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ANALYZING THE IMPACT OF SHADING ON PHOTOVOLTAIC ARRAYS TO OPTIMIZE SYSTEM EFFECTIVENESS

Jin Ho Jo, Dave Kennell, and Steve Richey
Illinois State University
215K Turner Hall Campus Box 5100, Normal, IL 61790, USA
e-mail: jjo@ilstu.edu, drkennell@ilstu.edu, spriche@ilstu.edu

ABSTRACT

Building integrated renewable energy systems, particularly photovoltaic or solar thermal systems on building rooftops, are currently of great interest to researchers, building managers, and developers. Although their benefits for individual buildings have been studied, as yet there is little understanding of the potential impact of rooftop objects that cast shadows over their light-gathering elements.

Rooftop objects such as HVAC equipment, skylights, or plumbing vents that overshadow part of a PV array can significantly reduce the electrical output of the system so the installation of PV systems near rooftop objects is generally avoided. However, their precise impact on system output and the return-on-investment of the system's capital costs are unclear.

We report the results of empirical and simulation modeling analyses of the impact of partial shading on a PV array mounted atop the roof of a large building and extend this to determine optimized system capacity, configuration and orientation. A renewable energy computer simulation, System Advisor Model, developed by the National Renewable Energy Laboratory, was utilized to examine the potential effects of different application options and suggest optimized array designs to maximize energy production and boost return-on-investment throughout the year.

A series of case studies were examined, ranging from a system that avoids all shade from roof objects to a full installation that covers the entire available roof space regardless of obstructions. The results will be of particular interest to developers and installers of solar energy systems seeking optimized application options based on the current condition of their available rooftop space.

Keywords: Photovoltaic system, renewable energy simulation, energy optimization

INTRODUCTION

Energy and material use are increasing significantly worldwide due to rapid urban development. Buildings are responsible for much of this growth in the intensity of energy and material consumption (Golden, 2003), impacting the urban environment through the emission of greenhouse gases (GHG) and the creation of microclimates. GHG emissions are directly related to the energy consumed during all the stages of a building's life, including manufacture, transportation, construction, operation and demolition. Of these, the operational energy is the most significant (UNEP, 2007), especially as most of this energy comes from fossil fuel based energy sources. The global economic and political conditions that are encouraging many countries to reduce their dependence on imported energy resources have thus led to a growing interest in the development and use of renewable energy to reduce the need for such imports (El-Shimy, 2009).

Among the many renewable energy sources that are becoming commercially viable, building integrated renewable energy systems, particularly photovoltaic or solar thermal systems on building rooftops, are of particular interest to researchers, building managers, and developers due to various benefits of on-site energy generation, such as reduced transmission costs and peak-time electrical load control. Although their benefits for individual buildings have been studied, as yet the potential impact of rooftop objects that cast shadows over the light-gathering elements of such systems is only poorly understood.

If rooftop objects such as HVAC equipment, skylights, or plumbing vents cast shadows over any part of a PV array, for example, this significantly reduces the electrical output of the system. Although the installation of PV systems near rooftop objects is generally avoided in order to safeguard system performance, their overall effect on system output and the return-on-investment of the system's capital costs are unclear. For example, even a massive shadow falling on the array early in the morning and late in the afternoon may have no significant impact on the overall system power output, since the amount of solar radiation is relatively low during those time periods. However, if every part of the rooftop area affected by shadow is avoided for PV installation, the remaining area deemed suitable for the PV system may be insufficient to provide enough electricity to the building.

Here we report the results of empirical and simulation modeling analyses to examine the impact of partial shading on a PV array mounted atop the roof of Turner Hall at Illinois State University. We go on to apply the results to determine the optimum system capacity and placement configuration on the roof. The research methodology included both on-site data collection from a pilot PV system installed on Turner Hall and modeling the same system using System Advisor Model (SAM), which was developed by National Renewable Energy Laboratory to estimate annual electrical energy production. The simulation tool was applied to several different case scenarios to suggest the optimal system for a given rooftop condition. These procedures are discussed in greater detail in the methodology section of this paper.

Site Description and Choice of PV Array

Turner Hall is located in Normal, Illinois (latitude 40°30'38" and longitude 88°59'50") and is a single story building with a double story section in the center. It has a total roof area of 7,337 m^2 (78,980 ft^2). The majority of the floor space is used for class rooms and offices.

Many types of PV-modules, each offering different characteristics, are available in today's market. For this study, we selected a PV module that represented the average efficiency of the commercially produced PV modules available locally. Twelve Sanyo mono-Si-HIP-195BA3 PV modules with 195 W peak capacity and 16.5 % efficiency comprised of Hetero-junction with Intrinsic Thin-layer (HIP) PV cells were installed on Turner Hall, as shown in Figure 1. Each module has a surface area of 1.18 m^2.

Fig.1. Turner Hall PV system.

Within each module, 36 silicon cells were connected in series to yield 18 V at the maximum power point. The modules were mounted on a steel structure that was ballasted on the rooftop surface. Six panels were connected in series and two strings (6 panels each) were connected in parallel. The electrical configuration is presented in Fig. 2.

