Impact of Distributed Energy Resources on Locational Marginal Prices and Electricity Networks

by

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Rensselaer Polytechnic Institute, 2013

SUBMITTED TO THE INSTITUTE FOR DATA, SYSTEMS, AND SOCIETY IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF SCIENCE IN TECHNOLOGY AND POLICY
AT THE
MASSACHUSETTS INSTITUTE OF TECHNOLOGY

JUNE 2016

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Abstract

Distributed energy resources (DERs) are projected to be significant components of the modern power grid, active players in electricity markets and salient tools used in the operation of electric grids. The objective of this thesis is to determine the impact distributed energy resources have on power grids and markets. This research investigates, models, and quantifies the influence of DERs on prices of electricity, networks and environmental effects. There is an evolving role between distribution and transmission system operations. Quantitative modeling and a qualitative literature, industry and regulatory review were utilized to determine the impact that DERs have on market prices, grid operations and the environment of the future.

Distributed energy resources will impact the electric grid: from market economics to grid operations and reliability to coordination, and regulations. Firstly, from the European Union to the United States, power systems across the world are transforming to include and integrate larger penetrations of decentralized resources, while maintaining or increasing efficiency and operational reliability. Secondly, distributed energy resources have a quantifiable impact on short-term wholesale pricing of electricity (LMPs). Thirdly, distribution locational marginal prices (DLMPs) have been approximated, using a direct current optimal power flow, and yield insight into the revenues, prices, emissions and other bulk power system impacts at the interface between real-world transmission and distribution electricity networks. Lastly, the impact and to whom, whether costly or beneficial, that distributed energy resources have in markets and society, depends on the location in which they are interconnected.

Thesis Supervisors:	Ignacio Pérez-Arriaga	Richard D. Tabors
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Acknowledgements

First and foremost, this thesis is dedicated to my family, friends and loved ones because without them I would not be who I am today.

I would like to acknowledge Richard Tabors for his mentorship, guidance and support because without him I would not be where I am today.

I would like to thank Ignacio Pérez-Arriaga for his direction and supervision.

I would like to thank Tomas and José Pablo for their guidance through critical and timely feedback. I would like to acknowledge the team at IIT Comillas in Madrid for their support and a wonderful summer in 2015.

I would like to thank Brian Conroy, and our friends at Avangrid, for their support through this research.

I would like to thank all those at TCR for their support during these months: Kofi, Hank, Elli, John, Alex and our friends at GMA at the office off the Commons at Park Plaza.

I would like to thank Alice for her constant support and challenging me to make lucid statements and descriptions.

I would like to thank all of those with whom I have shared a class, meal, walk, and story, because without you I would not be what I am today.

Special thanks to Ed, Barbara and all the students and faculty associated with the Technology and Policy Program at MIT. Ed and Barb do more for the students than I am sure many of us realize.

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1. Introduction

The electric grid is one of the most impressive and complex developments ever created. The US National Academy of Engineering named the electric system, including generation transmission and distribution, the world's greatest engineering achievement of the 20th century (NAE, 2003). Some observers have termed the grid, "the largest machine in the world" (NYISO, 2015). Electricity networks are vast, complex and expanding.

The US grid alone has over 7,000 power plants in operation, with a nameplate capacity over 1MW, where energy generation is sent "over 642,000 miles of high-voltage transmission lines and 6.3 million miles of distribution lines" (QER, 2015). Recently, 195 nations committed to enact policies and investment to mitigate climate change and maintain only a 1.5 degrees Celsius global temperature increase beyond pre-industrial levels (Nuttall, 2015). "Both long-distance transmission and distributed energy resource can enable lower-carbon electricity" (QER, 2015). The grid of the future will be more affordable, cleaner, and reliable as well as include a mix of central and decentralized generation, supporting a "highly distributed architecture that integrates the bulk electric and distribution systems" (QER, 2015). The grid of the future will "promote greater reliability, resilience, safety, security, affordability, and enable renewable energy, while achieving better economic and environmental performance, including reductions in greenhouse gas (GHG) emissions" (QER, 2015).

According to the Intergovernmental Panel on Climate Change, electricity and heat production make up about 25% of total greenhouse gas emissions, the largest sector; larger than agriculture, forestry and other land use (24%), industry (21%) and transportation (14%), based upon global emissions from 2010 (IPCC, 2014; EPA, 2016). "In 2014, the electricity sector was the largest source of U.S. greenhouse has emissions, accounting for about 30% of the U.S. total" (EPA, 2016).

The electricity sector is a single piece of the global energy puzzle, but changes can have a rippling impact. According to a 2014 Factsheet from the International Energy Agency, a cumulative global investment of approximately $53 trillion will be needed in order to approach a 2035 scenario where global temperature increase is limited to not more than 2 degrees Celsius[1] (EIA, 2014). In the US alone, over the next 20 years, the electricity industry is expected to add "7,000 miles of transmission lines to comply with the Clean Power Plan" and spend around $2.1 trillion on "grid technologies and infrastructure to prepare for higher penetrations of renewables" (Bade, 2015).

Changes in the power sector are underway. The provision of electricity services in the US and Europe is undergoing change to meet emission and renewable energy generation targets as well as an increased penetration of distributed energy resources, due to decreasing technology costs, advances in communication and information technology, societal and regulatory pressures and policy goals (Rohracher, 2008; EPA, 2015; Pérez-Arriaga, 2015). The traditional view of the power sector and the flow of electricity was "downhill," where centralized large-scale power systems sent power to customers

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[1] The gross domestic product (GDP) of the US is approximately $16 trillion USD

through high voltage cables (NYISO, 2015). The grid of the future will be different from the grid of the 20th century in that “two-way power flow will be common on both long-distance, high-voltage transmission lines and the local distribution network” (QER, 2015).

Reforming the Energy Vision (REV) is a New York State initiative proposed by the New York Public Service Commission. Utilities are currently completing plans to provide consumers with a more resilient, reliable[2] and an efficient grid with emphasis on appropriate costs, consumer awareness, and environmental effects, such as reduction in carbon emissions (NY PSC, 2014). To quote Rocky Mountain Institute, “the United States’ electric grid is in the midst of transformation, but that shift need not be an either/or between central and distributed generation. “Both forms of generation, connected by an evolving grid, have a role to play” (RMI, 2014).

Many of these factors along with the growth and decreasing costs of distributed energy resources, are leading many to rethink the structure of the power sector. According to the Department of Energy Quadrennial Energy Review (QER) investments in transmission are still expected to grow even though demand response, flexible operations, and demand-side resources can enable renewables and perhaps reduce the need for bulk system infrastructure (QER, 2015). In New York State, growth in total electric usage is expected to remain flat, while peak demand is expected to grow; energy efficiency and distributed energy resources are expected to reduce the growth of peak demand on the bulk power system by “more than 2,700 megawatts from projected levels by 2025... also lower annual energy usage served by the bulk power system by more than 14,000 gigawatt-hours in 2025” (NYISO, 2015).

In a 2015 report by Oak Ridge National Lab[3], distributed energy resources can impact five main drivers for bulk transmission expansion, including interconnection, reliability, economics, replacement, and environmental, but the conclusions are not yet firm, since models have only recently begun to incorporate demand resources realistically (Oak Ridge National Lab, 2015). DERs can impact reliability in that reduction in demand may lower the need for reserves and demand-side resources can provide reserves, which can free existing generation and transmission assets to provide power (Oak Ridge National Lab, 2015). Economically, demand resource would be located at or near loads therefore reducing the cost of distant generation, transmission and losses; however, lower demand near low-cost generation may increase the use of transmission as that power may seek more distant markets (Oak Ridge National Lab, 2015).

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[2] Superstorm Sandy impacted the Northeast towards the end of 2012 and left approximately 8.5 million people without power, caused around $65 billion in damages and led to 117 deaths (Lacey, 2014). The numbers of bulk power system outages are rising, and along with an ageing infrastructure, resiliency, reliability and cost are major concerns for utility companies, regulators and power system service providers around the country (Lacey, 2014).

[3] Oak Ridge National Lab. (2015) “Impacts of demand-side resources on electric transmission planning.”

Analysis on the bulk power system from DERs is nascent; therefore, pulling and expanding upon topics and analysis raised in the Oak Ridge National Lab report from 2015, the purpose of this thesis is to analyze distributed energy resources, in a real-world context, and to determine if and how they may support a grid that emits less greenhouse gases, is more dynamic, reliable and efficient. This analysis utilized a state of the art and industry vetted optimization algorithm for calculation of short-term electricity pricing with a data set for the New York State transmission network and generation system (Chapter 2)[4]. The contribution to the field is an exploration into the interface between distribution and transmission networks from regulatory, policy, operations and markets perspectives; utilizing an analysis into the qualitative and quantitative aspects that drive this sector (Chapters 3, 4, and 5). Chapter 3 explores the average system-wide impacts across the New York bulk power system from an increase in penetration of solar PV, Chapter 4 will explore and provide findings and recommendations for the current, transitory and future interaction between transmission system operators and distribution system operators in a qualitative (coordination and regulatory) context[5] and Chapter 5 explores a case study in which the interface between transmission and distribution utilizing a local distribution network co-optimized with the bulk New York Power system and.

1. Overview of electricity markets and restructuring

Before the 1980s and 90s, most electricity generation, transmission (high voltage), and step-down distribution were supplied by vertically integrated utilities. Utilities were considered vertically integrated because they controlled generation, transmission, distribution and retail of electricity pricing and operations. In the early part of the 20th century, private electricity companies began to emerge; government and state agencies had a role, but it was limited. The power sector itself was mostly a regulated industry (Pérez-Arriaga, 2015). Utilities maintained monopoly control, served consumers electricity, charged consumers tariffs or electricity prices set and confirmed by regulatory agencies, and were therefore remunerated according to cost of service regulation (to recover investment).

Vertically integrated utilities served consumers reliably for many years, but in the early 1990s, due in large part to technological change, electricity services, networks, company and industry structures and markets were reevaluated. Restructuring, in the context of electricity and energy services, is when a monopoly system is replaced with a competitive one (EIA, 2010). Along with deregulation of the power sector in the early 1990s, the generation portion of the utility was decoupled from the wires, or transmission and distribution services portion (T&D), in many states (Borenstein, 2015). The wires business remained a natural monopoly, while the generation, in many places in the United States, remains competitive (EIA, 2010).

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[4] Many of the bulk electricity systems in the United States deploy a direct current optimal power flow with an alternating current feasibility check and a direct current to alternating current (DC-AC) iteration, with a decoupled AC model, for the security constrained economic dispatch (SCED) (O'Neill, 2011).

[5] Birk, M., Chaves-Ávila, J. P., Gómez, T., and Tabors, R. (2016, forthcoming) "TSO/DSO Coordination in a Context of Distributed Energy Resource Penetration." MIT Energy Initiative, Utility of the Future Report

Independent system operators (ISOs) or regional transmission organizations (RTO) run wholesale electricity markets within many regions in the United States, and provide electricity services to over 2/3rd of the United States, by population. Wholesale electricity markets are the markets where resources, such as, but not limited to, coal power plants, nuclear power plants, hydropower facilities, and solar farms can bid generation or capacity into a market; load serving entities, such as utilities or energy service providers can bid in demand and the ISO or RTO runs an optimization algorithm to determine the least cost of supplying the load. The operator then dispatches the set of least cost generators, subject to network constraints and generator parameters. A product of the optimization is the shadow price or the marginal price at each transmission node, for serving the next incremental megawatt of demand (i.e. marginal value). ISOs and RTOs in the United States, such as CAISO, ISO-NE, PJM and NYISO calculate electricity prices in markets for day ahead and real-time periods through economic dispatch and unit commitment models, but all have slightly unique methods and market designs (O'Neill, 2011).

Wholesale markets, such as the New York Independent System Operator (NYISO), PJM or Independent System Operator New England (ISO-NE), calculate locational marginal prices or nodal prices or shadow prices that are defined as short-term prices of electricity (Schweppe, 1988). The definition of wholesale electricity markets is obviously more complex than previously expressed, but it provides a foundation of certain structuring of electricity networks and pricing within organized wholesale regions, for the remainder of the thesis. The dispatch and unit commitment of generation usually takes place at some predetermined interval prior to real-time and also again at or very close to the real dispatch time of power. In the New York ISO, there is a day-ahead market (24 hour before) as well as a real-time market occurring at specified intervals relative to operations. There are unique market designs in different regions across the US, the EU and other parts of the world.

2. Spot pricing and computation of locational marginal pricing

In many wholesale markets, the prices of wholesale electricity are based upon the concept of locational marginal prices first described as spot prices (Schweppe, 1988). "Optimal prices for electricity transmission can be seen as arising from the problem of maximizing the net welfare obtained from electricity consumption, subject to a number of constraints" (Green, 2004). The net welfare is the benefit from consuming the electricity netted against the cost of actually generating and transmitting it. Supply of electricity must equal demand plus losses, subject to line capacities and Kirchhoff laws.

Locational marginal prices are a quantitative value for the impact, in operation costs, imparted on the electricity system from an incremental change in supply or demand (typically 1 MWh). According to CAISO,

"Locational Marginal Price (LMP) is the marginal cost of supplying, at least cost, the next increment of electric demand at a specific location (node) on the electric power network, taking into account both supply (generation/import) bids and demand (load/export) offer and the physical aspects of the transmission system including transmission and other operational constraint" – Treinen, R (2005).

The LMP is the incremental cost or the marginal cost to the system in order to meet the demand. "Nodal prices[6]" or locational marginal prices can be decomposed into an energy component ($/MWh), a congestion component ($/MWh) and a loss component ($/MWh)[7]. The LMP is the wholesale price used by the New York Independent System Operator, or Locational-Based Marginal Price as defined in New York, which includes wholesale price of electricity, congestion charges, and line losses[8].

LMPs are calculated using an optimization logic, the objective function of which is to minimize total system cost. In a large transmission system (i.e. New York State), there are potentially hundreds or thousands of generators with different costs of producing energy[9] and there are potentially thousands of substations and lines connecting the generators to the loads with different voltage levels and physical characteristics; these individual characteristics and the meshed interconnection of the lines, nodes and generators make for a complex problem. The majority of the LMP-based wholesale market structure operates so as to assure overall security of supply within the system. The security-constrained aspect of the unit commitment is when the transmission grid is taken into account in the optimization (FERC, 2006). The objective function is generally subject to the main criteria that total supply must equal total load at all hours, constrained by losses and subject to operational constraints, such as interface flow limits, maximum generation from units, and thermal and/or voltage line ratings.

Another way to understand LMPs is to imagine that at a particular node there is an additional 1 MWh of load, what is the marginal cost to supply the next unit of energy (to supply the 1MWh load)?

The nodal price equation is displayed in Equation 1.

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[6] For a good description of a simplified version of the computation of nodal prices, see Pérez-Arriaga et al, 2013. For analysis into the fundamental mathematics behind spot prices, see Schweppe, 1988, and Rivier et al, 1993 (Pérez-Arriaga, 2010).

[7] LMPs broken down into components are arbitrary and although the LMP is reference bus independent, "the split of the LMP into components is dependent on the reference bus or slack bus" (Rivier, 1993; Litvinov, 2004). It is important to acknowledge the arbitrary nature of such decomposition, but elaborate in more depth on the calculation from algorithms used in PSO, as many of the real-world power systems express the breakdown in some form or another (Rivier, 1993). The calculation of LMPs depends upon a reference or slack bus to calculate the system losses and congestion, therefore, change the slack bus, and change the LMPs. This will be elaborated in more detail in the coming paragraphs.

[8] Case 15-E-0751, Comments of the Solar Progress Partnership on an Interim Successor to Net Energy Metering, In The Matter of the Value of Distributed Energy Resources (issued April 18, 2016).

[9] Start-up, shut-down, minimum run time for a generator, fuel prices, and other costs, to name a few, are variables that change the price of the generator to provide electricity.

$$\lambda_i = \lambda_{Ref} - L_i * \lambda_{Ref} - \sum_j (\mu_j * SF_{ji})$$

Equation 1: Nodal price calculation (Treinen, 2005)

To quote R. Treinen from CAISO, "λ_i is the nodal price at bus i, λ_{Ref} is the marginal cost or the nodal price at the reference bus, $L_i * \lambda_{Ref}$ is the marginal cost of losses[10] from the reference bus to bus i, and $\sum_j (\mu_j * SF_{ji})$ is the marginal cost of transmission congestion[11] from the reference bus to bus i" (Treinen, 2005). "The nodal price at a bus i shares the same component λ_{Ref} and it includes an implicit congestion component, which is the marginal cost of supplying the next increment of load at the reference bus taking into account the physical aspects of the transmission network (constraints and potential congestion)" (Treinen, 2005).

In New York ISO, the LBMP contains the same reference bus LMP for all buses and the loss component can be negative at times[12,13]. To quote Dr. Litvinov from ISO-NE, "shift factors and loss factors are zero at the slack or reference bus, the LMP at the reference bus is equal to the energy component" (Litvinov, 2004). LMPs are calculated as a result from the security constrained unit commitment and economic dispatch from the optimal power flow (OPF); optimization algorithms typically utilize a direct current power flow. Most markets currently employ direct current approximations and linearization to calculate the market-clearing prices. Linear-programming (LP) and DC approximations to power-flows are usually employed (Litvinov, 2004). "DC approximations do not include losses explicitly, by definition; therefore, it is more challenging to calculate the marginal effect for losses in the economic dispatch and pricing" (Litvinov, 2004)[14]. DC approximations generally model power flows without reactive power and reactive power losses and also have some linearization of the marginal losses.

In calculation of the LMPs, PSO[15] algorithms calculate a shift factor matrix, which incorporates the impact on losses through a loss penalty factor (LPF) associated with

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[10] "$L_i$is the marginal loss factor at bus i = $\frac{\delta Ploss}{\delta P_i}$, which is the change is losses per change in power flow; P_i is injection at bus i and Ploss is the system losses. L_i> 0 there is an increase in loss, L_i<0 for counter flow which decreases flow on transmission lines" (Treinen, 2005).

[11] "μ_j is the shadow price of a binding constraint j at a line limit ($/MWh) and SF_{ji} is the shift factor for real load at bus i (the reference bus for this specific shift factor) on constraint j or the incremental power flow on constraint j when an additional unit of power is injected at bus i and withdrawn at the reference bus" (Treinen, 2005).

[12] A negative loss component for a node might mean that there would be reductions in system losses by transferring power from a specific bus i to the reference bus, but again these components are based upon a selected slack bus or reference bus.

[13] "ISO-NE and NYISO find useful to split the LMP into these components of loss, congestion and energy is simply because of the need to calculate congestion revenue for FTRs (Financial Transmission Rights)" (Litvinov, 2004). "Neither congestion nor loss revenue is dependent on the location of the slack reference and the difference in congestion components between locations is not dependent on the slack reference" (Litvinov, 2004).

[14] For specifics on marginal loss modeling in DC OPFs in congestion managements systems (CMS) and standard market designs for pricing of electricity (LMPs), see Litvinov, 2004.

[15] See methodology, Chapter 2, for more details on PSO.

every generator node. Applying the loss penalty factor to the generators in essence creates a situation where the LMPs will vary by location even without congestion. Since the losses depend on the choice of reference bus, changing the reference bus can impact the loss component of the LMP, and could create issues for calculating FTRs, as mentioned above. The losses depend on power flows and transmission is first excluded when calculating LMPs. Power flows in the system are dependent upon every nodal generation or supply (Green, 2004).

The system losses are estimated, at first, by initial flows, the OPF is solved fully, and then a new set of flows is determined. These new flows are used to recalculate the losses and the full OPF is run again with the new losses. Only when losses converge in this process are the LMPs reported. If increasing generation would result in an increase in system losses, than the unit's offer curve is adjusted higher and the unit would look less attractive to dispatch. If an increase in generation would result in a decrease in system losses, the unit's offer curve is adjusted lower and it would look more attractive to dispatch[16].

3. Distributed energy resources in electricity markets and networks

Distributed energy resources (DERs)[17] are characterized by their wide dispersion throughout a low or medium voltage distribution network. Solar photovoltaics and battery storage can be deployed at scales ranging from kilowatts to megawatts depending on the location, i.e. region, demand growth, climate conditions, generation mix, and sector (i.e. industrial, commercial or residential). Demand response and combined heat and power units are also technologies that have been deployed at industrial, commercial and residential scale and are inherently "distributed." "The emergence and growth of distributed resources is leveling the landscape of the electric system" (NYISO, 2015).

Depending on the region, take New York State for example, distributed resources could mean, according to regulatory and governing bodies, any energy producing or offsetting technology or operation; such as demand response, combined heat and power, solar photovoltaic, fossil-fuel distributed generation (micro-turbines) and/or thermal and electric storage that is less than 2 MW (NY PSC, 2014; Newcomb, 2013). These resources can be "behind-the-meter," meaning that DERs are located on the consumers premises or close by[18] and offset consumption by supplying some or the entirety of the customer's load, e.g. rooftop photovoltaics, battery and thermal storage, back-up generators and solar farms[19]. Generating energy on the same site as consumption through

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[16] These are marginal losses to the system, which is the change in losses due to a change in power flow.

[17] Distributed energy resources include distributed generation, such as solar PV, wind or fuel cells, but also encompass storage technologies, and combined heat and power; these resources can be used as a primary or back-up energy source and is generally sited on the consumers premises to provide power needs and in some cases even provide energy back into the grid when there is excess.

[18] Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015)("CDG Order").

[19] Id.

the use of distributed energy resources such as solar photovoltaic, fuel cells or even micro-turbines may “facilitate the transition to a smarter grid” (EPRI, 2015).

a. Past, present, future

While the delivery of electricity began in the 1880s as local generation serving local customers, during the mid-20th century it evolved into today’s delivery network as economies of scale dictated investment in larger and more efficient generating facilities interconnected to higher voltage transmission wires. These generating units and the transmission network assets were generally less expensive per unit of output than smaller generating and transmission facilities” (NYISO, 2015). “The modern electric system evolved through massive generating facilities connected to high-voltage transmission lines, and the expansion of local distribution networks that deliver energy to customers. In that model, electricity is said to flow “downhill” from large power plants to a widespread set of residential, commercial and industrial customers” (NYISO, 2015).

Most homes and businesses were connected to a distribution grid and paid uniform tariffs for the electricity given the paradigm that load was the recipient of the service supplied by generation from centralized facilities through transmission and distribution networks. The tariffs bundled network costs (transmission and distribution) as well as energy costs (generation) and potentially for other public goods, such as energy conservation programs. The traditional “trickle-down” paradigm of old, where centralized facilities produced electrical energy from generators, stepped-up the voltage to transmit long distances along high-voltage wires, stepped-down to medium and low voltage distribution networks and eventually consumed at low-voltage at houses or buildings in towns or cities, is starting to evolve. The network was designed to have unidirectional flow, to enable efficient transfer of energy. Today’s grid is beginning to look quite different. Resources, that can provide not only energy generation, but also other electrical services, are beginning to be added at the household and low-voltage distribution level, causing the grid, flows of electricity, planning and operations to be more complex (Burger et al., 2016).

There is a trend in power systems around the world towards a cleaner and potentially more distributed future; driven in part by policy or by consumer social desires for distributed resources based upon locational dependent economic and environmental benefits (DNV GL, 2014). States in the US such as California, Hawaii, Arizona, New Jersey and New York are leading the way towards a distributed energy future by having the largest recent deployment in installed capacity of DERs (DNV GL, 2014).

DERs are currently established in many markets around the world; however, they are limited due to certain market restrictions and potential for added complexity in the operations of these resources. The dispatch and commitment of generation resources are typically calculated at the transmission level, but many of these distributed resources are connected at lower voltage, in which the operations and installation are typically undertaken by the distribution utility. This interface between the transmission and distribution system operators in a context of distributed energy penetration is addressed in this thesis Chapter 4 (Birk et al, 2016). The question remains, are distributed resources here to stay?

b. Are distributed resources here to stay?

