OBR does not require ratepayer or taxpayer funding.

1.A.1. OBR Benefits for Energy Efficiency

Energy efficiency (EE) is among the quickest and most cost-effective ways to improve economic and environmental prospects for Americans. McKinsey & Co. estimate that $500 billion in efficiency investments thru 2030 could net $700 billion in avoided energy costs.1 However, it takes money to make money, and a recent survey of business leaders by the PEW Center on Global Climate Change finds that access to financing is the largest barrier to investing in energy efficiency.2

If implemented at scale, EDF estimates OBR can achieve the following benefits for energy efficiency investments over a decade in the tri-state region:

- $14 billion investment in energy efficiency
- $98 billion direct avoided electricity costs to consumers from avoided energy use
- Over 100,000 high wage, non-exportable job-years3
- 200 million metric tons of avoided greenhouse gas (GHG) emissions

We describe these benefits, and our estimate methods, in Chapter 4, as well as Appendices A and B. While these benefits will depend on overcoming a variety of barriers in addition to access to capital, it illustrates the massive potential for positive economic and environmental returns of well-designed OBR. And these are just for energy efficiency; the potential is equally large for distributed generation investments.

1.A.2 OBR Benefits for Distributed Generation

In addition to energy efficiency, OBR can be used for local, distributed renewable electricity generation projects. Electricity generation from photovoltaic and solar thermal technologies is currently a $100 billion marketplace, and installed capacity is forecasted by grow ten-fold in the next 20 years.4 While rooftop solar thermal and electricity are growing quickly, we posit that OBR can further buoy growth by sweetening the deal for both lenders and building owners/occupants, and by expanding the pool of investment worthy buildings. Of course, access to capital is not the sole challenge for making distributed generation economically attractive. There are many well documented barriers, but OBR helps to ameliorate the challenges of attractive investment capital, high transactional costs and lender risks.

We have significant experience with California’s solar roofs initiative that we use to develop estimates for OBR-enabled projects in the New York metropolitan region. Over the next decade in New York, Connecticut and New Jersey, EDF estimates that OBR financing at scale for rooftop PV can yield the following benefits:

- Over 40,000 high wage, non-exportable job-years
- $3 billion in new project investments
- 1,200 MW in new rooftop PV capacity

We describe these benefits, and our estimation method in Chapter 4, but we caution that these estimated benefits are certainly conservative. Our numbers pertain only to OBR-enabled multifamily and single family residential and small scale (<10 kW capacity) commercial rooftop solar investments. Clearly, OBR can be beneficial for larger projects, such as rooftop PV on larger commercial buildings, such as malls, and from additional services, such as demand response.

While DG investments can also help to green the grid and avoid system-wide peaks, we do not attempt to quantify those values here. OBR can be beneficial for a variety of clean energy investments throughout the countryside. Eventually, at scale and over time, DG investments can avoid the need for utility-scale investments in generation and transmissions, thereby saving all electricity customers in the form of lower rates.

1. B. On-Bill is Everywhere

On-Bill Financing has emerged as an innovative financing solution for energy efficiency and renewable energy projects, with at least 20 states currently housing some form of a line-item billing program. However, there is significant variation in program design amongst them. Capital sourcing, administrative structure, project eligibility guidelines, target customers, and shutoff procedures (in case of loan defaults) are choices to be made during program design that will have significant influence on the efficacy of outcomes and scalability.

At present, several states use on-bill financing and repayment at modest scales because they rely on utility – rather than private – funding sources. This is a key distinction: on-bill finance programs are financed by utility or ratepayer funds, while on-bill repayment programs use third-party capital. Most existing programs are on-bill finance programs and are available mainly for businesses and government buildings, not residential buildings.

In this section, we provide a review of on-bill programs around the country, and a review of programs in the RPA region. Nationally, as listed in Table T1, there are about a dozen on-bill finance (OBF) programs currently operating successfully. Only a few, however, offer more than $10 million of financing per year.

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3. A “job-year” is a full time job for the period of one year.
Program design must consider unique utility regulatory structures and the business environment, as well as the existence of alternative access routes for public or private capital for clean energy investments. This chapter highlights the diversity of design components among two exemplary on-bill programs, and presents EDF’s on-bill repayment proposal for comparison.

The following table lists on-bill programs by state. Several states are now beyond pilot programs and beginning to pass legislation enabling on-bill financing programs. Illinois, Hawaii, Oregon, California, Kentucky, Georgia, South Carolina, Michigan and New York all have adopted laws to support the implementation of on-bill financing. Illinois, Michigan, Hawaii and New York are poised to begin pilot programs.

Table T1: On-Bill Programs in the United States

<table>
<thead>
<tr>
<th>State</th>
<th>Program Name</th>
<th>Program Administrator</th>
<th>Utility Type</th>
<th>Customer Type</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>AL</td>
<td>ERC Loan Program</td>
<td>Dixie Electric Cooperative</td>
<td>Utility</td>
<td>Coop</td>
<td>Residential, Commercial</td>
</tr>
<tr>
<td>CA</td>
<td>On-bill Financing Program</td>
<td>SoCalGas and SDG&amp;E</td>
<td>Utility</td>
<td>IOU</td>
<td>Non-residential + owners of multifamily units</td>
</tr>
<tr>
<td>GA</td>
<td>On-bill Financing</td>
<td>Oglethorpe Power Corporation</td>
<td>Utility</td>
<td>Coop</td>
<td>Residential</td>
</tr>
<tr>
<td>IL</td>
<td>Illinois On-Bill Programs</td>
<td>AFC First Financial</td>
<td>Lender</td>
<td>IOU</td>
<td>Residential</td>
</tr>
<tr>
<td>IN</td>
<td>Indianapolis Super Bowl Legacy BetterBuildings Project</td>
<td>City of Indianapolis</td>
<td>Govern-ment</td>
<td>IOU</td>
<td>Residential</td>
</tr>
<tr>
<td>KY</td>
<td>How$mart Kentucky</td>
<td>MACED</td>
<td>CDFI</td>
<td>Coop</td>
<td>Residential, Small Commercial</td>
</tr>
<tr>
<td>State</td>
<td>Program Name</td>
<td>Program Administrator</td>
<td>Administrator</td>
<td>Utility Type</td>
<td>Customer Type</td>
</tr>
<tr>
<td>-------</td>
<td>---------------------------</td>
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<td>---------------</td>
<td>--------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>MI</td>
<td>Michigan Saves</td>
<td>Michigan Saves</td>
<td>Non-profit</td>
<td>Coop</td>
<td>Residential, Commercial</td>
</tr>
<tr>
<td>MN</td>
<td>Shared Savings</td>
<td>Alliant</td>
<td>Utility</td>
<td>IOU</td>
<td>Commercial</td>
</tr>
<tr>
<td>NH</td>
<td>PSNH SmartStart</td>
<td>Public Service of New Hampshire</td>
<td>Utility</td>
<td>Coop</td>
<td>Municipal</td>
</tr>
<tr>
<td>NH</td>
<td>Residential Program</td>
<td>National Grid</td>
<td>Utility</td>
<td>IOU</td>
<td>Residential</td>
</tr>
<tr>
<td>NJ</td>
<td>SAVEGREEN: 0% APR On-Bill Recovery Option</td>
<td>NJNG</td>
<td>Utility</td>
<td>IOU</td>
<td>Residential</td>
</tr>
<tr>
<td>OR</td>
<td>Clean Energy Works</td>
<td>Clean Energy Works Oregon</td>
<td>Non-profit</td>
<td>IOU</td>
<td>Residential</td>
</tr>
<tr>
<td>OR</td>
<td>MPower</td>
<td>City of Portland Housing Bureau</td>
<td>City Government</td>
<td>IOU</td>
<td>Residential</td>
</tr>
<tr>
<td>PA</td>
<td>Keystone Help</td>
<td>AFC First Financial Corporation</td>
<td>Lender</td>
<td>IOU</td>
<td>Residential</td>
</tr>
<tr>
<td>SC</td>
<td>Rural Energy Savings Program</td>
<td>Electric Cooperatives of South Carolina</td>
<td>Utilities</td>
<td>Coop</td>
<td>Residential</td>
</tr>
<tr>
<td>WI</td>
<td>Shared Savings</td>
<td>Alliant</td>
<td>Utility</td>
<td>IOU</td>
<td>Commercial</td>
</tr>
</tbody>
</table>
2. The Challenge of Clean Energy Investing

OBR, in conjunction with other financing techniques, has the potential to help overcome major market barriers that limit investment in EE and DG projects for commercial and residential buildings. These challenges include:

- High loss rates for unsecured loans
- Borrower’s with relatively low credit scores
- Split incentives between the renter and building owner
- Commercial mortgages generally have limitations on additional indebtedness
- Competing priorities for would-be investors
- Poor time alignment between upfront costs and longer term benefits.

In this section, we discuss how OBR addresses each of these challenges.

2.A. Investor Risks

Lenders are reluctant to make unsecured loans at attractive rates to people with poor credit or financial history. Most commercial buildings are owned by limited liability companies that are protected from debts on the building. A creditor only has recourse to the asset, not the owner(s), so even if a loan is permitted by the first mortgage holder, it would be subordinated to the first mortgage and would often be perceived as having poor credit quality. That is, lenders would see these loans as high risk, and thus they would command higher rates of interest.

Under the terms of most commercial leases, tenants often pay for operating expenses including energy costs. Landlords, on the other hand, must absorb various capital expenses. For an EE project this may mean that landlords pay for the project but tenants capture the bulk of the savings. As a result, projects that yield a clear return are not undertaken.

Most commercial buildings have a first mortgage that includes a limitation on additional indebtedness or additional liens. OBR skirts this challenge as a subordinated investment as a tariff on the meter, not a lien on the property.

Lenders seek a scalable, proven investment strategy. To date, the market for underwriting EE investments has been small with few successfully established business models; it is an emerging industry without a proven track record.

2.B. Borrowers with Low Credit Scores

Energy users are frequently reluctant to invest their own capital in EE projects because of competing business or household priorities. They often seek “turn-key” structures with zero or low initial cost, when available. For homeowners with high debt-to-equity ratios, home equity loans are not available.

Owner or tenant turnover rates can be faster than the repayment period of some efficiency upgrades. Longer-term investments that stay with the building rather than a particular owner may extend beyond their ownership (tenancy).

OBR enables longer term investments, with customers realizing benefits from day one – and the financing stays with a building’s utility bill even when there is a change in ownership or occupancy. Lenders see the OBR mechanism as a key to high quality credit. Since building owners have an obvious incentive to pay their utility bills, lenders benefit from greater confidence in the likelihood of the loan being repaid. Thus, OBR can greatly reduce the cost of credit while increasing its availability to more borrowers.

EDF has developed OBR to address these barriers to achieving large scale investments in energy efficiency, as well as to financing distributed generation investments. In some instances, OBR might be a silver bullet to enable customers to afford a more efficient appliance, such as an emergency hot water heater replacement. In many cases, however, OBR is just one piece of a complex set of solutions.