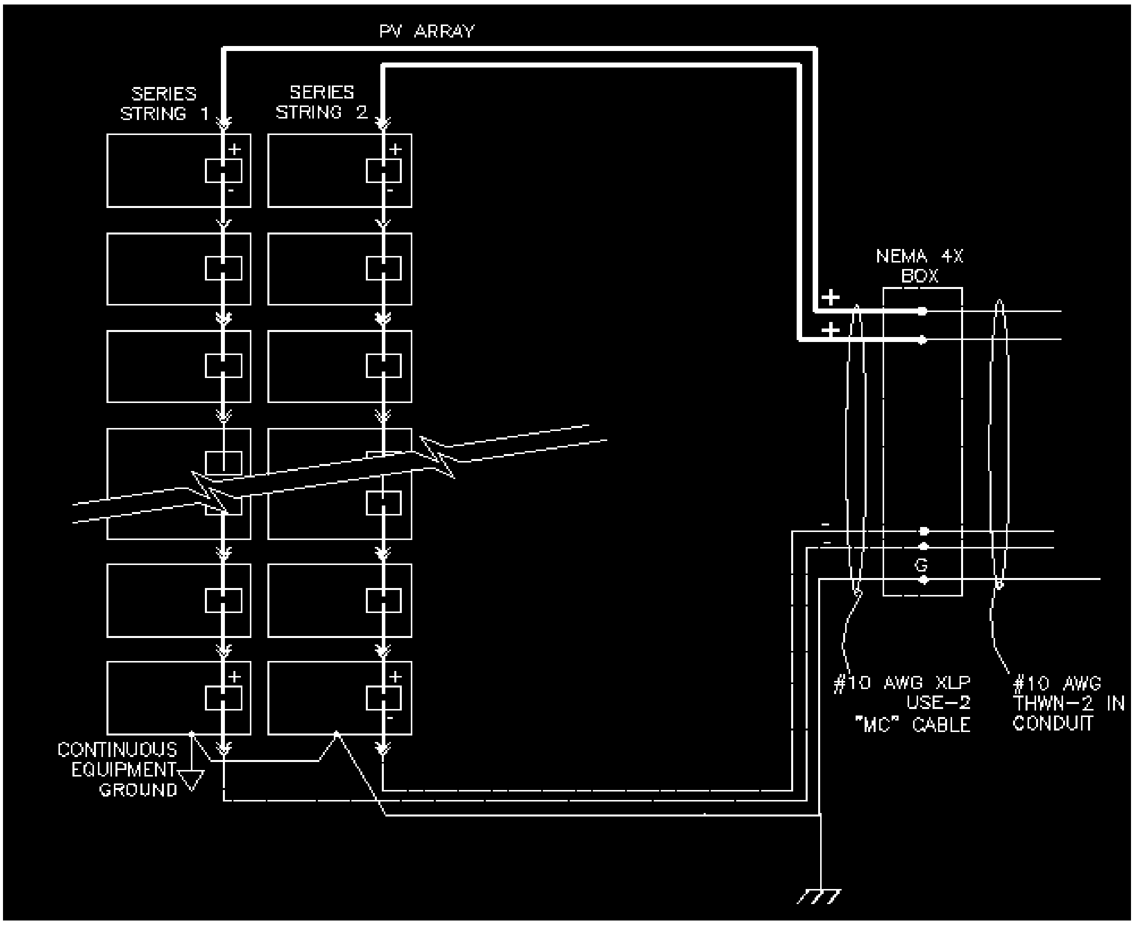

Fig. 2. Turner PV system electrical configuration.

For the simulation part of this study, we applied weather information for the period 1961 to 1990 (Typical Meteorology Year 2 or TMY2) provided by the Peoria Airport Station, which is located 38 miles west of the facility (NREL, 2011a). The central Illinois region's climate is characterized by high average temperatures in the summer months and low average temperatures in the winter months; relative humidity is consistent throughout the year. During the summer, the mean daily maximum temperature ranges from 22.7°C (72.8°F) in May to a maximum of 28.4°C (83.1°F) in August; the mean daily maximum relative humidity ranges from 66% to 74%. During the winter, the mean daily minimum temperature ranges from -10.4°C (13.3°F) in January, to -7.0°C (19.4°F) in December; the mean daily maximum relative humidity ranges from 74% to 78%. The solar radiation intensity and duration in the region is moderate, ranging from a minimum of 1.6 kWhm^{-2}(day)$^{-1}$ in November to a maximum of 6.4 kWhm^{-2}(day)$^{-1}$ in June.

METHODOLOGY

Optimized PV system design approach

Unsurprisingly, PV systems are generally operated in such a way as to maximize their annual energy output. Rooftop sites are typically selected to avoid rooftop objects such as HVAC equipment, skylights, or plumbing vents that may overshadow part of the PV array and therefore reduce the electrical output of the system. In practice, this means that a specific building rooftop may not be able to accommodate a PV system of the desired size. Avoiding all the area affected by shadow may leave only a very small space for PV system installation, which may then not be economically viable due to the limited system capacity. In practice, however, some shading in the early morning or late afternoon may not have a critical impact on the PV array electrical output due to the limited solar radiation at those times of day. As yet, it is not clear how much shadowing can be tolerated in accordance with best practice. Different buildings with various PV system options will have different outcomes and the optimum system size and array layout for each building may vary considerably. A greater understanding of this parameter is thus required in order to optimize PV systems both in terms of electrical output and return-on-investment (ROI). This study therefore adopted a methodological approach that considers existing rooftop objects and their subsequent impacts on a PV array to optimize the performance of a PV system. This design approach should prove particularly useful for developers seeking to implement a best practice technique that ensures the optimum performance of their PV systems.

As shown in Fig. 3, existing rooftop objects on Turner Hall were assessed and then modeled in Google Sketchup, which provided a shadow analysis revealing the shadow overcast pattern throughout the year. The PV array on Turner Hall was used as the reference system to develop different case scenarios based on shadow allowances. For a given shadow coverage, each model was simulated in System Advisor Model (SAM) to estimate the potential annual electrical production and determine the payback period for each system. The resulting optimized PV system was selected to combine the shortest payback period with the maximum electrical output.