All throughout the early 1900s, when the electric grid and power generation sectors were nascent, economies of scale and natural monopolies drove efficiency in generation and transmission of electricity. Demand for electricity was deemed inelastic, consumer demand was growing and economies of scale made central generating plants the most economical way to supply the demand (NY PSC, 2014). Power producers could produce more electricity by installing plants with higher capacities (topping out on the scale of GW), such as coal, nuclear and hydro and therefore produce electricity at a cheaper price per unit. With thicker wires and longer networks that reached more consumers, generators could provide electricity to many more customers. Transmission of electricity was inherently a natural monopoly; it was actually cheaper and more efficient for one entity to have monopoly control, and with regulatory oversight, these entities were able to provide a service at lower costs for consumers than if there was competition. A single distribution (lower voltages) network was the most efficient because parallel lines and having parties competing over them would not be economical (Pérez-Arriaga, 2015).

The penetration of DERs is an interesting and complex socio-economic topic. Many years ago, across the different power systems in the world, there were different reasons for reforming of the power industry; including reductions in economies of scale, such as the exhaustive size of generation (large enough power producing plants), increased penetration of smaller gas-fired plants, increased transmission capacity, demand growth and improvements in communication technologies (Pérez-Arriaga, 2015).

Today, new advances in information and communication technologies, computational capability, lower technology and manufacturing costs for building and installing distributed energy technologies "warrant a reevaluation of the assumptions of demand inelasticity and bulk economies of scale" (NY PSC, 2014). With ageing infrastructure, more stringent regulations for older generating units, technological transformation, consumer demand no longer rising, and changing of load patterns due to demand-side resources, "A shift in the century-old model of centralized grid operation is coming, but its pace and scope remain to be seen" (NYISO, 2015). According to the US Department of Energy Quadrennial Energy Review, the grid of the future will "accommodate and rely on an increasingly wide mix of resources, including central station and distributed generation, energy storage and responsive load" (QER, 2015).

The challenge lies in understanding the drivers of the change, the fundamental principles of economics and electricity services, and implementing research that can help inform policy makers and industry stakeholders on the impact of distributed energy resources in electricity networks. The broad challenge that this thesis seeks to address is what are the impacts DERs may have on the bulk centralized transmission system currently in place, what interaction will the distribution system have with the transmission system, and how best to inform policy makers, industry stakeholders and society of the effects, beneficial or otherwise, of the new wave of technologies and transformation of the sector?

c. New York's Initiative on *Reforming the Energy Vision*[20]

Many states, such as New York and California, have already begun to significantly change the way energy resources and electricity is generated, transmitted, priced (markets) and consumed within their jurisdictions. The New York Public Utility Commission and Governor Andrew M. Cuomo have defined and proposed a *Reforming the Energy Vision* (REV) initiative, which will be a transition towards a cleaner and more localized energy grid[21]. The REV initiative is intended to create a more efficient power grid, with lower costs for customers, lower carbon footprint, more competitive markets as well as transform the network to be more resilient and reliable with increased penetration of distributed resources[22].

The Renewing the Energy Vision Strategy (REV) and proceedings are a progressive set of guidelines set forth by the Department of Public Service of New York in April 2014, which strive to enable a more distributed marketplace and network for distributed energy resources, leverage new Distributed System Platform Providers (DSPP), lead to greater economic efficiency, meet state emission targets and maintain grid stability, reliability and resiliency (NY DPS, 2014). The REV proceedings are a progressive undertaking both from a policy and regulatory standpoint as well as for a Utility or distribution company. This process requires an overhaul of current structuring from pricing to interconnection to communication and coordination. The impact and value of distribution level resources on the larger grid, from a pricing to investment to operations standpoint, are open-ended questions at the point in time of the writing of this thesis. Many utilities are facing pressures from their governing agencies to adapt to a new paradigm.

Governor Cuomo and New York State set forth the Clean Energy Standard (CES) goal of 50% renewable by 2020[23] and in a Clean Energy Standard White Paper Cost Study it assumed 2,688 MW of new installed renewable capacity and over 3,594 GWh/year of energy generation by 2023[24].

Below are highlighted key points from the REV proceedings and for the integration of DERs into the bulk power system in the 2015 Power Trends report (NYISO, 2015). Findings and discussions include:

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[20] New York State Public Service Commission, "Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (Case 14-M-0101) April 2014.

[21] NY.gov, 2015

[22] Id.

[23] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Notice Soliciting Comments and Providing for Technical Conference and Public Statement Hearings (issued January 15, 2016)("Clean Energy Proceeding").

[24] Clean Energy Proceeding, Clean Energy Standard White paper – Cost Study (April 8, 2016), pp. 279, 281.

1. The current mix of DERs include combined heat and power (57%), solar PV (41%) and energy storage (2%) and with rapid expansion of DERs, successful integration is vital to grid reliability and resilience
2. REV identifies and implements regulatory changes to expand the role of DERs
3. Load forecasting and data for "behind-the-meter" will be needed to effectively integrate DERs into planning and operations
4. Wholesale market potential of DERs includes price responsive demand[25] and/or capacity and ancillary[26] services through aggregators, but these markets must evolve to address challenges of DERs[27]

4. The short blanket

The limitations of current modeling and computational capabilities, jokingly described by Professor Ignacio Pérez-Arriaga as the "short blanket theorem," refers to the idea that with current computational capacity, trying to encapsulate, cover and model the entire power system with complete granularity, there will inevitably be some loss or tradeoff; the tradeoffs, therefore, will bear an impact on results and output of certain efforts. The entire operations and investment decisions for networks and energy resources cannot yet be represented in full detail through the use of a single model with current capabilities. The analogy is that a person needs to cover oneself with a blanket, but only has a short blanket. The person must pick and choose which part of the body to cover as in the modeling world; one can chose the area of which to focus their primary effort. A person is analogous to the modeling of the entire power system as an infinitely long blanket is to the toolset of all the models that can cover the simulated environment, such as short-term economic dispatch and unit commitment or long-term capacity expansion.

The short-blanket theorem applies to modeling and simulating electricity networks. In electric power system networks, forecasting prices, investment and network impacts using power flows, economic dispatch, unit commitment, the stochastic nature of generation technologies, capacity expansion and transmission expansion models for millions of nodes, customers, lines, transformers, generation cites, regulatory paradigms and so on... is extremely computationally and time intensive to model in complete granularity. Temporally, spatially and computationally, using the current state of the art and resources, is a tremendous feat to optimize for all prices, constraints, unit commitment, losses, reserves, and power flow in real-world power systems and electricity networks. Nonetheless, modeling is supportive because it can provide as close to the real world as possible.

For the modeling aspect of the research, the methodology is to utilize a tool for calculation of security constrained unit commitment and economic dispatch model with a

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[25] Reducing consumption when prices are high, or increasing consumption when prices are low.

[26] These services are usually reserves or frequency regulation.

[27] As the markets have done to incorporate renewable resources. DERs impact real-time and projected load forecasting, therefore more advanced integration of metering and communication will be needed to support the growth of DERs.

direct current (DC) optimal power flow (DC OPF) from Polaris Systems Optimizations, Inc. called Power Systems Optimizer described throughout this thesis as PSO[28]. PSO is a detailed mixed integer program that simulates real-world electrical power systems by computing security constrained economic dispatch and unit commitment models through computation of locational marginal pricing or short-term pricing, emissions, reserves, contingencies and constraints for transmission networks. A more detailed description of PSO can be found in Chapter 2. PSO, as well as other models to simulate power systems, are used to guide discussions, potentially drive social and economic changes and, using the projections and forecasts, regarding policies and economics within electricity markets.

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[28] http://www.psopt.com

2. Methodology and Modeling Tool

This Chapter details the methodology utilized for researching the impact of DERs on bulk power systems as well as the specifics on the modeling tool.

1. Methodology

To analyze the impact of DERs on the bulk power system, a state of the art and industry vetted optimization tool for calculation of short-term electricity pricing (LMPs) with a real-world transmission network and data set for the New York State[29] system was utilized (Chapter 2, Section 1 and 2). The modeling approach is separated into 2 parts: (1) in which simplified or aggregated distribution networks are modeled up to the transmission level substation to calculate system impacts of distributed generation, solar PV[30], on operations and short-term marginal prices (Chapter 3) and (2) where a more detailed distribution network is included along with the transmission system in PSO to further investigate the interface between transmission and distribution, the local impacts of distributed generation, and the impacts on the bulk power system (Chapter 5). A novelty of this research was building into the data set for PSO, a distribution feeder to analyze DERs and their impacts with more granularity in combination with a transmission system.

To compliment the technical modeling component of the analysis, an in-depth qualitative study into the coordination and interface between transmission and distribution system operators was also undertaken. Chapter 3 investigated the economic and environmental impacts from large penetrations of DERs on the bulk power system. Chapter 4 analyzes qualitatively the implications of large penetrations of DERs on the distribution and transmission networks from an operation, planning, and industry structure and coordination standpoint. Chapter 5 explores a case study into the interface of transmission and distribution through the use of PSO. Taking the modeling down a level deeper, Chapter 5 studies a case study where the interface between transmission and distribution is modeled with more granularity to determine impacts from DERs that policy-makers, regulators, industry stakeholders and especially network operators would want to understand.

2. Description of Power Systems Optimizer and pCloudAnalytics

This thesis is largely based on analyzing the behavior of locational marginal prices impacted by distributed energy resources. PSO is a well-suited tool for the calculation of LMPs (defined in Chapter 1). PSO is utilized because of certain modeling, data and

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[29] The data set for the New York State transmission system was built, compiled and verified against historical prices. PSO and the calculation of LMPs provide a quantitative analysis into wholesale short-term electricity prices with increased penetration of DERs.

[30] Different distributed energy resources were not modeled in detail and described in this thesis. However, solar PV may act as a proxy for other types of distributed generation. The DOE QER published a finding in one of their analyses for transmission capacity needs, in which there was high deployment of low-cost solar PV to model changes in transmission through 2030 (QER, 2015). The QER scenario, similar to ones carried out in this thesis, did not consider the full detail of "distribution line needs" (QER, 2015).

simulation characteristics, which help to gather insight into trends in different real-world markets. Within PSO, the algorithms run a direct current optimal power flow and security constrained unit commitment and economic dispatch models (DCOPF and SCUC/SCED) for transmission networks. PSO is a mixed integer optimization program for electricity cost modeling (security constrained unit commitment and economic dispatch) for locational marginal prices for every substation, generator and load area. PSO can calculate on hourly and sub-hourly timescales. The unit commitment is a mixed integer linear program solved to the true optima using the Gurobi[31] solver. A gap tolerance is usually set, which is the difference between the best-known feasible solution and a known bound on the optimal solution.

PSO is structured into four distinct levels: inputs, models, algorithms and outputs and shown in Figure 1. Inputs include demand forecasts, generation and transmission expansion, emission prices, and fuel prices of which the data is obtained from reliable national and commercial agencies and forecasts from the specific network operators.

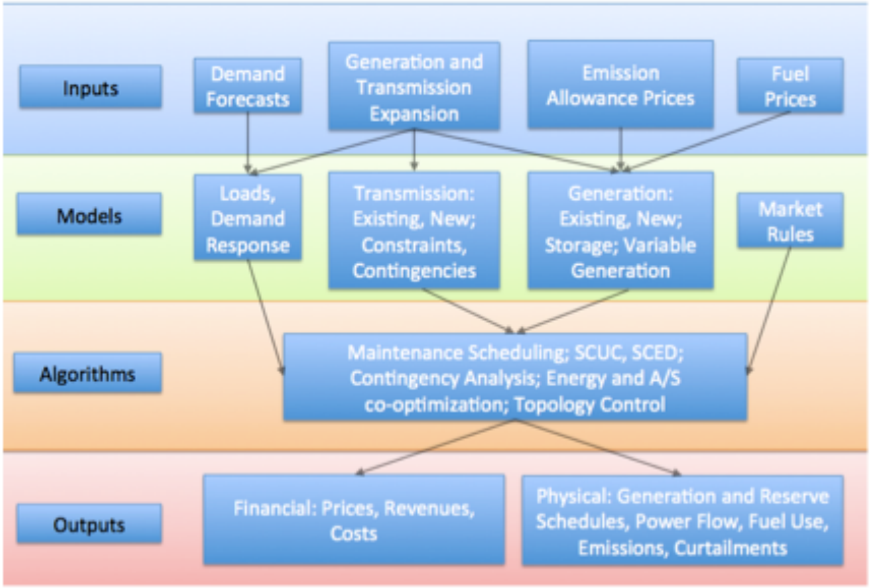

Figure 1: Analytical Structure of PSO (Tabors, Rudkevich and Hornby, 2014)

The models include loads, demand response, existing and new transmission network, constraints and contingencies, new and existing generation, storage, distributed and variable generation, as well as market design rules. The algorithms calculate unit maintenance scheduling, security constrained unit commitment and economic dispatch, contingency analysis, energy and ancillary services co-optimization as well as certain topology controls and switching. The outputs include financial and physical elements including LMPs, revenues, congestion costs or rents, generation and reserve schedules, power flows, fuel usage, emissions, curtailments which can be organized according to areas, nodes, and time periods.

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[31] Commercial Gurobi solver, http://www.gurobi.com/, at the time of writing this the solver has been switched to IBM CPLEX, http://www-01.ibm.com/software/commerce/optimization/cplex-optimizer/.

pCloudAnalytics (pCA)[32] is a "market simulation environment implemented on Amazon EC2 commercial cloud," which manages the data, is the user interface, and a post-processing tool (Rudkevich, 2014). The package of pCA and PSO has been used extensively in power market and operation simulations (Tabors et al., 2014). One of the advantages of PSO and pCA is the parallelization and partitioning of segments. Due to the parallelization of the computation, certain models can be run and analyzed in a fraction of the time that it would normally take to run for networks on the order of magnitudes of large scale, high voltage transmission networks, such as NYISO, PJM, MISO, and ISO-NE. A model can be partitioned weekly, bi-weekly, or monthly, greatly reducing the run time by segmenting the runs onto different servers. A scenario for direct current optimal power flow, security constrained economic dispatch and unit commitment for a real-world power system with 5000 nodes, 10,000 lines, 700 generators, and for 8760 hours, that might normally take in series 30 hours of computation time, only takes around 3 hours for computation, processing, and loading of the data; an immense improvement.

pCA manages the inputs for PSO, organizes the data into scenarios, partitions the scenario into segments, and uses virtual machines on the cloud to process the segments of PSO. Figure 2 displays the architecture of pCloudAnalytics.

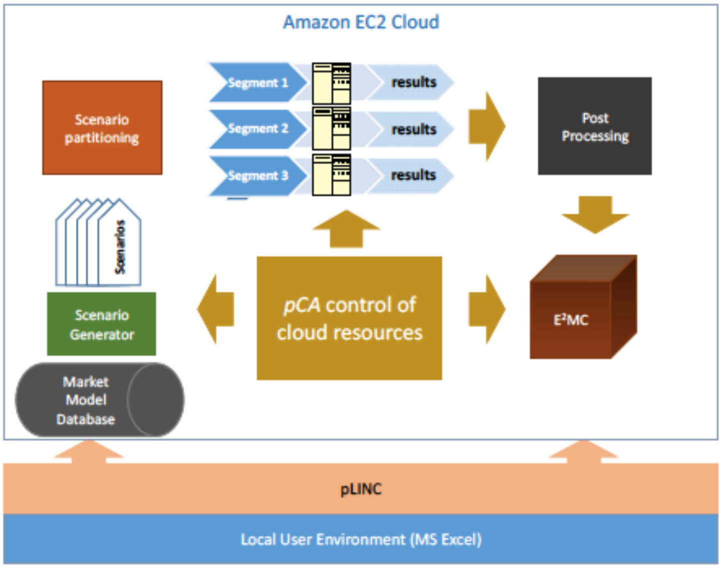

Figure 2: Architecture of pCloudAnalytics (Tabors, Rudkevich and Hornby, 2014)

Starting with a local environment via csv (comma separated values) or Microsoft excel format, the user can upload the data to be synced to the cloud. The user communicates with the cloud via pLINC[33] and through a website online. Any discontinuities, due to the different horizons through the segmentation in the data, are evaluated and reported. The results and outputs are loaded into, and processed in, the power market explorer (PME).

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[32] Newton Energy Group (NEG) is a software analytics and consulting company. www.newton-energy.com.

[33] A special software tool that links the user's local environment with the cloud environment

Once in the power market explorer, the results can once again be easily analyzed via a user-friendly interface of excel with pivot chart and table formats.

3. Inputs and data sources

For the analysis using PSO, the data sources and quality are of utmost importance. Many of the data points are always evolving and changing and the projections are thus widely dependent on where and when the data is extracted. To make a point and back it up with evidence, a line must be drawn somewhere and decide where the updating of data will halt for the time being; there will always be new and useful data to update with, but like all good modeling, one must weigh the pros and cons of including updated information.

The data for the high-voltage transmission substations and topology of lines were obtained from Federal Energy Regulatory Commission based upon 2013 FERC 715 powerflow filings for the summer peak 2015, for the specific use of Tabors Caramanis Rudkevich (TCR)[34], and permits only those that have applied for access to view and utilize the data; this information has been deemed, by the United States Federal Government, to be of critical national infrastructure and security concerns. The data was verified with the NYISO queue, so that all essential projects and upgrades were properly represented. Electrical nodes (eNodes) are mapped to busses/substations. There can be multiple eNodes mapped to busses/substations. The substations are mapped to zones and in New York State there are 11 zones (A through K). ENodes can represent physical connections or electrical connections of generation or load for power-flow analysis for generators at the same bus.

All major interfaces and critical contingencies were monitored to represent constraints. PowerGem[35] performed an initial contingency analysis using the TARA[36] tool. The powerflow model was solved to determine an initial state for injections and flows across the entire New York System. These initial powerflow is important because the loads across the entire system are deployed in accordance with and proportion to the initial states. The load inputs are hourly profiles for each area based upon template historical hourly load profiles.

Hourly load profiles were extracted from reported values from NYISO between February 2014 and January 2015, purposefully excluding the Polar Vortex due to the abnormally cold winter and abnormal patterns for prices[37]. Along with historical hourly load patterns, peak and energy forecasts from the NYISO 2014 Load and Capacity Data report or Gold Book are utilized to calculate the hourly load patterns for the calendar year 2020 (NYISO

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[34] Tabors Caramanis Rudkevich (TCR) is an energy and economics consulting company based out of Boston, MA and Richard Tabors is a Project Director for the MIT Utility of the Future Report as well as the President of TCR. MIT received an academic license for PSO, pCA, PME and the associated data from TCR for this project.

[35] A consulting and software firm for power grid engineering and markets. http://www.power-gem.com/

[36] Transmission Adequacy and Reliability Assessment. http://www.power-gem.com/TARA.html

[37] http://www.nyiso.com/public/markets_operations/market_data/load_data/index.jsp

Gold Book, 2014)[38]. Econometric predictions from the Gold Book for the peak and energy forecasts for the calendar year 2020 are provided; however, these are singular values for each area. The energy (GWh) and coincident peak demand (MW) predictions for 2014 through 2024 from the 2014 Gold Book include all transmission and distribution losses[39].

The initial states from the powerflow are used in coordination with the peak and energy forecasts for 2020 and the hourly load templates from NYISO, to calculate hourly load profiles for the year 2020 that are properly calendar shifted. The loads on each node in 2020 are in proportion to the initial state and the loads in each area in 2020 are in proportion equivalent to the loads in each area for the values obtained for 2014.

The NYISO Gold Book also provides for any new generator additions and assumed generator retirements. Thermal unit characteristics are also modeled in PSO which include non-fuel operation and maintenance costs, startup costs, forced and planned outage rates, quick start, minimum up and down time, heat rate curve shapes, regulation and spinning reserve capabilities from the North American Electric Reliability Corporation (NERC) Generating Availability Report (NERC GADS, 2014). Full load heat rates and emission rates for each generating unit were obtained from SNL Financial Services and developed by NEG. NEG calculated operational characteristics by using a multitude of publicly available data. Capacity ratings were also obtained from the 2014 Gold Book from summer and winter dependable maximum net generating capability (DMNC) for each unit.

Since there are many small generating units, NEG aggregated all units 20 MW and below by type and size into a smaller set of units. Full load heat rates for the aggregated units were calculated as the average of the individual units and all the other parameters were determined based upon unit type characteristics. Larger single block units were mapped to individual eNodes in the power flow, whereas larger combined cycle plants and aggregated units were mapped to aggregate nodes (Anodes), which represent multiple busses in the network.

The limits for interfaces were based upon information in the 2013 NYISO planning study for study year 2018 and upon historical data on interface limits enforced for the calendar year 2014 (NYISO, 2013).

Flows between NYISO and external areas were obtained from historical hourly reports by the NYISO between February 2014 and January 2015. There are 12 interchanges with varying capacity (MW) ranging from 100 MW for CEDARS-HQ to 3000 MW for PJM-NYISO. The external areas included: Hydro Quebec (HQ), Ontario (IMO), New England

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[38] http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2014_GoldBook_Final.pdf

[39] The values from the Gold Book for energy and demand forecasts include impacts from energy efficiency and retail solar PV in the econometric projections. 2014 was the first year NYISO developed forecasts for energy and peak demand including trends in retail solar PV installations, geographical considerations, and operational and performance parameters.

Independent System Operator (ISO-NE), and a few zones in PJM that border New York State (RECO, PSEG, PENELEC, and JCPL). These zones are connected to NYISO through multiple lines because the data was provided on an aggregated basis. The schedules are deterministic with external generators scaled to balance the load in the external areas across the branches that connect the external areas to NYISO zones.

The individual interchange lines are Hudson Transmission Partners (HTP), Neptune (NEPT), Cross-Sound Cable (CSC) and Linden Variable Frequency Transformer (LIND VFT) which are modeled as generator and load for simulation of bidirectional flows. The load and generation that make up the model for these interchanges are connected to physical eNodes within specific zones in NYISO.

Nuclear units were modeled with long up and down times of approximately 1 week (164 hours), given the base load or must run nature of such plants. The NERC Generating Availability Report was utilized to determine planned outage rates and forced outage rates. NEG assumed certain fuel and variable operations and maintenance for the production costs.

Hydro units were modeled according to a daily water flow pattern. NEG assumed that 40% of daily energy was at the same level for each hour of the specific day and the remaining 60% was scheduled optimally to minimize system-wide production costs. It was assumed hydro plant conditions did not vary significantly across seasons. Flow and generation data for certain plants were obtained from publicly available data from the Energy Information Administration (EIA)[40].

NEG utilized National Renewable Energy Laboratory (NREL) hourly generation profiles from Eastern Wind Integration and Transmission Study (EWITS) data for 2006 weather[41]. The wind sites were mapped to the nearest NREL wind site for the hourly schedules and scaled according to the installed capacity of the wind site. Solar photovoltaics are modeled under the assumption that they are fixed array installations and the energy is modeled deterministically through NREL's site specific PVWatts® Calculator[42]. The energy production assumes a nominal elevation of 5 meters, standard module type, fixed array (open rack), 20° array tilt, 180° array azimuth, 14% system losses and 96% inverter efficiency. Biomass was modeled as a dispatchable generation and subject to fuel prices.

Ancillary services are secondary services and NYISO has 3 types of reserves: 30 minute spinning reserves (30MR), 10 minute spinning (10MSR) and 10 minute non-spinning (10MNSR).

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[40] Survey form on detailed data http://www.eia.gov/electricity/data/eia923/

[41] National Renewable Energy Laboratory (US), "Wind Systems Integration - Eastern Wind Integration and Transmission Study," nrel.gov, 2010. http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html

[42] http://pvwatts.nrel.gov/pvwatts.php

3. Modeling DERs with Bulk Transmission System

This section is devoted to analyzing the bulk power system impact from solar PV as modeled as a distributed energy resource. This section modeled solar PV in New York. The hypothesis is that having the penetration of solar PV weighed more heavily towards zones of higher LMPs, there will be a temporary revenue loss for conventional generators, lower short-term market prices[43], decreased congestion and reduction in emissions. Policy makers and industry stakeholders such as power producer, utility companies and system operators can utilize these findings to better understand solar PV impacts on electricity networks.