3. Tri-State RPA Region Goals Programs for Clean Energy Investing

This chapter describes significant clean energy goals and financing programs in New York, New Jersey, and Connecticut. State governments and utilities, in partnership and in parallel to federal and local programs, implement numerous programs. We summarize some of these programs and evaluate them relative to the economic potential and scale of aspiration in the state goals, where they exist.

The majority of energy efficiency programs channel public and ratepayer funds that are currently of insufficient scale and not capable of achieving significantly larger scales. The sun-setting of the American Recovery and Reinvestment Act (ARRA) initiatives for energy efficiency and renewable investment signals a significant reduction in federal funds.

The briefing book from New York Governor Andrew Cuomo’s latest State of the State Address presciently assessed the emerging challenge facing clean energy financing the region:

“It is becoming evident that [subsidies] alone cannot achieve the level of clean energy deployment necessary.”

– Governor Cuomo 2013, p. 27

This chapter reviews the major strategies employed by the states of New York, New Jersey and Connecticut to achieve clean energy objectives. In terms of goals, we examine New York’s Energy Efficiency Portfolio Standard (EEPS), New York’s Renewable Energy Portfolio Standard (RPS), New Jersey’s RPS, and Connecticut’s RPS. Initiatives on clean energy financing that we discuss include:

3. A. State Energy Goals

**New York**

The New York State Energy Planning Board is developing the 2013 State Energy Plan with leadership members of the New York State Energy Research and Development Authority (NYSERDA), NYS Department of Environmental Conservation, the Empire State Development Corporation, and NYS Public Service Commission (PSC). At present, the state has implemented both an Energy Efficiency Portfolio Standard (EEPS) and a Renewable Portfolio Standard (RPS).

New York’s EEPS sets a goal of 15% below “business-as-usual” energy demand in 2015, commonly known as the ‘15 by 15’ goal. According to a 2012 study by Pace University (Figure F1), a reduction of 15% versus projected demand by 2015 would require annual energy savings of approximately 24 million MWh in 2015. Despite a large potential for energy savings through energy efficiency programs and energy code revisions (an estimated 37,000 GWh for the 2008-2015 period as calculated by Optimal Energy Inc.), New York State only achieved 54% of its 2008-2011 EEPS target of 3,943 GWh.

While all three states recognize the need for private capital in clean energy financing, it is evident that New Jersey’s approach differs quite significantly from those of New York and Connecticut. New Jersey’s recent withdrawal from RGGI does not bode well for the adoption of robust goals or measures for energy efficiency and renewable energy.

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The PSC issued a May 2009 order to set a natural gas reduction target of 14.7% versus projected demand by 2020, but it is not on track to get there. The target equates to a savings of 4.35 billion cubic feet (Bcf) per year for 2009-2011 and 3.44 Bcf annually for the period 2012-2020. Although these savings would total to 44.1 Bcf per year in 2020, reductions would have to be 112 Bcf by 2020 to meet the 14.7% target.

In 2010, the PSC updated New York’s RPS to 30% renewable electricity consumption by 2015; previously it had been 25% by 2013. NYSERDA is responsible for securing new renewable resources using an RPS fund. The New York RPS specifies a Main Tier and a Customer-Sited Tier. Of the 30% goal, 20.7% will be met with existing renewable facilities that began operating after 2002, and 1% will be met through voluntary green power sales. Of the remaining 8.3% of energy to be produced from renewable sources by 2015, 91.56% of that energy is expected to be generated from Main Tier facilities (utility scale renewable projects), while 8.44% is anticipated to be produced from the Customer Sited Tier. Programs designed to achieve these EEPS and RPS goals are administered by the state utility providers and NYSDERA.

Funding for EEPS and RPS-related programs comes from several sources. Principally, retail consumers of electricity and natural gas in New York fund clean energy programs through a System Benefits Charge (SBC) paid on their utility bills. In 2011, total program collections were $286 million. Anticipated contributions to the SBC charge are estimated to average about $295 million annually from 2012 to 2015. Additionally, New York receives EE/RE funding through its participation in the Regional Greenhouse Gas Initiative (RGGI) and through various federal grant programs.

New Jersey
New Jersey has 20.38% Renewable Portfolio Standard for energy year 2020-2021. To achieve the 20.38% RPS set by the state Board of Public Utilities (BPU), New Jersey is permitted to utilize Class I (Solar, wind, wave, hydro < 3 MW, geothermal, landfill gas, anaerobic digestion, fuel cells, and sustainable biomass) and Class II (hydro > 3 MW, Municipal Solid Waste to Energy) renewables. A distinguishing characteristic of New Jersey’s RPS is its specific targets for solar- electric and off-shore wind. New Jersey’s solar “carve-out” is 4.1% solar-electric by energy year 2027-2028, while the off-shore wind carve-out is 1,100 MW with no immediate timeline due to the regulatory uncertainty surrounding off-shore wind implementation in the United States.

For utilities failing to meet their RPS generation obligations, the RPS may alternatively be met with the purchase of Class I Renewable Energy Certificates (RECs), Class II RECs, Solar RECs (SRECs), Offshore Wind RECs (ORECs). While SRECs must be purchased from within New Jersey, all other RECs may be purchased from REC generators in the PJM Regional Transmission Organization (PJM) comprised of utilities in 13 states and the District of Columbia. According to the 2011 New Jersey Energy Master Plan, 87% of Class I RECs used to satisfy the annualized EY 2011 RPS target were produced out of state. To the extent that more SRECs can be generated within New Jersey or the tri-state region, be it a result of OBR or other policies, the benefits will be kept within the region.

While New Jersey does not have an EEPS, in 2003 the Board of Public Utilities created the Office of Clean Energy (OCE) to implement energy efficiency programs and encourage the adoption of renewable energy resources. The OCE is responsible for implementing the state’s “Clean Energy Program”, which includes overseeing the state’s Clean Energy Fund, as well as administering rebates, incentives, and green jobs training. The OCE is perhaps best known for its role in making New Jersey a national leader in solar energy through the SRECs registration program.

Connecticut
The Connecticut Public Utilities Regulatory Authority (PURA) set an RPS totaling 27% by 2020 and specifies three classes of clean energy resources:

1. Class I (solar, wind, fuel cells, landfill methane, anaerobic digestion, ocean thermal power, wave, tidal, low-emission advanced renewable energy conversion technologies, hydro-power facilities ≤ 5MW, and sustainable biomass); must comprise 20% of energy generation in 2020.
2. Class II (municipal solid waste to energy, certain biomass facilities not included in Class I, and certain hydropower facilities not included in Class I).
3. As of 2010, 4% of generation must come from Class III commercial/industrial customer-sited CHP systems.

Although Connecticut has no standalone EEPS, the Connecticut Department of Energy and Environmental Protection (CT DEEP) has identified that a strategy of implementing all cost-effective energy efficiency solutions could save 4,339 GWh annually by 2020 when compared against a business-as-usual projection. The 2012 Integrated Resource Plan for Connecticut attributes the potential for additional energy savings, among other things, to the growing availability of project financing through the state’s first-in-the-nation “green bank”, the Clean Energy Finance and Investment Authority (CEFIA).

The green bank will complement existing efficiency and renewable funding administered through the Connecticut Energy Efficiency Fund (CEEF) by the Energy Efficiency Board (EEB). Created in 1998, CEEF has been funded through a systems benefit charge and more recently through proceeds from RGGI. CT DEEP estimates that by increasing the EEB budget for conservation and load management to $206 million/year from a business as usual budget of $105 million/year, the state could achieve energy savings of 2% annually from 2012-2020, resulting in monetary savings of $534 million annually by 2020.
3.B. Existing State Resources and Programs

New York

New York State has a significant track record of investment in energy efficiency and renewable energy through NYSERDA, NYPA, LIPA, the Division of Housing and Community Renewal, the Department of State, and the PSC’s oversight of the utilities. In 2010 alone, the state’s electric utilities and energy efficiency programs saved more than 1,200 GWh, and in 2011, the American Council for an Energy Efficient Economy (ACEEE) State Energy Efficiency Scorecard estimated that statewide funding for electric energy efficiency topped $1 billion. Since June 2008, the state Public Service Commission (PSC), responsible for overseeing New York’s utilities, has approved over 100 programs for electric and gas efficiency. During the period 2012-2015 the programs associated with the state’s EEPS standard are expected to reach funding levels of $3 billion and achieve energy savings of 11,360 GWh (ACEEE 2011).18

The NY-Sun Initiative coordinates the various solar initiatives of NYSERDA, LIPA, and NYPA in their efforts to grow solar energy in New York. Through those entities, the initiative intends to channel $800 million through 2015, with the lion’s share dedicated to expanding solar PV deployment incentives (“NY-Sun Initiative Fact Sheet” 2012). For example, the initiative aims to quadruple customer-sited solar photovoltaic capacity from 2011 levels, by the end of 2013. The remaining $50 million in funding to 2015 will be put to work lowering the Balance of System costs (BOS) for PV in New York through research and development. NY-Sun, in partnership with LIPA, introduced New York’s first feed-in tariff system, which will encourage distributed generation by allowing Long Island utility customers to sell up to 50 MW of on-premises generated solar back to LIPA. In his most recent State of the State address, Governor Cuomo proposed extending funding for the NY-Sun initiative through 2023.19

New York’s participation in the Regional Greenhouse Gas Initiative (RGGI) has also supported investments in energy efficiency and renewable generation resources. Between 2009 and 2011, RGGI funds from the sale of carbon credits contributed $327.6 million to the state of New York. Of that funding administered by NYSERDA and the PSC, $163.7 million, or about half went to energy efficiency programs, energy audits, and benchmarking. Nearly $17 million was invested directly in renewables. Another $8.6 million went to Education, Outreach, and Job training.20 One specific beneficiary of RGGI funding is the Green Jobs-Green New York Program (GJGNY), which administers EE audits and financing through a revolving loan fund, while also providing workforce training and generating green jobs. GJGNY is now home to New York’s On Bill Recovery program, administered through NYSERDA.

Two years after the Green Jobs-Green New York Act established GJGNY, the Power NY Act of 2011 created the legal framework for an on-bill repayment mechanism in GJGNY (NYS Assembly Bill A08510 – “Power NY Act of 2011”). As part of Home Performance with Energy Star and GJGNY, NYSERDA began offering “On-Bill Recovery loans” to finance home, small business, and not-for-profit energy efficiency improvements in January 2012. The program incorporates many distinctive features of OBR: low interest repayment (3.49%) through the monthly utility bill, transferability of the debt obligation upon sale of the property, and monthly payments designed not to exceed the energy savings of the improvements.

While New York’s OBR program represents a huge step forward in EE/RE financing mechanisms, the On-Bill Recovery Financing Program has yet to be scaled to meaningful proportions (Figure F2). As shown in Table T3, through March 2013, the program has closed 721 loans amounting to $7.7 million. While this program is the clear predecessor to any expanded OBR efforts to come, the upfront loans are still provided from ratepayer and public funding, a major impediment to the program’s scalability. In order for NYSERDA’s OBR program to achieve statewide scale, it seems necessary to pair the mechanism with abundant private capital.