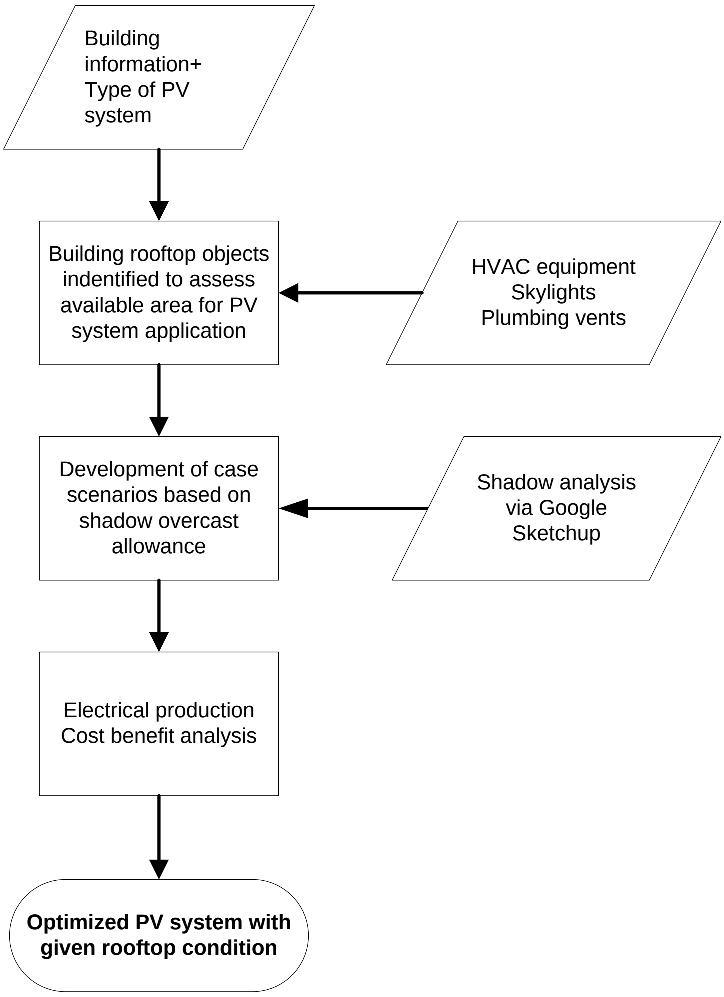

Fig.3. Optimized PV system design approach.

Simulated electrical outputs and on-site data collection

System Advisor Model (SAM) was selected as the simulation platform to estimate the annual electrical energy generation potential of the PV system. SAM is based on an hourly simulation engine that interacts with performance, cost, and finance models to calculate energy output, energy costs, and cash flows (NREL, 2011b). This study utilized a SAM simulation to assess the monthly electrical output, the impact of partial shading on the PV system, and the payback periods for different case scenarios to determine the optimum system configuration.

To validate the estimated electrical outputs from the SAM simulation, we compared the actual electrical output generated by the existing PV system with those predicted for the equivalent simulated system by SAM. We first collected electrical output data from the pilot PV system on Turner Hall from 2009 through early 2011. Although several months of data were missing due to the system being disconnected from the network, the collected data were sufficient to represent almost 12 months of electrical production (February-June 2009 and August-January 2010/11), lacking data only for July. The PV system output data is managed by Sentalis and the data collected from the system are available for download from the Sentalis website (www.sentalis.net).

The shading model in the SAM simulation specifies beam and sky diffuse shading factors and is capable of importing shading data from external software. SAM also displays a self-shading calculator, allowing the user to model module-to-module shading for fixed tilt arrays. Each shading factor is expressed in terms of a value between zero and one that represents the fraction of radiation (either beam or diffuse) that reaches the array (NREL, 2011b). A shading factor of one represents no shading whatsoever and a shading factor of zero represents complete blockage of either the beam or sky diffuse radiation from the array. To calculate the effect of shading on the array, SAM adjusts the incident beam and diffuse radiation value that it calculates from the data contained in the weather file and the solar angle for each hour of daylight. The value of the shading factor for each hour depends on the options the user specifies on the Shading page (NREL, 2011b). After the different PV application options based on system size and shading coverage had been selected, this shading model was utilized to estimate the actual impact of shading coverage on the PV array. The determination of PV system size based on shading pattern will be discussed in greater detail in the next section.

SAM's economic model calculates a project's cash flow over a given analysis period. The cash flow captures installation and operating costs, taxes, tax credits and incentive payments, as well as the cost of servicing debt (NREL, 2011b). SAM calculates the value of annual electricity sales for the cash flow based on the system's hourly output for a single year as predicted by the performance model. SAM also calculates a series of annual cash flows for operating costs, incentive payments, tax liabilities (accounting for any tax credits for which the project is eligible), and loan principal and interest payments and then reports a set of economic metrics such as the levelized cost of energy that it calculates from the cash flow (NREL, 2011b). The outcomes of this detailed analysis of return on investment support the efforts of PV system developers and installers to determine the best option available based on existing rooftop conditions.

Three-dimensional modeling and shadow analysis

To determine the available roof space for PV system installation, we simulated the objects on the rooftop of Turner Hall with Google SketchUp, as shown in Fig. 4. Shadow analysis was performed for a variety of PV system configurations to estimate the shadow coverage for different case scenarios utilizing a rich set of features for sun and shadow simulation. Based on physical measurements of the rooftop objects on Turner Hall, a simple three-dimensional model was constructed that featured basic shapes of several roof obstructions, most of which are part of the building’s HVAC system.