1. Scenario definition

System Impacts from Solar Photovoltaic (PV) Penetration in New York:

This section analyzes impacts from distributed energy resources, namely solar (PV) photovoltaic. This section is devoted to analyzing the bulk power system impacts from solar PV on LMPs and electricity networks. To model DERs in real-world power systems, this research focused on the New York State transmission, generation and market forecasted to the year 2020. Using PSO, as discussed in Chapter 2, certain scenarios were analyzed with the following inputs shown in Figure 3; the inputs are represented in Figure 3 as a percent (%) difference from the mean for weighing penetration of solar installations based on:

1. Insolation[44], used as a proxy for maximizing PV generation,
2. Market prices or LMPs ($/MWh), used as a proxy for the system value of PV generation[45],
3. Median household income for the zone[46], used as a proxy for consumers' wealth and therefore the availability to finance PV installations,
4. Demand[47], used location based according to forecasted peak demand for 2020.

The scenarios should be understood as the extremes of how DERs might penetrate in different regions and power systems. Installed capacity of solar PV was dispersed throughout New York zones in proportion to insolation, median income, demand and base case LMPs (i.e. places with wealthier median incomes, higher solar insolation, higher demand, and higher base prices received higher penetration of solar PV).

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[43] Any temporary price drops are losses for the incumbent generators and have to be corrected later, otherwise the market would not be viable. Higher marginal prices have been and continue to be incentives for investors to deploy resources of generation in those locations (i.e. solar PV).

[44] http://rredc.nrel.gov/solar/pubs/redbook/PDFs/NY.PDF

[45] The value of solar PV generation depends on the prices that apply to solar PV, which is not the average market price. See also MITei Solar Study Chapter 8 – Integration of Solar Generation in Wholesale Electricity markets

[46] http://www.indexmundi.com/facts/united-states/quick-facts/new-york/median-household-income#map

[47] NYISO 2014 Gold Book http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2014_GoldBook_Final.pdf

Compared to the mean and compared to the other scenario inputs, the demand weighted has the greatest difference from zone A through zone K in New York. The demand in zone J and zone K are large compared to the rest of NYISO.

Throughout this section and in this thesis, a term “base-case” will be used. Base-case is defined as an initial simulation where no additional installed capacity of solar PV is modeled because it is used as a reference point and the case study from which to compare the impacts from the other scenarios. Base-case LMPs are an initial simulation used to calculate hourly LMPs for the entire year of 2020 with no simulation of additional DERs. The amount of penetration of solar added to each of the nodes for the LMP-based scenario in each area was then allocated in proportion to the base case. In other words, places with higher average LMPs were given higher penetration of PV, in terms of installed capacity (MW or GW) and energy generation (MWh or GWh). For the income-weighted scenario, data from the US census on median household income was used to proportion the amount of solar, and for the insolation weighted scenario zonal differences in solar insolation were used to proportion the different penetration of solar. Throughout this thesis “solar PV” means solar photovoltaic energy generation.

The average LMPs obtained from a base-case run with no additional installation of solar PV yield reasonable results compared to historical values as displayed in Figure 3. Historical prices, LMPs, from NYISO were analyzed for the year 2014 and 2015 to determine if the base-case runs and trends followed similar patterns with actual previous values.

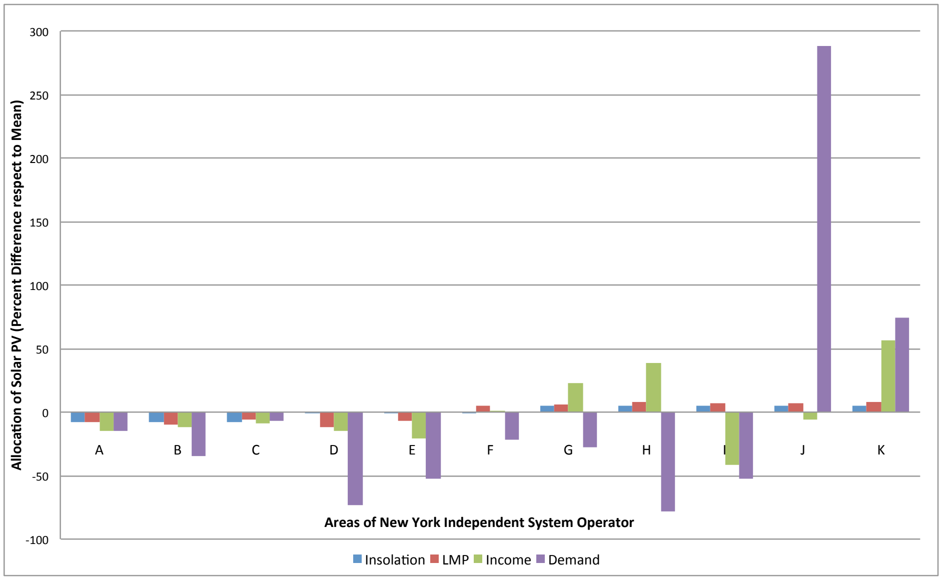

Figure 3: Inputs for solar simulations

Each scenario (Insolation, LMP, Income, Demand) consists of different simulated penetrations of solar PV. The tests varied installed capacity (MW) of solar PV penetration and the location geographically throughout the New York load zones. The scenario that proportioned solar PV to solar insolation allocated 5, 10, 15, 20, 25 and 50% of the projected peak demand in 2020 to the New York zones, in addition to the installed capacities already existent in the network. The installed capacity of all the generating units in each zone across the demand-weighted scenario is displayed in Table 1. The percent of peak demand in terms of installed capacity is displayed in Table 2. The total allocation across all zones is the same for all scenarios (Insolation, income, base price LMP and demand). The capacity factor used for the solar PV was approximately 13.8%.

Table 1: Installed capacity across each zone for demand-weighted scenario

Installed Capacity (MW)		***Base Case***	***5%***	***10%***	***15%***	***20%***	***25%***	***50%***
NY Zones	***A***	**4,615**	**4,748**	**4,881**	**5,014**	**5,147**	**5,280**	**5,944**
	B	**767**	**869**	**971**	**1,073**	**1,175**	**1,277**	**1,787**
	C	**6,791**	**6,936**	**7,081**	**7,226**	**7,370**	**7,515**	**8,240**
	D	**1,722**	**1,762**	**1,804**	**1,845**	**1,885**	**1,926**	**2,131**
	E	**2,309**	**2,383**	**2,458**	**2,533**	**2,607**	**2,682**	**3,055**
	F	**4,745**	**4,867**	**4,989**	**5,111**	**5,232**	**5,354**	**5,963**
	G	**2,936**	**3,049**	**3,163**	**3,276**	**3,389**	**3,502**	**4,068**
	H	**2,130**	**2,163**	**2,197**	**2,231**	**2,265**	**2,299**	**2,468**
	I	**3**	**76**	**150**	**224**	**298**	**372**	**741**
	J	**10,776**	**11,381**	**11,987**	**12,592**	**13,198**	**13,803**	**16,830**
	K	**5,777**	**6,049**	**6,321**	**6,593**	**6,865**	**7,137**	**8,498**

Table 2: Allocation of installed capacity of solar PV in terms of % peak demand

Solar PV Penetration (% of Peak Demand)	Installed Capacity (MW)
5	1714
10	3430
15	5146
20	6861
25	8577
50	17154
75	25731

According to the New York Reforming the Energy Vision strategy, NY-Sun[48], the department of public service is helping finance 3,000 MW of solar projects in the next 10 years; 3 GW of solar PV over the next 10 years would be approximately somewhere between the 5% and the 10% peak demand scenarios mentioned in Table 2.

Solar PV was allocated to individual nodes within the New York system. There are over 4900 substations modeled in the dataset for the NY system and over 730 different generators. Of the 4900 substations, approximately half were chosen (2213 nodes) to have generation added to them. The nodes within the New York zones are connected to the substations and are then mapped to the specific zones (A through K). The amount of installed capacity varies depending on the scenario and the capacity of installed solar PV. For instance, shown in Table 1 is the installed capacity across the different penetrations of solar PV for different zones. Table 2 only displays the demand-weighted scenario allocation. The installed capacity for the insolation-weighted scenario will have different penetration in each zone. The total installed capacity across all zones is the same, the

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[48] Reforming the Energy Vision.
http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

only aspects that differs within each case, is a different allocation to each zone (i.e. larger demand means larger penetration of solar PV).

2. New York State transmission system

The transmission system for New York is modeled in its entirety, but to add all the distribution systems would be an immense undertaking. Instead, the solar PV allocated to the substations is modeled as non-dispatchable, which means that the optimization algorithm cannot allow or stop the solar from generating when it does (i.e. solar curtailment is not allowed). The energy from solar generation that occurs at or below a given substation will first be seen to net against demand before being exported to the rest of the network, a load-reducing resource as seen by the system operator. Load at any substation is the aggregation of the demand of all consumers below the substation[49]. Any and all generation and load that sits below the substations are modeled as aggregations up to the meshed network transmission and sub-transmission nodes.

3. Results and discussion

Shown in Figure 4 is the effect of increasing penetration of solar PV on the average wholesale price (LMP, $/MWh) for the scenario in which solar PV was installed in proportion to insolation (kWh/m^2/day). Solar PV, for the insolation-weighted scenario, penetrated New York zones with an additional installed capacity ranging from 5% to 25% forecasted peak demand for 2020. There is an initial drop from no additional penetration (0) to 5% penetration and then through the next intervals of penetration. The decreasing market price is to be expected at these levels of penetration because the penetration is large enough to offset other generation that might otherwise have a high marginal cost, such as gas turbines or internal combustion turbines.

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[49] As noted in Chapter 2, the loads modeled for the zones include transmission and distribution losses, because transferring power from the distribution network up into the transmission system, there could be potentially significant losses. These losses can be thought of as inherent in the installed capacity to the nodes, which means to supply 10MW of power to a transmission node from the distribution network, there must be larger than 10MW of power installed on the distribution system.

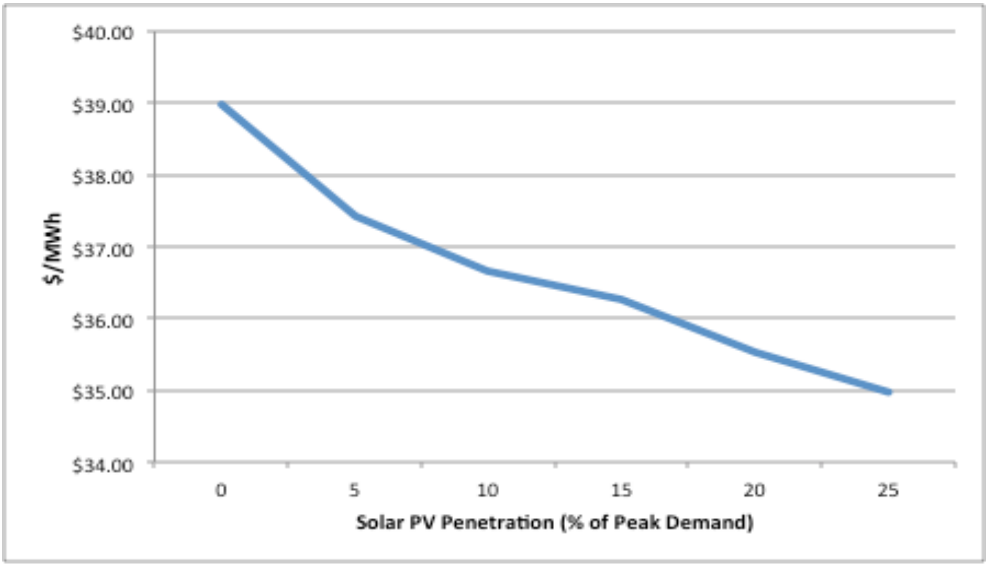

Figure 4: Market price impact from solar PV penetration

Figure 5 displays the change in market price as penetration of solar PV increases and compares the 4 scenarios.

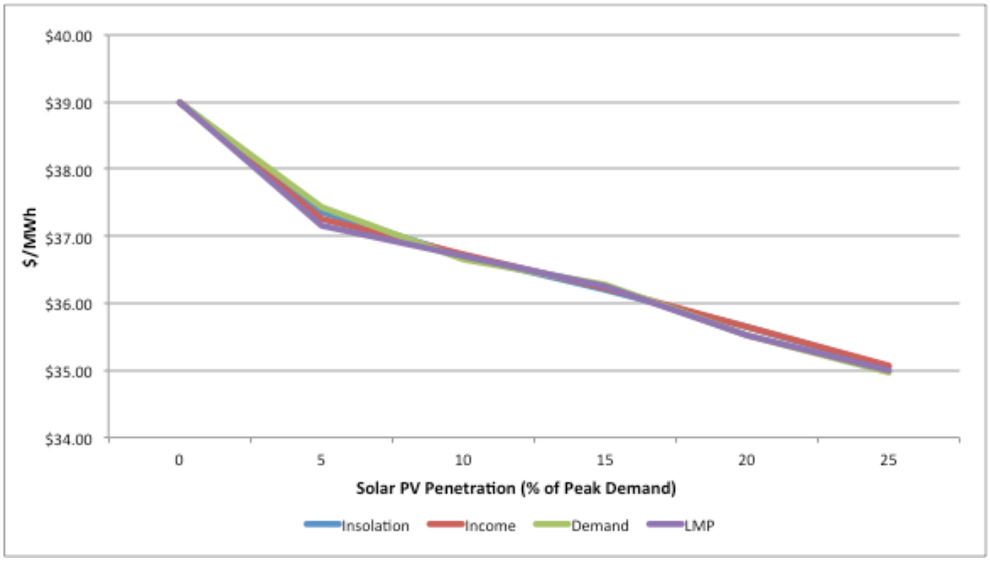

Figure 5: Comparison of different scenarios on wholesale market prices

The base case average market price ($/MWh) for New York 2020 came to approximately $39.00. From these trends, there is an immediate impact from the placement of solar photovoltaics on the New York system by the drop in $/MWh to around $37/MWh for the scenarios. On the x-axis, the base-case, 5% penetration, 10%, 15%, 20%, and 25%. The installed capacity of solar PV is a percentage of estimated peak demand for the total New York system in 2020. Some scenarios have a lower average market price at different penetrations, i.e. LMP-weighted scenario has the lowest average day-ahead market price for the 5% penetration case, but at 15% penetration it is actually the Insolation-weighted scenario with the lowest $/MWh.

Shown in Figure 6 is the average congestion (top) and losses (bottom) as a portion of total average LMP for each zone (A-K) for historical years 2014 and 2015 as well as a projection for the base case in 2020 with no additional installed capacity of solar PV. "Two-thirds of New York's electricity is used in the southeastern part of the state (Long Island, new York City, and the Lower Hudson Valley). Yet only half of the state's generating capacity is located in this region. Sustained and enhanced transmission capability is vital to efficiently moving power to address regional power needs" NYISO, 2015).

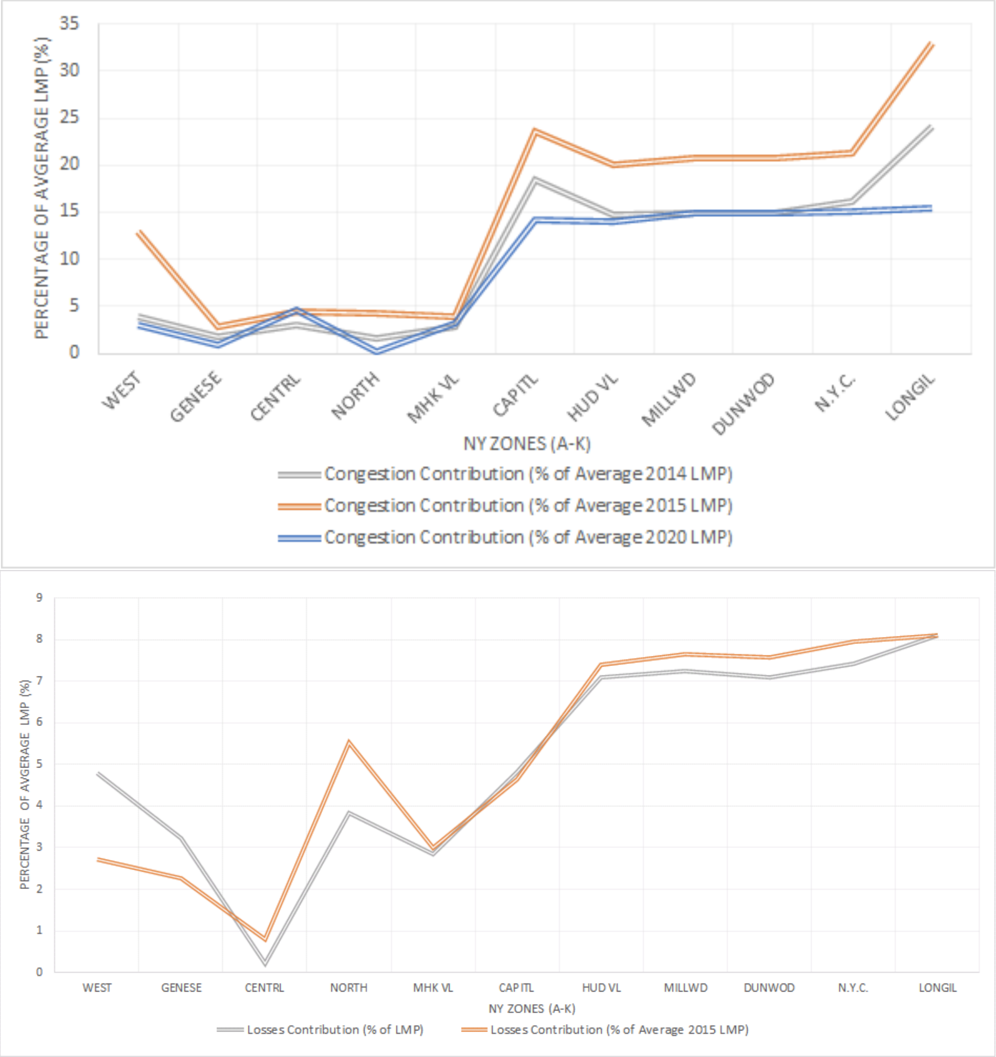

Figure 6: Portion of LMP from congestion (top) and losses (bottom), for historical years 2014 and 2015[50] and for projected values for year 2020

Important factors in the determination of impacts of DERs on transmission networks and wholesale markets, regarding LMPs, are the specific impacts DERs have on congestion and losses. Congestion and losses, at times in the New York system, make up a substantial portion of the total LMP, as shown in Figure 6. Losses in the transmission and

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[50] http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp

distribution system can account for anywhere from 0 to 8% of the LMP according to historical prices from NYISO in 2014 and 2015. Losses are higher in the more constrained geographic and electric transmission locations of the south Hudson Valley closest to New York City and Long Island. The average contribution from losses to the LMP in New York State from zones Hudson Valley to Long Island, according to historical prices from 2014 and 2015, can be between 7 and 8%.

Historically, New York City and Long Island have higher average market prices, compared to other New York zones, because of network and generation constraints. According to Figure 7, the average congestion component to the LMP in 2014 and 2015 can range from 1% to over 30% of the LMP. Congestion, at times, can make up a substantial portion of the LMP, especially in New York City and Long Island where the congestion component can range from 15% to over 30% of the LMP in both historical cases and future projections from PSO. A potential major value of DERs is their potential to mitigate congestion and losses on the transmission and distribution networks. DERs can impact the wholesale energy price (through dispatch and merit order changes), congestion and losses[51].

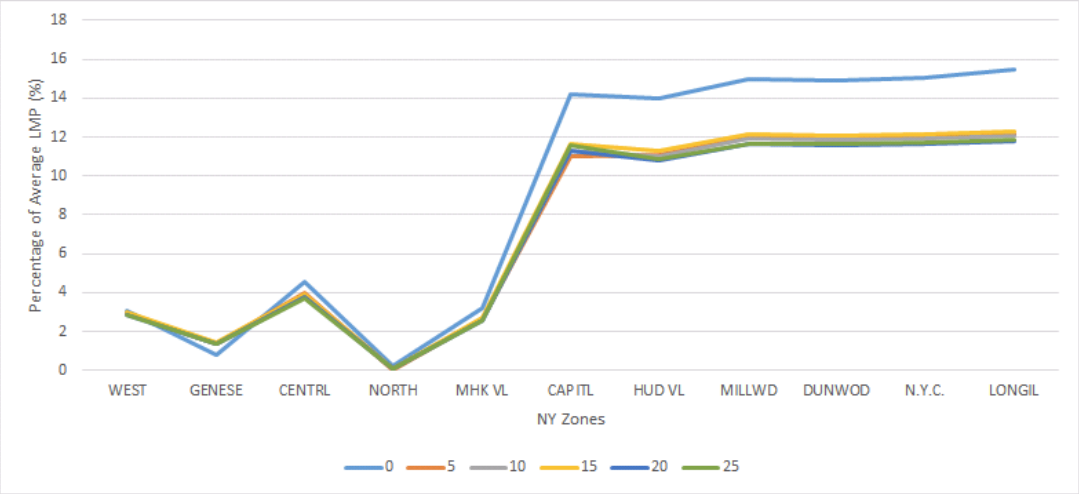

Figure 7: Congestion contribution across NY zones (%of LMP) for demand-weighted scenario for different penetration levels

Figure 8 displays the average congestion contribution for the demand-weighted scenario. There is an initial drop in the amount that congestion contributes to the market price for the average from the 0 to 5% case. The x-axis is non-linear after 25% because it jumps to 50%, but the trend of fluctuating congestion contribution continues across the penetration scenarios.

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[51] Potentially removing the need for distant power to be generated and sent over long high-voltage transmission cables to meet the load.

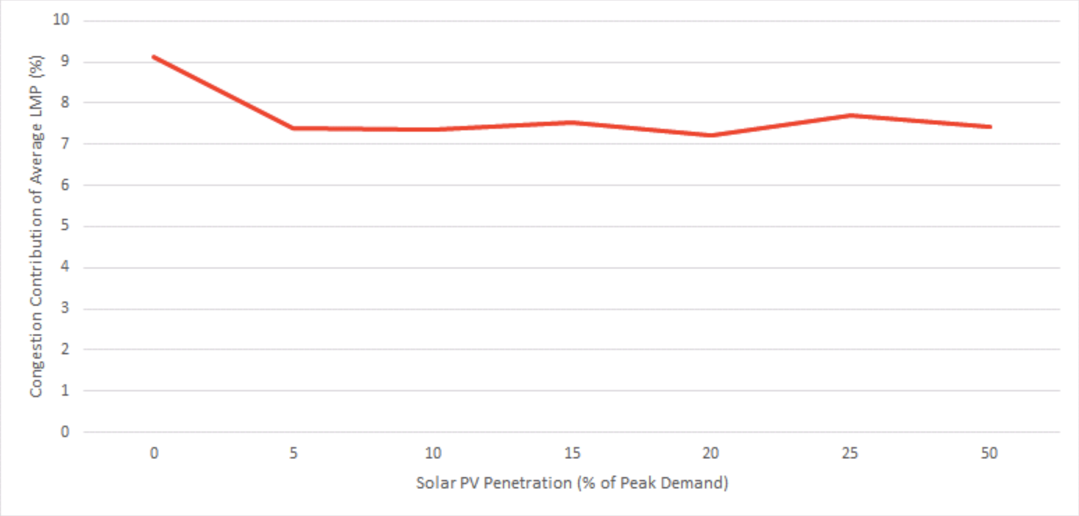

Figure 8: Average congestion contribution (% of LMP) for demand-weighted scenario

Figure 9 displays the difference in the market price across all zones in New York for a specific penetration of 25% of peak demand. Figure 9 displays the fluctuation of market price, between the scenarios, across the different zones of New York. New York Independent System Operator is divided into 11 zones (A-K). An interesting observation from the curves in Figure 9 is that through zones A-E for the LMP-weighted scenario the market price is suppressed the most; whereas between zones F-K in the demand-weighted scenario the market price is suppressed the most compared to the other scenarios. As noted in Figure 6, congestion and losses happen to be largest in zones G through K.

