ASSESSING POTENTIAL PV DEPLOYMENT ON NEW YORK CITY'S NETWORK DISTRIBUTION SYSTEM

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ABSTRACT

This paper describes a method for estimating the technical potential of rooftop photovoltaics (PV) based on satellite imagery. This method is applied to two utility network areas in New York City to estimate PV yield potential. PV power generation is compared to network loads to determine when and where PV generation can exceed network loads. The effects of energy exporting on network distribution systems are evaluated.

1. INTRODUCTION

While most areas of the United States use simpler radial distribution systems to distribute electricity, larger metropolitan areas like New York City typically use more complicated secondary network distribution systems ("networks") to provide increased reliability in large load centers. Unlike the radial distribution system, where each customer receives power through a single feeder and single transformer, a network provides power to each customer through several parallel feeders and transformers. This redundancy improves reliability, because the loss of a single line or transformer will not interrupt power. Networks require special protective devices called network protectors that prevent power from backfeeding from one transformer through another. Network protector operation may be disrupted by energy exported to the network from distributed PV systems [1].

Many utilities do not allow interconnection of distributed PV systems to their networks because of the threat they pose to network protector operation. Exporting PV systems may produce a reverse-current flow through the network protector, which causes the device to open unnecessarily and reduces network reliability. After opening, the network protector may try to reclose out of synch on an islanded PV system, which could damage utility equipment or the PV system. Utilities that do allow interconnections to networks (including New York City) typically require detailed studies and system designs that ensure the PV system does not export energy to the network. Exporting can be prevented by sizing the PV system so that it never produces more energy than the site can use, or by adding hardware that disconnects the PV system or ramps down production if the load drops below a preset threshold [2].

New York City recognizes the risks of connecting PV systems to networks, but believes PV offers important benefits as well. Demand has increased from 8,000 MW peak in 1980 to 14,000 MW peak in 2009, and PV-generated electricity can help meet this demand without the large capital costs associated with conventional power plants. Distributed PV systems also reduce distribution system requirements, because they are located at the load source. This is important in New York City, where space for the underground distribution system is limited, and upgrades are costly.

New York City has set a goal of installing 600 MW of renewables on their network by 2030 (there are currently 3 MW installed). They have enacted net metering legislation allowing residential systems up to 25 kW and commercial systems up to 2 MW to net meter. To further encourage and streamline the interconnection process, they are considering allowing smaller systems (up to 200 kW) to connect to their network[1] without detailed studies, and without devices to prevent exporting. While these systems may export electricity to the network, the utility expects that the PV generation will be so small compared to network loads that the electricity will be consumed by nearby loads, and will

[1] This applies to area networks only, not spot networks.

not backfeed through any network protectors. This may be a safe assumption at the current low levels of PV penetration. At higher levels of penetration, PV systems could generate enough electricity to backfeed through network protectors, reducing network reliability.

To assess PV generation at high penetration levels, and the effect it may have on the network, this study evaluates the technical potential of rooftop photovoltaics in two New York City network areas. PV generation is calculated assuming all suitable rooftop space is covered with PV systems. PV power generation is then compared to network loads to determine what portion of loads PV generation can meet and how this varies throughout the year. This comparison shows when and where PV generation approaches or exceeds network loads, and is most likely to disrupt network protection equipment. The results may assist the utility in evaluating future PV interconnection applications and in planning future network protection system upgrades. This study may also assist other utilities interconnecting PV systems to networks by defining a method for assessing the technical potential of PV in the network and its impact on network loads.

2. METHODOLOGY

To assess the technical potential of rooftop photovoltaics, the suitable rooftop area, or geographic potential, must first be calculated. The literature suggests two approaches for determining geographic potential. For large areas (countries or continents) where it is impractical to carry out detailed building-by-building studies, rough estimates can be calculated from statistical data including building footprints, building use, climate, building density, and population density [3-4]. For smaller areas, map-based data can be used to more accurately estimate geographic potential. Map-based methods vary in complexity, from simple extraction of building footprint areas [5-6] to more complicated tools that take into account shading due to roof slope and orientation or nearby structures [7].