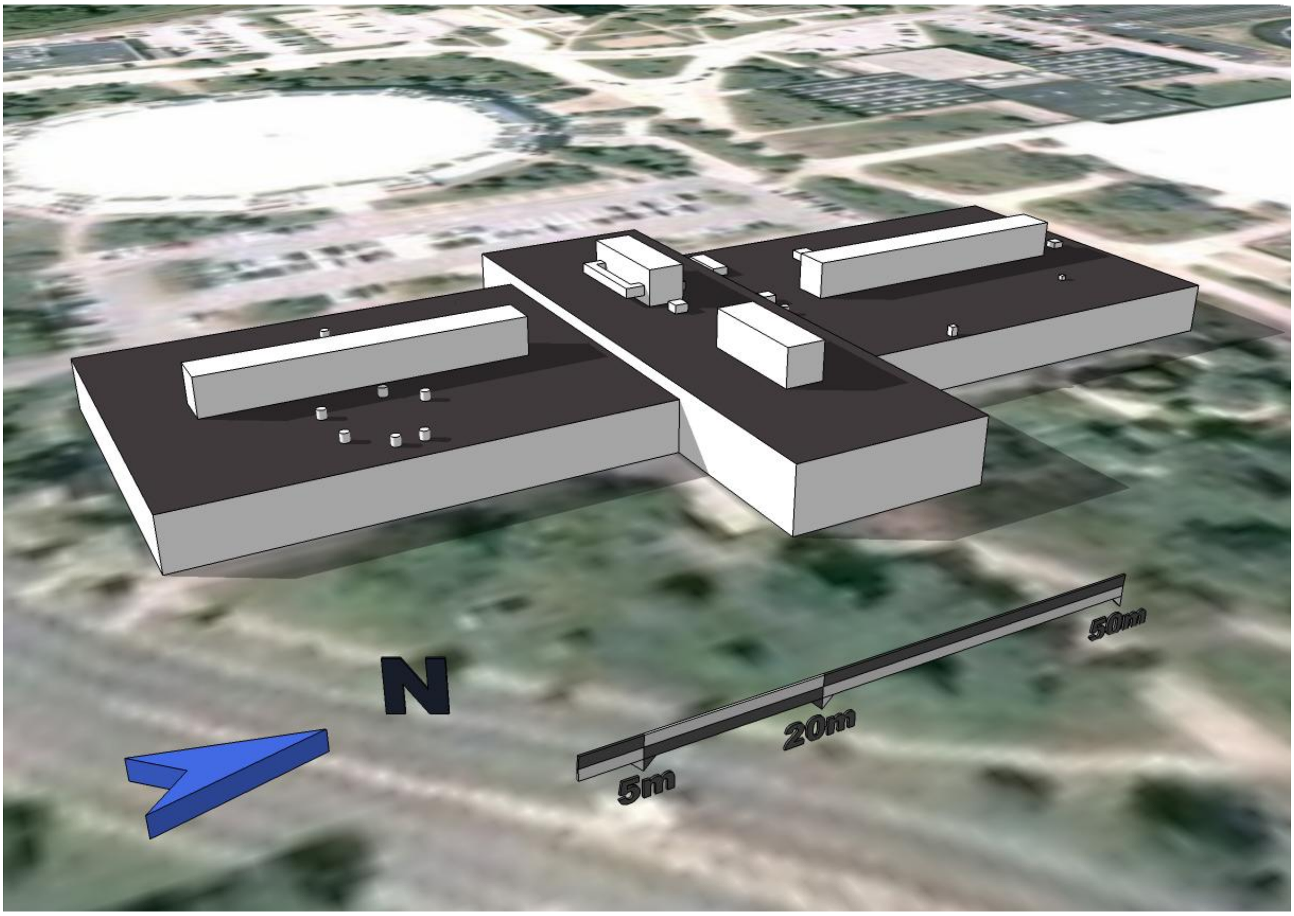

Fig. 4. 3D model of turner hall in google sketchup.

After constructing the basic design of the existing structure, shadow analysis was performed for four possible case scenarios for solar panel installation. In all cases, the minimum distance to the roof edge of any module was 0.3m, all modules were placed on the roof at a 5 degree angle, and module rows were spaced 0.4m apart. Each different case was based on a thumb rule which could be used to determine the location of the solar panel installation on the roof.

- “5x Rule”: Avoid only those shadows which are within five times the object height.
- “4x Rule”: Avoid only those shadows which are within four times the object height.
- “1x Rule”: Avoid only those shadows which are equal to the object height.
- “Max”: Avoid no shadows; install as many solar panels as possible.

In each of these scenarios, a diagram was drawn that represented the exact position of shadows cast on the summer and winter solstice, as well as the approximate path that the shadows would follow throughout the year. Color variation was used to represent the intensities of the shadows to facilitate analysis. An example of this “butterfly” diagram is shown in Fig. 5.