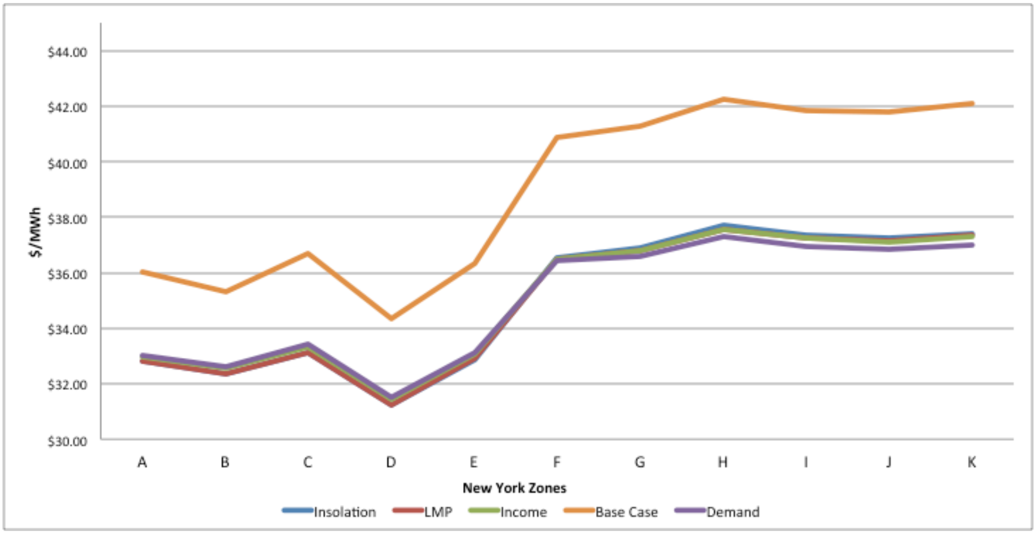

Figure 9: Solar PV penetration scenarios for a 25% case

The LMP-weighted scenario suppresses the LMPs in zones A through E, where there is more generation and less load as compared to zones F through K where there are larger load pockets and less generation locations[52]. From F through K, the demand-weighted

---

[52] “Two-thirds of New York’s electricity is used in the southeastern part of the state (Long Island, new York City, and the Lower Hudson Valley). Yet only half of the state’s generating capacity is located in this

scenario has the greatest impact on the LMPs because there is a greater proportion of PV applied to those regions. Zone F through K have larger loads and are typically more congested than the zones of upstate New York. Zones A through E have a more dispersed population, more generation and central generating plants, and generally less absolute demand than zones G through K. Zones G through K have a more dense population, larger absolute demand and less amount of centralized generation to meet the loads.

Figure 10 displays the congestion rent reduction in millions of dollar (MM$)[53]. The chart details the decrease in congestion from the base-case scenario. An increase in penetration of solar PV increased the reduction in the congestion rent, or in other words, increases in penetration of solar PV decreases congestion costs, across all the allocation scenarios. The scenario in which demand is used as the parameter to proportion solar PV installation has the largest reduction in congestion across the scenarios. The demand-weighted scenario has a largest difference in congestion compared to the other scenarios at 25% penetration. The demand-weighted has a larger impact compared to the other scenarios, because a larger proportion of solar PV was installed in the zones with larger demand, such as New York City and Long Island.

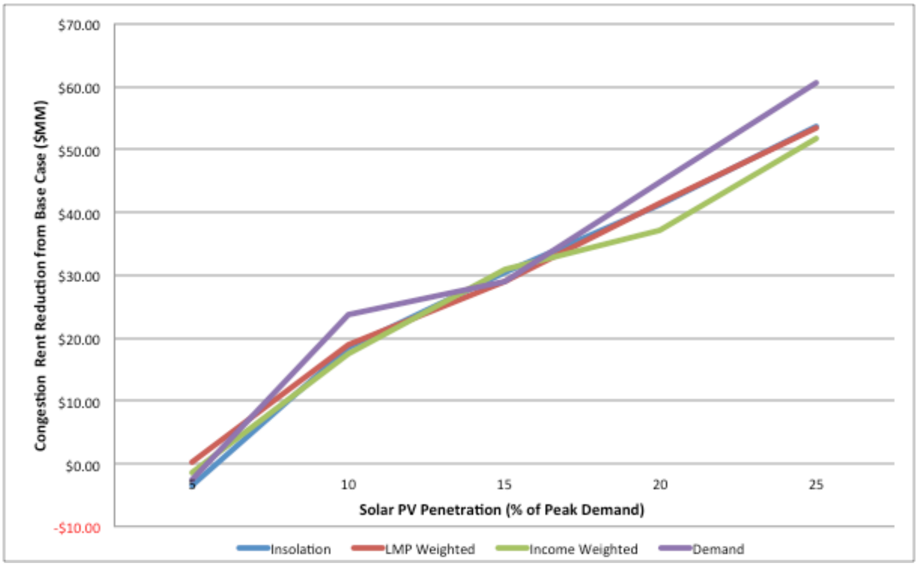

Figure 10: Congestion rent differences for the solar PV scenarios

Figure 10 displays the congestion rent for each of the scenarios. According to Figure 10, the insufficiency of transmission capacity, or congestion, decreases the most (solar PV helps relieve congestion) in the demand-weighted scenario compared to the other scenarios. From 0% to 25%, there is a decrease in the congestion component rent compared to the base case with 0% solar PV penetration; as the penetration increases from 5% to 25%, all 4 scenarios see a decrease in overall congestion with some fluctuations amongst the scenarios.

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region. Sustained and enhanced transmission capability is vital to efficiently moving power to address regional power needs" NYISO, 2015).

[53] Congestion rent is the calculation of all the differences in nodal prices multiplied by the power across the lines connecting the nodes with differing prices.

Figure 11 displays the specific trend because congestion rent was not due to solar PV in the first place, that is why the trend is a drop in inverse proportion to the volume of installed PV capacity.

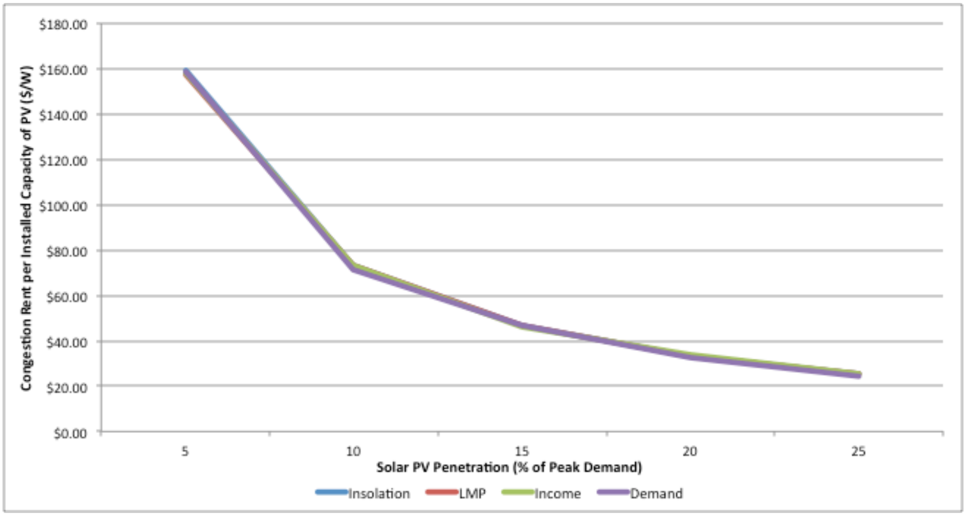
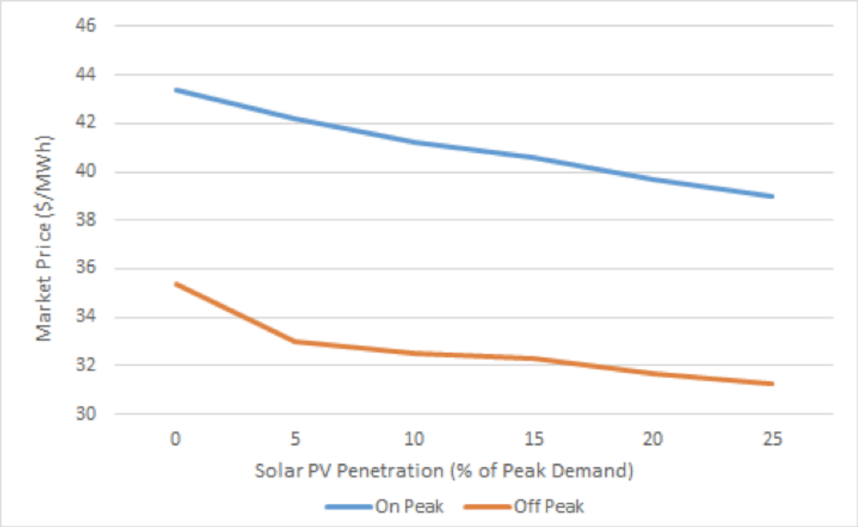


Figure 11: Congestion rent for the LMP scenario

Figure 12 displays the average yearly market price (top) and congestion rent (bottom) for on and off peak hours for the demand-weighted scenario. There is a noticeable difference in congestion rent and market prices when the sun is shining and when the sun does not shine. The observation that on summer peak hours there is a larger decrease in congestion and market prices displays that solar energy is coincident with peak demand and has the potential to reduce congestion in congested areas as well as suppress market prices.



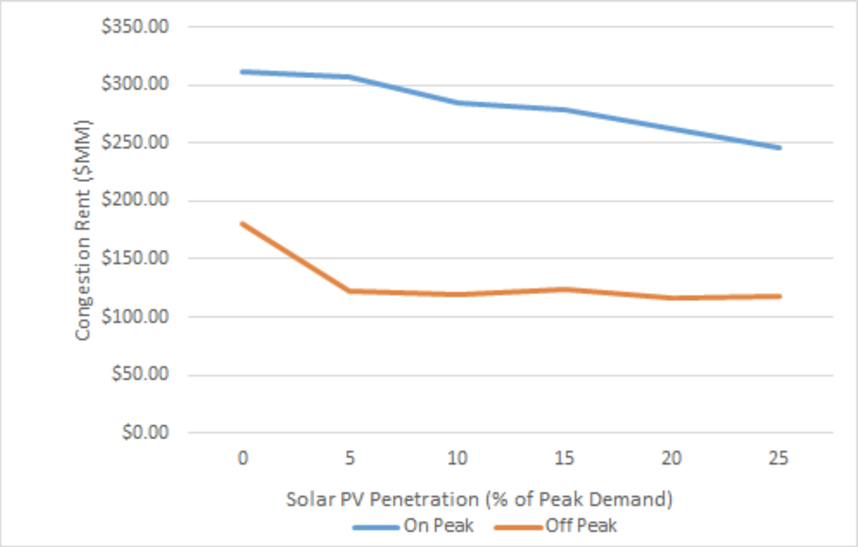
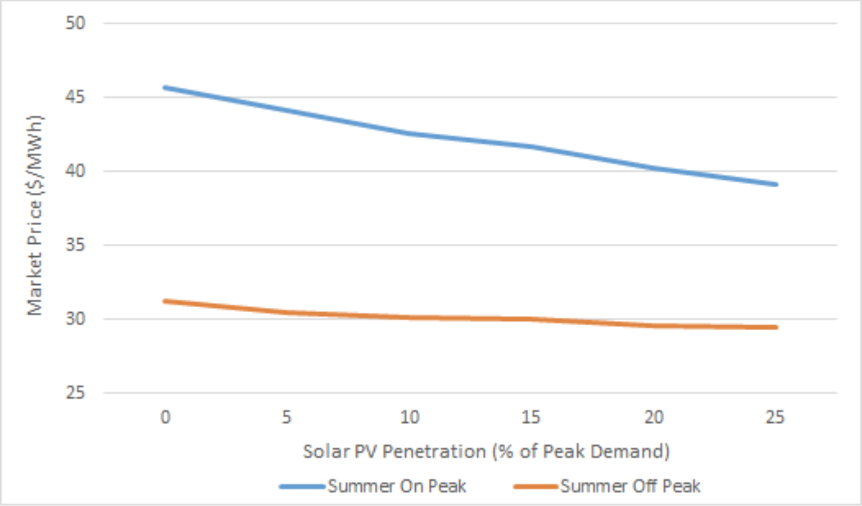


Figure 12: Average yearly market price (top) and congestion rent (bottom) for on and off peak demand-weighted scenario

Figure 13 displays the summer market price (top) and congestion rent (bottom) for on and off peak hours for the demand-weighted scenario. There is an even bigger difference in congestion rent and market prices when the sun is shining and when the sun does not shine in the summer months of June, July and August. On peak hours have a larger decrease in congestion and market prices because solar energy is coincident with peak demand and has the potential to reduce congestion in congested areas as well as suppress market prices in the summer months[54].



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[54] Summer months in this study include June, July, and August.

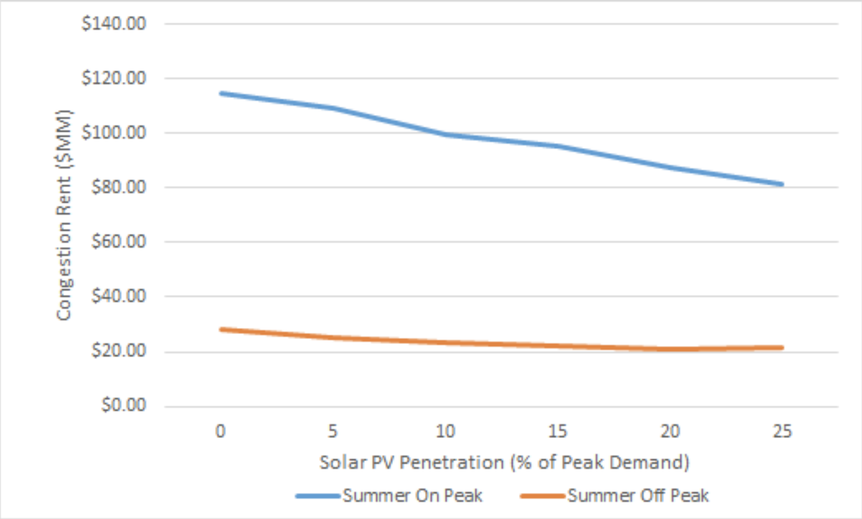

Figure 13: Summer market price (top) and congestion rent (bottom) for on and off peak hours for the demand-weighted scenario

Figure 14 displays the price-duration curve for different penetrations of solar PV. As the penetration of solar PV increases, there are increases in number of hours where there are lower or even zero prices. With increasing penetration of solar PV and lower energy prices, there is a merit order impact for the dispatch of units. During sunny hours, solar PV essentially offsets the need for certain peaking unit or higher variable costs units that increase the market price for electricity; however, solar PV creates a need for ramping units at sunrise and sunset hours. Flexibility of generating units is needed on the network to maintain grid balance of supply and demand, and functionality, with increasing penetration of intermittent and variable renewable energy generation such as solar PV.

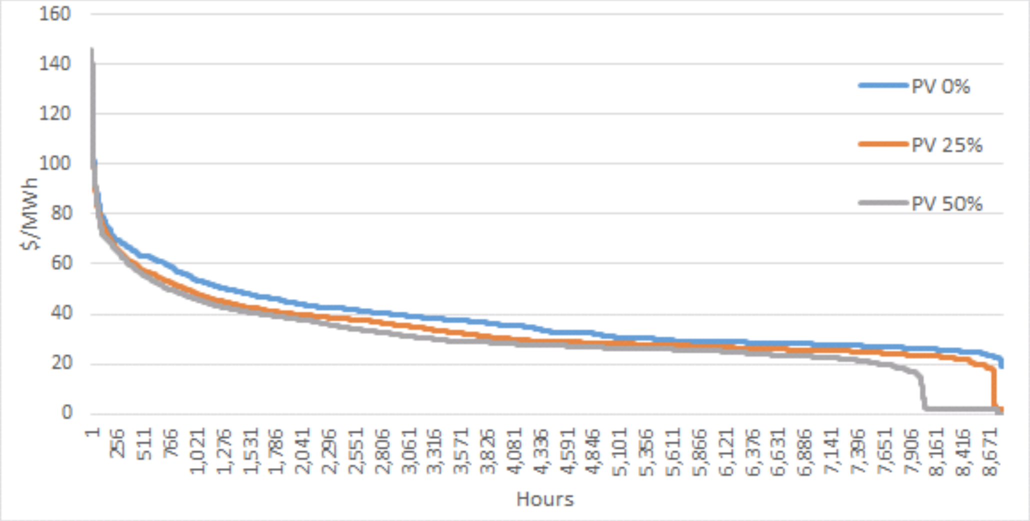

Figure 14: Price-duration curve for 3 penetrations of solar PV

Market prices do not drop below zero for 50% penetration of solar PV; however, for a 75% penetration of solar PV case, there are negative prices for market prices for about 200 hours. With 75% penetration from solar PV, this is a lot of solar penetration for the New York State system to handle especially when peak solar PV generation aligns with low demand. A test case was investigated where 75% penetration of solar PV was installed in New York and negative prices were observed during 198 hours. There were even 5 hours where the price dropped to near -$1,200/MWh[55]. With increasing penetrations of solar PV, it is likely that solar will be producing more and more during zero-price hours.

Lower electricity prices in wholesale markets could mean that solar PV is impacting how often conventional or peaking units must cycle (i.e. turn on and off with greater frequency). Cycling is an increased cost for the generator. A generator would much rather stay on at minimum capacity to avoid start-up and shutdown costs associated with providing electricity to the grid. Figure 15 displays the number of starts across different penetrations.

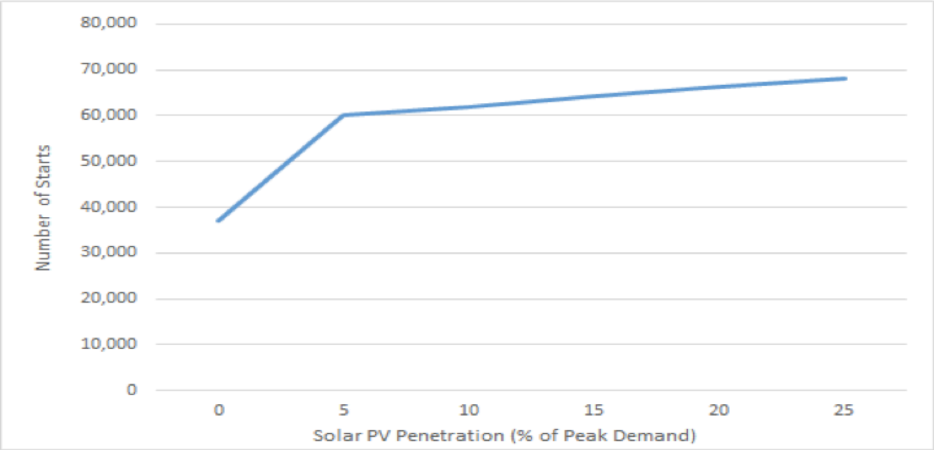

Figure 15: Number of starts for all fuel types of generation except solar PV

Observed in Figure 15 is the number of starts that are needed from all the other generation units such as coal, hydro, and fuel oils in order to compensate and cope with the additional penetration of solar PV. Units, such as peaking generators, fuel oil units, and more flexible units must be turned on and off more rapidly for the system to compensate for the increased penetration. Figure 16 displays the type of units that are starting more frequently because of increased penetration of solar PV.

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[55] This is a huge value and is, potentially, unrealistic in other power markets due to price caps and floors. The value was obtained here because it is subject to specific market rules, such as modeled in PSO. Average negative market prices as observed today generally do not reach such low negative values. Curtailment of solar PV was not modeled because of the must-run status of the DER.

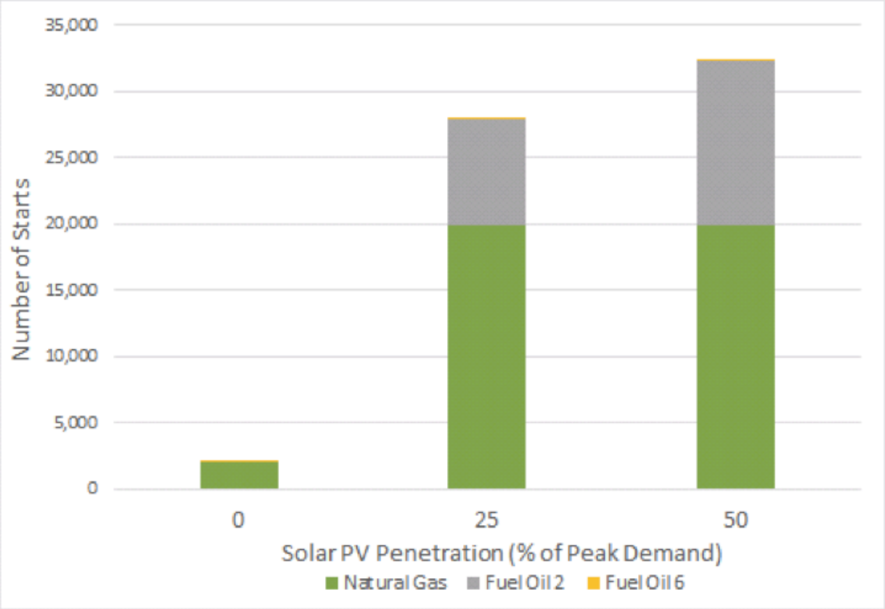

Figure 16: Number of starts for specific units across solar PV scenarios

Natural gas generators make up only about 5% of the total number of starts for the entire year in NY, but when the penetration of solar PV increases to 25%, the number of natural gas units starting up increases to around 30% of the total starts observed. Hydro unit generation is based upon predefined daily operating schedules[56]. Coal units also stay relatively constant across the scenarios of penetration. Units that utilize oil as a main source of fuel increase from around 1% of total starts to around 12% of total starts with penetration of solar PV making up 25% of peak demand or an installed capacity of solar PV of 8.5 GW. Natural gas units are starting more often too, however, they are making up less of the generation mix as increases in solar PV occur in the system. Fuel oil and natural gas units are starting up more often because they are inherently flexible[57] units that are utilized by the system to maintain system reliability due to the variability and intermittency of solar PV.

Shown in Figure 17 is the generation mix for a case with no additional solar PV penetration (top), the generation mix for a case with 25% of forecasted peak demand in 2020 amount of installed capacity of solar PV penetration (middle) and 50% (bottom). The amount of generation of natural gas is decreasing, but units using fuel oil 2 increase.

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[56] Historical hydro output was used because it was the only data available and their operation is not typically subject to optimization in the same way as thermal units; at least not in the US and especially in the Northeast. See Methodology, Chapter 2, for more information.

[57] Flexibility can be from the supply or the demand and can be storage units, flexible generation and/or new transmission. Flexibility of a resource is the ability to respond to scheduled or even unscheduled changes of conditions of the power system at different times of the day.