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### Table T3: Green Jobs - Green New York:
Monthly Update (March 2013)

<table>
<thead>
<tr>
<th></th>
<th>Tier 1</th>
<th>Tier 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Applications Received</td>
<td>2,878</td>
<td>224</td>
</tr>
<tr>
<td>Applications Approved</td>
<td>1,574</td>
<td>156</td>
</tr>
<tr>
<td>Approval Rate</td>
<td>54.7%</td>
<td>69.6%</td>
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<tr>
<td>Loans Closed</td>
<td>650</td>
<td>71</td>
</tr>
<tr>
<td>Value</td>
<td>$7,005,889</td>
<td>$707,540</td>
</tr>
<tr>
<td>Loans Pending</td>
<td>29</td>
<td>1</td>
</tr>
<tr>
<td>Loans Denied</td>
<td>762</td>
<td>33</td>
</tr>
<tr>
<td>Loans Withdrawn</td>
<td>579</td>
<td>61</td>
</tr>
</tbody>
</table>

Note: As of the March 2013 Progress Report, 9 Small Business/Not-For-Profit OBR Loans had been approved amounting to $304,023. No loans had yet been closed.

### Table T4: NJ Clean Energy Program 2012-2013

<table>
<thead>
<tr>
<th>Energy Efficiency Programs</th>
<th>Approved Budget*</th>
<th>Expenditures To Date 2/28/13</th>
<th>Committed Expenditures</th>
<th>Prorated 18 Month</th>
<th>% Projected Completion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential HVAC - Electric &amp; Gas</td>
<td>$26,891,450</td>
<td>$16,856,346</td>
<td>$0</td>
<td>$21,672,444</td>
<td>80.6%</td>
</tr>
<tr>
<td>Residential New Construction</td>
<td>$20,264,931</td>
<td>$12,077,220</td>
<td>$8,371,023</td>
<td>$26,290,598</td>
<td>129.7%</td>
</tr>
<tr>
<td>Energy Efficient Products</td>
<td>$22,137,799</td>
<td>$16,066,447</td>
<td>$0</td>
<td>$20,656,860</td>
<td>93.3%</td>
</tr>
<tr>
<td>Home Performance with Energy Star</td>
<td>$39,358,735</td>
<td>$27,971,079</td>
<td>$6,077,867</td>
<td>$43,777,217</td>
<td>111.2%</td>
</tr>
<tr>
<td>Marketing - Residential EE</td>
<td>$1,743,976</td>
<td>$1,278,555</td>
<td>$0</td>
<td>$1,643,857</td>
<td>94.3%</td>
</tr>
<tr>
<td>Sub-Total: Residential Energy Efficiency Programs</td>
<td>$110,396,892</td>
<td>$74,249,646</td>
<td>$14,448,890</td>
<td>$114,040,976</td>
<td>103.3%</td>
</tr>
<tr>
<td>Residential Low Income</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Comfort Partners</td>
<td>$50,000,000</td>
<td>$36,091,483</td>
<td>$0</td>
<td>$46,403,336</td>
<td>92.8%</td>
</tr>
<tr>
<td>Sub-Total: Residential Low Income</td>
<td>$50,000,000</td>
<td>$36,091,483</td>
<td>$0</td>
<td>$46,403,336</td>
<td>92.8%</td>
</tr>
<tr>
<td>C &amp; I New Construction</td>
<td>$5,524,122</td>
<td>$1,955,797</td>
<td>$678,078</td>
<td>$3,386,411</td>
<td>61.3%</td>
</tr>
<tr>
<td>C &amp; I Retrofit</td>
<td>$57,257,019</td>
<td>$23,667,267</td>
<td>$21,972,909</td>
<td>$58,680,226</td>
<td>102.5%</td>
</tr>
<tr>
<td>Pay-for-Performance New Construction</td>
<td>$7,610,818</td>
<td>$1,150,977</td>
<td>$3,168,443</td>
<td>$5,553,540</td>
<td>73.0%</td>
</tr>
<tr>
<td>Pay-for-Performance</td>
<td>$50,055,958</td>
<td>$9,696,476</td>
<td>$29,556,578</td>
<td>$50,468,213</td>
<td>100.8%</td>
</tr>
<tr>
<td>Combined Heat &amp; Power (CHP)</td>
<td>$17,000,000</td>
<td>$191,367</td>
<td>$3,602,000</td>
<td>$4,877,186</td>
<td>28.7%</td>
</tr>
<tr>
<td>Local Government Energy Audit</td>
<td>$5,000,000</td>
<td>$2,979,705</td>
<td>$2,125,091</td>
<td>$6,563,309</td>
<td>131.3%</td>
</tr>
<tr>
<td>Direct Install</td>
<td>$60,632,162</td>
<td>$25,529,126</td>
<td>$11,176,772</td>
<td>$47,193,297</td>
<td>77.8%</td>
</tr>
<tr>
<td>Marketing - Commercial &amp; Industrial EE</td>
<td>$1,575,000</td>
<td>$1,278,154</td>
<td>$0</td>
<td>$1,643,341</td>
<td>104.3%</td>
</tr>
<tr>
<td>Large Energy Users Pilot</td>
<td>$20,835,057</td>
<td>$308,297</td>
<td>$8,587,389</td>
<td>$11,437,311</td>
<td>54.9%</td>
</tr>
<tr>
<td>Sub-Total: C &amp; I Energy Efficiency Programs</td>
<td>$225,490,135</td>
<td>$66,754,165</td>
<td>$80,867,261</td>
<td>$189,802,833</td>
<td>84.2%</td>
</tr>
<tr>
<td>Other Energy Efficiency Programs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Green Jobs and Building Code Training</td>
<td>$386,450</td>
<td>$280,151</td>
<td>$0</td>
<td>$360,195</td>
<td>93.2%</td>
</tr>
<tr>
<td>Sustainable Jersey</td>
<td>$1,439,851</td>
<td>$732,764</td>
<td>$0</td>
<td>$942,125</td>
<td>65.4%</td>
</tr>
<tr>
<td>Sub-Total: Other Energy Efficiency Programs</td>
<td>$1,826,301</td>
<td>$1,012,915</td>
<td>$0</td>
<td>$1,302,320</td>
<td>71.3%</td>
</tr>
</tbody>
</table>

Total: $387,713,328 | $178,111,210 | $95,316,151 | $351,549,465 | 90.7%

Note: Program budget period is actually 18 months, Jan 1, 2012 through June 30, 2013.
New Jersey

The cornerstones of New Jersey’s clean energy strategy are its commitment to solar-electric (photovoltaic, PV) energy through the Office of Clean Energy, the Board of Public Utilities, and the SREC registration program. Although there are no rebates available for solar installation in New Jersey, there is a reliable stream of income for solar adopters through the sale of Solar Renewable Energy Certificates (SRECs).

Due to the state RPS standard’s “carveout” for solar – 4.1% of electricity by FY 2027-2028 – theoretically, there should be a growing demand amongst utility providers for SRECs to meet their solar obligations. Before installation, individuals and businesses must announce their intent to the SREC program. Upon installation and approval of the responsible Electric Distribution Company, each MWh of energy produced generates an SREC that is registered in the PJM Generation Attribute Tracking System (GATS). SRECs are sold on an open market, and solar installations remain eligible to produce SRECs for 15 years from the date of installation. One issue that New Jersey has faced in recent years is the dropping price of SRECs as more capacity has come online and demand has stagnated. SREC prices have dropped from $410.48 in August 2011, to $312.37 in August 2012, to $195.57 in March 2013.21

Solar and other on-site renewable systems also benefit from a 2008 statute that exempts those systems from local property taxes. Additionally, solar equipment is exempt from the state’s 7% sales tax. Still, upfront funding to finance such projects is in short supply. For example, in 2012, the Clean Energy Solutions Energy Efficiency Revolving Loan Fund had funding of $17.6 million. For comparison, the analogous low interest Smart-E Loan program in Connecticut, a state with less than half the population of New Jersey, is funded at the level of approximately $30 million.

Certain programs like the New Jersey Natural Gas SAVEG-REEN On-bill financing program make upfront capital available, but not from private sources that can be scaled up dramatically. The loan amounts are limited and not for everybody. Customers can qualify for $2,500 to $10,000 at 0% APR for a period of 10 years for investments in gas efficiency. This existing program demonstrates that there are opportunities to increase the availability of such funding sources by expanding to on-bill repayment.

Connecticut

With a relatively small industrial base, residential and commercial buildings dominate Connecticut’s energy demand, accounting for nearly 90% of electricity consumption.22 Connecticut’s 2013 Comprehensive Energy Strategy called a focus on the energy efficiency retrofits “essential” and emphasizes energy efficiency investment. Like New York and New Jersey, Connecticut relies on a surcharge “system benefits” fee and RGGI auction proceeds to fund its energy programs.

Statewide investment in electric and natural gas energy efficiency totaled $140 million in 2011.23 Contributing to that funding was a $0.003/kWh System Benefit Charge, as well as a portion of Connecticut’s $51.7 million in RGGI proceeds between 2009 and 2011. While CEEF funded a number of clean energy programs with that money in 2011, the state more notably made history that year by establishing the Clean Energy Finance and Investment Authority, the nation’s first state-level “green bank” designed to “leverage public money with private sector funds and expertise.”24

Public Act 11-80 established CEFIA with the charge of “developing programs to leverage private sector capital to create long-term, sustainable financing opportunities to support residential, commercial, and industrial sector implementation of energy efficiency and clean energy measures.”25 Of its early achievements, CEFIA has teamed up with CEEF to create Energize CT, an outreach initiative designed to connect residents, businesses, non-profits, and municipalities with the relevant clean energy resources. “Energize Connecticut is now the overarching public-facing brand that represents programs and services supported by the [EEB] and the [CEFIA].”26 Energize CT, like NYSEDA’s outreach efforts, seeks to efficiently present EE/RE choices to all manners of consumer. CEFIA holds so much promise because, rather than employing a predominately grant-based system, as was the prevailing financing model of the ARRA days, it distinguishes itself through its organizational mission of establishing a robust connection between EE/RE projects and the upfront capital of private investors.27

Property-Assessed Clean Energy (PACE) financing allows municipalities to extend low interest loans to homeowners and businesses, which are paid off over an up to 15-year period as an item on the recipient’s property tax bill. Typically, because the clean energy financing payments are attached to the property tax, the payments will stay with the property, rather than the owner if the owner decides to sell the property. The transferability of PACE financing between owners is an important feature shared by EDF’s proposed OBR program structure.