For this study, Google Map satellite images were used to measure total rooftop space in two New York City network areas. The map-based method was chosen to give a more accurate estimate of geographic potential, and to allow evaluation of the effects of PV generation on specific utility networks. While a statistical data-based evaluation would have allowed analysis of a larger area, statistical building data corresponding to specific network areas were not available, so PV generation could not have been compared to loads at the network level.

The utility networks were chosen to represent different types of areas within the city. Network A is a ten square block (0.25 km^2) area of dense high-rise buildings in downtown Manhattan (see Fig. 1), and Network B is a 15 km^2 area of dense low-rise apartments and warehouses in Brooklyn (see Fig. 2).

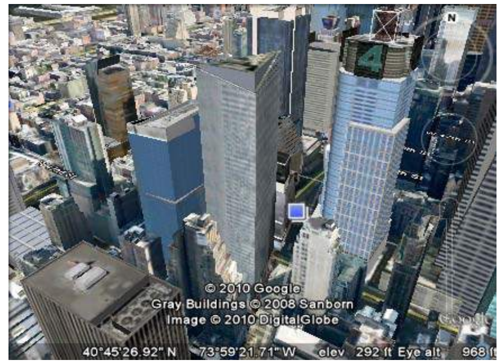

Fig. 1: High-Rise Buildings in Network A.

Fig. 2: Low-Rise Buildings Network B.

Satellite images were evaluated first to determine total rooftop area, and then to estimate the percentage of total rooftop space suitable for PV arrays. Based on the suitable area and a PV power density characteristic of today's mid-efficiency multicrystalline technology, the total potential capacity of rooftop PV was determined. Hourly PV production was calculated based on this capacity and site weather data, and then reduced to account for shading losses from nearby buildings and trees. Shading losses were estimated by modeling typical areas of each network.

2.1 Geographic Potential

To estimate geographic potential, the total rooftop space in each network was calculated, and reductions were applied to calculate suitable rooftop space.

2.1.1 Total Rooftop Area

The National Renewable Energy Laboratory's (NREL) In My Backyard (IMBY) tool [8] was used to measure total rooftop space in each network. IMBY uses a Google map-based interface and calculates the area of polygons drawn on the map (see Fig. 3).