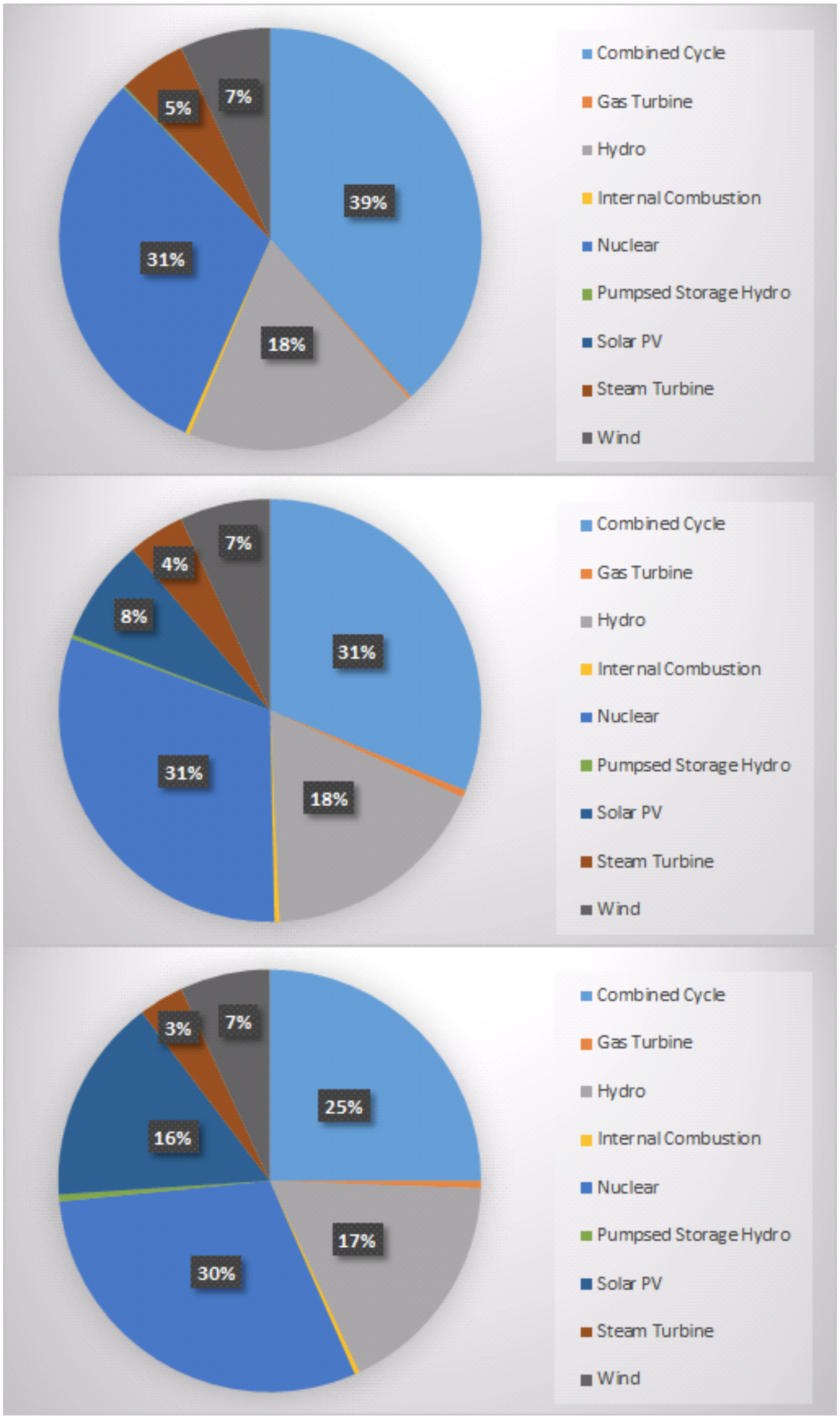

Figure 17: Generation mix for the case with no additional solar PV penetration (top), the generation mix for the case with 25% of forecasted peak demand in 2020 installed capacity of solar PV penetration (middle) and 50% (bottom)

As increases in solar PV penetration occur, wind curtailment also increases as shown in Figure 18.

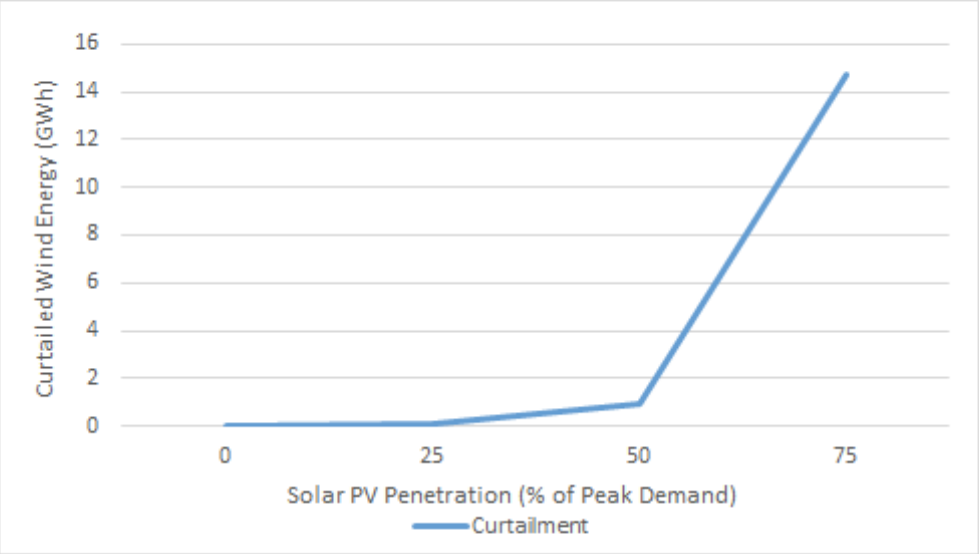

Figure 18: Wind curtailment in GWh as solar PV penetration increases

Curtailment of resources, such as wind, is important from a system standpoint because it is energy that could have been produced, but was not, due to system constraints. Where there is increasing curtailment, there is an opportunity for storage technologies to find value.

As penetration of solar PV increases in New York, natural gas generators make up less of the total generation mix. The fact that natural gas units will make up less of the generation mix will cut into profits and reduce revenues these generators will have. From 0 to 25% additional penetration cases, natural gas generators drop from 40% of total generation mix, to 33%. There are some small changes in generation mix for other units, but the largest impact is to natural gas injectors. Fuel oil 2 units are also increasing in usage and therefore increasing the CO_2 emissions from these units as well as helping to lessen the dampening effect on market prices, since fuel oil resources have higher variable costs.

Another interesting impact to note is the impact on total emissions. Figure 19 displays the decreasing trend in total emissions (millions of metric tonnes) per solar PV installed (Watt), as solar PV penetration increases. Figure 20 displays the emissions from each individual zone in New York in millions of metric tonnes.

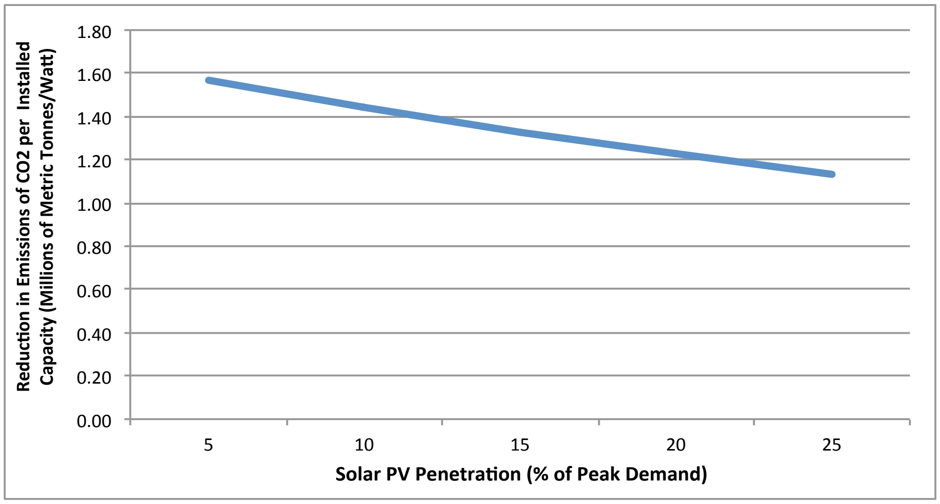

Figure 19: Total reduction in emissions per watt of installed PV capacity

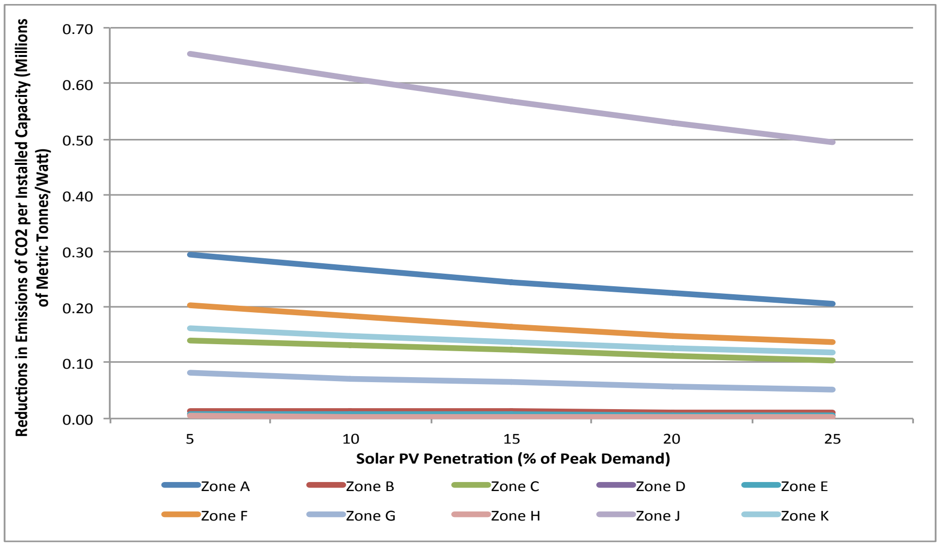

Figure 20: Emissions per zone with increasing solar PV penetration

Figure 21 and 22 display the millions of metric tonnes of CO_2 emitted in absolute terms across all the areas of New York and across only Zone G and Zone K, respectively.

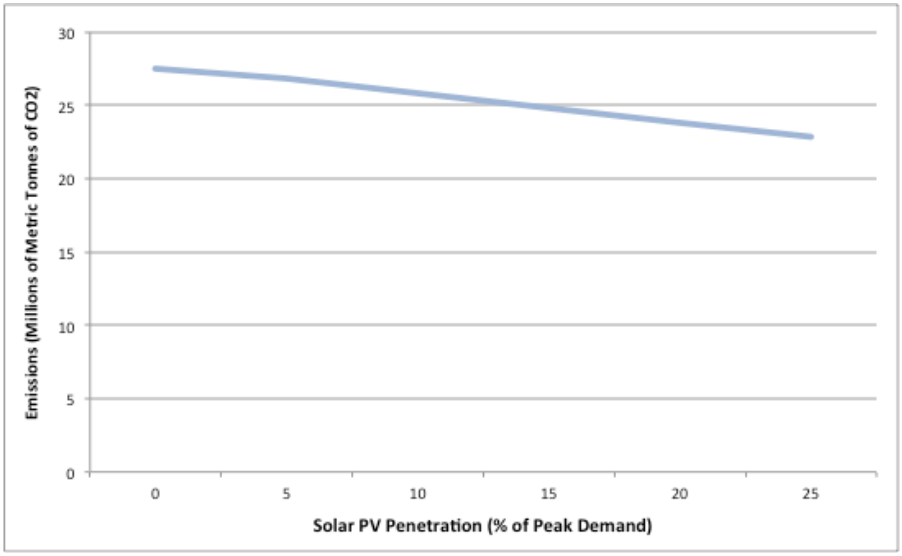

Figure 21: Millions of metric tonnes of CO2 emitted in NYISO 2020 with increasing penetration of solar PV

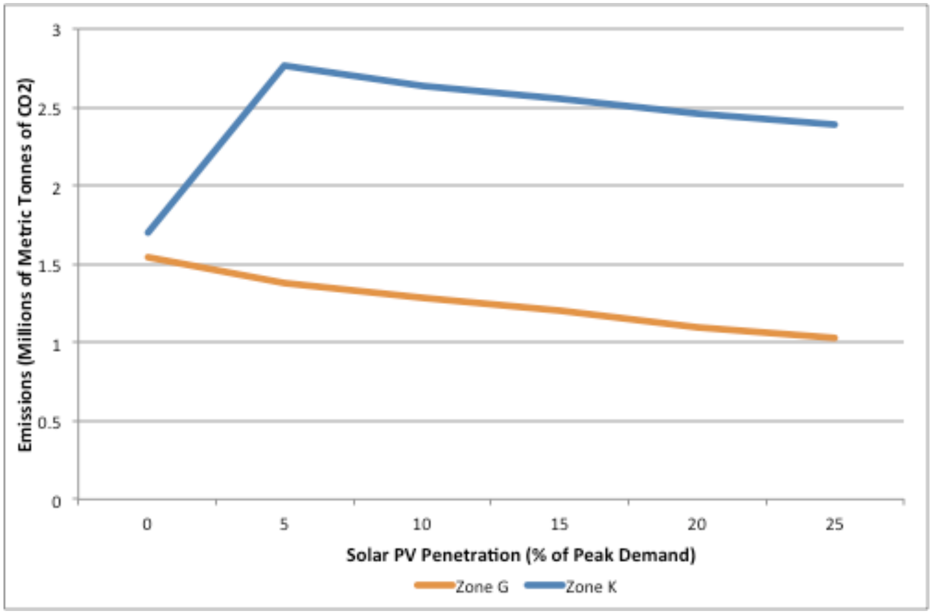

Figure 22: Millions of metric tonnes of CO_2 emitted in Zone G and Zone K

Figure 22 details the difference in zones where emissions actually increase with increase in solar penetration and zones that decrease in emissions of CO_2. There is a greater need for flexibility on the system; therefore, since these units (fuel oil 2) are flexible and can ramp up and down, they happen to increase emissions due to greater use in the networks. Zone K is Long Island, New York; a place in New York State where the mix of generation is mostly fossil fuel, shown in Figure 23 and Figure 24. As penetration of solar PV increases from a base case to a case with larger solar PV penetration, the emissions of CO_2 almost double and through a test case up to 25%, the emissions do not ever drop below the level they were before significant increases in solar PV penetration.

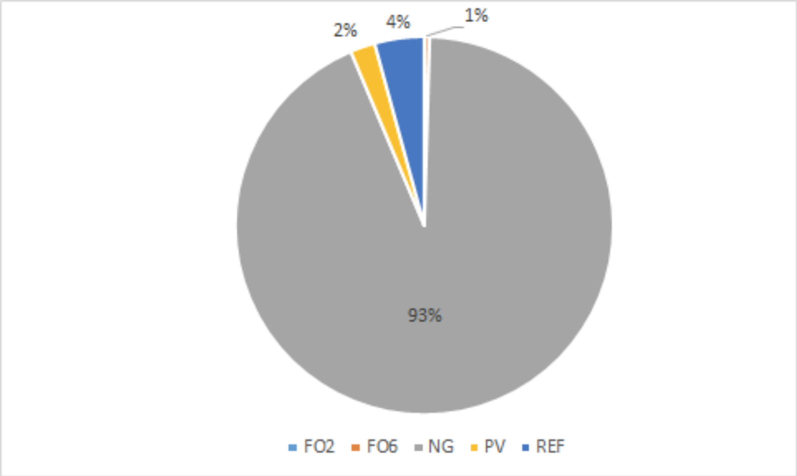

Figure 23: Generation mix on Long Island (Zone K) NYISO

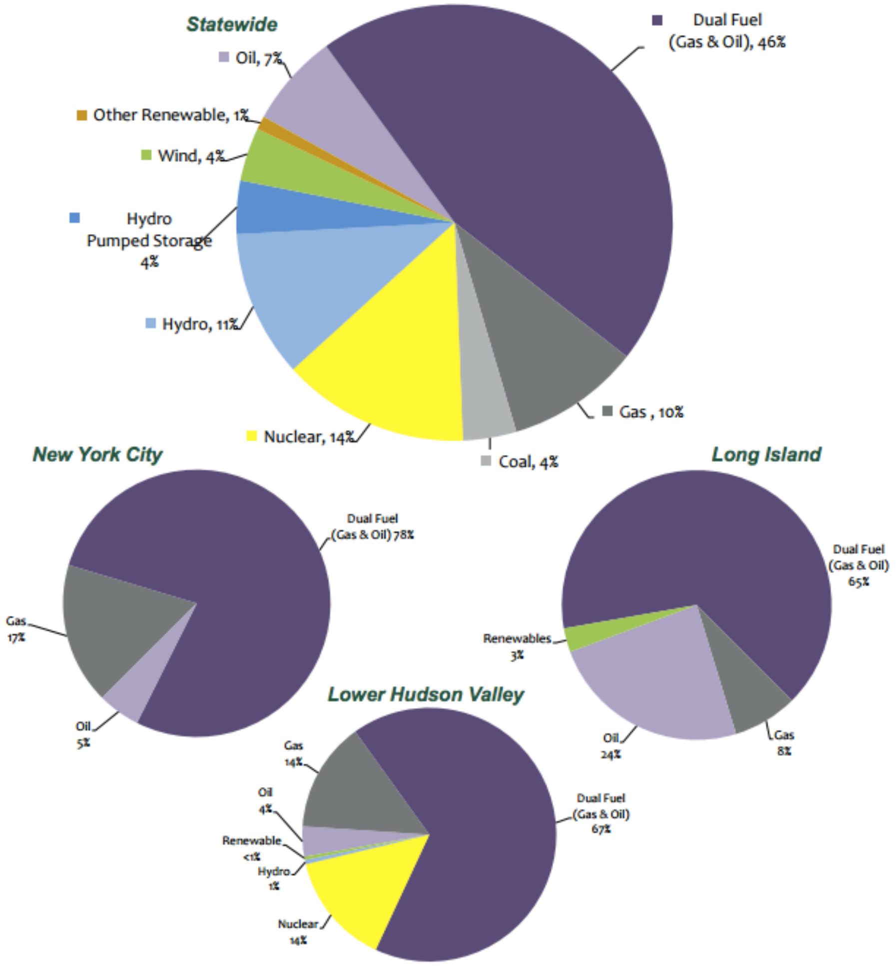

Figure 24: Generating capability in New York State by fuel source - Statewide, New York City, Long Island and Lower Hudson Valley: 2015. [58]

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[58] http://www.nyiso.com/public/webdocs/media_room/press_releases/2015/Child_PowerTrends_2015/ptrends2015_FINAL.pdf

Figure 25 and 26 display the revenues for the different technologies per watt of installed capacity of each technology. The revenues these technologies see are the market prices they receive, not the zonal average prices described above. Figure 25 and 26 use abbreviations for the unit types; CCg is combined cycle with gas fuel, STg is steam turbine with gas fuel, GTo is gas turbine with oil fuel, and Hyd is hydro.

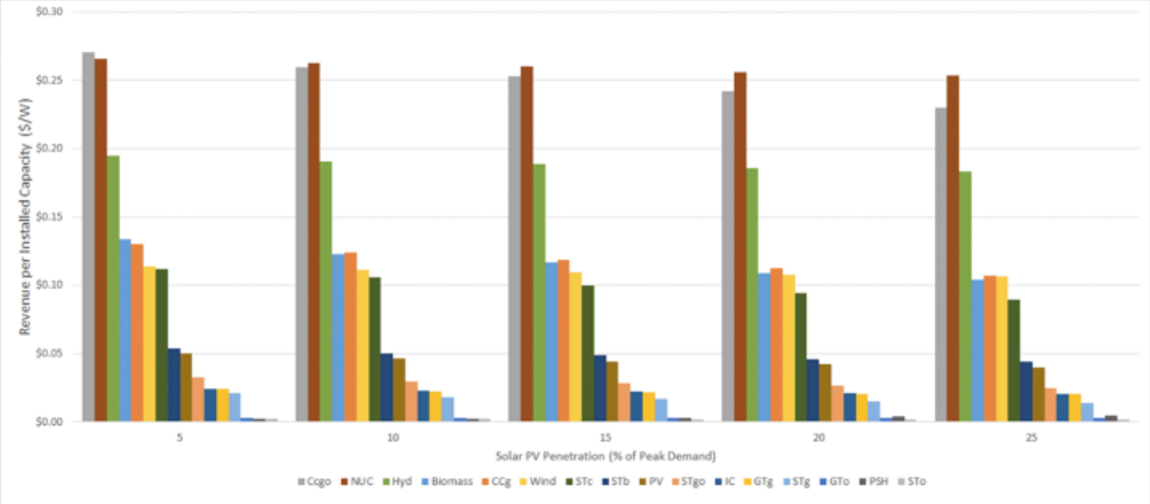

Figure 25: Generator unit type revenue per watt of installed capacity of each technology

Figure 25 displays that revenue does not change that much through the different penetrations scenarios except for combined cycle gas turbine market revenues, which decrease from around $0.27/Watt in the 5% penetration scenario to around $0.17/Watt in the 25% penetration scenario. Figure 26 displays graphically that remuneration goes down with increasing penetration of solar PV and mainly to fossil fuel units.

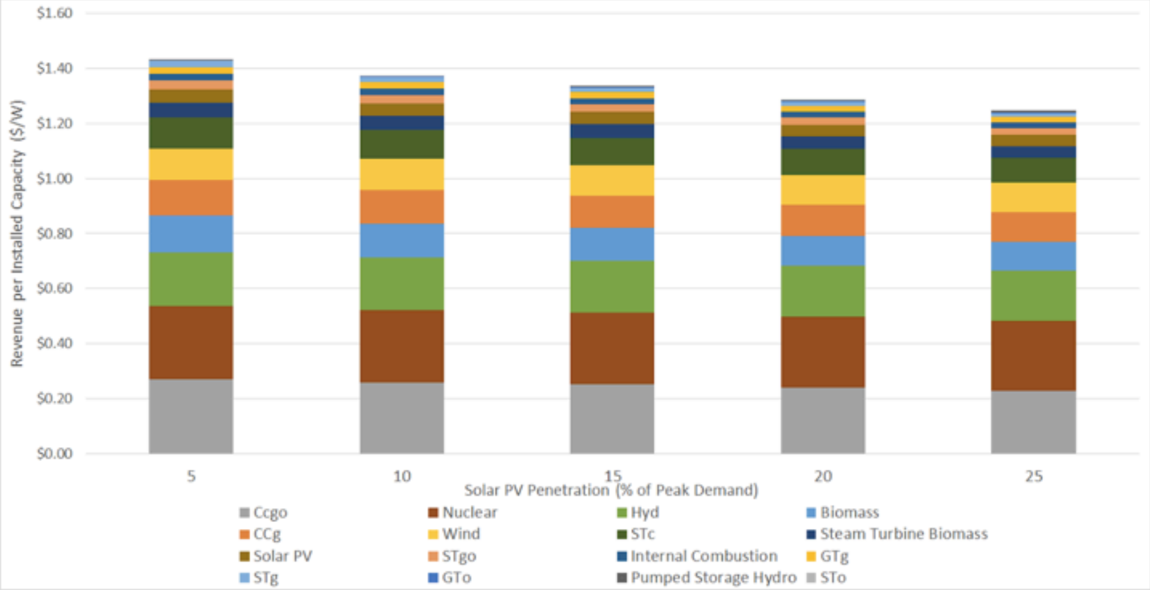

Figure 26: Stacked generator revenue per watt of installed capacity of each technology

Figure 25 and 26 display the market remuneration (revenue) for all generation types, including solar PV, in $ per installed capacity ($/Watt). Figure 27 displays how with increases in installed capacity of solar PV, the marginal revenue decreases, making the other generation unit types less profitable per unit Watt of solar PV. Installing solar PV not only makes solar PV less profitable, from a market price standpoint, for the next unit of installed solar PV, but it decreases the other technologies market value as well, see Figures 25 and 28. Combined cycle gas turbines, nuclear, hydro and wind all have large decreasing revenues with increasing solar PV. The other technology and fuel types have decreasing revenues, but the decrease is less significant. Figure 27 displays, for the change in penetration from 5% to 25%, the solar PV wholesale market energy revenue goes from $0.5/Watt to $0.4/Watt.

