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Strategies for correlating solar PV array production with electricity demand

David B. Richardson*, L.D.D. Harvey

Department of Geography, University of Toronto, 100 St. George Street, Toronto, Ontario M5S 3G3, Canada

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ABSTRACT

One of the main advantages of solar photovoltaic (PV) energy is its availability during periods of high electricity demand, namely hot, sunny days. Unfortunately, the daily energy peak of a south-facing solar panel, oriented to maximize energy production, rarely coincides with the actual peak in electricity demand, which is usually in the late afternoon or evening. Using the Province of Ontario, Canada, as a case study, this paper evaluates three strategies for improving the correlation between PV energy production and electricity demand: optimally orienting PV modules, combining geographically dispersed arrays, and using a simple energy storage system. The strategies are compared based on their ability to improve the supply-demand correlation, their relative cost of energy, and the capacity credit of each strategy. We find that optimally orienting multiple modules in an array offers little potential to improve correlation, while the cost of energy increases between 30 and 40%. Geographically dispersed PV arrays and energy storage offer a better approach to improving the correlation between PV production and electricity demand.

1. Introduction

Solar photovoltaic (PV) energy is projected to be an important component of future sustainable energy systems. As module prices continue to fall, the cost of electricity from solar PV is getting closer to parity with grid electricity in countries around the world [1]. It is expected that grid parity will lead to the widespread adoption of solar PV, especially on rooftops and buildings in urban areas where solar PV electricity could directly reduce consumer's energy bills. The potential benefits of distributed PV include reduced transmission losses, an ability to match peak load, a reduction in distribution network investments, a reduction in the need for additional generation capacity, and reduced environmental impacts [12].

The ability of solar PV to act as a peaking electricity supply (or as a peak-shaving distributed load) has received substantial attention in recent years. Assessments of the peak-matching ability of solar PV have been conducted for a number of US utilities [21,22], and in Italy [12], Minnesota [34], Guelph and Calgary in Canada (2005) [27]; Helsinki and Lisbon [19], Toronto [20], Sweden [37] and Pennsylvania [3].

Methods to quantify the peak matching ability of solar PV vary depending on whether the magnitude of the system load and the PV penetration are considered. For systems with a non-negligible penetration of PV panels, the electricity from PV will affect the power output of the rest of the system; therefore, the capacity value (or capacity credit) of the PV system is generally considered (see Ref. [14] for an overview of PV capacity value calculation methods). For single PV modules or arrays, the overall contribution to an electric grid is negligible; thus, the main consideration is the extent to which PV production coincides with periods of peak demand. The Pearson correlation coefficient is a commonly used statistic for comparing the load-matching ability of a single module or array [16,27,34].

The ability of solar PV production to match electricity demand depends on a location's solar resource and its daily electricity demand profile. Jurisdictions in high latitudes with high winter electricity demand for heating will not have as good a match between supply and demand as an equatorial region with mid-day energy peaks driven by air-conditioning. Ref. [27] calculated the correlation between global horizontal irradiance and system electricity demand for Guelph, a mid-sized city in the Province of Ontario, Canada. Using hourly data for the summer months of 2002 and 2003, the correlation between irradiance and demand was found to be 0.272, which is significant at the $p = 0.01$ level (Lower values of p indicate it is less likely that a correlation coefficient will

* Corresponding author. Tel.: +1 647 457 1121.
E-mail address: dave.richardson@mail.utoronto.ca (D.B. Richardson).

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occur given no relationship in the population). It should be noted that correlations with an absolute value less than 0.3 are generally considered weak, so Rowland's finding does not indicate a strong match between solar radiation and energy demand at this one site in Ontario.

A number of strategies have been proposed to increase the correlation between PV supply and electricity demand. Strategies include the use of energy storage, load shifting, and optimization of PV array location and orientation [5,37]. Energy storage combined with a PV system can provide a better match between supply and demand by storing excess production for use when demand exceeds supply. Load shifting uses demand management strategies and technologies to shift electricity demand to periods of high PV energy availability. The basic idea behind using PV panel orientation to match demand is demonstrated in Fig. 1, which shows normalized Ontario peak demand (demand above minimum baseload) and the normalized ideal clear sky solar radiation for both a south and west facing surface, with a 20.5° and 60° tilt angle respectively, in Toronto, Ontario on June 21, 2012. The figure demonstrates how shifting panel orientation to the west can shift the peak in solar energy closer to the peak in demand. Studies to date have only considered a single module or building orientation; a PV system with many different array orientations has not been evaluated.

No study to date evaluates the correlation between PV output and electricity demand for a PV system that is explicitly designed to match load. Existing studies use either measured PV output, which wasn't optimized for peak load, or modeled PV output for flat or south-facing arrays. Ref. [3] investigate different panel azimuths, but consider only due south or east-west orientations, and compare PV output to electricity price, not load. Ref. [30] determine the optimum azimuth to meet a small domestic load, but do not consider optimal tilt angle or larger grid load profiles.

This paper address a key knowledge gap by assessing the ability of a power system planner to strategically deploy PV panels at various orientations within a geographic region to increase the load matching capability of solar PV. The hypothesis is that an optimal combination of PV modules with different tilt and azimuth angles has the potential to significantly increase the correlation between PV output and electricity demand. Three strategies are investigated: first, optimally orienting PV modules in an array; second, combining geographically dispersed arrays, and finally, employing a simple energy storage system. Each of the strategies is assessed on its ability to increase the correlation between PV energy output and electricity demand, as well as based on the resulting cost of energy and capacity credit. The investigation is conducted using hourly PV production and electricity demand data for the Province of Ontario, Canada. The results and findings of the study give insight into if and how power system planners should consider the orientation and deployment of PV modules in electricity grids as the price of PV modules falls and solar PV becomes more widespread.