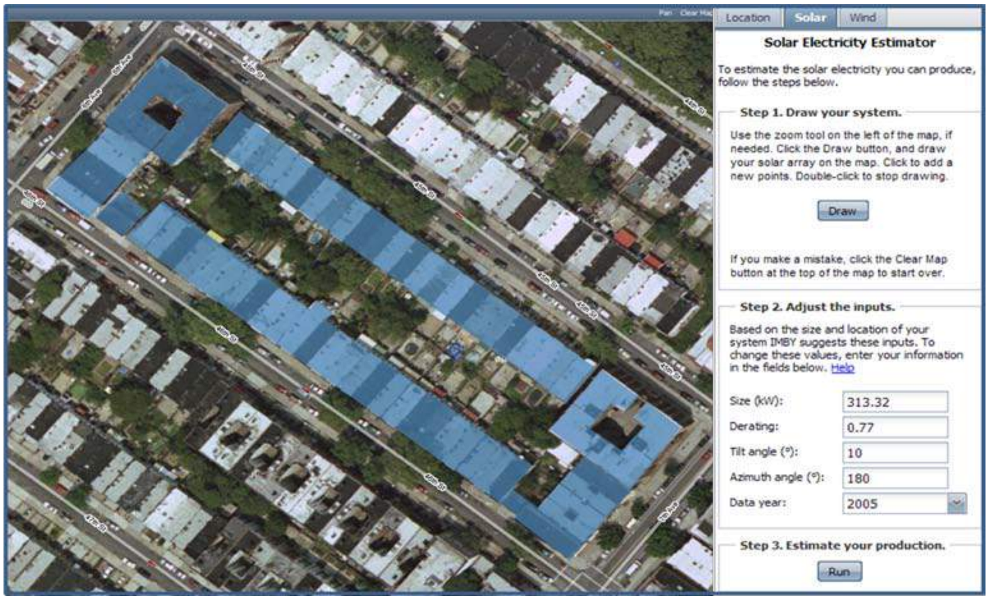

Fig. 3: Measuring Rooftop Area in IMBY. http://www.nrel.gov/eis/imby/, accessed August 26, 2009.

Total rooftop area was measured for each network. For the smaller Network A, IMBY was used to measure rooftop area for the entire network. For the larger network B, rooftop area was measured over a representative sample area (10% of the network), and then extrapolated to estimate total rooftop area in the entire network (see Table 1). While the extrapolation introduces some inaccuracy, the network is fairly homogenous, with similar building types and densities throughout, so this method provides a reasonable estimate of total rooftop area. The IMBY area calculation was validated by comparison to GIS shapefiles of the building footprints in each network. The IMBY estimate was within 3% of the GIS estimate in each network.

2.1.2 Total Suitable Roof Space

Rooftop space may be unavailable or unsuitable for PV arrays for a variety of reasons. To estimate the space suitable for PV arrays, reductions were applied to the total rooftop area to account for:

- **Occupied Space**: Roof areas occupied by HVAC installations, chimneys, vent stacks, antennae, etc. were considered unsuitable for PV arrays.
- **Shading by Rooftop Obstructions**: An average height of 1.25 meters was assumed for all obstructions, and a space equal to this height was avoided on the east, west, and north side of rooftop obstructions to minimize shading.
- **Access Space**: A 1.25-meter wide path around the rooftop perimeter was considered unsuitable for safety and access reasons. A 0.5-meter path was avoided on the south side of obstructions to allow for maintenance access.
- **Roof Orientation**: North-facing roofs are unsuitable because they do not receive adequate sunlight for PV arrays. Because roofs in these networks are flat, roof orientation does not restrict suitable space.
- **Structural Adequacy**: Because New York City roofs are designed for high wind and snow loads, this analysis assumes structural adequacy does not limit suitable space.
- **Historical Building Restrictions**: Because PV arrays on flat roofs are largely hidden, this analysis assumes historical building restrictions do not limit suitable space.

Reductions due to occupied space, shading by rooftop obstructions, and access space were estimated by analyzing satellite images of the roofspace in each network, using IMBY. Suitable space was divided by total roof space to calculate a percent suitability factor (see Table 1). The analysis was performed for all buildings in Network A. For the larger network B, space suitability was calculated based on a sample area of buildings. While suitability can vary significantly from building to building, network B is fairly uniform in building type, so the suitability calculated in the sample area provides a good estimate of suitability across the network.

TABLE 1: CALCULATION OF PV CAPACITY

Network	A	B
Total Rooftop Area (m^2)	147,000	4,549,000
Percent Suitable Space	12%	40%
Total Suitable Rooftop Space (m^2)	17,640	1,819,600
Total Rooftop PV Capacity (MW DC)	1.76	181.96

2.2 Technical Potential

To estimate technical potential, PV capacity was estimated from geographic potential and PV power density. Energy production was then predicted based on solar resource and shading losses.

2.2.1 Total Capacity of Rooftop PV

From the total rooftop space suitable in each network, the total PV capacity was estimated assuming a power density of 100 W DC/square meter (see Table 1). This value is based on the average module efficiency of the top technologies on the market and a packing factor that accounts for space for access between modules, wiring, and inverters [3].