PACE financing emerged as a promising way for cities and municipalities to extend clean energy financing to the relatively untapped market of residential and commercial renters. To date, 28 states (including New York, New Jersey, and Connecticut) have passed PACE-enabling legislation. However, a July 2010 statement issued by the Federal Housing Financing Authority, acting as conservator of Fannie Mae and Freddie Mac, advised the two home mortgage giants to limit the types of mortgages available to homeowners in municipalities participating in PACE programs. Because PACE loans were deemed to act as first liens over pre-existing mortgages, mortgages with PACE liens were regarded by the FHFA as bearing substantial additional risk in comparison to the typical mortgage. “This ruling has effectively ended residential PACE financing, with many local governments suspending their programs as a result.”28

The Connecticut legislature took an innovative step forward amidst the unresolved legal quagmire of residential PACE by establishing Connecticut’s Commercial PACE (C-PACE) program in June 2012. The program is open to commercial, industrial, and multifamily buildings. C-PACE is “owner-arranged” in that the property owners transact with private capital directly to acquire the requisite financing. The municipality still assesses.

26 Energy Efficiency Board 2012 Programs and Operations Report, CEEF
the building owner on their property tax bill, and the payments still stay with the property, rather than the owner. The fact that the financing is owner-obtained allows the municipality to avoid the legal uncertainties of traditional residential PACE financing. CEFIA administers PACE and is tasked with enrolling municipalities. As of January 2013, 12 towns had enrolled.

3.C. Recent Developments and the Market for Clean Energy Financing

New York
New York has announced its intention to found a Green Bank to attract private capital to clean energy investment. In his January 2013 State of the State Address, Governor Cuomo announced his intention to use public/ratepayer funds amounting to $1 billion to leverage private sector capital towards investments in the clean energy economy.

Overseeing the development of the proposed Green Bank will be the newly appointed Chairman for Energy Policy and Finance, Richard Kauffman. The new cabinet level position will be responsible for coalescing the numerous institutional stakeholders that administer New York’s EE and RE programs around the specific goals and objectives of state’s comprehensive State Energy Plan.

Governor Cuomo has also mentioned the growing importance of distributed generation (DG) in ensuring the state’s energy security: “Utilizing distributed generation resources, or on-site power generation, reduces dependence on the electric distribution system that is susceptible to damage during a natural disaster. Distributed generation resources, such as solar and wind, can also contribute to a cleaner electricity supply.”

A 2008 report cited by the 2009 State Energy Plan conducted under Governor Patterson estimates that New York’s maximum achievable end user electricity efficiency through 2015 is 26,000 GWh in reductions over the 7 year period from 2009-2015, a reduction of 14% below projected energy usage; improved building and appliance codes over the 7 year period could potentially provide an additional 11,000 GWh reduction from projected (5.7%).

The ‘15 by 15’ is demonstrably achievable, if not cost effective solely through public funding. Governor Cuomo acknowledges the limits of public funding and potential of third party financing: “through the use of bonding, loans and various credit enhancements (e.g., loan loss reserves and guarantees), a Green Bank is a fiscally practical option in a conceivable strategy.”

On Bill Repayment, while not yet widely implemented at large scale, seems to be one suitable mechanism through which to efficiently channel the public and private funds of New York’s nascent Green Bank.

New Jersey
The environment for energy efficiency and renewables funding in New Jersey is quite different than that of New York. Following the administration of Governor Jon Corzine (D), Governor Chris Christie (R) significantly altered the course of the state’s clean energy policy. Most notably, Governor Christie announced in May 2011, that New Jersey would withdraw from the Regional Greenhouse Gas Initiative. The Governor set a course forward for New Jersey’s Clean Energy Program independent of RGGI and any funding it might provide. Notably, New Jersey did not use any of its 2009-2011 RGGI proceeds for energy efficiency programs; it used 22.9% of its $118.3 million in RGGI funds for renewable energy investment and retained 63.4% of the proceeds for the purpose of funding the state government during that period.

The alternative clean energy financing philosophy to which New Jersey currently subscribes is one that downplays the role of government and seeks the minimal cost effective use of taxpayer dollars for the implementation of its clean energy programs. The New Jersey EMP of 2011 recognizes a different, more restricted set of tools at the state’s disposal to meet its clean energy goals.

“In light of New Jersey’s fiscal challenges, efforts must be made to strip away any largesse that constitutes a transfer of wealth from New Jersey’s ratepayers to EE/Demand Response program developers. While the Administration remains committed to increased EE/DR penetration to meet the State’s planning goals, [...] EE and DR programs are being evaluated to determine if PJM wholesale markets already provide adequate compensation to ensure program success, thereby obviating the need for continued State sponsorship and assistance.”

The report goes on to explain, “the Christie Administration encourages reliance on third-party providers that have the requisite ‘know-how’ and access to capital to structure DR programs that obviate the need for capital investment by the State.”

This alludes to the NJ Office of Clean Energy’s reliance upon two private companies, Honeywell and TRC, to administer the state’s more than $300 million in clean energy program funding in 2012. If New York and Connecticut are determined to leverage existing sources of clean energy funding to attract private capital, then New Jersey is seeking to stretch each ratepayer dollar much, much further.

While it seems likely that the Christie Administration would consider adopting an equivalent of Governor Cuomo’s proposed $1 billion Green Bank to fall into the category of “largesse”, it is reasonable to conclude it would have fewer objections to wide scale implementation of another New Jersey’s clean energy tool: OBR.

Despite New Jersey’s relative reluctance to tap into ratepayer and public funding, it nonetheless seems conceptually well-suited to OBR. The EMP acknowledges New Jersey’s search for a “new way to provide capital for EE and renewable energy programs that can eliminate the need for cost incurrence through SBC.” The form of upfront financing for which the EMP advo-

cates, revolving loan funds, are compatible with OBR. The EMP concludes that once these funds begin to leverage private capital, the state could perhaps reduce or even eliminate its surcharge.

**Connecticut**

Connecticut is perhaps best positioned for OBR. Governor Malloy’s Comprehensive Energy Strategy touches on a common theme in clean energy financing today:

> “establishing and sustaining a consistent, sufficient level of investment is critical to realizing the State’s goal of capturing all cost-effective efficiency. While Connecticut has increased funding for natural gas and electricity efficiency programs over the years, the levels fall short of what is needed to achieve an all cost-effective efficiency goal.”

Connecticut’s leadership in establishing its first-in-the-nation green bank further distinguishes it as a trailblazer in clean energy financing. “Created as a key component of a broader energy law that received almost complete bipartisan support, CEFIA is a quasi-public clean energy finance authority that combines several existing state clean energy and energy efficiency funds, enables the new entity to make loans, and to leverage its capital with private capital, permitting private investment in and alongside the bank with the investors receiving a reasonable rate of return on their investments. As such, CEFIA holds out a flexible and attainable model for states to employ in constructing clean energy finance banks.” As in the case of New York and New Jersey, Connecticut affirms the need for private capital in clean energy financing. However, the state’s early adoption of a clean energy finance bank, CEFIA, positions Connecticut to realize this goal.

In April of 2013, Connecticut launched a pilot program as a first step towards fulfilling the capital-attracting mission of CEFIA. Using $2.5 million of ARRA-SEP funding from DEEP as a loan loss reserve fund, CEFIA has secured approximately $27.8 million in committed funding from community banks and credit unions around the state.

“This Smart-E pilot program will offer affordable interest rates and enable a five to twelve year payback period for the homeowner. Participating lending institutions will provide unsecured loans of up to $25,000 to qualifying residential borrowers to finance comprehensive energy assessments and efficiency retrofits, in addition to qualifying renewable energy improvements and fuel and equipment conversions. All contractors qualified under CEFIA, the utilities, or CEEF are eligible to participate. Customers can finance all measures that qualify for a rebate under CEFIA, CEEF, or the utilities, as well as other measures that increase the energy efficiency or renewable energy production of a home.” The program launched in Norwich, CT as a cooperative effort of Norwich Public Utilities, CEFIA, CorePlus Credit Union, and Eastern Savings bank. Soon, the entire pool of funding will become available to the rest of the state. Through Smart-E, residents are eligible for over 40 potential home energy improvement measures, including natural gas conversion and high efficiency natural gas equipment. By introducing private lending entities to energy efficiency investments, Connecticut is taking a huge step towards growing the marketplace. OBF programs, with default rates typically lower than 2%, can offer a unique opportunity for financial institutions to safely tap into traditionally underserved markets by leveraging the utility’s relationship with the customer to provide safe, cost-effective investments with steady returns.

Connecticut has experience with both OBF and OBF. The Connecticut Utilities (Connecticut Light & Power, United Illuminating, Connecticut Natural Gas, Yankee Gas, and Southern Connecticut Gas) ran a pilot OBF program as a part of the state’s residential Home Energy Solutions (HES) from June 2010 to May 2011. With interest rates of 0.0 to 4.99%, the program issued approximately $15.5 million in loans to 1,350 residents. After the pilot expired, the Utilities were challenged by PURA to develop a cost effective, scalable OBF program to administer HES upgrades. They chose to “outsource [financing the residential loans] to a [non-profit third party lending institution], [the] Connecticut Housing Investment Fund (CHIF).”

Eight energy upgrades (detailed below) are covered by the program at 2.99% or 4.99% depending on the procedure. While United Illuminating chose to require On Bill Repayment for this subsection of the HES program, Connecticut Light & Power (the larger electric utility) opted to offer consumers the choice of financing approaches.

As of May 2012, UI and CL&P had issued 70 loans amounting to $750,000. “The current program is working, but all involved hope it can be expanded to include more measures.” Although Connecticut has yet to scale up its OBF efforts, it appears to have satisfied many of the preconditions for establishing an innovative program that will ultimately be funded “primarily through third party financing, such as local, regional or money-center banks rather than ratepayers.” OBR is a natural fit for such a system.

### 3.D. Conclusion

Although New York, New Jersey, and Connecticut have significantly different circumstances surrounding their respective clean energy goals and financing strategies, they have similar disconnects between opportunity, aspiration and implementation.

Connecticut and New York have demonstrated eagerness to link private capital to clean energy investments. New Jersey similarly prefers private investment over government subsidies. OBR fits all three state circumstances.

Connecticut needs to scale up clean energy financing through CEFIA; New York likewise requires a mechanism to funnel funding through its new Green Bank; New Jersey is seeking an avenue through which to channel third party financing to its residents and business. OBR satisfies the requirements of all three states while offering the potential to expand the marketplace to underserved utility customers and private sources of capital looking for low-risk investment opportunities.

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4. Benefits of OBR

4.A. Benefits to Households and Small Businesses

For single family homeowners, OBR offers the chance to transform the marketplace by offering them a simple way to finance energy efficiency. A useful rule of thumb, based on study of California homes, is that an average homeowner needs to invest $7,200 to achieve at least a 25 percent energy use reduction.47

Given today’s housing market – where 30 percent of homes are still under water, and 50 percent of all home sales are distressed, most homeowners probably do not have easy access to the capital necessary to reduce their home energy consumption. OBR offers a solution for providing that capital to homeowners.

Figure 3 illustrates the monthly utility bill costs before and after OBR. Assuming a homeowner makes an OBR investment that reduces her monthly bill by 1/3 using capital from a private lender that is to be repaid at a 5 percent per year rate of interest over period of 15 years, she can save a total of $1,080 as she pays off the loan, and save more than $60 per month thereafter for the lifetime of the investment. For example, rooftop PV, insulation and window replacements can last 30 years or longer.