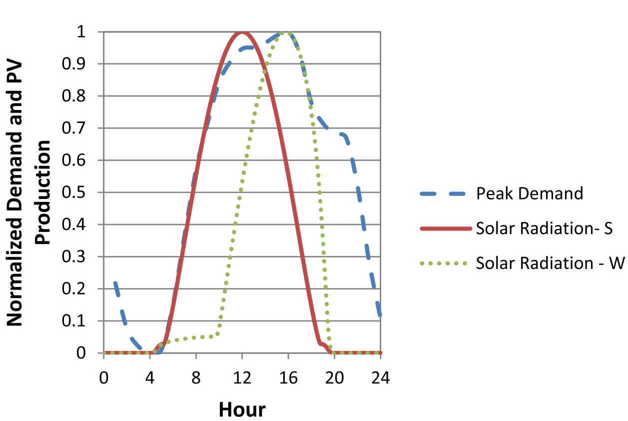

Fig. 1. Normalized Ontario peak electricity demand and normalized clear sky solar radiation for a south and west facing surface in Toronto on June 21st, 2012. Electricity data source: [15].

2. Methods

2.1. Solar PV energy modeling

Solar PV output is modeled on an hourly time-scale, matching the hourly resolution of provincial electricity demand data. Hourly global horizontal irradiance (GHI), wind speed, and temperature data from the Modern-Era Retrospective Analysis for Research and Applications (MERRA) dataset are used to model PV production [26]. Ref. [24] have shown that the MERRA data are suitable inputs for hourly modeling of solar PV production. Energy production is modeled for the Eclipsall Energy Corp. NRG60 245M photovoltaic module [8].

PV electricity production is calculated using the best combination of solar radiation and solar PV models for Ontario, based on the results of a field study assessing models at two sites in Ontario [23]. GHI is split into its direct and diffuse components using the BRL model [25]. Radiation on a tilted surface is calculated using the Skartveit-Olseth model [32]. Reflection losses are modeled using the Sandia model [17]; the coefficients used in the reflection loss model are those suggested by Ref. [4] for mono-crystalline silicon modules. The PV cell temperature is calculated using the Faiman [9] model and module energy output is calculated using a 3 parameter ideal diode model, described by [7]. A constant derate factor of 0.85 is applied.

2.2. Correlation strategies

Three basic strategies for improving the correlation between solar PV energy output and energy demand are investigated.

2.2.1. Strategy #1 – optimal orientation

The first strategy aims to improve the correlation between output and demand by selecting an optimal combination of module orientations in a multi-module array at one site. Two basic approaches are applied for this strategy. The first approach is to optimally orient each individual module in an array. The tilt angle for each module can be between 0° (horizontal) and 90° (vertical); the azimuth angle can be between −90° (due east) and 90° (due west). The individual modules are allowed any orientation within those ranges that best correlates the combined output of the array with demand. This approach is used for arrays of one, two, three, four, five, and eight modules.

For larger arrays, varying the orientation of each individual module requires significant computational effort. To correlate the output of larger arrays with electricity demand, many pre-set orientations are considered; the pre-set orientations cover the full sky view. A fixed number (1000) of units of 1 kW_p capacity are optimally allocated among the pre-set orientations in order to best correlate PV supply with demand.

A single site in Ontario, Toronto, is considered for this strategy. It is possible that a better correlation could be achieved using the same strategy at a different site; however, the goal here is to investigate the potential for improving correlation using the strategy as opposed to finding the best combination of site and panel orientation.

2.2.2. Strategy #2 — dispersed sites

The second strategy is to take advantage of geographically dispersed sites to improve the correlation between PV energy supply and electricity demand. The 35 largest urban areas in the Province of Ontario are considered for this strategy; the site locations are shown in Fig. 2.

As in the analysis for large arrays in Section 2.2.1, 1000 PV units are optimally distributed among the 35 sites in order to best correlate PV supply with electricity demand. The analysis is conducted using two different arrays at each site. The first array consists of south-facing panels tilted at the latitude of each site; the second array is the optimal mix of module orientations determined for Toronto through the analysis of Section 2.2.1. We recognize that an optimal mix could be determined for each site, but this process would take significant computational time with little expected net benefit.

2.2.3. Strategy #3 — energy storage

The final strategy for correlating PV supply with energy demand is to combine a PV module, oriented for maximum yearly energy production with an energy storage system. For this study, energy storage is modeled on a generic battery technology using parameter values cited in a recent review of storage technologies [6]. A round trip energy efficiency of 81% is assumed, with equal losses for charging and discharging. The battery system is assumed to have a daily self-discharge rate of 0.2%. The power of the storage system is assumed to be equal to the power of the PV module. The analysis is run repeatedly for different energy storage capacities, which increase as hourly multiples of peak system power. For example, if the system capacity is 1 kW, analysis is conducted for storage capacities of 1 kWh, 2 kWh, 3 kWh, and so on.

A number of charge/discharge strategies were considered for use in the analysis; the strategy that was ultimately selected is likely to be one that would be used in a real energy system. The storage strategy begins at 6 am; before that, there is no solar energy available and low nighttime electricity demand can be easily met by existing grid resources. At 6 am, the maximum demand above the minimum system baseload and the total PV production for the rest of the day are determined; this assumes perfect knowledge of the future, which is not unreasonable given the accuracy of daily electricity and solar irradiance forecasts. Beginning at 6 am in hourly intervals, the system allocates the daily PV energy production to the hourly demand above the baseload demand such that a constant fraction of demand above baseload during each hour is met by PV, if available. If the fraction of PV production is less than the hourly demand fraction, energy is discharged from the battery if it is available. If the hourly PV production fraction is greater than the demand fraction, the extra PV supply is put into storage for later use. Note that this strategy is designed for fluctuations in demand and supply at an hourly resolution or longer; in reality, higher resolution fluctuations (seconds, minutes) would require alternative storage methods and strategies, such as flywheels. The analysis for this strategy is performed using input data for Toronto, as in Section 2.2.1.

2.3. Analysis

Improvements in correlation are measured relative to a base-case scenario, which involves a single module oriented to maximize annual energy production. The correlation between energy supply and energy demand for sun-tracking PV modules, as well as the actual coal, natural gas, and combined fossil fuel power plant production in Ontario, are calculated as well for comparison. Power plant production data are obtained from the Independent Electricity System Operator. Analysis is performed using hourly data from 00:00 January 1, 2011 to 18:00 December 31, 2012. In each case, the correlation is calculated for all hours in each year as well as for the hours in the summer months (April to September).