2.2.2 Energy Production

Hourly AC energy production was modeled for a crystalline silicon PV system using IMBY's solar estimator. Calculations were based on a nominal 10kW DC system, and results were scaled up to correspond to the total cumulative size of all PV arrays in the network area. All PV arrays were assumed fixed with a 0° degree tilt angle. Most roof-mounted systems in New York City are mounted at angles of 0°-20° to minimize shading from adjacent panels and reduce wind loads on ballasted systems.

The solar estimator used 2005 Perez Satellite Solar Resource Data (satellite-derived, high-resolution data from visible channel images from geostationary satellites) for New York City and the PVWatts performance model [9] to calculate the solar radiation incident on the PV array and the PV cell temperature for each hour of the year. The DC energy for each hour was calculated from the PV system DC rating and the incident solar radiation, and then corrected for the PV cell temperature. The calculation assumed an installed nominal operating temperature of 45°C, and 0.5%/°C power degradation due to temperature. Angle-of-incidence (reflection) losses for a glass PV module cover were calculated as presented in [10]. The AC energy for each hour was calculated by multiplying the DC energy by the overall DC to AC derate factor and adjusting for inverter efficiency as a function of load. A DC-to-AC derate factor of 0.77 was used to account for losses from the components of the PV system, including: inverter and transformer; mismatch; diodes and connections; DC wiring; AC wiring; soiling; and system availability.

2.2.3 Shading Losses

Areas likely to be shaded by rooftop obstructions were avoided in the analysis of suitable roofspace. Shading losses from surrounding buildings and trees were estimated separately using PVsyst shading simulation software [11]. Several blocks of each network were modeled (see Figs. 4 and 5). PV systems were placed on the roofs, and shading obstacles (nearby buildings and trees) were added.

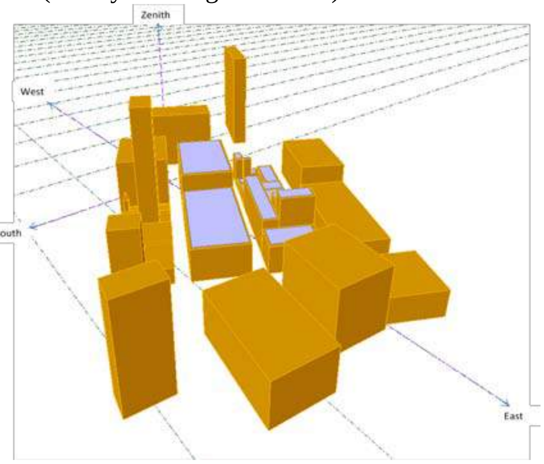

Fig. 4: Shading Model of Network A. Kate Anderson, NREL.

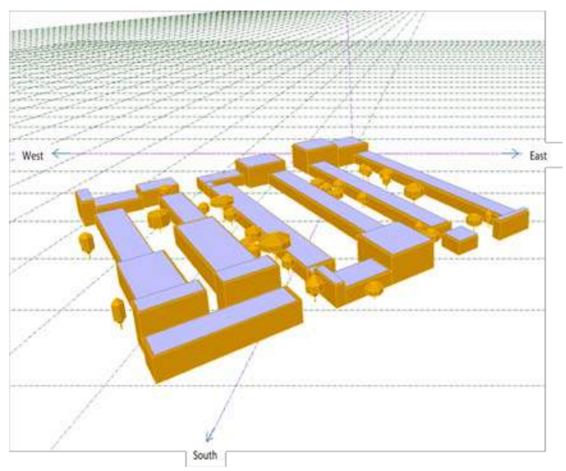

Fig. 5: Shading Model of Network B. Kate Anderson, NREL.

To account for the non-linear effect of partial shading on the electrical production of the PV arrays, the arrays were divided into strings of modules in series. As soon as a string is hit by a shadow, the entire string is considered electrically unproductive. While not a perfect model, this gives a good approximation of shading loss.