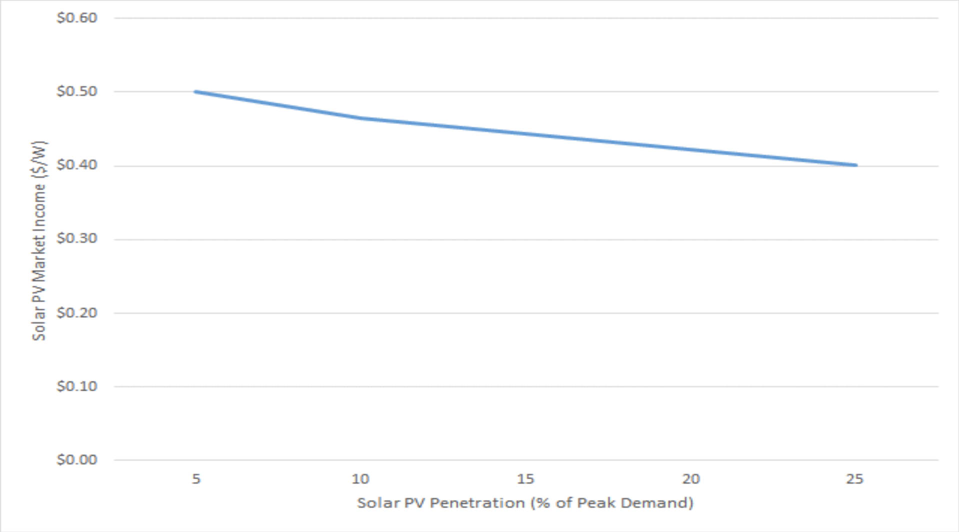

Figure 27: Market remuneration for Solar PV production in ($/W) as a function of solar PV penetration

Figure 28 displays a finding that is similar to one of the major findings from the MIT Solar Study[59]. The average "solar owner" price is initially higher than the wholesale average system price, but then the "solar owner" price decreases much faster with increasing penetration of solar PV. Net load will diminish with increasing solar PV penetration, causing the solar PV market prices to decrease faster than the system average market price. Distributed solar PV has the potential to reduce load and therefore market prices will fall more rapidly compared to when solar PV does not shine at other times of the day. Again, these values for prices are averaged over 8784 hours for a projected year in 2020.

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[59] MIT Energy Initiative, Future of Solar Study – Chapter 8 – Integration of Solar Generation in Wholesale Electricity Markets.
https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

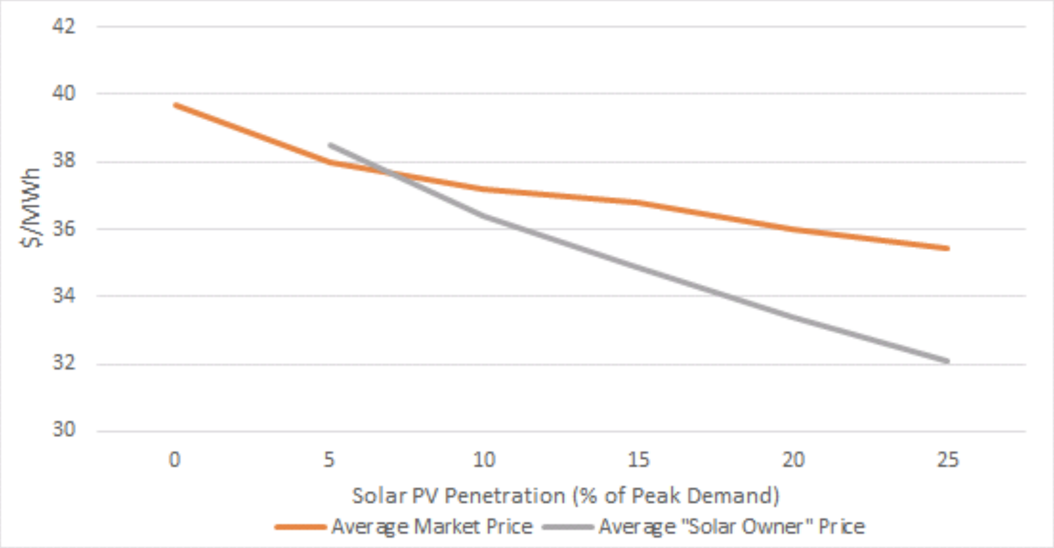

Figure 28: Average market price and Solar PV average prices

This chapter explored the interface between the bulk power system and a large-scale influx of a distributed energy resource, solar PV. System level impacts from solar PV were noted and discussed, such as revenue implications for different technology types, average zonal market prices, congestion rent differences, and environmental emissions.

4. TSO.DSO Coordination in a Context of Distributed Energy Resource Penetration[60]

1. Introduction

Chapter 3 analyzed the bulk power system impacts from DERs and as the worlds of the bulk power system and distribution become further intertwined, there will inevitably be both technical grid operations, planning impacts and coordinated requirements needed to integrate these two worlds. In most bulk power systems, there exists an operator or operators at the lower voltage distribution that maintains the wires and provides reliable electricity to the consumers (usually the distribution system operator[61]). In addition there is the operator on the transmission side of the network maintaining the larger system balancing and operation (usually transmission system operator[62]). Distributed energy resources are generally connected to the grid on the lower voltage network, but as modeled and described in earlier chapters, distributed energy resources impact the bulk power system, which is the responsibility of the TSO or ISO/RTO. The industry structure and regulatory paradigm is changing along with the roles and thus the cooperation and coordination between these entities.

2. Coordination and industry analysis

"With growth of renewables, the increased interconnection of European grids, the developments of local energy initiatives and the specific requirements on TSO-DSO cooperation as set forth in the different Network Codes and Guidelines, TSO and DSOs face new challenges that will require greater coordination." – "General Guidelines for improving TSO-DSO Cooperation," - EDSO, ENTSO-E and Eurelectric, 2015.

Eurelectric, California ISO, New York ISO, ENTSO-E, CIGRÉ, GO15, PJM and ISGAN all have task forces and working groups investigating future roles for, relationships, markets, and coordination requirements between, the operators (Birk et al., forthcoming 2016). A future with decentralized and centralized electricity is plausible. DERS have market and operational impacts, therefore creating the need for new roles for DSOs and TSOs and creating a more complex and interwoven communication and operation structure for this industry.

Many power systems are handling this challenge differently and are potentially at different stages of penetration of DERs, coordination and communication between operators and physical operations of the networks. The transition towards a more efficiently run grid requires phases and transitions and can understood by Figure 29.

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[60] Birk, M., Chaves-Ávila, J. P., Gómez, T., and Tabors, R. (2016, forthcoming) "TSO/DSO Coordination in a Context of Distributed Energy Resource Penetration." MIT Energy Initiative, Utility of the Future Report

[61] Distribution System Operator in the EU and Utility in the US

[62] Transmission System Operator in the EU and Independent System Operator or Regional Transmission Operator in the US

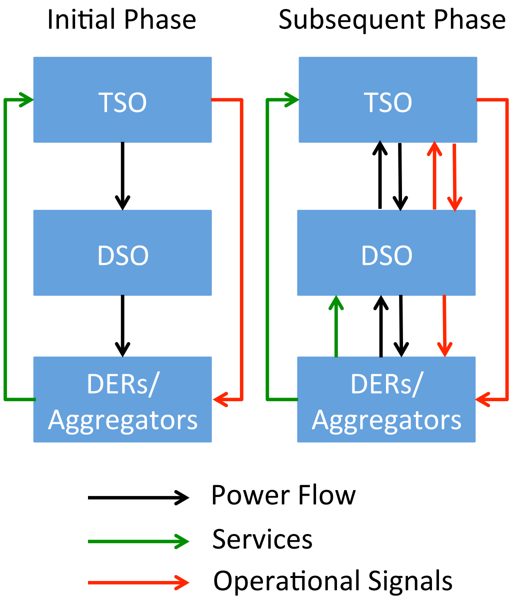


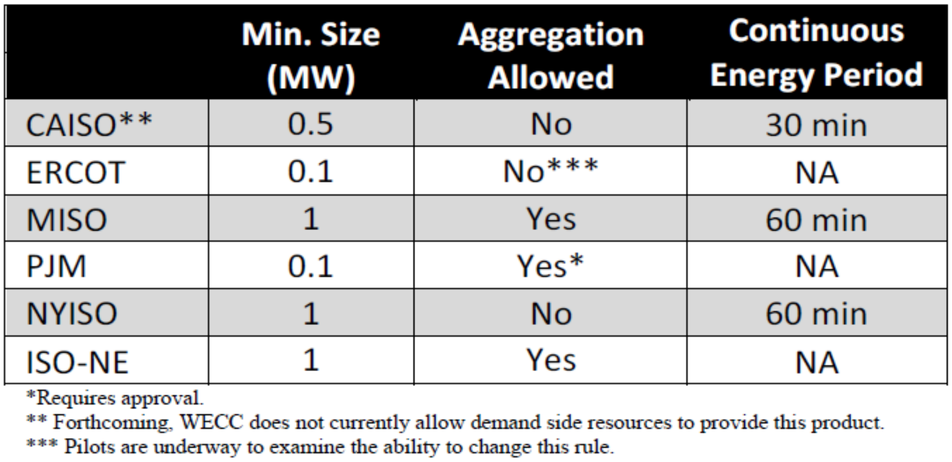
Figure 29: Diagram of the main interactions between TSOs, DSOs and DERs/Aggregators

DERs can provide electricity services to the power system (Fitzgerald, 2015; Pérez-Arriaga, 2016). Shown in Figure 30 is a list of energy related services, network related services and secondary electricity services (Birk et. al., forthcoming 2016).

Energy Related Services	Network Related Services	Secondary Electricity Services
Electrical Energy *Firm Capacity* *Black-start* *Primary Operating Reserves* *Secondary and Tertiary Reserves*	*Network Connection* *Voltage Control* *Power Quality* *Energy Loss Reduction* *Network Constraint Management*	*Emissions Restrictions* *Renewables Incentives (FiT, ITC, or PTC)* *Domestic Fuel Content Requirement*

Figure 30: Electricity services separated into categories: energy, network and secondary services (Pérez-Arriaga, Burger, & Gómez, 2016; Birk et. al., forthcoming 2016).

Some challenges facing the electricity industry occurring in the initial phase and some others are in the subsequent phase. Some challenges in the initial phase revolve around the access of certain DERs into wholesale power markets. Figure 31 details a size requirement that most wholesale market have that restrict access from DERs.



	Min. Size (MW)	Aggregation Allowed	Continuous Energy Period
CAISO**	0.5	No	30 min
ERCOT	0.1	No***	NA
MISO	1	Yes	60 min
PJM	0.1	Yes*	NA
NYISO	1	No	60 min
ISO-NE	1	Yes	NA

*Requires approval.
** Forthcoming. WECC does not currently allow demand side resources to provide this product.
*** Pilots are underway to examine the ability to change this rule.

Figure 31: Size requirement and length of production requirement for resources to access wholesale markets (MacDonald, 2012).

DERs can provide services, but certain restrictions limit their prevalence; restrictions may include size requirements, aggregation, length of production of energy, jurisdictional barriers in the US, and classification challenges of DERs or of demand side resources (Birk et al., forthcoming 2016).

Services can also conflict with one-another such as resources that provide operating reserves cannot also be dispatched for selling energy or reducing losses. Services can also compete across the system, meaning that a resource providing, for instance, capacity to the transmission system, may not also provide the capacity to the distribution system, and vice-versa. Certain activation of DER services to the transmission system could activate voltage constraints, for instance, on the distribution grid, although this is most likely to happen in a few years from now when the prevalence of DERs is ubiquitous and immense.

As penetration of DERs continues, new roles for distribution system operators and utilities will also likely emerge. DSOs mainly maintain local constraints, ensure power quality, and manage Volt/Var regulation, outage management and reducing energy losses. DSOs must plan for the network, provide regular maintenance (preventative and corrective) and activate line switching and load shedding during certain emergency situations.

During the initial phase it is likely that DSOs would need to increase the control and monitoring of their systems and the resources that are connected. DSOs may need to adapt protection systems to handle the bi-directional power flows and perhaps adapt a system to be able to function in an islanding operation. DSOs would need schedules from all users and even from TSOs to run their reliability and security analysis through for instance an optimal power flow to analyze grid level constraints. With increased penetration of DERs, a DSO may evolve into an active network manager facilitating retail markets, operating advanced metering, storing data on all customer loads and resources connected to their grids, and perhaps controlling infrastructure for electric vehicle charging, as seen in Denmark (EDSO, 2012). There is no shortage of research and analysis into the future roles for DSOs in the EU, US and around the world (De Martini, 2014, Ecorys, 2014; EDSO, 2014; Kristov, 2015). DSOs should understand the trends associated with DER adoption, integration and interconnection and adapt their networks accordingly, such as utilizing DERs as potential non-wires alternatives to infrastructure.

Figure 32 details characteristics and define challenges associated with an initial phase.

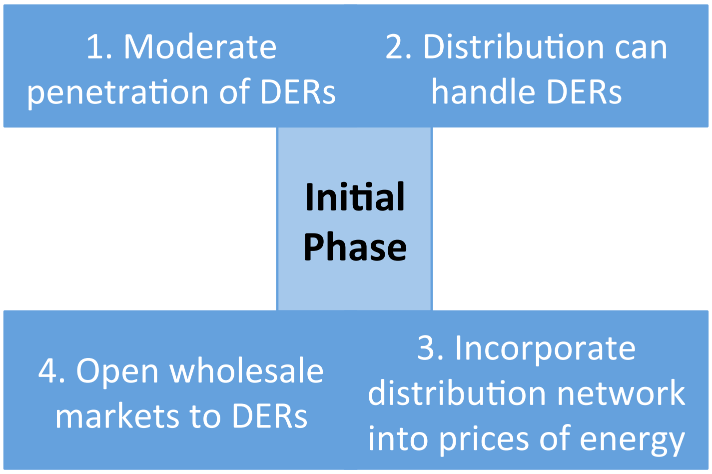


Figure 32: Initial phase characteristics and description of challenges

Figure 33 describes the subsequent phase characteristics and challenges.

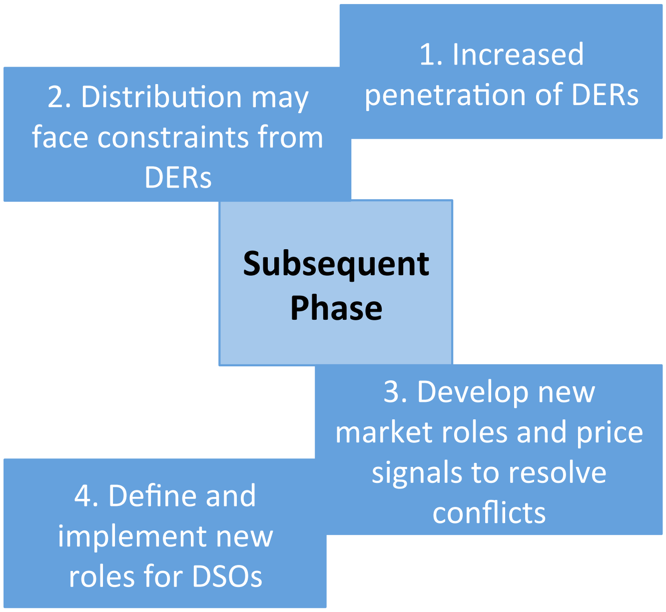


Figure 33: Subsequent phase characteristics and description of challenges

“So far, rapidly expanding deployments of DER are connected to the grid but not integrated into grid operations, which is a pattern that is unlikely to be sustainable.” –

"The Integrated Grid" EPRI (2014). Metering requirements and communications infrastructure are pertinent to the grid operations of the future as well as successful integration of DERs into the markets (NYISO, 2015).

A challenge currently facing the industry is the way and the amount to which the operators and DERs communicate between each other. Currently, the TSO or ISO has none or very little visibility into the effects of dispatched DERs on the distribution system (De Martini, 2015). The DSO must manage the distribution system with many DERs, some of which are acting autonomously, some are responding to TSO or ISO dispatches and some are potentially providing DSO level services (De Martini, 2015). De Martini and Kristov have analyzed industry structures and determined a robust and scalable model for the interaction between the operators and DERs/Aggregators, displayed in Figure 34.

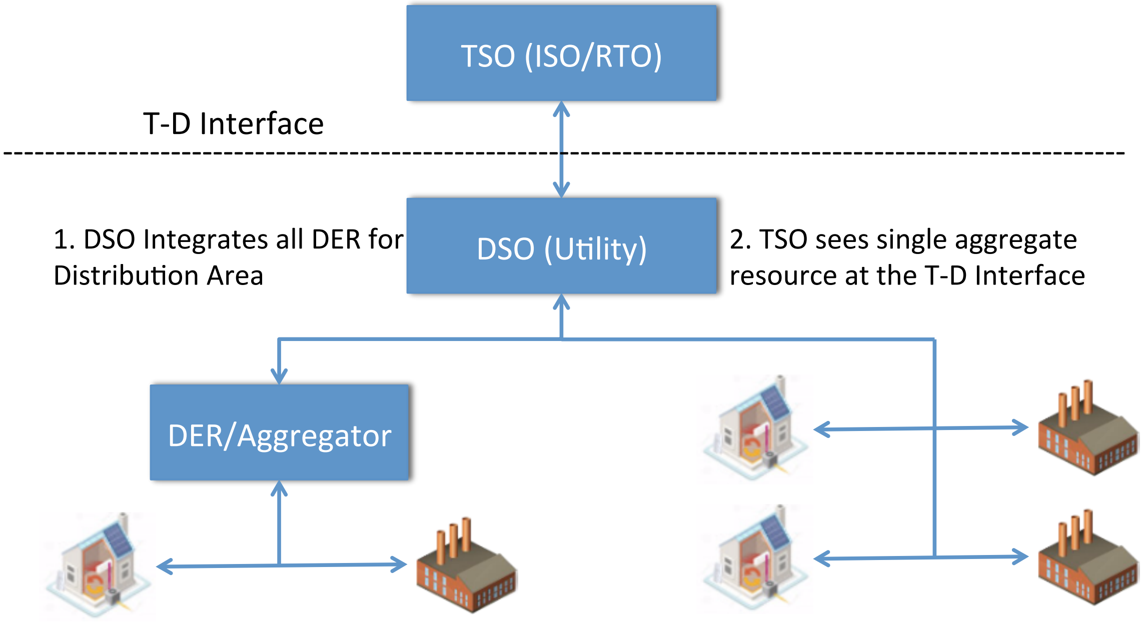


Figure 34: A robust and scalable model for the interaction between TSOs and DSOs (De Martini, 2015)[63]

Another quite similar system, more like the one in the US, is detailed in Figure 35.

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[63] De Martini, 2015; Birk, forthcoming 2016. Of course, where there are multiple DSOs operating a jurisdiction below the TSO or ISO, there will also need to be enhanced coordination and information sharing between all active actors.

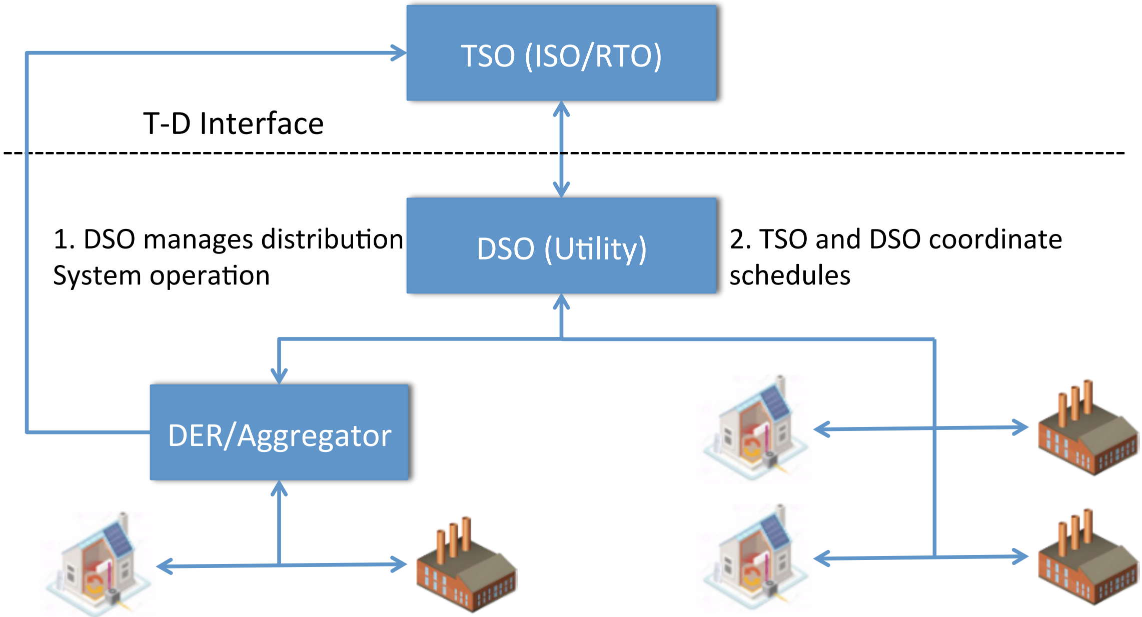

Figure 35: Another robust and scalable model for the interaction between TSOs and DSOs (De Martini, 2015)

The model described in Figure 35 displays a structure seen in today's power markets, such as in PJM or NYISO. Certain demand side resources have the capability to access wholesale markets directly to the ISO, without the resource being coordinated with the utility or even the utility have full detail on the resource. Some DSOs or utilities may have SCADA[64] for only some DERs that may not participate in ISO markets (Birk, forthcoming 2016).

3. Possible Pathways to the Future

DSOs and TSOs should maintain best practices for balancing and service restoration and regulators should maintain and enhance certain network codes given the changing landscape of operations, planning and, potentially, markets. Communication between the TSO/ISO, the DSO/Utility and the DERs/Aggregators is of utmost importance. Communication and information technologies must be utilized as well as smart meters that can collect real-time and send real-time data for operations as well as planning purposes. Energy flow forecasts and schedules sent at different timeframes as well as coordinated dispatch would make for a more efficient grid. Certain operating procedures to manage TSO dispatch of DERs in DSO territory should be agreed upon and applied. Long-term planning and long-term contracting should be coordinated since DERs are potentially non-wires solutions for network expansion. Electricity regulators and commissions throughout the US and the EU should continue to create, apply and enforce standards for operation and communication between the actors within the power system. The power system is evolving and rapidly changing, the regulation and standards that regulates and maintains the system should evolve in kind.

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[64] SCADA, acronym for Supervisory Control and Data Acquisition

DSOs could use 8760 load profiles to understand variable distributed generation on their networks and estimate, measure and value certain DERs. System inertia might be declining due to DERs, but smart inverters can replace this lost inertia and maintain voltages within required specifications and ranges. Standards for communication and linking the IT are also pertinent. For network operators to manage the dispatch of certain resources on the grid, operating procedures could call for an iterative approach to calculating impact. If the TSO/ISO wants to dispatch DERs to solve network constraints, the TSO/ISO could run a day-ahead market with DERs and inform the DSO. The TSO/ISO would compute the price and send the signal to the DSO. The DSO could monitor the resources it has, ideally, integrated into the grid and compute a DLMP or contract for the entire local distribution area[65] and send the information back to the TSO. The TSO could then optimize the dispatch of resources on the transmission system and distribution system to solve the constraint at lowest cost.

Chapter 3 looked into system-wide impacts from solar PV in the New York transmission system with an emphasis on the modeling of electricity prices and a large penetration of distribution-side resources. Chapter 4 analyzed the interface, relationship and coordination of actors between transmission and distribution in a context of high DER penetration. Chapter 5 takes the investigation another step further into the interface between transmission and distribution by modeling both the entire New York State transmission system and a part of a distribution system. Chapter 5 analyzes market prices, network impacts and environmental residuals at the interface of transmission and distribution with increased penetration of solar PV.

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[65] Of course, in regions where there are multiple Utilities or DSOs, the local distribution area may be interconnected with other DSOs territories and in that case monitoring and sending information would also have to be between the multiple DSOs and the DERs/Aggregators and the TSO/ISO.