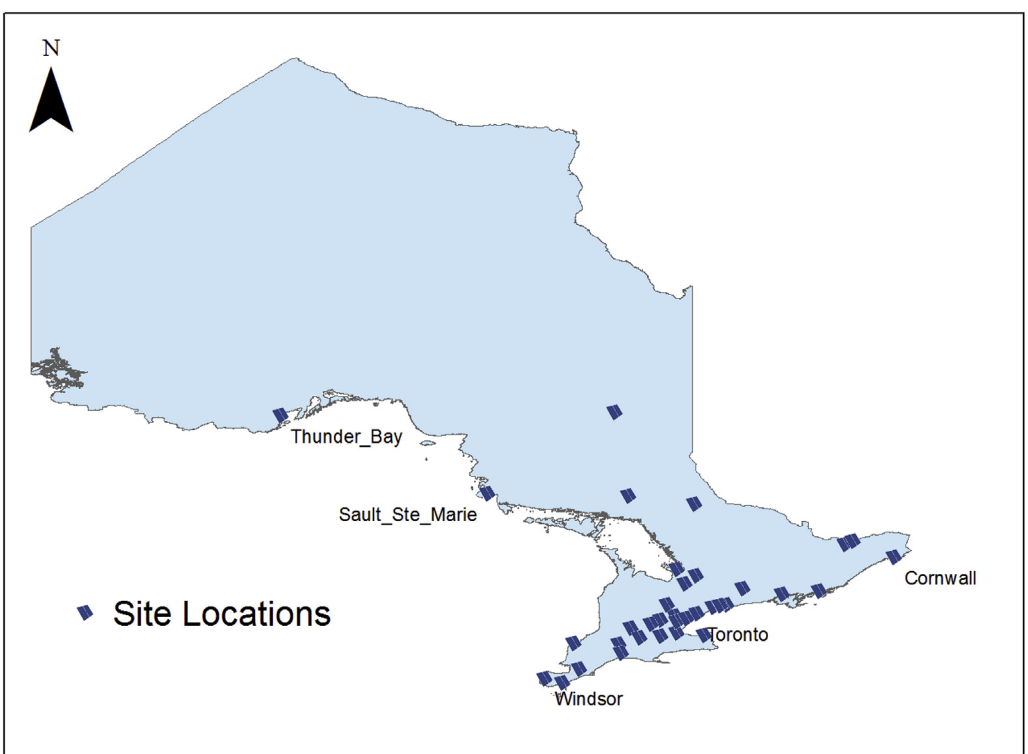

Fig. 2. Modeled site locations.

The model optimizes the system by varying the orientation or distribution of PV modules among using a Nelder-Mead simplex algorithm [38]. This algorithm is found to converge on a solution faster than many other more complex optimization approaches. The analysis is run for a range of initial conditions with convergence on the final optimal results.

For each strategy, the levelized cost of energy, relative to the base case, is calculated in order to give an indication of the extra associated costs arising from the different system configurations. The levelized cost of PV electricity (*LCOE*) for each resource is calculated on a per kWh basis as,

$$\mathrm{LCOE} = \frac{\mathrm{CRF} \times C_{\mathrm{cap}} + \mathrm{OM}_{\mathrm{fixed}}}{8760\mathrm{CF}} + \mathrm{OM}_{\mathrm{variable}}, \tag{1}$$

where CRF is the cost recovery factor based on a 5% interest rate and 25 year project life (15 years for storage [6]), C_{cap} is the capital cost (\$/kW), and CF is the capacity factor. Operation and maintenance (O&M) costs are subdivided into fixed costs, $\mathrm{OM}_{\mathrm{fixed}}$ (\$/kW/year) and variable costs, $\mathrm{OM}_{\mathrm{variable}}$ (\$/kWh. The capital cost for solar is assumed to be \$2500/kW [31], which is the average installed cost for a commercial-scale PV system in the U.S as of Q1, 2014. The most recent available Canadian data are for 2012, when large grid-connected systems cost between \$2800–4000/kW [18]. With further cost reductions over the coming years, \$2500/kW installed costs should soon be available in Canada. The fixed O&M cost is assumed to be 1.5% of the capital cost, with no variable O&M or fuel costs [13]. For the storage system, a cost of \$500/kWh is assumed, based on the mid-range value for batteries in [6]; with a fixed O&M cost of 2% of the capital cost, based on [36]. The storage costs are added to the solar costs for the applicable scenarios.

The solar PV capacity credit is calculated for each strategy. The capacity credit of a generator indicates the amount of dispatchable generation that can be replaced by that generating unit. Previous work has found that the capacity credit of solar PV in Toronto, Ontario is around 40% of installed PV capacity at low grid penetrations [20]; this means that for every MW of installed solar PV, 0.4 MW of dispatchable generation can be retired. Following the recommendations of [14]; a modified version of the Garver approximation [11] is used to determine capacity credit (*CC*), namely,

$$CC = m \ln\left[\frac{\sum_i \{\exp(-(L_P - l_i)/m\}}{\sum_i \{\exp(-(L_P - l_i + x_i)/m\}}\right] \Big/ X, \tag{2}$$

where L_P is peak load, m is the Garver coefficient set to equal $0.03L_P$, l_i is the load at hour i, X is the capacity of the new generator, and x_i is the output or availability of the new generator at hour i.

3. Results and discussion

Correlations of PV output with provincial electricity demand for the output-maximizing base-case module, tracking PV modules, and fossil fuel generators are presented in Table 1. The relative cost, compared to the base case, for sun-tracking PV systems is given, using a capital cost increase of 15% for single axis trackers [10] and 20% for two-axis trackers [2]. Two single axis tracking systems are considered: a module rotated about a horizontal east-west axis (EW tracker) and a module rotated about a horizontal north–south axis (NS tracker). Sun-tracking PV modules generally have a greater output than the base case but the extra cost of the tracking systems increases the *LCOE* for the single-axis trackers. For the two-axis tracker, the increase in output outweighs the extra costs, resulting in lower energy cost. All of the tracking systems have a fairly similar correlation between output and electricity demand, because PV trackers have the same basic output profile as a south facing PV module. The correlation between demand and power plant production is quite high, especially for natural gas and the combined fossil fuel output. This is no surprise, as these resources are dispatchable and generally reserved as peaking facilities, so fossil fuel generation would naturally follow demand. There is a large disparity between the correlations of the PV modules and fossil fuel generators with demand. The results in the following sections indicate the extent to which the different proposed strategies can close that gap.