The total irradiance on the tilted plane represents the sum of the three components: beam, diffuse, and ground-reflect. To calculate the irradiance loss due to shading, the loss inherent to each component of the total irradiance must be determined. In this case, because the PV arrays have a 0° tilt angle, the ground-reflect component is zero. For the beam component of shading, PVsyst estimated a table of shading factors as a function of the sun's height and azimuth, and calculated an hourly beam shading factor by interpolation. For the diffuse irradiation component, PVsyst computed a constant shading factor. From these component shading factors, the irradiance loss is determined by multiplying each component of irradiance by the corresponding component shading factor. The irradiance loss caused by shading is then compared to irradiance on the unshaded plane to arrive at an overall hourly shading factor.

This method provides an accurate estimate for the modeled building geometry and shading obstacles. To apply these shading losses to the entire network, it must be assumed that the building geometry and shading obstacles are similar throughout the network. Because building and foliage heights and densities are fairly uniform, these models give a reasonable estimate. Variations in building geometry, however, can considerably affect shading losses, and modeling a larger area would improve the shading analysis.

3. DATA ANALYSIS

3.1 Effect of Shading

PV arrays in both networks experienced significant shading from surrounding buildings and trees. Shading losses were highest at the beginning and end of the day, when the sun was low in the sky. In network A, hourly module shading losses varied from 6% (noon on the summer solstice) to 95% near the end of a fall day when the sun was lower and nearby obstructions largely blocked solar access. Overall daily module losses varied from 14.4% on the summer solstice to 36.5% on the winter solstice. Fig. 6 shows hourly module losses for the summer and winter solstices.

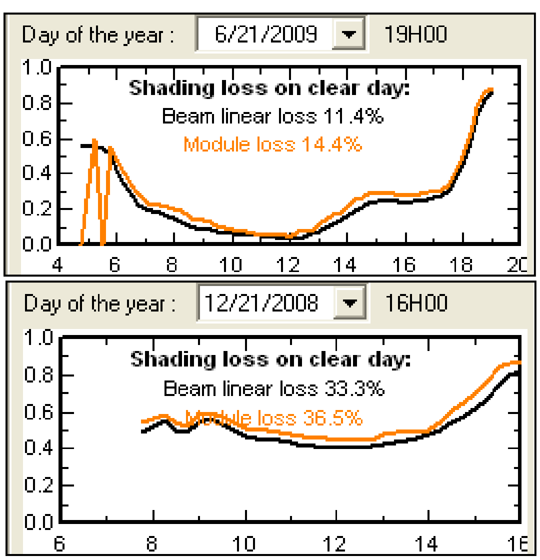

Fig. 6: Shading Losses in Network A on the Summer and Winter Solstice

In network B, where building heights are lower and more uniform, the majority of shading was caused by foliage. Shading losses were lower than in the high-rise network A, with hourly module shading losses between 4 to 54%. Overall daily module losses varied from 4.8 to 9.0%. Fig. 7 shows hourly module losses for the summer and winter solstices.

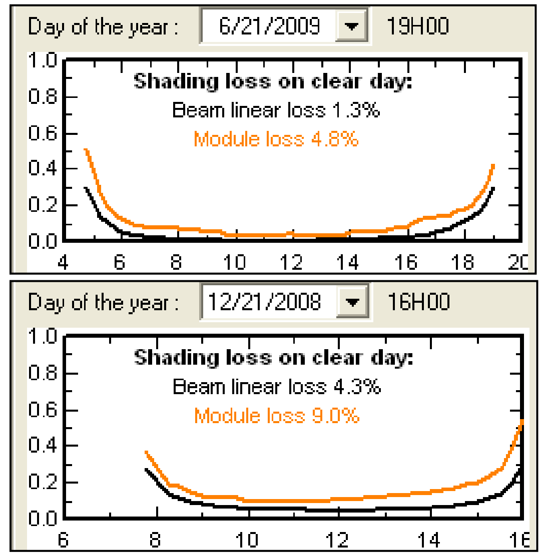

Fig. 7: Shading Losses in Network B on the Summer and Winter Solstice

In this study, shading from rooftop obstructions was accounted for separately in the analysis of suitable space. Assuming shading due to rooftop obstructions is responsible for about a third of the suitable space reduction (the remaining two thirds due to occupied space and access space), average total annual shading reductions are 54% for network A and 27% for network B. These values are comparable to estimates found in other studies of shading reductions over large areas. [12] estimates total shading reductions of 36% for buildings in high-density areas of Spain (including both shading from other buildings and shading from rooftop obstructions). [3] estimates shading reductions of 35% for flat roofs in the U.S.