**Figure F3: Energy Upgrades Repaid On-Bill Can Lower Utility Bills**

In the multifamily/multi-tenant arena, OBR offers owners of master-metered buildings the chance to access currently scarce, standalone low-cost capital. OBR also helps tenants in individually metered buildings finance improvements to their respective units while building owners make improvements to common areas. Tenants prefer energy efficient residential space since they would then pay less for utilities; hence, OBR also helps landlords to increase the appeal of their rental property.

OBR can be designed to provide financing for commercial, public and residential buildings including multi-family rental buildings. OBR will also significantly improve the credit quality of a wide variety of financing mechanisms including loans, leases, Energy Services Agreements (“ESAs”) and Power Purchase Agreements (“PPAs”).

As OBR helps firms to become more energy efficient, they gain additionally from improved company image, and longer appliance working life. Firms that use electricity intensively, such as those in the industrial sector, further benefit from the reduced electricity cost volatility that comes with higher energy efficiency. Buildings that perform better on energy will have inhabitants that perform better as well.

4.B. Benefits to Utilities

OBR offers utilities a way to meet their state-mandated energy efficiency and renewable portfolio goals. It will complement and build upon existing programs without using utility or ratepayer funds. Utilities may not have sufficient expertise to evaluate the risk of a particular investment, whereas third party financiers are experts in risk evaluation and management.

Utilities may also receive fees from lenders in exchange for providing billing services. Utilities can provide this billing service at very low marginal cost, especially once billing systems have been modified for the pilot on-bill financing programs.

4.C. Benefits to Society from OBR-Enabled EE and DG Investments

Economically attractive efficiency investments thru 2030 could net $700 billion in avoided energy costs.48 Electricity generation from photovoltaic and solar thermal technologies is currently a $100 billion marketplace, and installed capacity is forecasted by grow ten-fold in the next 20 years.49

While rooftop solar thermal and electricity are growing quickly, we posit that OBR can further buoy growth by sweetening the deal for both lenders and building owners/occupants, and by expanding the pool of investment worthy buildings. Of course, access to capital is not the sole challenge for making distributed generation economically attractive. There are many well documented barriers, but OBR helps to ameliorate the challenges of attractive investment capital, high transactional costs and lender risks.

The simple step of allowing building owners and occupants to repay loans through utility bills overcomes several important hurdles to clean energy investment:

- High capital costs, particularly for customers will FICA credit scores below 650 and for customers without access to home equity loans
- High costs of customer acquisition for EE and DG service providers
- Payback timelines misaligned with investor preferences and expected length of renter occupancy
- Split incentives between building owners and tenant/occupants, particularly where renting tenant pays the utility bill.

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EDF estimates that a well-constructed OBR program can overcome these hurdles. Below we quantify these benefits based on the following key assumptions:

- Reduced default risk so the interest rate on investment funds is reduced from 15% per year to 5% per year
- Expanded pool of eligible customers to include those with FICA scores between 600 and 650
- Reduced cost of customer acquisition by 50% as an outcome of new customer offerings in a new competitive marketplace where service providers (building contractors and rooftop solar PV installers) develop turnkey solutions in partnership with lenders (banks and credit unions).

When OBR is applied to increased energy efficiency and distributed generation investment, it is possible to compute potential societal benefits, as summarized in Table T6.

Table T6: Tri-State Benefits of OBR over Next Decade

<table>
<thead>
<tr>
<th>Potential Benefits over a decade in Tri-State Region</th>
<th>Rooftop Solar PV</th>
<th>Energy Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jobs (Job-Years)</td>
<td>40,000 (12,000 – 63,000)</td>
<td>110,000 (25,000 – 29,000)</td>
</tr>
<tr>
<td>Clean Energy Investments ($2012 Billions)</td>
<td>$3 (1 – 5)</td>
<td>$14 (3 – 5)</td>
</tr>
<tr>
<td>Emissions (million metric tons GHGs)</td>
<td>-</td>
<td>195 (39 – 64)</td>
</tr>
<tr>
<td>Ratepayer and state energy bill savings ($2012 Billions)</td>
<td>-</td>
<td>$98 (19 – 32)</td>
</tr>
<tr>
<td>New Installed Rooftop PV (MW)</td>
<td>1,200 (400 – 2,000)</td>
<td>-</td>
</tr>
</tbody>
</table>

Based on EDF OBR Benefits model version: May 08, 2013
Benefits accrue over a 12-year period (“about a decade”) based on a 12-year McKinsey dataset of EE potential for residential, commercial and combined heat and power.

We calculate benefits associated with OBR-enabled energy efficiency for each of the three states, and compare to the national potential in Table T7.

Table T7: OBR Benefits from Energy Efficiency

<table>
<thead>
<tr>
<th>Benefits over a decade</th>
<th>National</th>
<th>NJ</th>
<th>CT</th>
<th>NY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jobs (Job-Years)</td>
<td>600,000 (560,000 – 660,000)</td>
<td>27,000 (25,000 – 29,000)</td>
<td>8,000 (7,500 – 9,000)</td>
<td>75,000 (67,000 – 83,000)</td>
</tr>
<tr>
<td>Emissions (million metric tons GHGs)</td>
<td>1,200 (900 – 1,400)</td>
<td>52 (39 – 61)</td>
<td>15 (11 – 19)</td>
<td>128 (95 – 160)</td>
</tr>
<tr>
<td>Ratepayer and state energy bill savings ($2012 Billions)</td>
<td>$590 (440 - 740)</td>
<td>$24 (18 - 30)</td>
<td>$8 (6 - 10)</td>
<td>$66 (49 - 84)</td>
</tr>
<tr>
<td>Clean Energy Investments ($2012 Billions)</td>
<td>$87 (80 – 94)</td>
<td>$3 (3 – 4)</td>
<td>$1 (0 – 1)</td>
<td>$10 (9 – 12)</td>
</tr>
</tbody>
</table>

Based on EDF OBR Benefits model version: May 17, 2013.
Benefits accrue over a 12-year period (“about a decade”) based on a 12-year McKinsey dataset of EE potential for residential, commercial and CHP.
4.C.1. Building and Appliance Energy Efficiency

In this section we provide quantitative estimates of the benefits of OBR with respect to increased investment in energy efficiency and rooftop solar PV. We develop separate spreadsheet-based models; details for each are provided in Appendices A and B.

For a bounded estimate of energy efficiency investments attributable to OBR, EDF constructed a financial model with two sets of inputs to represent the two scenarios - with and without OBR. We modeled the deployment of energy efficiency using two main levers (1) reducing the cost of capital, and; (2) lowering the transaction costs and other barriers. To estimate the values of these inputs, we relied on empirical studies and expert judgment.

The model’s key outputs – energy savings, and the associated cost savings and carbon dioxide emission reductions – under the two scenarios can then be compared to obtain the effect of OBR. We go one step further by estimating the new jobs that could be created as a result of investments enabled by OBR. We used as our underlying data of energy savings, investment amounts, cost savings, emission reductions the findings by McKinsey & Co. in its study of the economic potential of US energy efficiency nationwide. Our model thus uses a top-down approach in four steps.

1. We estimate the internal rate of return (IRR) of energy efficiency upgrades in several subsectors in the economy by using the investment and savings estimates made by McKinsey & Co.
2. By comparing the IRRs against estimated market lending rates with and without OBR, we project the nationwide benefits from OBR in terms of energy savings, cost savings, and carbon dioxide emission reductions, which result from the increased investments in energy efficiency.
3. We analyze the further impact of these investments, including the potential direct benefits, such as jobs, and indirect benefits, such as from avoiding future fossil fuel use.
4. Finally, we translate these into household- and firm-level benefits.

To obtain the implied IRRs from McKinsey’s aggregate estimates for upfront investment and savings, we made assumptions about the timing of these investments and savings. To obtain two IRR point estimates for each subsector in the economy, we used two scenarios: (1) all investments take place in the first year of analysis, and (2) investments occur in a linearly declining fashion.

To represent the variation in project returns, we further assume that each point estimate represents the mean of a normally distributed profile of IRRs. We thus create a range of IRRs for each subsector, which in turn drives the range of benefits estimated. For an in-depth discussion on our benefits estimation methodology, see Appendix A.

Interest rates for unsecured investments in energy efficiency upgrades are likely to be in the range of credit cards, which are currently about 16 percent per annum. Firms are likely to be able to borrow at a slightly lower rate of about 15 percent. With OBR, we believe based on extensive consultation with the lending industry that these borrowing rates can be reduced to slightly above current home equity loan rates, i.e. about 5 percent.

While empirical studies estimating transaction costs of energy efficiency projects are limited, they indicate that as a proportion of total project cost, transaction costs range from 8-36 percent for the residential sector, 15-40 percent for the commercial sector, and 2-8 percent for the industrial sector. As with investment rates, these estimates are project-dependent.

With OBR, we believe that transaction costs for EE investments can be reduced by 70 percent for each sector. As estimates are not available for the CHP sector, we used the same transaction cost percentages as the existing homes category under the residential sector.

As shown in the following four figures, assuming these input values, our model shows that with OBR, energy savings in the US could reach $2 billion kWh by the twelfth year of program implementation, avoiding 55 million metric tons of carbon dioxide emissions in that same year. The energy savings correspond to more than $15 billion in utility bills saved. Under our analysis, the residential and commercial sectors will be the main beneficiaries of OBR. The industrial sector will see little benefit from OBR for two key reasons. First, not all energy-consuming activities in the industrial sector are eligible for OBR because they do not use utility-generated electricity. Second, of the eligible activities, returns from efficiency upgrades are already high enough to incentivize firms to take up investments at market rates; the fact that such efficiency opportunities are not yet realized suggests that other barriers exist for industries; for example, more efficient versions of machinery are not easily available on the market and must instead be custom-made.

The job creation benefit of OBR is difficult to estimate but potentially substantial. One study indicates that national employment in the energy efficiency sector could quadruple to nearly 400,000 jobs by 2020. By dividing the total investment by the average wage of a worker in the energy efficiency sector, we estimate that up to 360,000 jobs could be created as a result of OBR in the program’s twelfth year.

While we try our best to quantify as much of OBR’s impact using the model, it is difficult to put figures to benefits such as OBR’s ability to align incentives and the increased customer awareness from promoting OBR. Nor have we attempted to quantify the broader and longer-term social benefits of the incremental energy efficiency OBR brings about, such as lower electricity prices and their effect on the poor and avoiding the costs of the worst effects of climate change.

4.C.2. Distributed Generation

EDF also developed a bounded analysis (with high and low scenarios) to forecast the uptick in rooftop PV projects in tri-state region due to OBR. Extensive details are provided in Appendix B. In addition to adding demand (by expanding eligibility to borrowers with lower FICO scores) and shifting costs downward, we consider recent trends for rooftop PV installation. We translate our findings from California based on our observation of the policy setting in the tri-state region, as detailed in Chapter 3. We also observe that New Jersey has seen a recent boom in DG investment. Finally, we observe that New Jersey, Connecticut and New York, when combined, are quite similar in scale to California, as shown in Figure F8. Though a bit smaller by all measures, the tri-state region has another important economic forcing function for EE and DG investments: significantly higher average electricity prices.
The low scenario assumes flat (zero) growth in rooftop installations such that investments continue at levels observed in 2012. The high scenario has growth continuing on the trend established from 2007 through 2012.