Table 1
Relative cost of electricity for various PV cases, & correlation between supply and demand for solar cases and for fossil fuel generation.

	Relative cost	Correlation of output with demand	
		All hours	Summer hours
Base case	1.000	0.316	0.408
EW tracker	1.219	0.310	0.407
NS tracker	1.135	0.309	0.411
Two axis tracker	0.987	0.310	0.402
Fossil fuel generators			
Natural gas		0.853	0.889
Coal		0.691	0.753
Combined fossil fuel		0.881	0.915

3.1. Optimal array orientation

Fig. 3 presents the improvement on the base-case correlation when varying numbers of PV arrays are optimally oriented. Fig. 3(a) shows the correlation, for both all hours and summer hours, by the number of modules in the array. Fig. 3(b) shows the correlation by the relative cost of energy production as compared to the base case. Fig. 3(c) shows the correlation compared to the capacity factor of the arrays. Note that in Fig. 3(b) and (c), the summer hours and all hours data points do not line up along the *x*-axes because the summer and all hours conditions were optimized independently, leading to different sets of costs and capacity factors. This is because the optimal orientations for a given set of modules are different for the all-hours and summer-hours cases. The orientations of the panels in the optimally oriented arrays are presented in Table 2. The base-case scenario is angled slightly east and tilted below latitude; this is consistent with the findings of [28] for Toronto (2011).

The results in Fig. 3 indicate that there is a limited ability to increase the correlation between PV production and electricity demand by optimally orienting arrays of up to eight modules. With eight optimally oriented modules, the correlation increases from 0.316 (0.408 for summer hours) for the base case to 0.341 (0.458 for summer hours). The roughly 10% increase in correlation (relative to the base case) is accompanied by an electricity cost increase of over 30% (almost 40% for optimal summer hours correlation). The cost increase is a result of panels increasingly being oriented away from due south, which tends to decrease energy production. In fact, modules quite often face due west, especially for the summer hours optimizations, to take advantage of the late afternoon sunshine that better matches the peak in demand. Many of these west-facing modules are close to horizontal with very small tilt angles, meaning they receive some direct solar irradiance well before noon.

As noted in Section 2.2.1, optimizing arrays with more than eight modules is computationally intensive. To investigate the potential for optimizing arrays with many more modules than eight, a different approach is employed. The hourly output for many modules, with orientations covering the full range of potential positions, was calculated; 1000 PV units were then optimally distributed among the potential orientations. Table 3 shows the orientation and relative distribution of these 1000 units, optimally

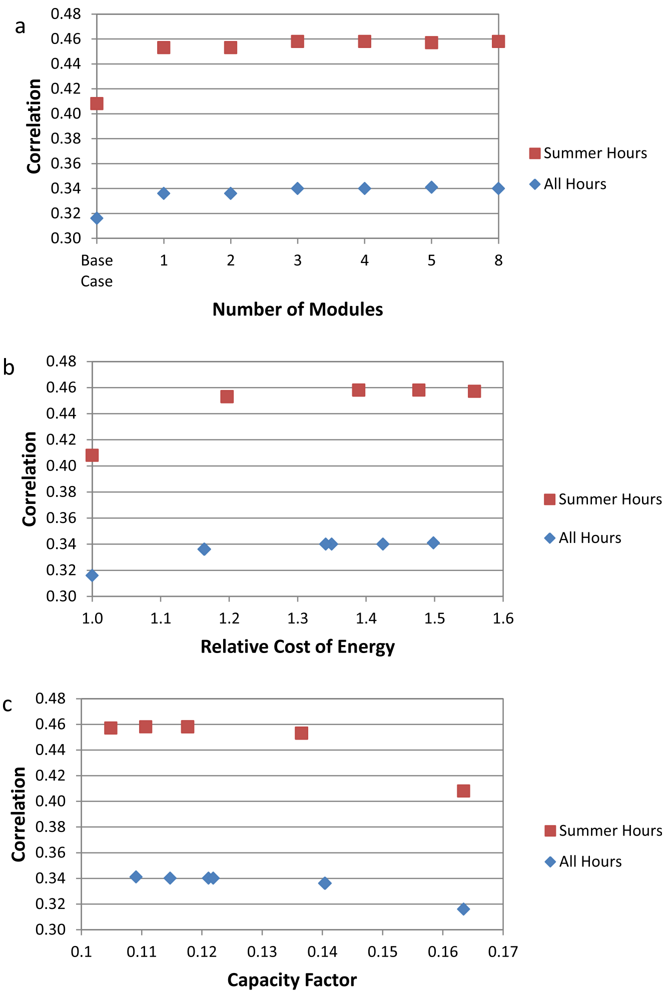

Fig. 3. Correlation versus (a) the number of modules in an optimally oriented array, (b) the relative cost of energy for an optimally oriented array, and (c) the capacity factor for the arrays.

Table 2
Optimal orientations for multi-module arrays.

Number of modules	All hours		Summer hours	
	Tilt	Azimuth	Tilt	Azimuth
Base case	29.47	−4.11		
1	11.05	81.98	13.38	90
2	6.56	49.54	11.12	90
	17.14	90	15.52	90
3	3.83	3.61	4.1	90
	5.19	38.9	4.1	90
	90	90	90	90
4	5.61	42.59	6.63	90
	5.67	41.3	6.63	90
	6.59	90	6.7	90
	90	90	90	90
5	12.47	90	1.41	90
	13.77	90	1.41	90
	13.85	90	1.51	90
	79.09	90	90	90
	90	−61.15	90	90
8	4.89	11.49	6.63	90
	5.96	59.2	6.63	90
	5.97	59.04	6.63	90
	6.03	58.48	6.63	90
	6.12	56.78	6.7	90
	6.16	57.96	6.7	90
	90	90	90	90
	90	90	90	90

Table 3
Orientation and relative distribution for an optimally oriented array of 1000 units of capacity.