3.2 Comparing PV Generation to Network Load

The hourly energy production estimated by IMBY's solar estimator was reduced by the hourly shading factors calculated in PVsyst. The predicted PV generation was then compared to network loads in each network. Figure 8 charts network load and PV power generation over the course of 2005 in network A.

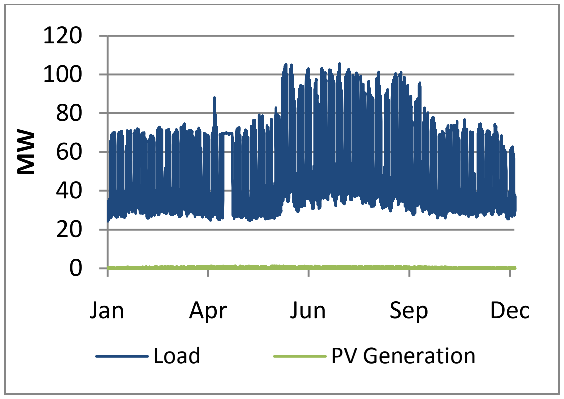

Fig. 8: Network A Load and PV Generation

From Figure 8, we see that PV generation in network A never approaches network load levels. The maximum percent of load provided by PV- generated energy during the year is 3.58% (occurring at noon on May 7). The combination of limited roofspace for PV arrays, high shading losses, and high loads make energy exporting unlikely, even if all suitable space is covered in PV arrays. Overall, PV arrays contribute only 0.42% of total network energy needs over the year and reduce required peak generating capacity by 2.8 MW (2.64%).

Results for network B, however, are very different.

Fig. 9 charts network load and PV power generation over the course of 2005 in network B.

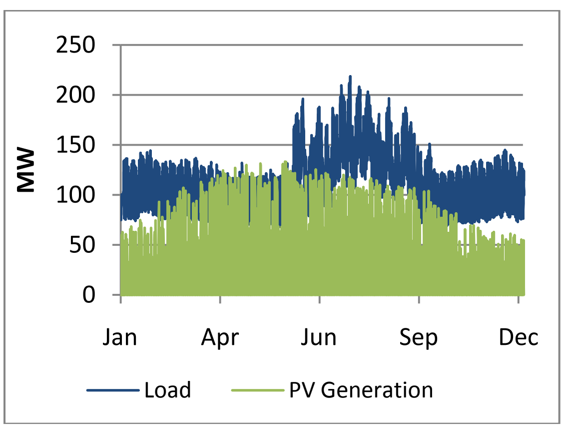

Fig. 9: Network B Load and PV Generation

Fig. 9 shows that PV generation surpasses network load levels occasionally. The maximum percent of load provided by PV generated energy is 136% (at noon on May 29).

Figure 10 provides a closer look at the highest exporting week during the year.

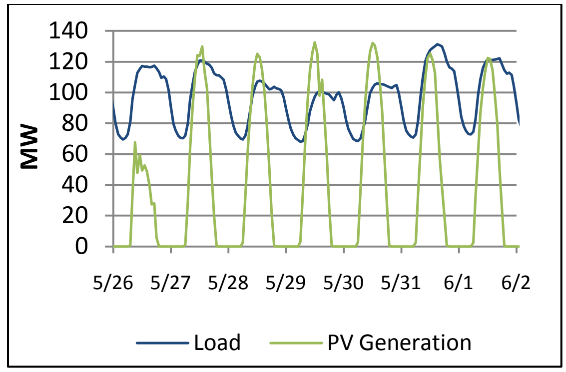

Fig. 10: Network B Load and PV Generation During Highest Exporting Week

There are 103 hours during the year when total PV generation surpasses total network load, resulting in a net export of energy from the network. During these hours, energy will backfeed through network protectors and cause them to open. Because PV generation and loads are unlikely to be evenly distributed across the network, some areas of the network will generate more energy than can be consumed in the immediate area, resulting in additional backfeed and network protector operation beyond the 103 hours shown here.