We find a range of 70,000 to 170,000 new rooftop PV projects between 2013 and 2022 as a result of OBR effects in New Jersey alone. This is corroborated by the recent boom in rooftop PV, such that New Jersey outpaced California to become the top installation state in the country in 2012.

The benefits from the potential OBR-enabled rooftop PV investments are shown in the table, including between 6,000 and 21,000 jobs, and $1.5 billion in new investments in rooftop PV.

When combined with Connecticut and New York, the potential OBR-enabled rooftop solar PV projection also grows. While New York has a much larger customer base, it also has a less well-developed solar incentive program, and less solar resource in its northern reaches. Still, combined, the three states could enjoy between 100,000 and 400,000 new rooftop solar PV investment projects with OBR in place.
5: Foundational Features of OBR

EDF has identified several foundational design features for an OBR program, based on our outreach to building, lending and real estate stakeholders. These features seek to minimize transactional costs while providing confidence for consumers, lenders, ratepayers and utilities. A successful program will attract significant private capital by creating a marketplace for underwriting energy efficiency investment.

5.A. Presenting Scalable Opportunity for Lenders

OBR can be designed and made available for all building sectors. It can overcome the traditional split-incentive barrier to EE investment in rentals, where tenants pay utility bills while building owners incur the capital costs of EE upgrades. Therefore, single family, multi-family, commercial and industrial building owners could be eligible for participation, including owners of leased buildings. Both single measure (with some minimum value) and whole-building interventions could be eligible for OBR-enabled investments. Public spaces within multi-family dwellings, such as court yards with lighting or pool pumps, are particularly well-suited for OBR, in cases where the public spaces are metered separately.

In addition to the types of buildings, a diversity of financial arrangements ought to be eligible. For example, in addition to loans, leases may qualify to be repaid on utility bills. This may be particularly important because many residential rooftop solar installations are structured as leases. Similarly, energy services agreements and power purchase agreements can be transacted through OBR.

5.B. Ensuring Consumer and Lender Confidence in Energy Efficiency

While rooftop PV has no moving parts and relies principally on sunshine for long term performance, it is relatively easy to calculate investment returns for a self-generation system. For energy efficiency, however, both borrowers and lenders need assurance that when a borrower agrees to make repayments on his/her utility bill, he/she has invested in reasonable measures at reasonable costs, and that projects have been properly designed and installed. To provide this assurance, several program features focus on reliable investments, robust verification and careful guidance to installers and verifiers.

Government agencies may choose to provide a list of approved energy efficiency and renewable generation measures that can be funded with OBR. Projects must also meet tests for financial viability – customers must expect to see their energy bills decline, and this expectation must be based on an accurate forecast (with some margin of error).

The list of approved measures can initially be based on measures that currently receive rebates and are fixtures (i.e., not easily removed from the premises). The list should be updated continually to reflect new technologies, to remove measures that are ineffective or not cost effective, and to codify a growing body of experience that pushes toward deeper upgrades. Measures with highly variable performance or measures highly dependent on customer behavior may also be excluded or severely discounted when calculating forecasted costs and benefits.

As a financial threshold to protect both the borrower and lender, debt service should be no more than estimated savings from the EE project, with an adequate margin of safety. That is, projects must be reasonably forecasted to lower energy bills more than the installment repayments for the clean energy investment. This might involve several steps. The contractor can be required to provide customers with a well-formatted, written estimate of average monthly energy and dollar savings for the project, compared against the monthly investment payment.

When distributed generation, electric vehicles and/or storage are added to the project, the analysis of cost and benefits is necessarily complex but still worthwhile.

Once the project is installed, it should be inspected by an independent, expert inspector. Inspectors could be local city building inspectors, or a private third party, but there must be no conflicts of interest between inspector and installer. Both the inspector and the contractor should also be required to meet eligibility criteria and certification requirements.

Another means of providing confidence for a burgeoning clean energy industry is methodological guidance for contractors and inspectors to estimate energy savings for energy measures. The U.S. EPA and U.S. Department of Energy are contributing to a growing record of building and appliance energy efficiency best practices. A robust methodology will have several attributes:

- Savings estimates will take into account historical usage patterns for the building and/or building type.
- Calculations will be conservative to ensure that most customers will experience better than forecasted energy savings.
- For projects that do not meet forecasted energy savings, the contractor may be given the option of remedying installation and/or reducing project price so that debt service will be within program criteria.

Other features to protect lenders and consumers can be considered. For example, all investments can be fully pre-payable at any time by arrangement between the lender and utility. All investments will also be subject to standard consumer lending protection laws applied to the investment originator (e.g., bank or leasing company). Furthermore, the PUC or CEC might maintain a database of failed inspections and revoke program eligibility for a contractor with repeated failed inspections.

5.C. Providing for Long Term, Low Interest Rate Investments

To provide attractive investment terms, lenders must have confidence that borrowers have a strong incentive to repay their investments. If the capital for investments is seen as unsecured consumer debt, however, lenders will expect terms similar to credit cards (i.e., high rates of interest, short repayment schedules). Interest rates and other terms will reflect lender perception of risk.

OBR can minimize lending risks by making the repayment obligation a rate tariff on the meter, and by keeping that obligation with the meter in the event of change in occupancy or ownership. Without these features, lenders would see less benefit from using an OBR structure and the less attractive investment terms would result in lower demand for investment capital.
An OBR structure in which the repayment is a rate tariff on the meter will give confidence to lenders that these are investments of high quality – that they are likely to be repaid in full and on time. While delinquencies on credit cards and, recently, mortgages have been relatively high, utility bill defaults tend to be much lower. As such, lenders will view investments repaid via OBR as lower risk, and thus be willing to provide more attractive rates of interest.

A secondary element of lender confidence pertains to the treatment of partial payments. To the extent that customers pay only a portion of a utility bill that includes a clean energy investment repayment, the repayment should be proportionally allocated pro rata to the energy and loan line items. In the event of continual incomplete payment, the utility will follow all standard consumer protection processes for delinquent accounts prior to disconnection. As a means to further provide lender and consumer confidence, another source of funds could be used to establish a loan-loss reserve that serves as a safety net for consumers and lenders alike.

OBR can eliminate the concern that a current owner or occupant might not remain in the property long enough to personally recoup EE investments. A tariff on the meter that remains when ownership or occupancy changes will facilitate long-term repayment schedules. As such, monthly payments can be lower, and projects with payback periods that exceed the expected residency of the current occupant can be underwritten.

This design feature also overcomes the “split incentive” faced by rental and multi-tenant properties, where the property owner is not motivated to make capital expenditures because the tenant(s) pays utility bill(s).

Affixing a long-term repayment to the meter would require disclosure and consent procedures at time of building sale or change of occupancy. These procedures will need to be developed and strongly enforced. The new owner/tenant should be provided with the original estimate of savings from the project as well as the terms of the remaining obligation. The debt obligation would be effectively assigned to the new buyer or tenant through the mechanism of a continuing rate tariff. Similarly, a rate tariff covering on-bill-repayment continues for a new owner after foreclosure. This is appropriate and equitable, since the new owner or tenant receives continued bill savings from the upgrades while paying remaining debt service.

5.D. Avoiding Indebtedness on Property

Many commercial buildings mortgages prohibit additional indebtedness. Even if additional investments were allowed contractually, they would be seen as subordinate to mortgages, and therefore would be considered unsecured from the perspective of lenders. Attaching the investment repayment obligation to the meter avoids placing additional debt on the property.

5.E. Appropriate Role and Compensation for Utilities

The OBR program can be integrated into existing energy efficiency programs. By providing investments at attractive terms, OBR should increase the cost-effectiveness of existing programs. Marketing efforts by contractors and lenders may also increase consumer awareness and market integration of EE measures.

The utility will provide a valuable billing service for the lender for which it should receive appropriate compensation. This could take the form of a monthly payment origination fee from the lender. The utility can also play a role in these areas: marketing: reporting program outcomes: contractor and project qualification; and inspection.

Utilities can also collect and maintain a performance database of project outcomes, while aggregating data sufficiently to prevent sharing of confidential information. PUCs will consider whether to also collect information about changes in occupancy to enhance the value of the database.

For utilities, interfacing with a large number of lenders might be seen as burdensome and administratively costly. If so, a transaction processing company could provide a single interface for all utilities. This would allow each bank to also have a single point of interface. The transaction processing company would be paid for by the lenders.

5.F. Enabling an Innovative Marketplace

The goal of OBR is to facilitate a robust, competitive marketplace for underwriting building energy efficiency investments. This suggests a programmatic objective of creating an open, competitive marketplace that allows various business models to develop attractive solutions to meet a variety of customer needs. For example, insurance products could be developed that guarantee project performance for a fee. A variety of contractual arrangements could be embraced, as well as many different contractor-lender business models. These creations should be allowed to flourish while ensuring that relevant stakeholders are protected.

6. Conclusion: EDF’s On-Bill Repayment Proposal

An on-bill repayment program allows building owners to repay loans for eligible energy efficiency and renewable electricity generation projects through their monthly utility bills. The investments are underwritten and financed by private, third-party capital providers, such as banks and credit unions, while utilities provide a billing service. The program creates a marketplace for clean energy lending, allowing contractors to provide customers with an integrated package of building upgrades and financing.

An OBR program can mobilize billions of dollars in private capital for EE investments in existing buildings, thereby avoiding millions of tons of greenhouse gas emissions while providing consumers net economic savings. A well-designed OBR would have these key features:

- **Savings Matched with Costs** – Customers will pay a single monthly bill for both energy and loan payments that together are lower than previous utility bills.

- **Obligation Tied to Meter** – Loan repayment is a tariff that stays with the meter to enable upgrades with long payback periods without worrying about sale or change in tenant.
Lower rates and Better Terms - Default (i.e., nonpayment) rates on utility bills tend to be far lower than for other debts, such as mortgages and credit card balances. Utilizing this attribute for EE loans will attract capital with substantially lower interest rates, longer maturities and better terms.

Flexibility - OBR can be designed to provide financing for commercial, public and residential buildings including multi-family rental buildings. Additionally, OBR will significantly improve the credit quality of a wide variety of financing mechanisms including loans, leases, Energy Services Agreements (“ESAs”) and Power Purchase Agreements (“PPAs”).

We find that OBR has significant promise as an innovative approach to connect private capital to previously underserved residents and businesses in the New York metropolitan region and that, for various yet different reasons, each state is well positioned to lead the evolution from on-bill financing to on-bill repayment.

While the States in the New York metropolitan region have state-level renewable energy and energy efficiency goals, and on-bill programs, there remain disconnects between the aspiration of the state goals, available sources of financing, and economic opportunity. OBR has the potential to align investors and funds at the scales needed to achieve and even exceed goals on the books today.