All hours			Summer hours		
Tilt	Azimuth	Distribution	Tilt	Azimuth	Distribution
90	−60	0.157	90	−90	0.005
10	90	0.592	5	90	0.690
90	90	0.251	90	90	0.305

oriented to correlate output with either electricity demand for all hours or for just the summer hours. The optimization analysis considered many more orientations than those presented in Table 3; only those orientations which are included in the optimal distribution are displayed. The optimization algorithm allotted different installed capacities of PV to the different pre-set orientations in order to determine the combination that resulted in the highest correlation. The correlation between the output of the large arrays and electricity demand is 0.341 for all hours and 0.459 for summer hours, with relative costs of energy of 1.54 and 1.45 respectively. This indicates that there is no substantial opportunity to improve the correlation between PV supply and electricity demand by using more than eight optimally-oriented panels at a single site.

Determining the capacity credit of a resource, using the Garver approximation shown in Equation (2), requires knowledge of the installed capacity of that grid resource. As such, we cannot determine one capacity credit for each optimal array; rather, we can investigate the capacity credit for an array at differing grid penetration levels. Fig. 4 shows the effect of grid penetration, here defined as the ratio of installed solar PV capacity to peak demand, on the capacity credit of each of the optimal arrays for all hours of the year. There is an increase in capacity credit over the base-case situation for optimally oriented arrays of one and two modules, but the addition of more modules tends to decrease the capacity credit. As seen in Table 3, beyond two-optimally oriented modules there tends to be modules tilted vertically, aiming due west. This orientation provides excellent correlation with electricity demand, but it decreases the annual output and hence the capacity factor of the module, which in turn decreases the capacity credit of the array.

3.2. Dispersed sites

For the second strategy, PV panels are distributed across 35 urban centers in the Province. The analysis is performed for a south-facing panel, tilted at latitude, and for the two optimally

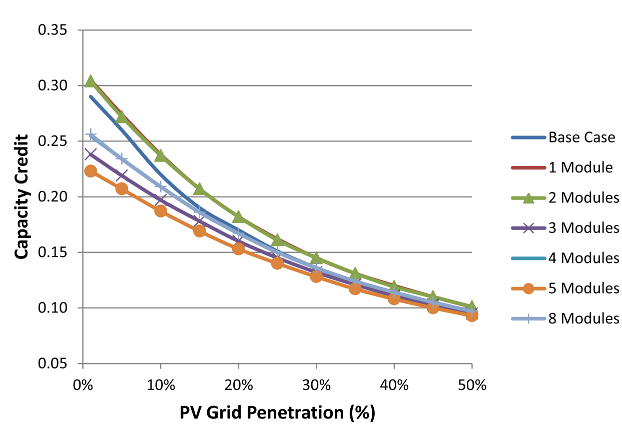

Fig. 4. Effect of solar PV grid penetration on capacity credit for optimal array combinations.

distributed orientations shown in Table 3. The allotted distribution by site for the geographic analysis is presented in Table 4. Many sites that are shown in Fig. 2 are not shown in Table 4; in the optimization analysis, no PV panels were distributed to the sites that are in Fig. 2 but not Table 4. The correlation for the south-facing, latitude-tilted dispersed sites is 0.342 for all hours and 0.433 for summer hours (compared to 0.316 and 0.408 for the base case), with relative costs of energy of 1.07 and 1.05, respectively. The correlation for the optimally oriented dispersed arrays is 0.373 for all hours and 0.503 for summer hours, with relative costs of energy of 1.6 and 1.51, respectively.

Distributing PV panels across geographically dispersed sites has a greater potential for increasing the correlation between PV supply and electricity demand than the first strategy, optimally orienting an array at a single site. Use of dispersed sites reduces the hourly variability of PV output through aggregation and allows for a longer period of production by spreading the sites out in the East-West direction. The large percentage of PV panels at the Thunder Bay site for all modeled scenarios is evidence of the benefit of geographic dispersion.

Thunder Bay is the western-most site modeled, almost 15° longitude west of Cornwall and roughly 10° longitude west of much of the Province's population. Thunder Bay's western position means it is roughly 60 min behind Cornwall and 40 min behind much of the Province in solar production, allowing for PV output that more closely coincides with the afternoon demand peaks produced in the load centers in the eastern part of the Province. The western location of Sault Ste. Marie (10° west of Cornwall) and Windsor (9° west) likely explain the importance of these two sites in Table 4. Fig. 5 demonstrates the temporal distribution of PV production that results from geographic dispersion by plotting the modeled PV power for south-facing latitude tilted PV modules in Cornwall, Thunder Bay, and Toronto for 29 June, 2012.

3.3. *Energy storage*

Correlation with demand for a combined PV/energy storage system, using a simple charge/discharge strategy, is shown in Fig. 6. As the size of the storage system increases, the cost of energy increases due to higher capital costs. The correlation between system output and electricity demand also increases, though it begins to plateau after the ratio of energy storage to system power reaches 4 Wh/W. Beyond a ratio of 4 Wh/W, increasing the amount of energy storage in the system provides negligible value, as there will rarely be enough PV production to warrant 4 Wh/W of PV capacity. To use 4 Wh of storage, a 1 W system would have to produce at full capacity for four hours (or for a longer duration at partial capacity), with all energy production going to storage. Four hours of maximum production is not likely (except potentially for a tracking system on a clear summer day), and it is very likely that some PV production will always be required by the grid. There could also be periods during which a substantial amount of energy is not needed during the day and stored overnight for use the next day, but this does not occur often.

The combined storage-PV system modeled here achieves significantly higher correlations than the previous strategies, up to 0.566 for all-hours and 0.649 for summer-hours. On a completely sunny day, the combined PV-storage system can achieve a very good match between energy output and electricity demand, with correlations as high as 0.98 for a single day. The PV-storage system cannot overcome the lack of irradiance on cloudy days, or winter

Table 4
Relative distribution of panels by site, for the cases of either all south-facing or an optimally oriented mix of panels at each site.