The most likely time of year for PV energy exporting is the spring, when PV generation is high and loads are low. In network B, almost all exporting occurred during April and May (see Fig. 11).

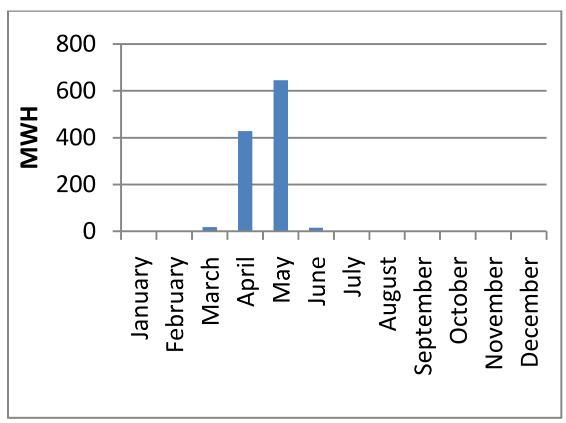

Fig. 11: Energy Exported by Month

The most common time of the week for energy to export to the grid is Saturday and Sunday, because loads drop on the weekends when businesses close (see Fig. 12).

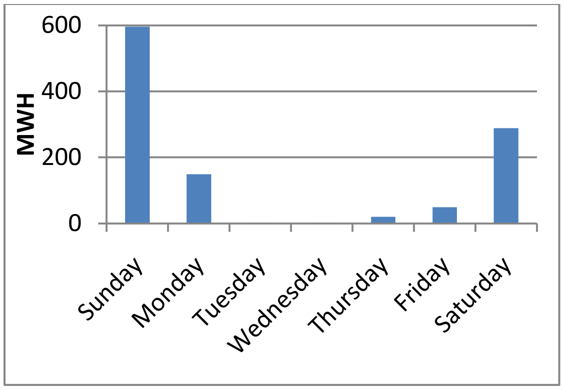

Fig. 12: Energy Exported by Day

Over the course of a day, exporting is most likely to occur between 10:00 a.m. and 2:00 p.m., peaking at noon. This is because PV generation is highest at mid-day, when the sun is directly overhead. The low mid-day load also contributes to high exporting (see Fig. 13).

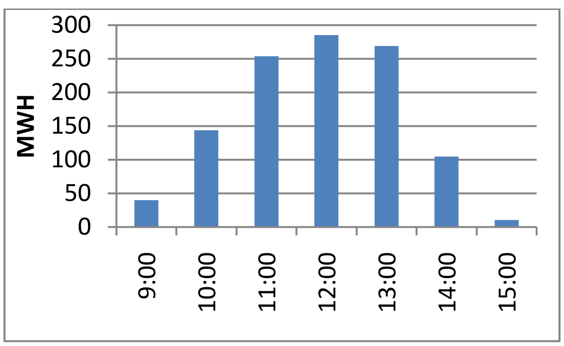

Fig. 13: Energy Exported by Time

Overall, PV arrays contribute 18.20% of total network B energy needs over the year. They reduce peak load by 12.4 MW (5.50%).