5. Modeling the Bulk Power System with a Distribution Interface

Chapter 3 described the impact on the bulk power system from distributed energy resources modeled as aggregated resources bundled up onto the transmission system substations. Chapter 4 investigated the coordination between TSO and DSO system operators under penetration of DERs. Chapter 5 details distributed energy resources and prices in more granularity by taking the modeling effort another level down, into the sub-transmission and high voltage distribution system. This chapter integrates a distribution network, connected to the bulk transmission system. High-voltage distribution nodes and wires were modeled in detail along with the New York State high-voltage transmission system to determine locational marginal prices and other network impacts[66].

The objective of this chapter is to investigate the complex relationships that are developing between the high and low voltage elements of the power system. Through modeling of both the bulk transmission system and the high-voltage and medium-voltage elements of the distribution system, it may be possible to evaluate the effects of increased penetration of distributed energy resources within a larger portion of the integrated power system. The focus is on the effects of transmission and distribution network integration, such as electricity pricing, revenues, constraints as well as environmental residuals, such as CO_2.

1. Background and context

This section provides an analysis of the impact of resources located within the distribution system on the bulk transmission system by modeling the New York wholesale power market and network of transmission and centralized generation co-optimized with a distribution feeder. By extending the optimization modeling to include a distribution feeder, it is possible to study the impact of the distributed energy resources with more granularity. Solar PV was placed on nodes at voltage levels down to 4.8 kV. The transmission substations in New York State range in voltage levels from 34.5 kV up to 500 kV. PSO is utilized because it calculates security constrained economic dispatch and unit commitment, and locational marginal prices for the entire transmission network co-optimized with the effects from distributed energy resources, such as solar PV.

The added distribution community or sub-transmission system has 11 substations rated at 34.5 kV, 148 physical nodes were additionally modeled at a voltage level of 12.5 kV and 2 nodes at a voltage level of 4.8 kV. The peak demand in the community system is approximately 150 MW. On the added modeled feeder (the 150 nodes at lower voltages), there is 25 MW of peak demand. The feeder with the added 150 nodes is operated radially and connected to the transmission system via 1 transmission substation, see Figure 36 for a representation of the feeder and connection to the bulk system. There are 10 other substations modeled that were compared to the existing PSO and New York State model, but, for this analysis, do not have lower voltage transformers and nodes

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[66] LMPs and approximated DLMPs calculated at transmission and sub-transmission (high voltage distribution or medium voltage distribution) substations or nodes.

modeled below them. The data received for the lower voltage distribution network was compared to the substations and vetted against the New York transmission network in PSO.

The lower voltage network, obtained from a MIT Energy Initiative Utility of the Future Report[67] consortium member, was modeled as close to the actual network as possible. The main purpose of the added network is to gain insight into general trends and curves regarding penetration of DERs and bulk power system impacts; therefore, the exact location is important because it guides the modeling effort, but it is not meant to make specific statements on the distribution network defined; it is more of an analysis that can lend itself to making statements on the interface impact, as well as locational and geographic implications from DERs. The transmission substation was connected to the high-voltage grid in the zone displayed with the red arrow in Figure 36. The 4.8kV nodes are displayed in green in Figure 36.

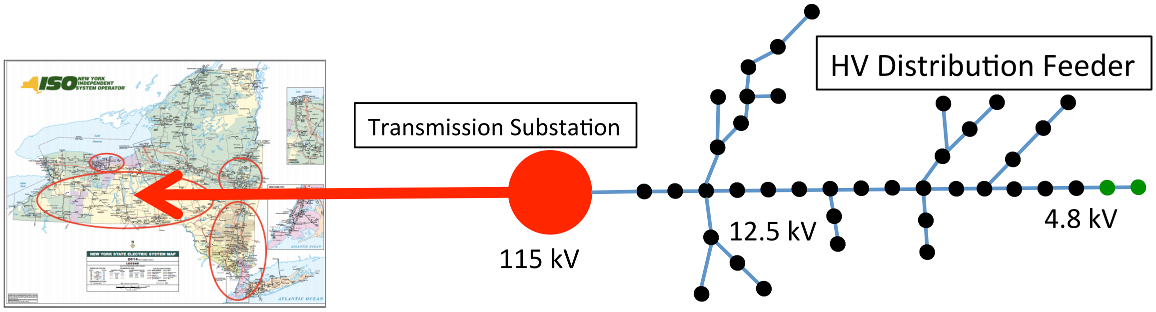

Figure 36: Schematic diagram for the feeder and bulk system connection (NYISO, 2015)

1MW, 10MW, 20MW, and 30MW of solar PV were added to the distribution feeder in equal proportion along the feeders. In the 1MW case, each node would receive 6.67 kW of solar PV, in the 10MW scenario each node received 66.67kW, in the 20MW case each node received 133.33kW and in the 30MW test each received 200kW. The nominal household in this zone might need about 5kW of solar PV; therefore each test represents a specific number of households connected to the nodes. The 1MW case would be representative of a single house with solar PV connected to each node. Due to physical limitations of most distribution networks,[68] anything more than 30MW would be expected to cause voltage constraints during periods of high solar PV energy production[69].

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[67] MIT Energy Initiative Utility of the Future Study https://mitei.mit.edu/research/utility-future-study

[68] Modeling this system with an AC powerflow would yield thermal and voltage constraints at higher penetrations of solar PV.

[69] There are instances in this study where there are upwards of 100MW placed on the feeder, although it is possible this would yield serious constraints on the distribution system, from a modeling standpoint it is interesting to note some of the system and local implications of such penetrations, as noted in the following sections. There was real LV distribution grids (~240 V) in southern Germany where the PV capacity exceeds the peak load by 900% (Von Appen, 2013).

2. Feeder and system impacts

Figure 37 displays load for a typical week in winter for the distribution feeder that was modeled and Figure 38 a typical summer week.

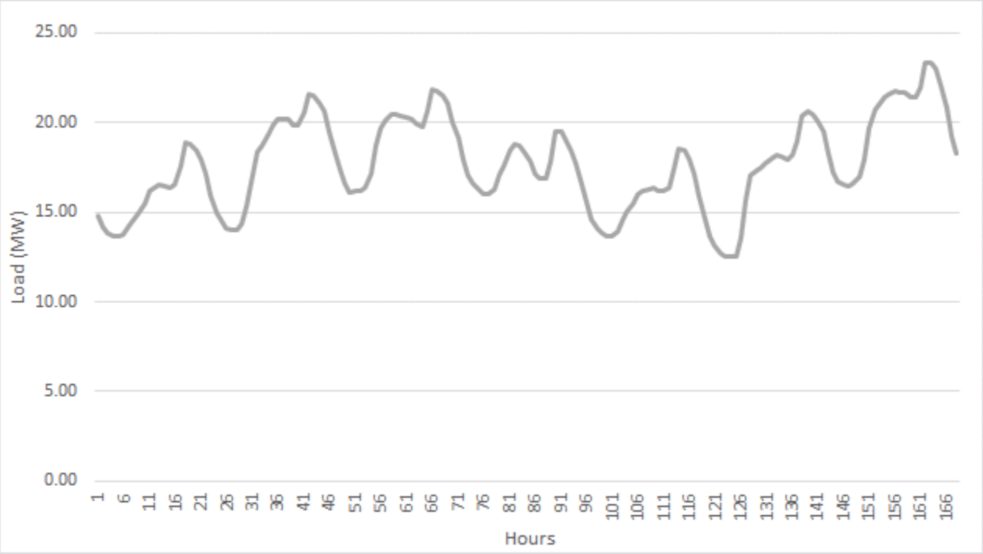

Figure 37: Typical winter week load pattern

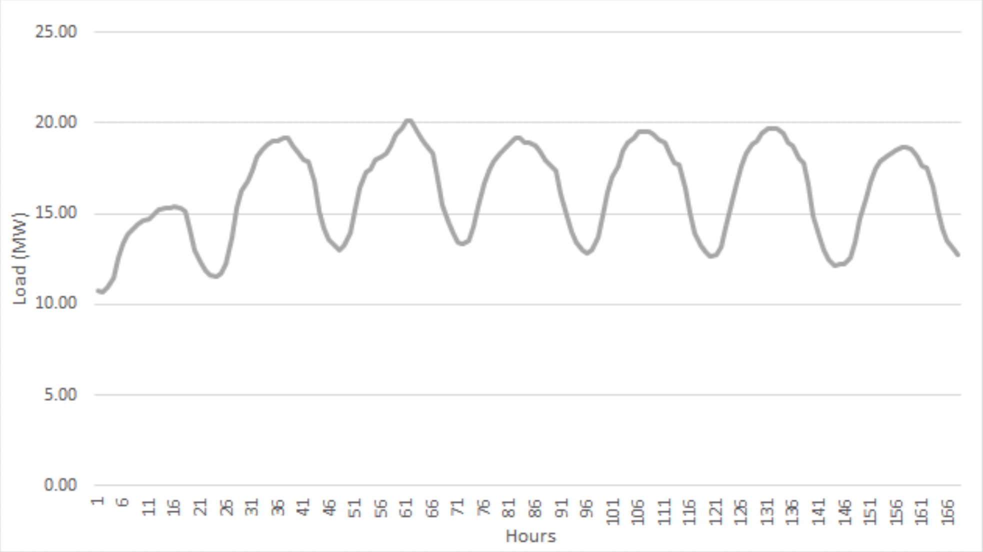

Figure 38: Typical summer week load pattern

Figure 39 displays a typical week in winter for the feeder that was modeled with an increment of 1MW solar PV. Figure 40 displays a typical summer week for the feeder that was modeled in terms of load with an incremental MW of solar PV. Even though in these two weeks chosen, the winter week has a larger peak demand, the summer week displays a greater penetration of solar PV, due in part to the higher solar insolation during summer months than winter months.

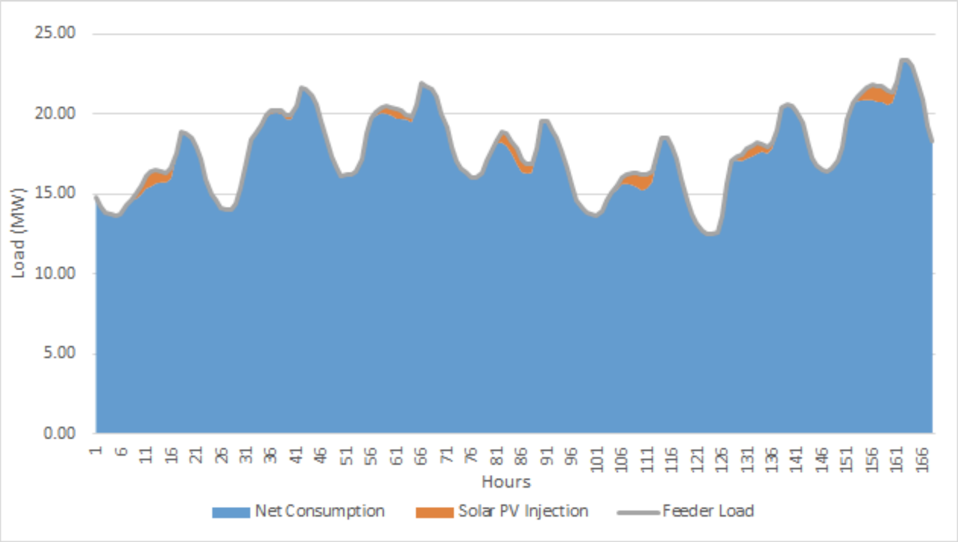

Figure 39: Typical winter week load pattern with 1MW of solar PV installed

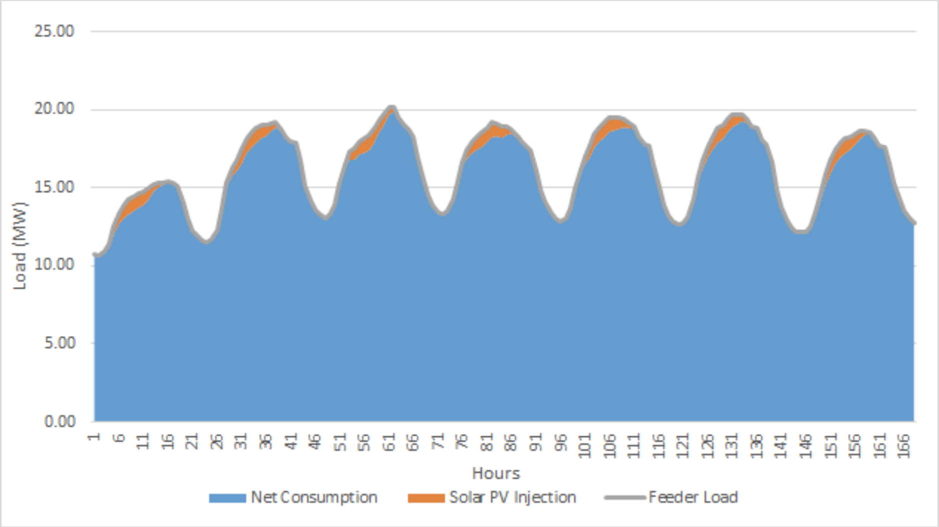

Figure 40: Typical summer week load pattern with 1MW of solar PV installed

Figures 41 and 42 show the effect with 10MW of solar PV demonstrating the high-expected daily variability in winter relative to summer.

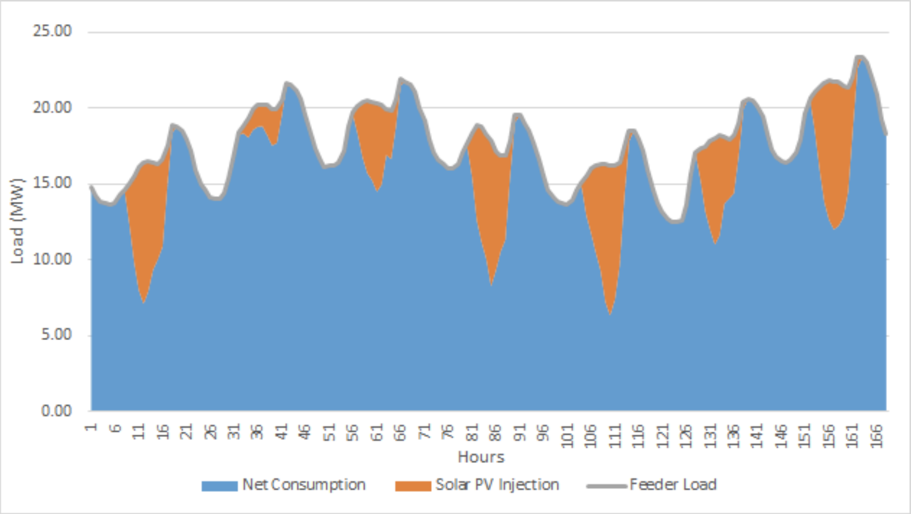

Figure 41: Typical winter week load pattern with 10MW of solar PV installed

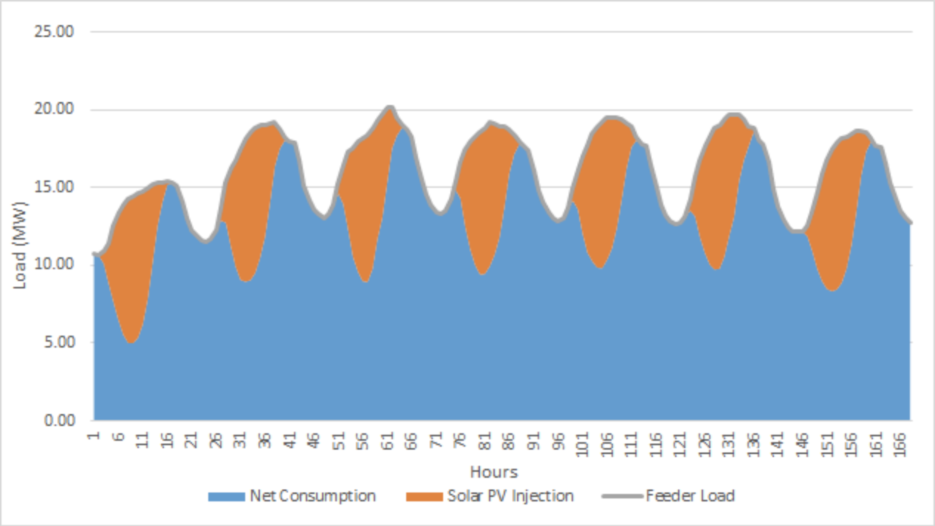

Figure 42: Typical summer week load pattern with 10MW of solar PV installed

The solar PV is impacting the load pattern that conventional units would normally have had to supply. Since the solar PV is reducing the demand for electricity during these hours, as shown in the orange, the system must compensate. There is increased penetration of solar PV during the summer week as compared to the winter week.

Shown below in Figures 43 and 44 are the winter and summer weeks with 20 MW of installed solar PV. The peaks shown in orange are hours when the solar PV production is greater than the consumption on the feeder, such that solar PV energy is exported to the rest of the NYISO system where it could have positive or negative system impacts.

These system impacts can be in terms of reliability, economics, and environmental residuals. Reduction in demand may lower the need for system reserves because demand side resources could free up existing generation and transmission; demand resources such as solar PV as modeled here might help avoid the cost of farther distant generation, transmission and system losses, or it may increase system losses as that power might seek farther markets; if the demand side resource is a renewable, this might alleviate the need for dirtier, farther transmission and generation assets or it may transmit further distance because the local demand is met (Oak Ridge National Lab, 2015).

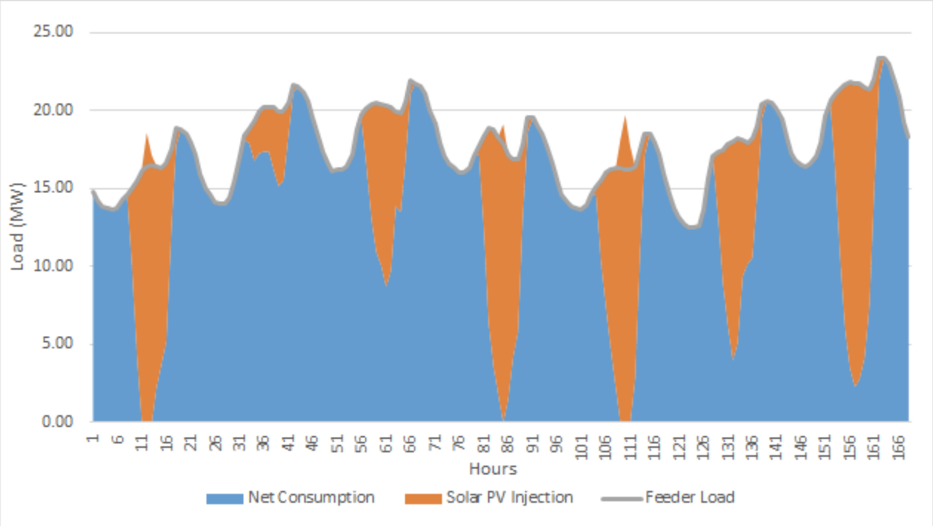

Figure 43: Typical winter week load pattern with 20MW of solar PV installed

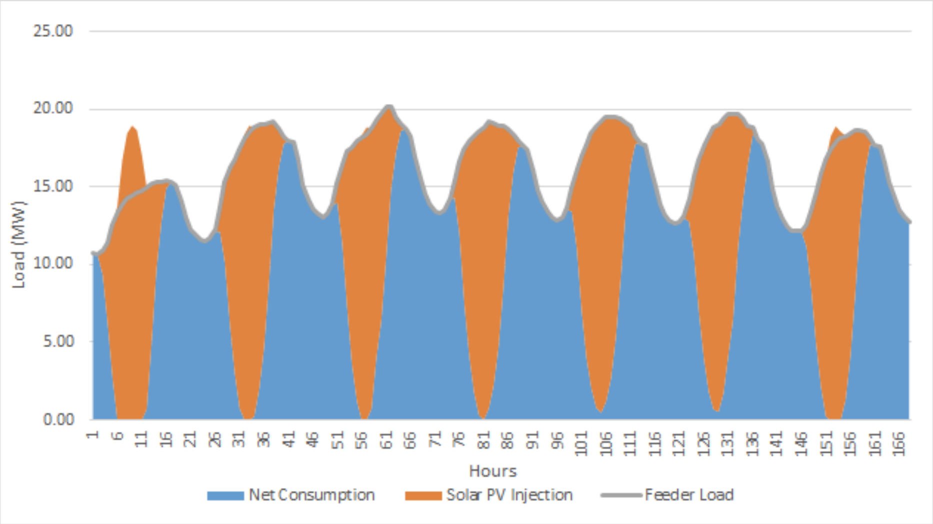

Figure 44: Typical summer week load pattern with 20MW of solar PV installed

NYISO (transmission) Zone C is typically not a heavily congested zone compared to the other zones in New York State with less than 5% of the average LMP for historical years 2014 and 2015 coming from congestion.

Figure 45 displays the change in generation across the scenarios of PV penetration for combined cycle and gas turbine units. Combined cycle generation is displayed on the primary left-hand-side y-axis and gas turbine generation is displayed on the secondary right-hand-side y-axis. There are fluctuations in generation of these units in this zone, because during certain penetrations, i.e. 20MW, the generation of combined cycle gas turbines increases above the base case scenario. The observation is showing the utilization of flexible units to maintain a reliable system given the intermittency of solar PV and the impact solar PV has on more the centralized incumbent generation. There is a decrease in generation from the base case to the scenario with 1MW penetration of solar PV and then the rise in generation from 1MW solar PV to 10 MW solar PV and 20 MW solar PV. From 20 MW to 30 MW there is a decrease in generation; this has an impact on the market price as well as emissions in the area. Even with relatively small penetrations of DERs, there could be larger system impacts. Combined cycle units make up a large portion of the energy generation in this zone. The entire generation fleet in New York responds to the 30 MW of solar PV in the zone.

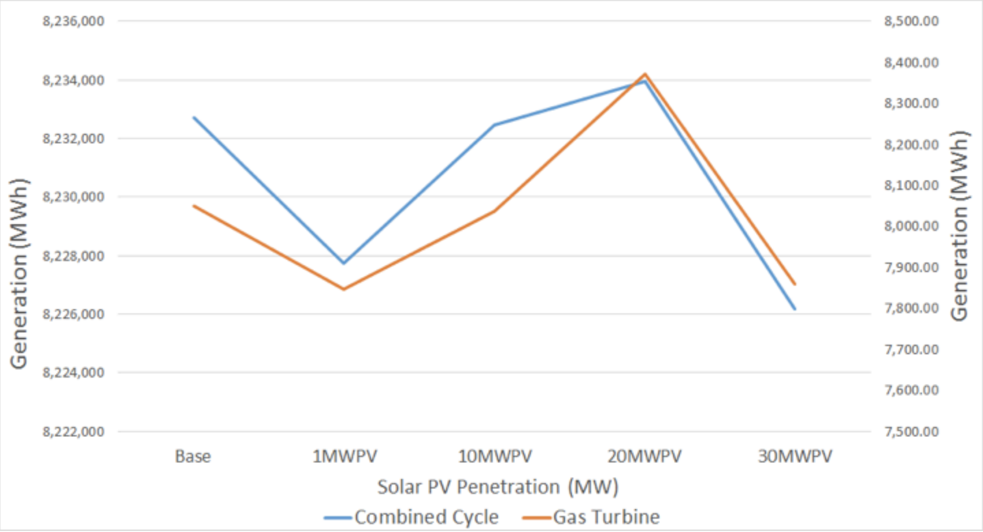

Figure 45: Zone C energy generation for combined cycle units and gas turbines (MWh)

The change in generation for the combined cycle units as well as the gas turbine units have a very similar pattern. With a 1MW increase in solar PV, the change in total generation for the combined cycle units is a decrement of greater than 4,000 MWh, whereas for the gas turbines units the change is a decrement of 700 MWh. Even a small increment in solar PV, could mean, such as in this case, a small decrement in load, can have a rippling effect throughout the power system. Somewhere else in zone C, there are units that do not need to respond where they might have needed to in a case without load pattern changing of solar PV.