Site	All hours		Summer hours	
	South facing	Optimal mix	South facing	Optimal mix
Barrie		0.057		
Chatham	0.138	0.000		
Cornwall	0.170	0.160	0.039	0.124
Kingston	0.002			
Leamington		0.004		0.002
Midland			0.156	0.118
North Bay	0.043		0.022	0.044
Orillia	0.032			
Sault Ste. Marie	0.028		0.095	0.063
Sudbury	0.106	0.151	0.055	0.144
Thunder Bay	0.479	0.529	0.466	0.499
Windsor	0.002	0.099	0.167	0.006

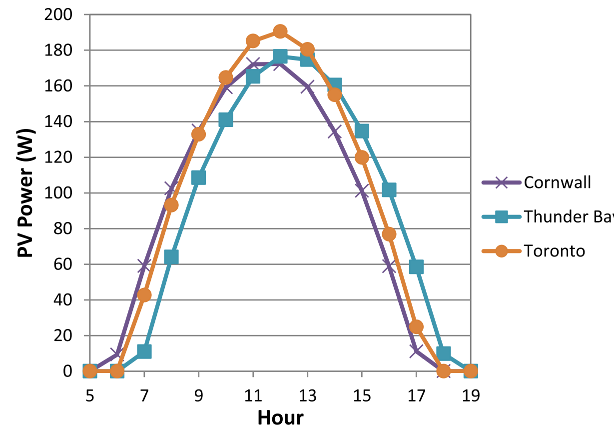

Fig. 5. Modeled PV production for south-facing, latitude tilted modules in different cities on 29 June, 2012.

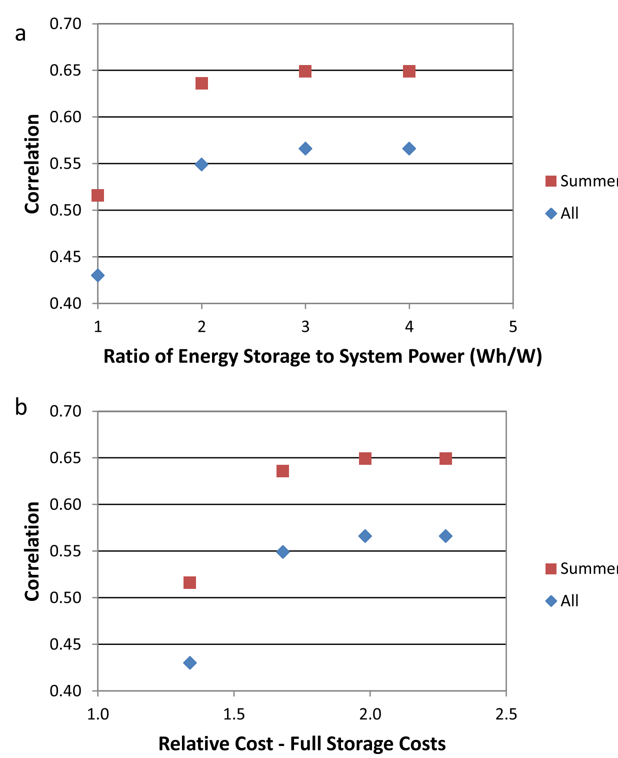

Fig. 6. Combined PV-energy storage results, (a) correlation between yearly electricity demand and PV-storage supply versus ratio of energy storage to system power, (b) correlation versus relative cost of energy compared to a south-facing panel tilted at latitude.

days with very little sunshine; as such, the correlations for this approach are still well below those of the fossil fuel generators used in the Province. While the addition of storage offers potential to better correlate output with demand, this approach is still limited by the fundamental limits of the available solar resource.

3.4. Summary and comparison

Combined scatter plots of correlation versus relative cost of energy for all strategies are shown in Fig. 7. It is clear from Fig. 7 that using geographically dispersed sites or energy storage is a more effective method to increase the correlation between PV energy supply and system electricity demand than altering the orientation of PV modules. Using a range of optimally oriented panels in a PV array produces a very small increase in correlation but relatively high cost of energy.

Both the energy storage strategy and the dispersed-sites strategy produce correlations over 0.5 for the summer hours, which is considered to be a high correlation. Fig. 8 provides a visual explanation for the limit on correlation between PV supply and demand, as compared to fossil fuel generation. Fig. 8 depicts the hourly demand and PV energy production for a cloudy, low-correlation day (3 December, 2011), with the hourly load profiles shown for the base-case, multiple-modules strategy, dispersed-sites strategy, and energy-storage strategy.

As one moves through the strategies, the mid-day fluctuations in PV supply are smoothed out to better match demand. The limit for all of these approaches is that the sun sets late in the afternoon in December, but electricity demand peaks later in the evening. The benefit of the PV-storage system is demonstrated in Fig. 8. The PV-storage system is the only strategy that is able to replicate the shape of the demand curve, particularly the 17:00 h demand peak that occurs after the sun sets.

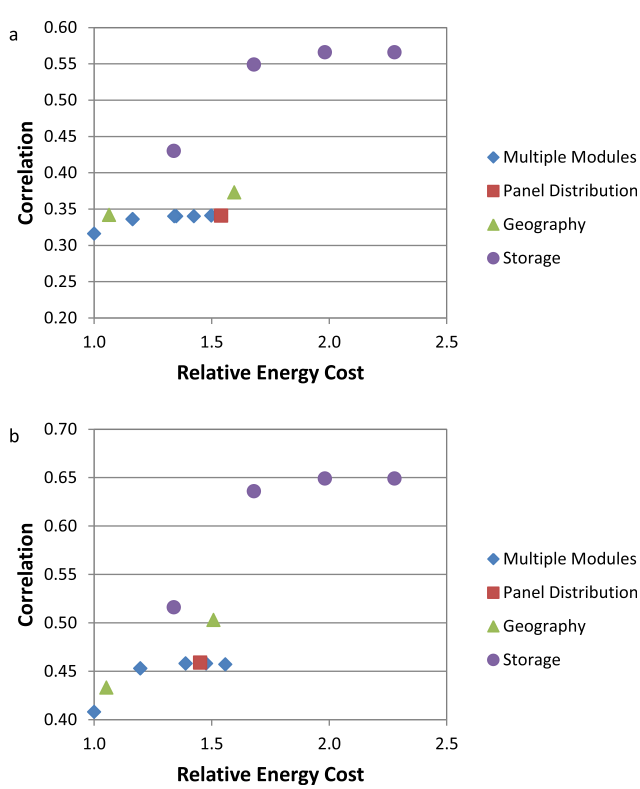

Fig. 7. Combined results of correlation versus relative cost of energy for (a) all hours and (b) summer hours.