4. DISCUSSION

4.1 Likely Areas for Exporting Energy

The analysis suggests that in areas of dense high-rise buildings, as in network A, limited roofspace for PV arrays, high shading losses, and high loads make energy exporting unlikely, even if all suitable space is covered in PV arrays. Therefore, the utility can allow PV systems to interconnect to the network without detailed studies or devices to prevent exporting and feel confident that they will not experience backfeed through network protectors. Areas of dense low-rise buildings, however, need to be approached with more caution. Network B has the potential to accommodate a significant capacity of PV arrays. If all suitable roofspace was occupied by PV arrays, they would sometimes generate more energy than the network could use.

In general, the most likely areas to experience exporting are those with the highest amount of rooftop space per person. In areas of dense high-rise buildings, where many people live or work under one roof, space suitable for PV arrays is small, and the energy they produce will be small, compared to the load generated by all the people under that roof. In more residential areas, like the outer boroughs of New York City, people mainly live in single family homes, and office buildings tend to have only a few stories. There is a much larger amount of roof space per person, and therefore PV can generate a much higher percent of the minimum load.

This analysis was performed at the macro level, comparing total loads and total PV generation across entire networks. While this provides an estimate of net energy exported from the network as a whole, network protectors operate within the network, and will respond to more localized energy exporting. A more detailed understanding of energy exported at the individual building level is required to estimate how often network protectors would operate due to exporting PV energy. Exporting is most likely to occur when PV generation is high and loads are low. Probable sites are near single-story warehouses, schools, and offices on sunny weekends, when the unoccupied buildings would have low loads but high PV generation. Further analysis on PV generation and load by building type might help the utility identify likely exporting installations that should be studied more carefully before interconnection.

4.2 Solutions for Exporting Energy in Networks

While some networks will never experience problems with energy exporting, others are likely to export energy at high levels of PV deployment. This raises concerns for the utility, because this exported power can disrupt protection and coordination schemes essential to the reliable operation of the network. High deployment of distributed PV systems can also cause challenges for load forecasting and power system planning, increased potential for unintentional islands, and power quality problems like voltage flicker [1].

Currently, the best way to prevent disruption to networks from distributed PV systems is to ensure they do not export power to the network. This can be achieved by sizing systems so they never produce more power than is consumed at the site, or by adding hardware (reverse power relays, minimum import relays, dynamically controlled inverters, or energy storage) that prevents power from exporting. While preventing exporting allays most of the concerns associated with connecting PV systems to networks, it also imposes undesirable limits on PV system size and power generation for a city planning to increase PV capacity. In order to connect PV systems that export power, the utility needs to understand how that system may impact network operations. Currently, the utility must perform detailed load flow studies of installations that can export energy, which is time-consuming and costly. In order to move away from case-by-case evaluations and streamline the interconnection process, research in the following areas is suggested:

- **Identify system level impacts of high PV penetration in networks**: While the effects of individual PV system connections to networks are well addressed, little is known about how the whole system is affected at high penetrations of PV.
- **Identify maximum penetration levels in network systems**: PV penetration levels of 20-30% are considered to be the maximum level allowable in radial distribution systems. It is unclear, however, what the maximum allowable penetration level is on a network system.
- **Improve modeling of distributed generation in network systems**: Current modeling solutions do not adequately address the system impacts of distributed generation in network systems.
- **Develop smart grid technologies**: Future smart grid technologies may offer intelligent monitoring and control of PV systems that will allow better integration into network systems.

5. CONCLUSIONS

New York City has tremendous technical potential for rooftop PV systems. PV can help New York meet increasing energy demands with cleaner energy and potentially lower infrastructure costs than conventional generation. It presents challenges, however, because it has the potential to export energy onto the distribution network and disrupt network protection schemes. The results of this analysis can help New York in planning for greater deployment of rooftop PV systems by identifying areas where PV generation can exceed network load, and by showing when exporting of electricity is most likely to occur. This may assist the utility in evaluating future PV interconnection applications, and in planning future network protection system upgrades. This study may also assist other utilities interconnecting PV systems to networks by defining a method for assessing the technical potential of PV in the network and its impact on network loads.

6. ACKNOWLEDGEMENTS

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