Appendix A: Benefits Estimation Methodology for Energy Efficiency

This appendix describes how EDF arrived at an estimate of the benefits of OBR with respect to additional investment in energy efficiency. We translate OBR-enabled investments into benefits measured in terms of dollars of investment, job creation, avoided electricity consumption, avoided consumer spending on energy and avoided greenhouse gas pollution.


We obtain our underlying data for the potential of energy efficiency projects from McKinsey & Co.’s 2009 report “Unlocking Energy Efficiency in the U.S. Economy”.

In its study, McKinsey & Co. estimates the energy savings and emissions reductions from energy efficiency improvements in fourteen subsectors, and aggregates them into four broad economic sectors: residential, commercial, industrial, and combined heat and power (CHP).

For the residential and commercial sectors, as well as CHP, we assume that energy efficiency improvements identified by McKinsey & Co. can be attained through OBR, while for the industrial sector, we assume that only the reductions under the “buildings” category within the “energy support systems” cluster can be attained. The other energy efficiency improvements deemed not applicable to OBR in the industrial sector include those from steam systems, motor systems, and energy-intensive and non-energy-intensive industry processes.

A.b. RPA Energy Efficiency Potential

To obtain the corresponding figures for the tri-state region containing the 31 counties of the RPA, we scale down the national data from the McKinsey analysis using energy consumption data.

For the residential sector, we use data from the Renewable Energy Consumption Survey (RECS). For the “existing non-low-income homes” and “existing low-income homes” clusters, we define low-income homes as those with incomes at or below 150% of the poverty line and scale the respective data from each cluster down by the share of each type of home located in the tri-state area containing the RPA counties. To analyze benefits at the level of individual states, we scale down national data by the share of electricity consumption for home appliances and lighting in the region for the “electrical devices and small appliances” cluster, and by the share of electricity consumption for space heating, air conditioning, water heating, home appliances and lighting for the “lighting and major appliances” cluster.

For the commercial sector, we use data from the Commercial Building Energy Consumption Survey (CBECS). Since state-level energy consumption data is not readily available, we calculate the share of energy consumption in the tri-state area encompassing RPA counties by multiplying the energy intensity per square foot by the square footage of each building type, except for the “community infrastructure” cluster. Since data is not readily available for this last cluster, which includes outdoor lighting, water services, and telecom infrastructure, we approximate the share attributable to the tri-state’s share of national population.

Since projections for residential and commercial construction are not available at the state level, we approximate the share of “new homes” and “new private buildings” as the share of national population growth through 2020 that occurs in the study region, using data from the Census Bureau.

For the industrial sector, the McKinsey analysis also gives data to the industry level, including cement, iron & steel, refining, pulp & paper, and chemicals. We use data from the Manufacturing Energy Consumption Survey (MECS) to scale down each of these using the share of energy consumption in these industries that takes place in the region.

The McKinsey analysis attributes the CHP potential to the industrial and commercial sectors. We use the sectoral and census-region-level geographical breakdown of CHP potential given in the McKinsey report, and scale these down using the respective shares of industrial and commercial electricity consumption in the East Census Region.

We translate the expected energy savings into cost savings using a projected average electricity rate.

Since the McKinsey analysis assumes no change in national system-wide emissions intensity between 2008 and 2020, we scale down the region’s annual emission reduction figures in proportion to the state’s emissions intensity pathway through 2020.

Why isn’t Energy Efficiency Embraced if It Pays for Itself Many Times Over?

McKinsey’s study estimates the economic potential of energy efficiency, i.e. what makes economic sense, but did not quantify the market barriers such as low consumer awareness, access to
capital, and transaction costs. That energy efficiency projects are NPV-positive but are not undertaken points clearly to the significant magnitude of these barriers faced by households and firms.

OBR addresses at least three of these major barriers. First, OBR lowers the barrier of access to capital by obtaining lower-than-market loan rates for ratepayers planning to undertake energy efficiency projects. This is particularly important for small-medium-enterprises and low-income households, which have less access to capital and credit. By facilitating loan repayments to be made directly from electricity bills, OBR reduces investors’ exposure to default risk. Investors then become more willing to lend to customers they otherwise would not give a loan to, specifically for energy efficiency upgrades. In our analysis, we capture this direct effect by calculating the incremental emission reductions and cost savings from the estimated lower loan rate OBR could obtain from investors as compared to the usual market rate.

Second, OBR reduces transaction costs. We simplify our analysis by treating all barriers other than access to capital as a collective cost, which we refer to as transaction costs. The marketing effect from promoting OBR reduces the barrier of low consumer awareness on two levels — by bringing to their attention the potential savings from energy efficiency, and by highlighting OBR as a convenient practical measure of reaping these savings. OBR also lowers search costs for consumers and third party financiers as described in Chapter 2A. The magnitude of transaction costs is a key input to the model that directly drives our results. Hence, we were careful in selecting what we analyze to be reasonable cost values, approximating the range of the limited empirical literature available. We use higher cost values for the residential sector than the commercial and industrial sectors, which benefit from economies of scale and are more likely to have business relations with equipment suppliers.

Comparing the Returns and Capital Costs of Investment

We use the McKinsey & Co. figures to estimate the internal rate of return (IRR) for the energy efficiency projects in each subsector. The IRR tells us the return of a project in percentage terms, much like how we would think of the returns from holding an equity share or bond when deciding whether to invest in these instruments. Energy efficiency projects typically require ratepayers to invest a high upfront cost. Large projects might require loan financing to be feasible, especially for firms that need to consider their cash flow. The IRR allows us to compare the return from investing in energy efficiency to its financing cost, i.e. the cost of capital or market loan rate. A project that has an IRR higher than the cost of capital is a worthwhile investment. Because OBR directly lowers the cost of capital for energy efficiency improvement projects, we can evaluate the amount of energy efficiency potential that can be realistically captured with and without OBR by comparing the respective loan rates against the project IRRs. Projects with IRRs at least equal to the OBR loan rate but lower than the market rate make financial sense only if OBR is available. We then sum the relevant metrics of these projects, to obtain OBR’s total impact.

To obtain the implied IRRs from McKinsey & Co.’s aggregate estimates for upfront investment and savings, we need to make assumptions about the timing of the projected investments; the timing of projected savings follows accordingly. We use two scenarios with different assumptions of when the McKinsey study expects investments in energy efficient capital to be made. The first scenario assumes that all investment occurs in the first year, the second assumes that investments decline linearly. The rationale for these two scenarios is as such: since McKinsey estimates the economic potential of energy efficiency using a bottom-up approach, most of the “backlog” of upgrades that should have already occurred, but have not, would be calculated as taking place in the first year of the analysis. The investment in reality is thus likely to lie somewhere between the parameters of the two scenarios. Since investments in later years are discounted, the first scenario produces lower IRR estimates than the second scenario.

Under the two scenarios, we obtain two point estimates for the IRRs of energy efficiency investments for each subsector in the economy. In reality, upgrade projects in each subsector vary widely, as do their returns. To represent this variation, we further assume that project IRRs are normally distributed around the point estimates, which we take to be the mean, with a standard deviation of 2 percentage points. In other words, we think that the normal distribution is a good approximation of the profile of IRRs in a particular subsector, i.e. most (38 percent) of upgrades in a subsector yield IRRs of 1 percentage point higher or lower than the mean, another large proportion of upgrades (30 percent) yield IRRs of 2 percentage points higher or lower than the mean, and very few types of upgrades give very high or very low returns.

Deployment Rate

To project OBR’s impact over time more realistically, we assume that program uptake will increase linearly. Our estimate assumes that the entire potential estimated in McKinsey & Co.’s study and profitable due to OBR financing will be employed within a twelve year period, the duration studied in the McKinsey & Co. analysis (2009-2020).

Potential Impact on New Jobs

We calculate the potential impact of OBR on job creation using industry-specific ratios on the average revenue per employee as reported by the 2002 Economic Census, adjusting for inflation. We apply these to the present value of upfront investment in each energy efficiency improvement category as identified by McKinsey & Co.

Limitations

Certain aspects of consumer borrowing behavior are not captured in this analysis. For instance, we might observe a discontinuity in the loan rate to total loan value function at the 10% rate, i.e. the incremental increase in consumers willing to take up a loan when the borrowing rate is lowered from 10% to 9.9% is likely to be much larger than when the rate is lowered from 10.1% to 10.0%, and from 9.9% to 9.8%. Neither does this analysis take into consideration the rebound effect, i.e. the increase in energy consumed when improved energy efficiency reduces a consumer’s total energy expenditure.
Appendix B. Benefits Estimation Methodology for Distributed Generation

This appendix describes how EDF arrived at an estimate of the benefits of OBR with respect to additional investment in distributed generation, such as rooftop PV on commercial and residential rooftops.

We translate OBR-enabled investments into benefits measured in terms of dollars of investment, job generation, and generation capacity installed, avoided (for EE) and created (for distributed generation). For EE, we further estimate avoided consumer spending on energy and avoided greenhouse gas pollution.

A. Distributed Generation – Rooftop Solar

For calculating distributed generation investments made economically feasible by OBR, we begin with the goals of the program:

- OBR can expand the pool of eligible customers.
- OBR can lower the cost of financing a DG investment.
- OBR can inspire turn-key consumer product offerings that dramatically reduce the transactional costs of marketing and customer acquisition.

OBR has the potential to make more projects economically viable for more customers by lowering the cost of capital (i.e., loan interest rate) and expanding the pool of eligible borrowers. These OBR consequences are shown in the theoretical graph of supply and demand. When these shifts occur, the equilibrium between supply and demand will involve more quantity of product.

Figure B-F1: OBR Expands Demand & Supply for Clean Energy Investments

Using real marketplace observations of historical investments in rooftop PV – California’s Solar Initiative data - and forecasts of declining costs, we can tease out the additional investments to be spurred by OBR. That is, we estimate how cost reductions attributable to OBR would incrementally increase DG investments using historical demand data, while adjusting for recently observed and expected cost declines. We base our analysis on the robust dataset of rooftop solar (PV, photovoltaic) projects in California.

Although we develop a bounded estimate for the value of OBR in the rooftop solar industry, it is an incomplete and thus conservative estimate of the potential value of OBR in spurring more DG investment. We do not consider how more attractive OBR might spur other types of DG, including storage, demand response and DG co-located with electric vehicles.

To estimate how OBR will increase DG investment, we develop a bounded estimate by studying historical demand and forecasted costs. Furthermore, we consider evidence in the context of traditional new technology market penetration rates.

Rooftop PV Costs are declining while Demand is Rising

Using California Solar Incentive data for residential and small commercial rooftop PV, we derive a demand curve observed from 2007 through 2011. It reveals increasing demand for each price bin in each successive year, even as the CSI subsidy amount has declined dramatically. Initially at $2.50 per watt, the CSI subsidy has dropped to $0.20, a 92% decline. While the overall project financing does benefit from a persistent federal tax credit, demand for rooftop PV has grown robustly while subsidies have production costs and subsidies have declined.