Fig. 9 shows the hourly load profiles for a clear, high-correlation day (28 June, 2011), demonstrating the higher correlation achieved during the summer months. The axes for demand and normalized PV output are deliberately scaled to best show the match between PV production and electricity demand. There is a clear improvement as we move from the base case through the rest of the strategies; the energy storage strategy in particular follows electricity demand quite closely. That being said, even on a high-correlation day there are limits to how closely PV production can follow demand; there is a minor variation in the evening's downward demand trend around 21:00 h that PV can't follow, as the sun is down and there is limited energy availability in the storage system.

The capacity credit at differing levels of PV grid penetration for the main correlation strategies is shown in Fig. 10, for cases maximizing correlation based on all hours of the year. The multiple-modules strategy has a lower capacity credit than the other options for the reason described in Section 3.1: low mean annual output due to vertical modules facing west. The base-case and geography strategies have similar capacity credits at very low grid penetration; however, the base-case capacity credit declines quite quickly as grid penetration increases compared to a much slower decline for the dispersed site approach. Capacity credit declines less rapidly with PV grid penetration for the dispersed-site approach because aggregating dispersed sites reduces the fluctuation in total output, leading to a more dependable resource. The energy-storage strategy has the highest capacity credit at all grid penetration levels; this is because each day the PV-storage system allocates energy production to reflect the actual demand, and it does so across a longer period of time, so it is able to reduce the maximum non-solar electrical power supply needed. The PV-storage system is thus a much more reliable generating source than panels that directly convert the sun's energy into electricity.

Another way to measure the impact of the different correlation strategies on the electric grid is to consider the impact of the PV deployment on the required ramp rate of the system. Ramp rate is the rate at which generating stations need to increase or decrease power output to ensure supply is equal to demand. In the study year, the maximum hourly ramp up rate was 2400 MW and the maximum hourly ramp down rate was 2200 MW. The change in maximum required ramp-up rate and ramp-down rate in MW h^{-1}, compared to the Ontario system with no PV, are given in Figs. 11 and 12 respectively for the main correlation strategies.

At low grid penetrations, PV power reduces the maximum hourly ramp-up rate as it tends to shave off peak demands. Moving from the base-case scenario to the multiple-modules, dispersed-sites, and energy-storage correlation strategies, higher capacities of PV can be integrated into the grid before the required ramp-up rate increases relative to the no PV scenario, suggesting that increasing the correlation of PV supply with demand can actually reduce the required ramp-up rate for the system, up to a point. For the energy storage approach, even at close to 25% PV penetration, the maximum ramp-up rate is reduced compared to the no PV scenario.

The energy storage strategy is the only approach that reduces the maximum ramp-down rate; this is because in the no PV scenario, the maximum ramp-down occurs between 21:00 h and 22:00 h, well after the sun has set. None of the other PV strategies has any impact on the maximum ramp-down rate at grid penetrations below 10%. The maximum ramp-down rate increases for the base case scenario at higher penetrations; this occurs when large amounts of PV power are injected into the grid mid-morning during a plateau or dip in electricity demand, requiring rapid ramp-down of other generators. This situation is avoided for the multiple-modules and dispersed-sites approaches, as both these strategies tend to shift PV production to the afternoon.

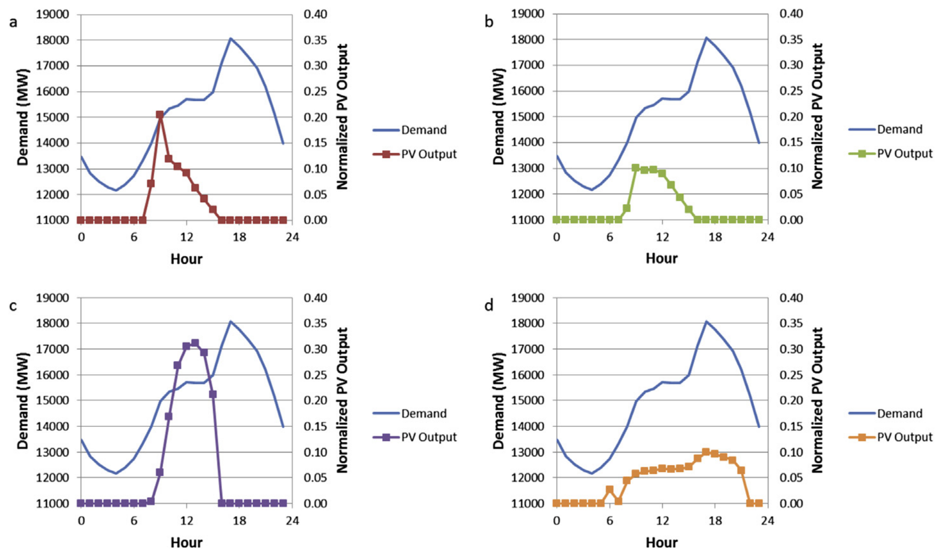

Fig. 8. Hourly demand and PV supply for a low correlation day (3 December, 2011) for (a) base case, and cases with (b) multiple modules, (c) dispersed sites and (d) energy storage.