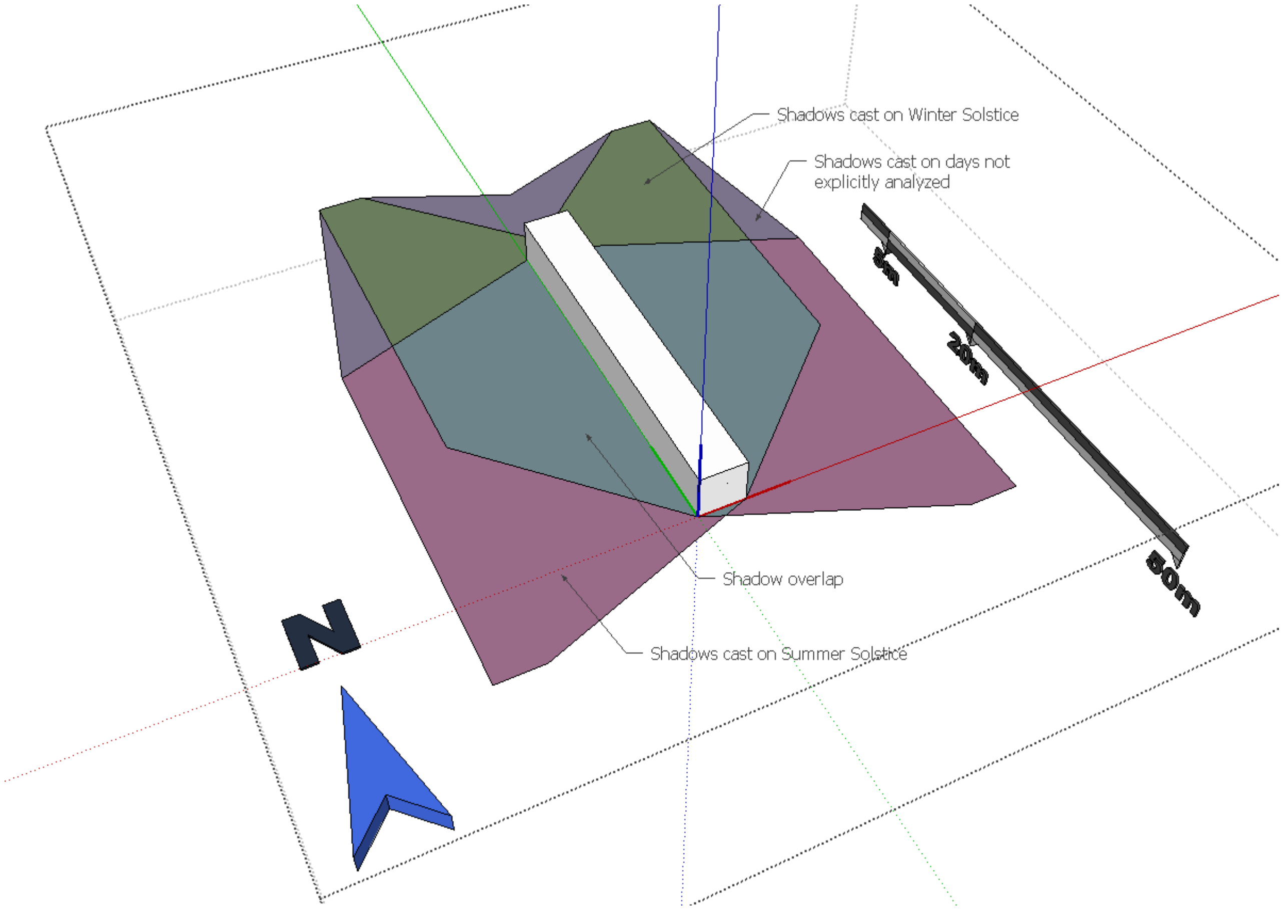

Fig.5. Shadow cast on the summer and winter solstices.

Similar diagrams were created for all rooftop obstructions to estimate the area available for PV installation. After indentifying the available area, we modeled the solar panels to quantify the number of PV modules (system capacity). The type of solar panels used for this analysis is the same as those used for a small pilot solar installation already in place on the Turner Hall rooftop. These Sanyo HIP 195-BA3 PV modules were modeled to exact dimensions within SketchUp using information obtained from the module data sheet. The panel angle matches that of the angle used for the pilot installation (facing south, with a 5 degree tilt). Ultimately, it was possible to see the resultant configurations that occurred when following each of the different thumb rules, as presented in Fig. 6.

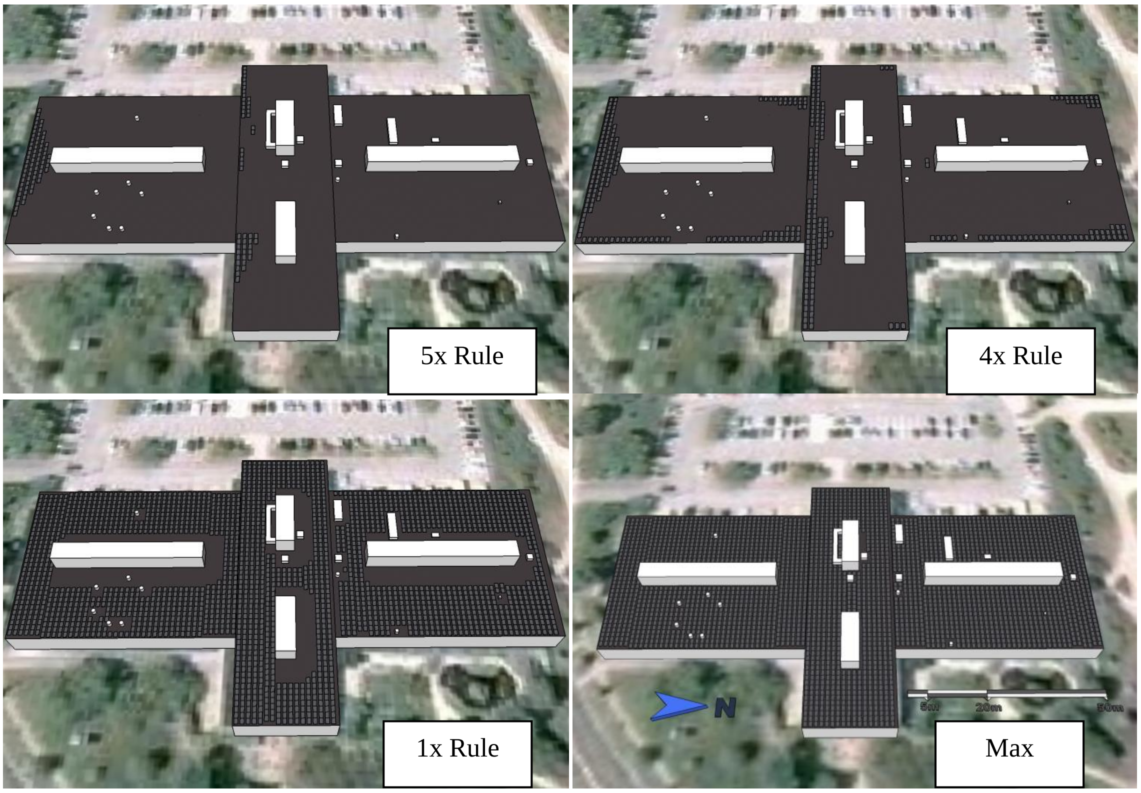

Fig.6. Case scenarios based on a rule set.

The system size of each case, in terms of the number of solar modules, is as follows:

- 5x Rule: 114 modules, corresponding to 134.52 m^2.
- 4x Rule: 342 modules, corresponding to 403.56 m^2.
- 1x Rule: 2,358 modules, corresponding to 2782.44 m^2.
- Max: 3,138 modules, corresponding to 3702.84 m^2.