Observed is an increase in combined cycle and gas turbine generation when the PV installed capacity increases to 20MW. These units are also generally regarded as flexible, meaning they can ramp up and down quickly to respond to changes in load and generation within the power system. When there are more significant penetrations of solar PV, the power system must adapt, and therefore call upon certain resources to provide energy or react in other ways. Displayed in Figure 46 is combined cycle turbine energy generation for a typical July week displaying the change across the scenarios in generation depending upon the penetration of solar PV. On July 3rd, there is more generation for the 1MW and the 30MW solar PV scenario than for the 0, 10 and 20 MW solar PV penetration scenarios.

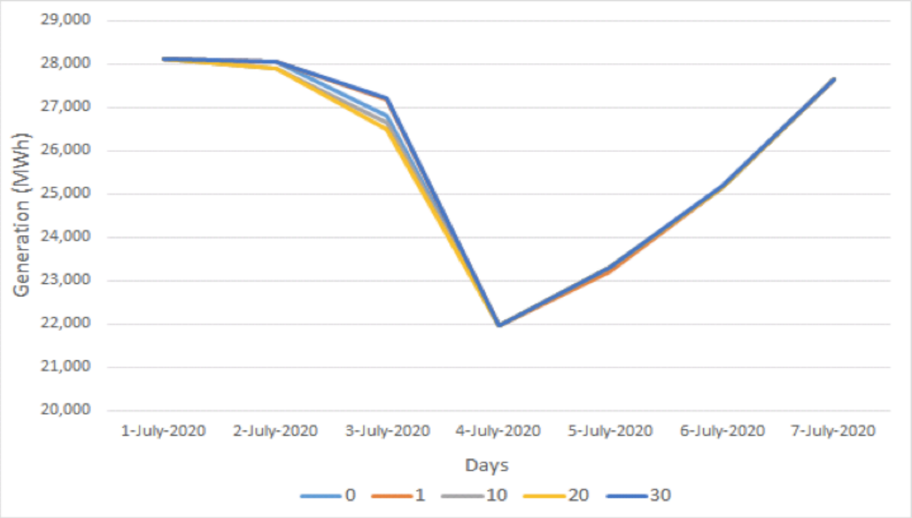

Figure 46: Generation (MWh) for combined cycle turbine units for a sample week in July

When there are even small variations to load or generation in a zone, the power grid and generation must compensate for it, to maintain the balance of supply and demand in the entire system. The dispatch of certain flexible units, such as combined cycle gas turbines, are some of the ways power systems may handle the impact of intermittent distributed energy resources.

Figure 47 displays the change in CO_2 emissions of zone C in New York State with increasing penetration of solar PV in the modeled distribution feeder. The study in Chapter 3 displays the impact of large penetrations of solar PV in New York on emissions, whereas Figure 47 highlights a more local impact.

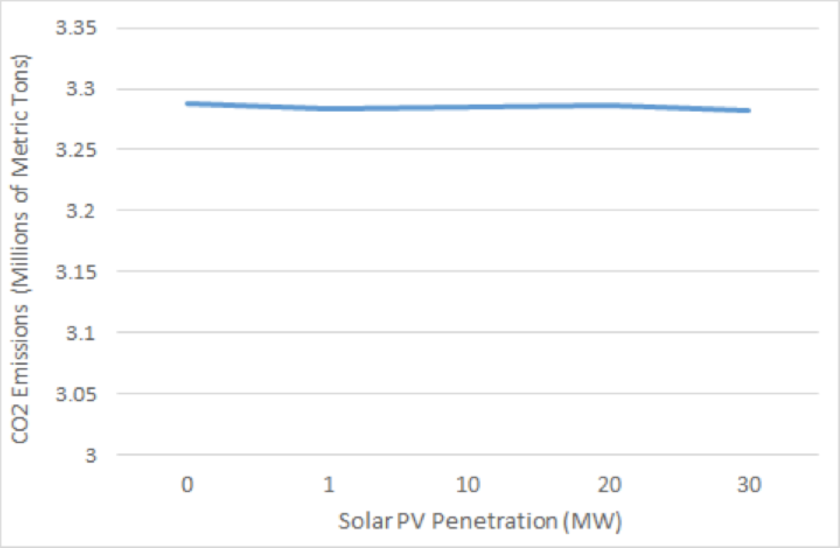

Figure 47: Change in CO_2 emissions (Million Tons) in zone C

With increasing penetration of solar PV, there is a decrease in emissions of CO_2 with greater penetrations; however, in smaller penetrations of solar PV, there are potentially fluctuating impacts regarding carbon emissions due to thermal unit characteristics and dispatch order impacts (i.e. ramping start-up/shut-down). During certain hours the system must compensate for the new load patterns by committing more flexible and potentially dirtier units, such as gas turbines and internal combustion engines.

Shown in Figure 48 is a closer visual of the change in CO_2 emissions across the different solar PV penetrations.

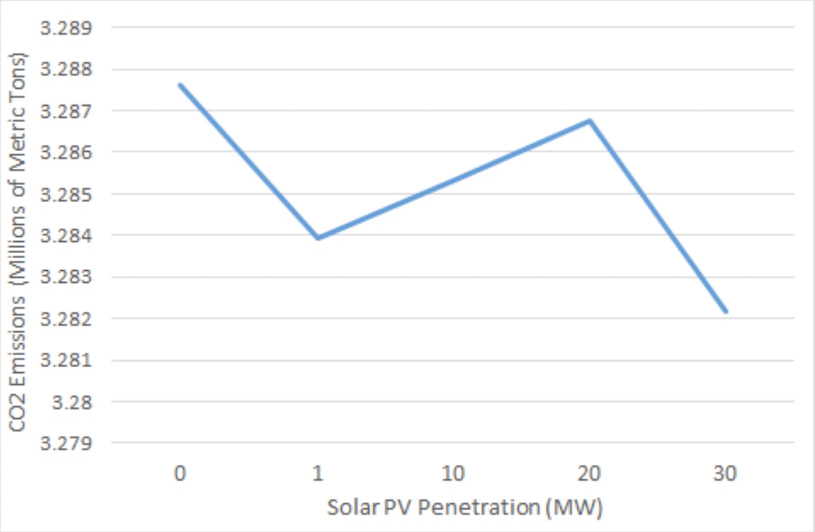

Figure 48: CO_2 emissions in Zone C

The fluctuations in CO_2 are due in part to the fact that steam turbines and gas turbines, running on fuel oil, are generating more across the penetration levels. There are fluctuations across the different penetrations in terms of CO_2 emissions; however, a key takeaway is that to model the environmental impact from renewables and intermittent distributed energy resources, it is important to investigate the larger power system because even small-scale renewables might impact dispatch order and generation of other technologies at the bulk power system level. If for instance solar PV causes a certain generator to turn off, it may now be optimal for the system to leave the unit off and dispatch other units.

Figure 49 displays the zonal average market price across all the nodes in zone C. As penetration of solar PV increases, there is a slight downward trend in market prices that while positive, is a reflection of the small penetration of solar PV in the full Zone C even though significant in the modeled feeder.

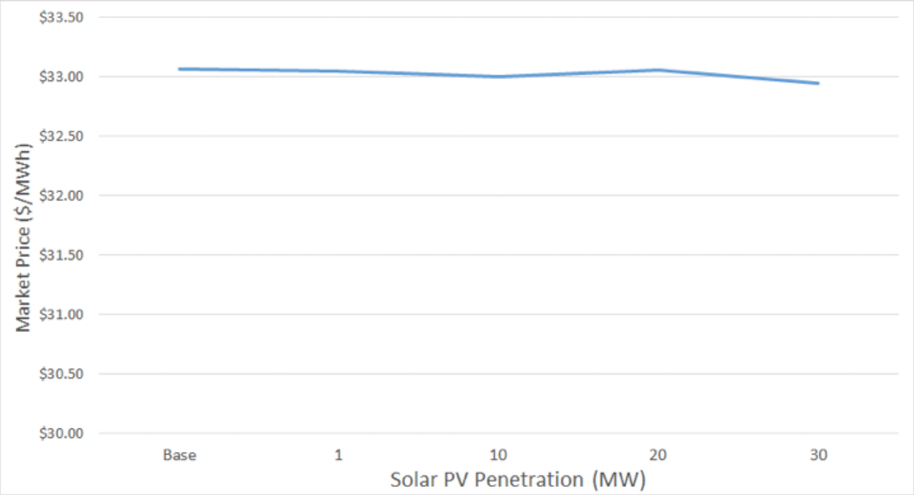

Figure 49: Market price impact from solar PV penetration across all nodes in zone C

Figure 50 displays a closer visual of the fluctuations in market price across zone C. There are fluctuations in average market price for Zone C due to the bulk system impacts from small penetrations of DER. The spike in price as well as emissions are due to steam turbine and gas turbine units, running on oil as a fuel, generating more energy than in the base case. The general trend over the penetrations is downward regarding market price and emissions, with some variability of prices and emissions within the range.

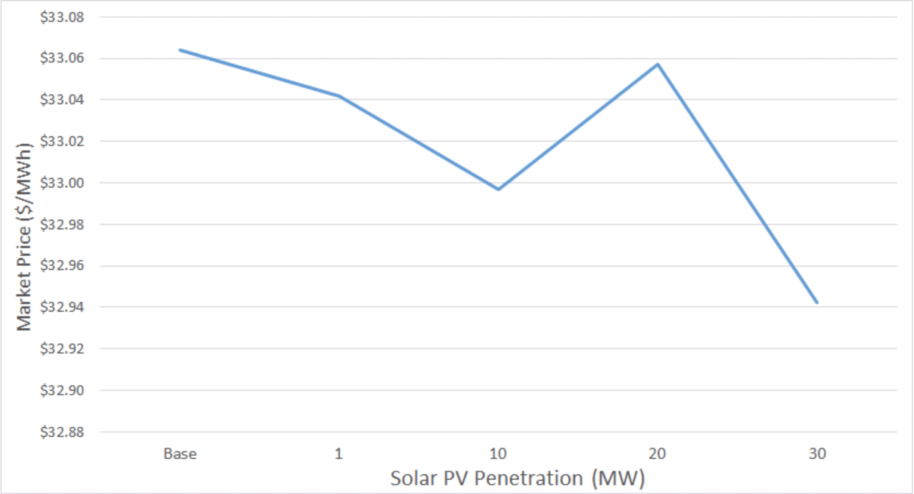

Figure 50: Market price across Zone C

Figure 51 displays the revenue[70] solar PV receives from the market as well as the revenue per installed capacity of solar PV. An interesting trend to note is the decreasing marginal revenue from solar PV.

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[70] The revenue is purely an energy generation (MWh) value multiplied by the generator LMP, so when the sun does not shine, there is no revenue for solar PV. Revenue = Generation (MWh) * GeneratorLMP ($/MWh). This revenue is a different value than the average market price.

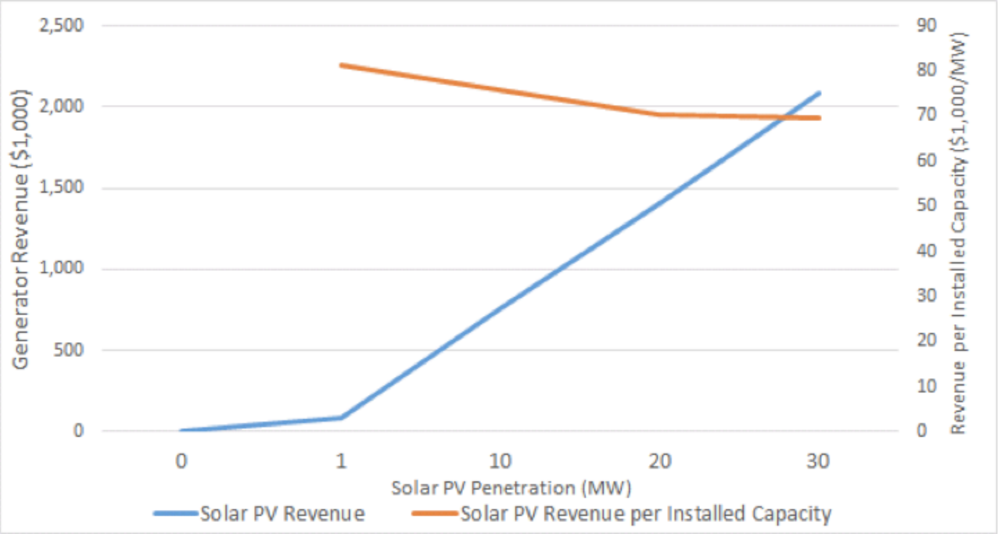

Figure 51: Solar PV revenue and solar PV revenue per installed capacity

Table 3 displays the average "solar owner" price for solar PV placed on the distribution feeder compared to the NY zone C average market price. From the columns labeled "Delta from Base," the Solar PV "Owner" delta is larger than the zone C average market price; the table displays the faster diminishing returns solar PV "owners" would have in the wholesale market compared to the average zonal market price. The change in market price for the "solar owner" is on the order of dollars ($) per MWh, whereas for the Zone C market average the delta is on the order of cents per MWh.

Table 3: Solar PV "Owner" market price and the NY Zone C average market price

Solar PV Penetration (MW)	**Solar PV "Owner" Price ($/MWh)**	*Delta from Base*	**Zone C Market Average ($/MWh)**	*Delta from Base*
0			33.06	
1	49.37		33.04	**0.02**
10	48.10	**1.27**	33.00	**0.07**
20	47.07	**2.30**	33.06	**0.01**
30	45.37	**4.01**	32.94	**0.12**

Similar to a result described in Chapter 3 regarding solar "owner" market price and average market price, is that solar PV in this test with a distribution feeder also displays a faster decreasing market price that solar PV receives compared to the average market price.

3. Local implications

Shown in Figure 52 is the transmission-distribution interface substation. With increasing penetration of solar PV, the transmission-distribution interface substation has decreasing LMP or market prices. At higher penetrations of solar PV on the distribution feeder the interface node has lower LMPs with the caveat, again, that only one of the 4 feeders at the substation has incremental solar PV in the model.

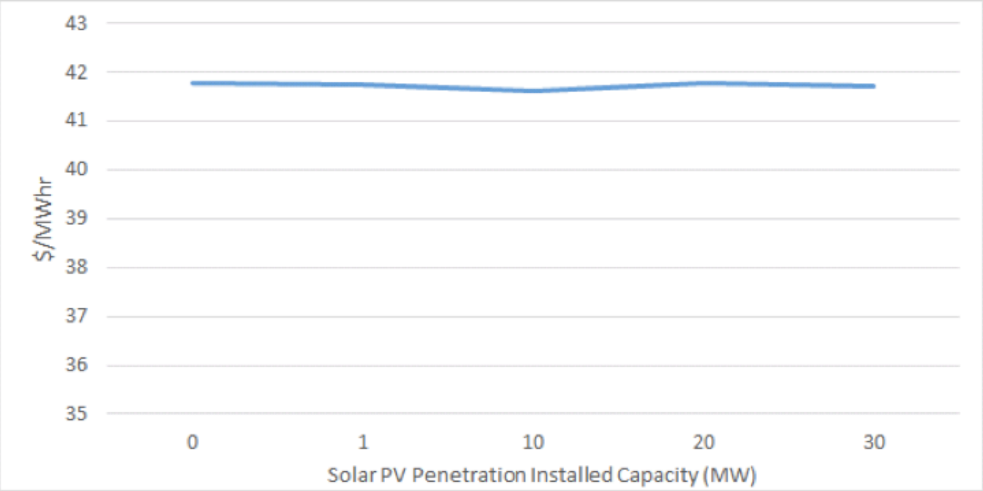

Figure 52: Transmission-distribution interface for the specific feeder

Since penetration of solar PV impacts the load and consumption pattern on the distribution feeder, less power will be needed to transfer from the system to the transmission interface and then to the feeder. The drop in market price for the node for the 10MW penetration scenario is only $0.02/MWh, which is not significant, but it does display an interesting result that due to the increase in solar PV on even the single distribution feeder, a change occurs throughout the bulk power system, which causes the decrease in nodal price at 10MW penetration. The change that occurs in the system due to solar PV on the distribution feeder may be a result of a reduction in congestion, or a change in dispatch order.

In Figure 53, node 1 is connected to the substation transmission-distribution interface. The feeder is modeled radially, and as the power flows further along the line, the resistive losses increase, thereby increasing the prices; but as solar PV increases in penetration, the difference in prices between the transmission substation interface and the distribution system nodes decreases. With increasing penetration of solar PV, the DLMPs are lower due to lower losses along those lines that would normally have had to feed the nodes the power from the bulk system. Increasing penetration of DERs such as solar PV impacts the system. Figure 53 displays the 150 nodes on the feeder that was modeled and the LMPs or DLMPs approximated by a DC OPF, with increasing penetration of solar PV. The further down into the distribution feeder, the LMPs or approximated DLMPs become more expensive. Node 149 and 150 are at 4.8 kV and are the farthest away from the transmission-distribution interface substation and show a marked step increase in DLMPs.

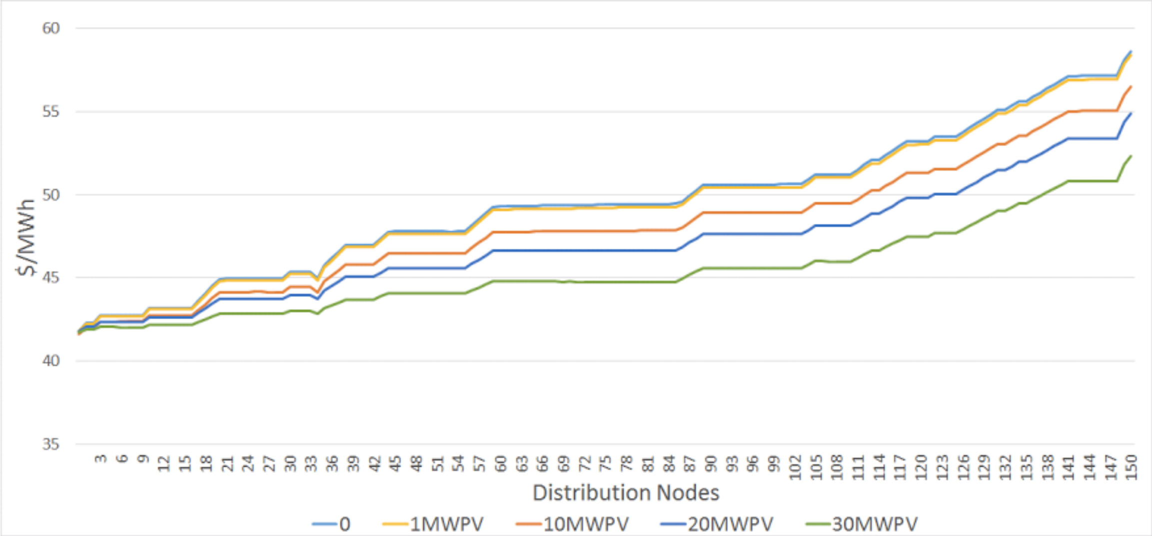

Figure 53: Distribution feeder nodal prices with increasing penetration of solar PV

With 1MW of installed solar PV, there is a slight decrease in the nodal prices observed on the feeder, but with 10 MW there is a more noticeable decrease in prices, and the trend continues with increasing penetration. Figure 53 displays a good visual for an approximation to DLMPs. The trend is generally an increasing DLMP further down into the distribution feeder. There is also an increase in DLMP when the nodes go from 12.5 kV to 4.8 kV; this is mainly due to the increase in resistance (and therefore resistive losses) along the lines that connect the lower voltage nodes.

When the penetration of solar PV reaches twice the peak demand on the feeder (50MW), there are points on the distribution feeder at which there are lower prices than at the transmission substation interface[71]. It is possible that with combinations of DER the DLMPs will be lower than the LMP at the transmission interface node. Under this condition, an increase in load on the feeder could actually decrease (marginally) total system losses. When the PV capacity exceeds the peak load, the grid is “subject to reverse power flows over the transformer and a rise in voltage” (Von Appen, 2013).

In this chapter, the interface between transmission and distribution was explored and DLMPs and LMPs were calculated using data from the New York power system. Since this method utilized a DC approximation to power flows, thermal losses were the focus. In this region, thermal and voltage congestion is not known to be particularly high. Chapter 5 investigated the computation of the DLMP down into the radial network, with a direct current optimal power flow, and analyzed an interface point where the meshed network connects to the radial network.

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[71] It should be noted that there are likely to be voltage constraints inside the feeder that is not accounted for in the DC optimal power flow.

6. Summary and Conclusions

The objective of this thesis has been to evaluate a set of issues at the core of the interface between the transmission and distribution systems using state-of-the-art utility market modeling methods to calculate the locational value of DER in the larger power system. By modeling locational it has been possible to evaluate the impact of increased penetration of solar PV in a single radial feeder interconnected physically, electrically and economically to the New York power system. The result has shown that under large, though reasonable, penetration of solar PV there will be New York power system level impacts measured by changes in LMPs and environmental emissions.

This thesis has explored the interface between distribution and transmission networks from regulatory, policy, operations and markets perspectives. It has driven deeper into the interaction between the operations of the distribution and transmission systems from an operations and economics standpoint. The study analyzed different scenarios across the New York transmission system (system-wide impacts) as well at more local impacts (transmission and distribution network interface). LMPs were calculated and DLMPs were approximated at the interface of the meshed and radial network. A qualitative assessment of the coordination and cooperation efforts amongst power system operators was undertaken, which has policy and regulatory implications for the changing structure of the electricity sector.

There is still further research to be done in analyzing the impacts of additional and combinations of DERs on the bulk power system. It would be very interesting to model central station pumped storage hydro as well as decentralized battery storage within the bulk power system. Adding new distribution feeders at different voltage levels to the transmission system would be quite novel especially with also varying quantity of penetration (MW) of different DERs. Another interesting test would be to model this distribution feeder and a lower voltage distribution network with an AC power flow. It is acknowledged that there is a need to evaluate and value both real and reactive power (AC modeling) when studying the distribution system rather than only using DC modeling as is the case in this thesis. In addition there will be significant benefits to adding distribution feeders at different configurations and voltage levels to the expanded modeling of the transmission system beyond what has been done here. Another interesting test would be to model this distribution feeder and a lower voltage distribution network with an AC power flow.

This thesis was able to analyze a single radial feeder and in so doing provided a glimpse of the impact and understanding of system impacts (albeit with DC modeling) of moving the LMP calculation and valuation process deeper into the distribution system (i.e. making the prices more granular, in the vocabulary of the NY REV proceedings).

Appendix

Acronyms

AC: Alternating current
CA: California
CMS: Congestion Management System
DC: Direct current
DER: Distributed energy resource
DES: Distributed energy system
DLMP: Distribution locational marginal price
DOE: Department of Energy
DSO: Distribution system operator
DSPP: Distributed System Platform Provider
FERC: Federal Energy Regulatory Commission
GDP: Gross domestic product
GW: Gigawatt
ISO: Independent system operator
kW: Kilowatt (Power)
kWh: Kilowatt-hour (Energy)
LMP: Locational marginal price
MW: Megawatt (Power)
MWh: Megawatt-hour (Energy)
NY: New York
NYISO: New York Independent system operator
OPF: Optimal power flow
PEV: Plug-in electric vehicle
PF: Power flow
PJM: Pennsylvania, New Jersey, Maryland Interconnection LLC
PSC: Public Service Commission
PSO: Power systems optimizer
PV: Solar photovoltaic
QER: Quadrennial Energy Review
RTO: Regional transmission organization
SCADA: Supervisory Control and Data Acquisition
SCED: Security constrained economic dispatch
SCUC: Security constrained unit commitment
TSO: Transmission system operator

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