We identify relationship between growth in commercial and residential rooftop PV project applications to the California Solar Initiative program and production cost trends; extrapolate past relationships to structural financing costs enabled by OBR. (Essentially, this is an analysis of first derivatives: how much does change in demand change as a function of change in cost?) To represent OBR – and associated uncertainty inherent in this broad brush approach – we represent OBR as reducing both lending costs (interest rates paid on the investments) and transactional costs (marketing and customer acquisition).

1. DG Supply Estimates: We examine other estimates of localized DG and reanalyze potential using cost enhancements of OBR.

2. Traditional technology market penetration rates and the potential for OBR to improve the rate of market penetration of rooftop PV.

For the cost-demand relationship, we examine how demand for rooftop solar electricity has grown as costs have declined. Then we extrapolate growth for various assumptions about how OBR lowers project costs. Finally, we overlay recent experience with DG growth rates against a traditional curve for new technology market penetration to forecast penetration levels in the future.

A.1. Cost-Demand Relationship

We seek to understand the cost trajectory for installed rooftop PV so that we can estimate how OBR might spur more projects by affecting costs. We study California’s small residential and commercial rooftop PV projects (by number and total project value) over the past five years to understand demand and cost trends. As well we identified cost components for PV projects.
It is logical to bound the potential benefits of OBR for DG investments by isolating a portion of DG potential that becomes viable only with OBR. This is the approach we use to estimate OBR benefits in the context of energy efficiency investments. For EE, however, we have McKinsey & Company estimates of EE potential (See Appendix A).

While many factors influence the realization of an installed project, there remains a fundamental relationship between supply cost and customer demand. We don’t claim a direct causal link between cost and demand in this context due to many other factors. It is nevertheless illustrative to estimate the potential benefits of OBR by asking: how might demand grow incrementally as a consequence of an incremental decline in cost?

Figure B-F2 shows cost trends reported by Lawrence Berkeley Laboratory and the California Solar Initiative, as well as a cost forecast from Black and Veatch. Clearly, costs are on the decline and are forecasted to drop significantly in the coming decades. We also show the US Dept of Energy’s Sunshot program goal for rooftop PV: $1 per watt in total, with half in soft costs. OBR could significantly help to meet the goals of the Sunshot program.

Figure B-F3 begins with cost components estimated by the US Dept of Energy’s Sunshot Program and then shows how OBR might reduce them. In EDF’s judgment, OBR scenario considers a one-third reduction in costs of financing and customer acquisition/marketing. Shown in the bar charts is how OBR has the potential to reduce both transactional and financing costs. In this respect, OBR can make a significant contribution toward meeting Sunshot goals for residential rooftop solar PV.

Soft project costs in year 2010 were estimated to be $2.50 per watt and $2.00 per watt for residential and small commercial rooftop PV; where hard costs are approximately twice soft costs, the total project range is $6 to $8 per installed watt of rooftop PV. OBR has the potential to reduce soft costs of customer acquisition and financing through scaling and partnership with service providers (e.g., building contractors, rooftop PV installers). At a one-third soft cost savings, total project costs could decline in the range of $0.50 to $1.00. This could represent a 20% project cost decline as other cost components fall too. In developing scenarios for low and high benefits from OBR, we consider soft cost declines of $0.50 per installed watt and $1.00 per installed watt, respectively.

Figure F-B4 is the demand curve for rooftop solar PV in California. It plots the number of projects (n ~ 65,000) at each price point between 2007 and the end of 2011. (This is a cumulative histogram with $0.25 bins plotted horizontally to look like
These two figures show the large and growing demand for rooftop PV in California. Most forecasts show consistent exponential growth through 2020.

The CSI program has a goal of 2 GW of installed rooftop PV by 2016. In 2011 the CSI program will be halfway toward the goal, with over 1 GW installed capacity across over 100,000 sites.

Between $6 per watt and $11 per watt there is a fairly consistent slope in the aggregate demand graph. Based on this relationship, we can predict a change in demand when price changes; essentially, for each $1 per watt price decline, demand increases by 15,000 projects for the period 2007 through 2012. For example, there were 23,000 projects at or above $10 per watt and an additional 15,000 projects between $10 per watt and $9 per watt.

Figure B-F5 shows the number of CSI projects over time by household income category; clearly, there is an upward trend in all homes. However, CSI applications for year 2012 show a slight cooling from the growth trends of prior years.

4.B. Bounded Estimate of OBR-Enabled Rooftop Solar

Having now described cost components and recent trends in the rooftop PV investment, we are ready to calculate a bounded estimate of the potential benefits of OBR for rooftop PV investments. We begin with a demand trajectory through 2022, approximately one decade into the future, and explore how OBR creates additional demand by lowering credit score requirements. Second, we consider the downward trend in costs, and explore how OBR further shifts costs downward to spur additional projects. This is consciously a “marginal analysis” to explore how much extra rooftop PV investment OBR can deliver in the face of current trends.
Supply Side OBR-Benefits for Rooftop PV
Figure B-F6 shows forecasted California demand for small commercial and residential rooftop PV projects in 2022 based on trends from 2007 through 2011. In the prior section, we used DOE Sunshot data to estimate that OBR could lower project soft costs (financing, marketing and other transactional costs) in the range of $0.50 per watt to $1.00 per watt. This would have the effect of making future projects more attractive, and making some projects attractive that otherwise would be noneconomic to execute. This OBR-related cost decline can be seen as capturing a new set of projects. Essentially, this is a short-hand, transparent approach to considering a full shift in the cost curve as shown conceptually in Figure B-F1.

At a $0.50/watt cost decline, we estimate approximately 23,000 additional rooftop PV projects enabled by OBR. At a $1/watt cost savings, PV projects due to OBR ticks up to 75,000.

Demand Side OBR-Benefits for Rooftop PV
Figure B-F7 shows that approximately 25% of homes have FICO credit scores between 600 and 700. In hearing from lenders, EDF believes OBR can expand the pool of eligible borrowers to include homes with FICO scores below 650. We bound our estimate of OBR-enabled demand increases by considering the expansion of eligible homes. At a low end of the range, we consider just a 15% expansion of eligible homes, and a high scenario as a 25% demand increase. There were 11.5 million, 12.2 million and 12.6 million households in California in 2000, 2009 and 2011, respectively. This represents an annual growth rate of approximately 6.5% per year. If this trend continues, California will experience a doubling of households in the next decade.

It is reasonable to envision a second reason for expanding rooftop PV projects due to OBR, that due to additional customers. An addition of 15% of California homes with access to rooftop PV financing due to OBR equals almost 2 million homes today and over 3.5 million homes in 2022. Approximately 6 million California households have FICO scores above 700, a pool of homes that has dominated demand for rooftop PV. Expanding the population of loan-worthy homes by 2 million (low scenario) to 3.5 million (high scenario) will increase the pool of potential rooftop PV customers up to 60%. To be conservative, EDF’s low scenario considers a 15% demand increase, whereas the high scenario considers a 25% increase.

Low and High Scenarios for OBR-Benefits
We develop two scenarios to forecast the uptick in rooftop PV projects due to OBR. In addition to adding demand by expanding eligibility to borrowers with lower FICO scores and shifting costs downward, we develop a bounded forecast. The low scenario assumes flat (zero) growth in rooftop installations such that investments continue at levels observed in 2012. The high scenario has growth continuing on the trend established from 2007 through 2012.

We find a range of 70,000 to 170,000 new rooftop PV projects between 2013 and 2022 as a result of OBR effects.

50 U.S. Census.
What would 60,000 or 170,000 new rooftop PV projects mean for California’s economy and environment over the next decade? A 2009 study estimated that PV projects generate 42 jobs per installed MW nowadays, but that employment intensity will drop to 19 jobs per installed MW in 2025. We consider 30 jobs per installed MW of solar PV in our analysis. Results are summarized in Table B.T1.

Table B.T1: Estimate of OBR Benefits for Rooftop PV in California

<table>
<thead>
<tr>
<th>Benefit Scenario</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rooftop PV Industry Growth</td>
<td>Flat at 2011 thru 2022</td>
<td>Trend from 2007 thru 2011 continues thru 2022</td>
</tr>
<tr>
<td>Cost Decline due to OBR</td>
<td>-$0.50</td>
<td>-$1.00</td>
</tr>
<tr>
<td>Demand Increase due to OBR</td>
<td>15%</td>
<td>25%</td>
</tr>
<tr>
<td>Number of OBR-Enabled Projects, 2013 through 2022</td>
<td>59,000</td>
<td>169,000</td>
</tr>
<tr>
<td>Rooftop PV Project Size (kW)</td>
<td>4.11</td>
<td>4.11</td>
</tr>
<tr>
<td>Total Cost ($/watt)</td>
<td>$3.25</td>
<td>$2.75</td>
</tr>
<tr>
<td>2012 Invested, all projects</td>
<td>$788,000,000</td>
<td>$1,910,000,000</td>
</tr>
<tr>
<td>New Installed PV Capacity (MW)</td>
<td>200</td>
<td>700</td>
</tr>
<tr>
<td>Annual Generation from Installed PV (GWh)</td>
<td>300</td>
<td>1,050</td>
</tr>
<tr>
<td>Job per Installed PV Capacity (jobs per MW)</td>
<td>30</td>
<td>30</td>
</tr>
</tbody>
</table>

As a secondary effect, OBR can avoid costly electricity generation and infrastructure costs and can eventually contribute to economies of scale, notably lowered marginal costs of production. Of course, by avoided electricity generation, OBR avoids air pollution from conventional generation resources.

4.B.1.d. Limitations of Benefit Estimation Method

OBR is a way to finance a variety of benefits; we’ve captured only rooftop PV in our estimate for DG benefits. Our estimate of rooftop PV projects enabled by OBR is a conservative approach for several reasons:

- We consider only rooftop PV, not the solar thermal or other localized DG markets
- We exclude significant opportunities to harvest OBR-enabled benefits from combined heat and power, electric vehicles and other forms of storage, and demand response.
- We study only 2014 thru 2022, benefits may accrue for many decades thereafter
- Our assumptions are conservative whenever a range is not used, such as jobs per installed PV capacity.

The forecasts for PV industry growth suggest a very dynamic marketplace. Any attempt at precise prediction is folly. We remain grounded in a diversity of peer-reviewed forecasts.
and direct observation from California’s rooftop PV industry. Still, the future is certain to be different – production cost will decline, policy will constrain and spur innovation, and customers will procrastinate and react, often in illogical crowd-following ways. New technologies will pair with new business models, any one pairing might be a game-changer, just as the rooftop leasing model has changed the game in California in a few short years.

Investments in cost-saving efficiency and distributed generation can be sweetened. For example, demand response - by short term load shifting when called upon to provide system-wide peak load mitigation or to provide ancillary services – can be integrated with variable energy resources like rooftop PV. These combinations, and the role of OBR in financing them, remain largely unexplored.

The market for demand response (DR) is already robust in many parts of the country. California utilities are counting on increasingly large amounts of DR resources from residential, commercial and industrial customers52. While we do not attempt to quantify how OBR can deliver addition benefits through demand response, such benefits have the potential to be real and significant.

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