Shading effect on PV electrical output

The number of modules that could be accommodated for each configuration was determined and the shading pattern analyzed using the SAM shadow simulation. Table 1 represents this shading data, representing the shadow patterns in the model constructed with Google Sketchup in a manner similar to that used by SAM. Each model was analyzed for every month of the year, at times ranging from 5 AM to 7 PM. As early analysis confirmed that the sun never shines at this location before 5 AM or after 8 PM, these time frames were not analyzed, but rather assumed to have no sun. As shown in Table 1 for the 5x Rule case, a value of zero represents full system shading, a value of one represents no shading, and any values in between indicate the percentage of the system which is receiving incident solar radiation.

Table 1. Shading effect on the PV array.

	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11
Jan	0	0	0	0	0	0	0	0	0.9	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0.9	1	1	1	1	1	1	1	0.8	0.9	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Apr	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0.9	0	0	0	0	0
May	0	0	0	0	0	0.9	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Jun	0	0	0	0	0	0.9	1	1	1	1	1	1	1	1	1	1	1	1	1	0.8	0	0	0	0
Jul	0	0	0	0	0	0.9	1	1	1	1	1	1	1	1	1	1	1	1	1	0.8	0	0	0	0
Aug	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0.9	0	0	0	0	0
Sep	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0.9	1	1	1	1	1	1	1	1	1	0.9	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0.9	1	1	1	1	1	1	1	1	0.9	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0.9	1	1	1	1	1	1	1	0.9	0	0	0	0	0	0	0

A series of analyses were performed to optimize the system configuration by considering the payback period and system performance for Turner Hall, the results of which suggested that the “2.5x Rule” would represent an “Ideal” scenario. Further details on how this was determined are described in Section 4.2 below.

The repetitive task of shadow analysis was made somewhat simpler via the observations made during the previous four cases. As shown in Fig. 7, morning shadows (2.5 times object height) on the summer solstice are always cast at 14.1 degrees from a straight line running east to west; evening shadows are cast at 11.3 degrees. Similarly, morning shadows (again, 2.5 times object height) on the winter solstice are cast at 66.3 degrees to the same straight line; evening shadows are cast at 63.1 degrees. Once these angles are known, one only has to draw a line equal to 2.5 times object height at that angle, and draw the shadow as it would be cast considering object shape. This requires drawing one line which is equal to the object’s width, and one line which is equal to the object’s length. Using this method to draw the diagrams required significantly less time, and was found to be highly accurate. Future analyses can be made much simpler by using software-based solutions. SketchUp supports plug-ins capable of performing a variety of functions, including shadow analysis.

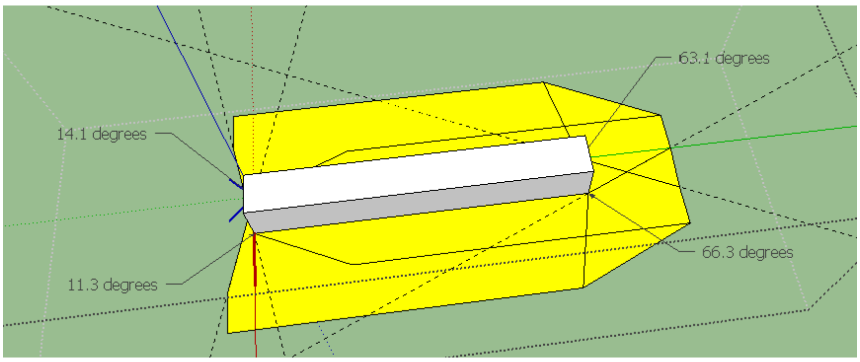

Fig. 7. Shadow pattern analysis in google sketchup.

After all shadows had been analyzed, the available roof area was quantified. In Fig. 8, the yellow portion represents the area to be avoided due to shading and the green portion represents the available roof space.

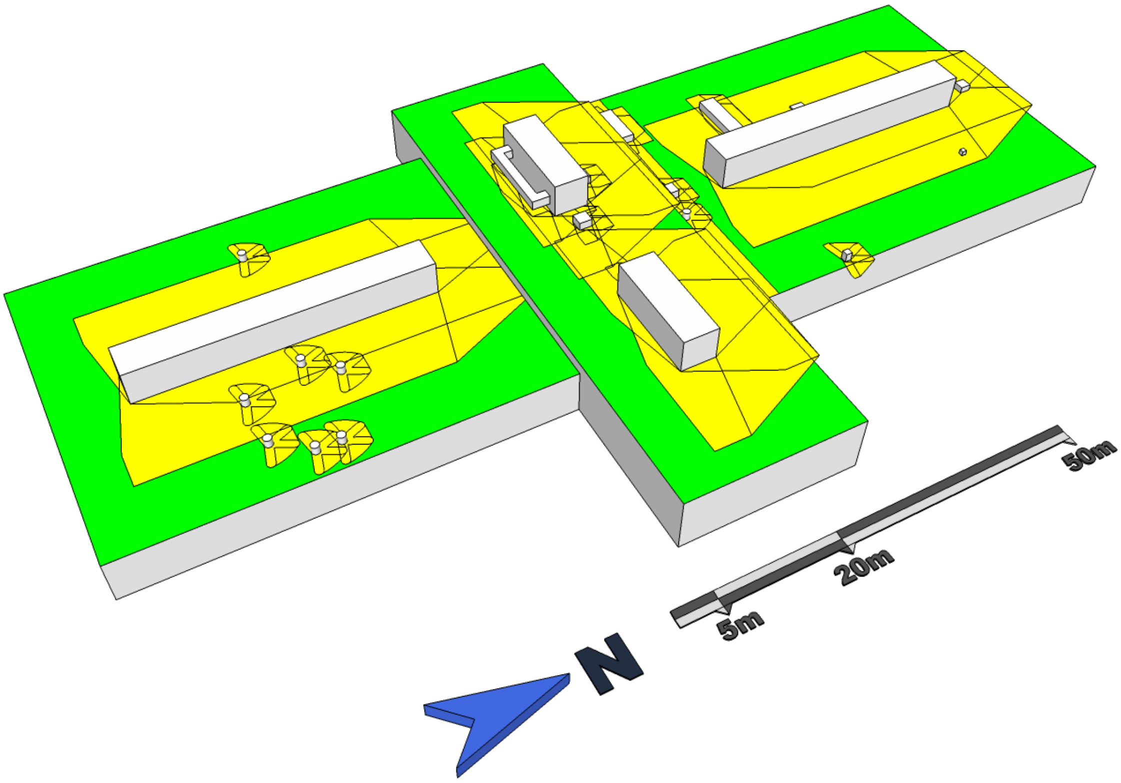

Fig.8. Available area for PV installation (in green).