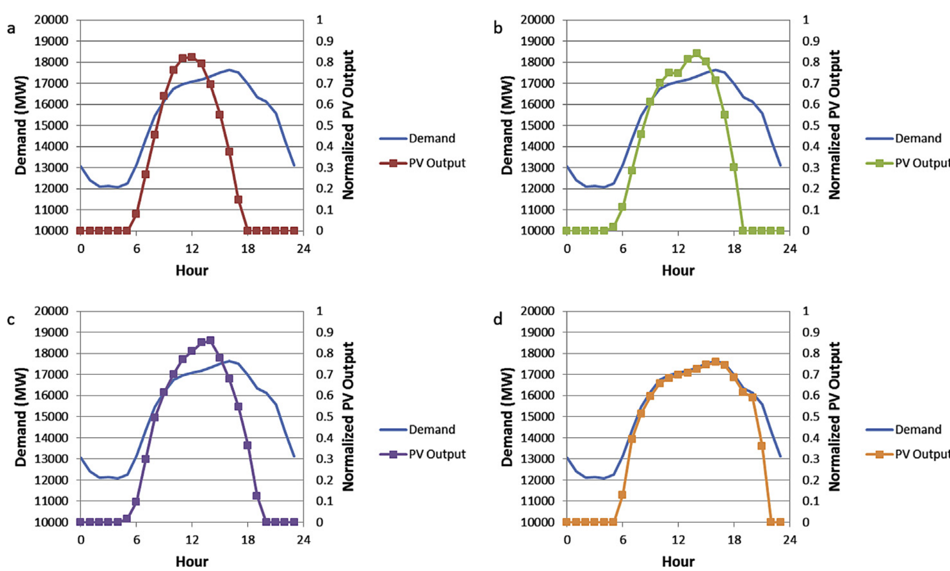

Fig. 9. Hourly demand and PV supply for a high correlation day (28 June, 2011) for (a) the base case, (b) multiple-modules, (c) dispersed-sites and (d) energy-storage strategies.

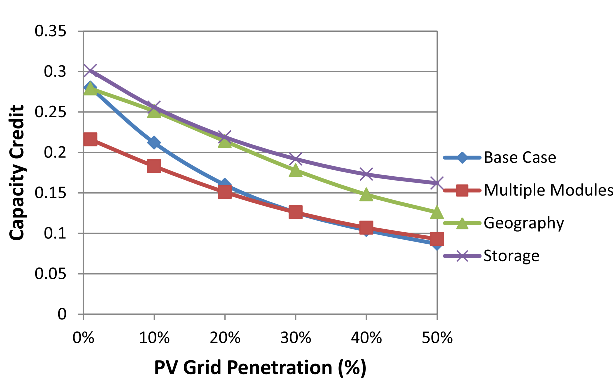

Fig. 10. Effect of solar PV grid penetration on capacity credit for different correlation strategies.

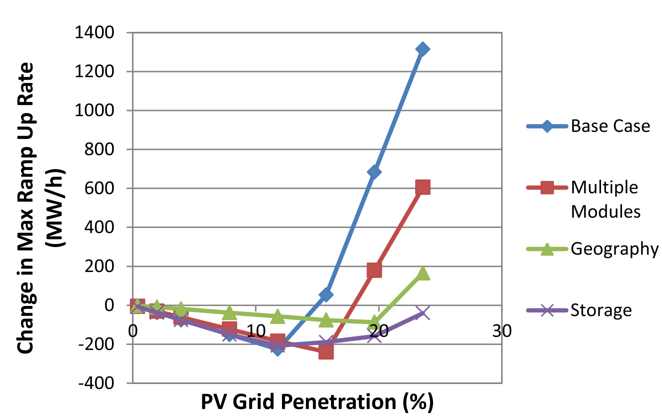

Fig. 11. Effect of solar PV grid penetration on changes in the maximum ramp-up rate for different correlation strategies.

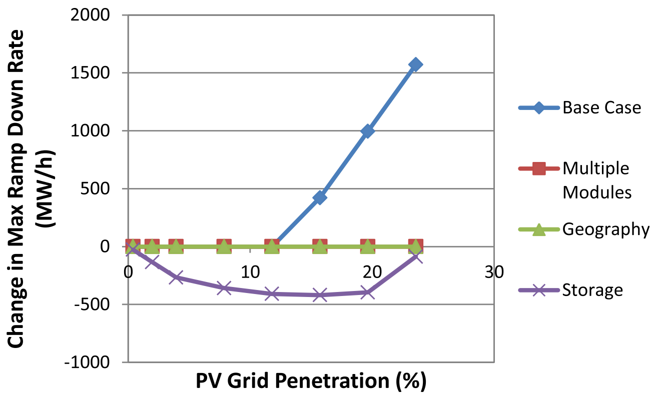

Fig. 12. Effect of solar PV grid penetration on changes in the maximum ramp-down rate for different correlation strategies.

We should note that both the ramp-up and ramp-down findings are based on hourly simulations; the maximum ramp rates would be different, and likely much higher, if sub-hourly data were used [35]. There is substantial evidence that geographic dispersion can reduce PV output variability, and consequently required ramp-up rates [29,33,35]; however, dispatchable short-term storage, such as flywheels or supercapacitors, would certainly help manage sub-hourly fluctuations in PV generation and electricity demand.

4. Conclusion

Three strategies to increase the correlation between the output of a solar PV system and electricity demand are investigated for the Province of Ontario. The strategies investigated are optimal orientation of modules in a multi-module array, use of geographically dispersed sites, and use of energy storage. Correlation analysis is performed for all hours of the year and for hours in the summer months only (April to September only) using two years of hourly data. The results of each strategy are compared to a base-case panel oriented for maximum yearly energy production, as well as to sun-tracking PV arrays and fossil fuel generators in the Province. The relative cost of energy and the capacity credit for each strategy are calculated relative to the base case.

The results show that geographically dispersed sites and energy storage are more effective strategies for correlating PV production with electricity demand than optimally orienting PV panels. Systems designed for a higher correlation tend to have higher relative costs of energy; however, higher correlation strategies tend to have higher capacity credit and are more beneficial to the system, in terms of hourly ramp-up and ramp-down rates. Future work will assess whether a higher correlation between PV production and electricity demand assists in the integration of solar PV into an electric grid through a load-matching analysis.

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