As before, solar panels were placed on the roof within the module. Any panel rows of less than two total panels were removed. The mathematical analysis predicted approximately 1100 panels; in total, this case had 1164 panels, as shown in Fig 9. As with the previous four cases, shadow analysis was performed for twenty four hours a day, every day, for every month of the year.

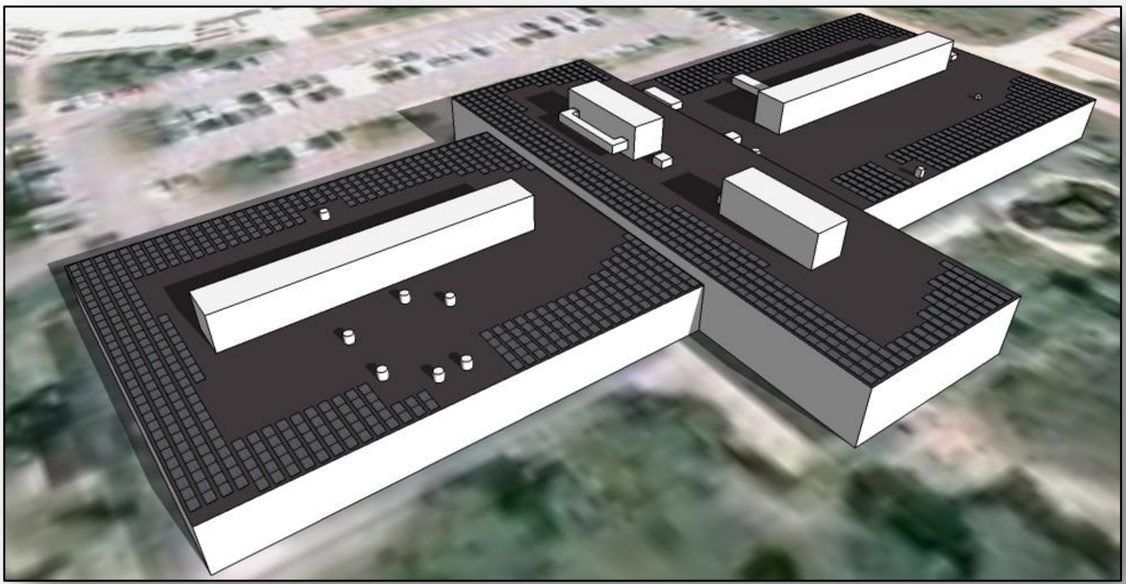

Fig.9. PV array location based on the 2.5x rule.

RESULTS AND DISCUSSION

Simulated and actual electrical production

To further utilize the SAM software package to examine PV system output under various shadow coverage scenarios, we first compared the actual monthly electrical outputs with the simulated outputs for the same months in the SAM software, as shown in Fig. 10. The simulated total output (2,909 kWh) was 22% more than the actual output (2,386 kWh). However, the simulated monthly outputs during the summer months from March to August (excluding July, for which no output data was available) remained within +/- 5% of the actual outputs. The actual monthly electrical outputs of the Turner Hall PV system during the winter months were markedly lower than the simulated outputs due to the heavy snowfall during the winter of 2010-2011. Analysis using a longer data collection period from the Turner PV system is required to improve and further validate the accuracy of the simulated outcomes. However, the weather condition in the study years of 2009, 2010 and 2011 corresponds to the reduced electrical outputs during the winter months as compared to the averaged winter months' electrical outputs from the SAM simulation. We believe the SAM software can adequately address average outputs of longer period PV system life based on the results of our comparative analysis and the results from previous studies using the SAM simulation software such as Cameron et al. (2008) and King et al. (2007).

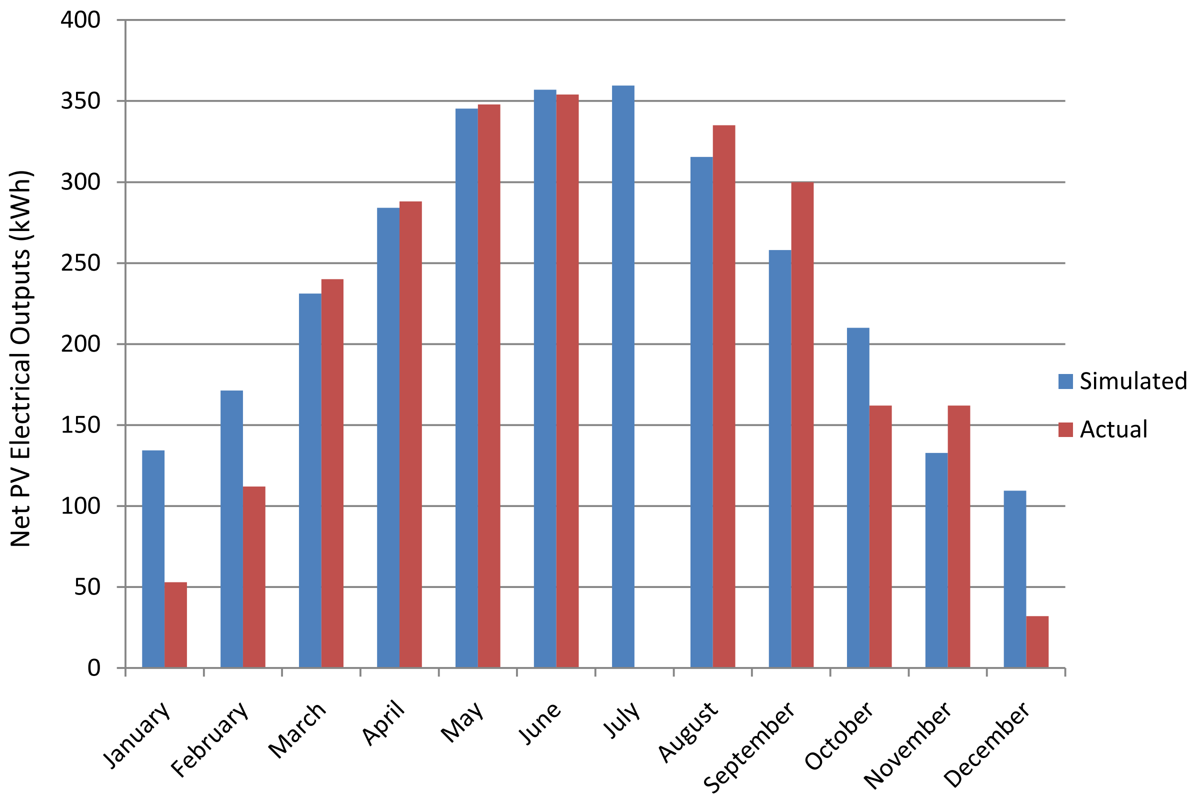

Fig.10. Actual and simulated Turner PV system monthly net electrical outputs.

PV system optimization

To identify the optimum system configuration, each case scenario was analyzed with the SAM software to estimate the annual output of a PV array and provide information on the predicted payback period. We incorporated information on the system capacity based on the available roof area for PV system installation, the shadow coverage on the PV array, and system cost information into the SAM software.

Pricing data from the actual system cost of the pilot solar installation on Turner Hall was used, as was the system's physical location, shading data from Table 1, and the panel tilt angle, and module and inverter type used for the pilot system. In addition to the cases described above, a sixth case that analyzed the theoretical output of the "Max" case with no shading was run to provide a clear comparison with the real world "Max" case with potential shadow cast. A summary of the results are provided in Table 2.

Table 2. System capacity, annual energy output, and payback period of each case scenario.

Case	Modules	Payback Period (years)	Nameplate Capacity (kW DC)	Net Annual Energy (kWh)	Output per Size (Annual kWh/kW)
5x Rule	114	16.97	22.23	26,157.00	1,176.40
4x Rule	342	16.93	66.70	78,416.00	1,175.60
"Ideal" – 2.5x Rule	1164	16.97	227.02	266,084.00	1,172.10
1x Rule	2358	17.21	459.9	529,765.00	1,151.90
Max	3138	17.93	612.03	671,782.00	1,097.60
Max – No Shading	3138	16.88	612.03	721,051.00	1,178.10

After the 5x Rule, 4x Rule, 1x Rule, and Max cases were analyzed, an attempt was made to determine where the ideal case would lie, namely the system size with the minimum payback period. In order to determine this, a graph of nameplate capacity against payback period was plotted, as shown in Fig. 11, for each of the four cases analyzed so far. By fitting a third-order polynomial trend line to the data set, an approximate location for the minimum payback period was ascertained.

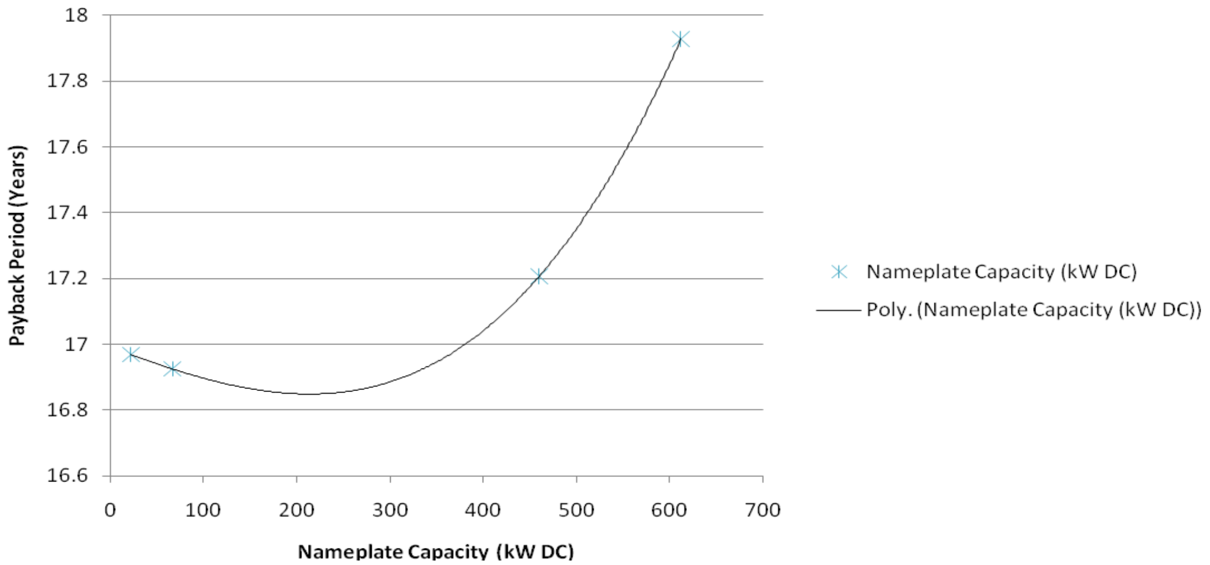

Fig.11. PV system optimization curve with 4 data points.

The results of the analysis indicated that an installation with an approximate nameplate capacity of 215 kW DC – and thus approximately 1100 modules – would provide the optimum payback period and that this should be combined with a thumb rule which avoided only those shadows which were 2.5 times object height. Applying this rule resulted in a system size of 1164 modules, slightly higher than anticipated but within acceptable tolerances. The results of adding this new simulation data to the previous data are shown in Fig. 12.

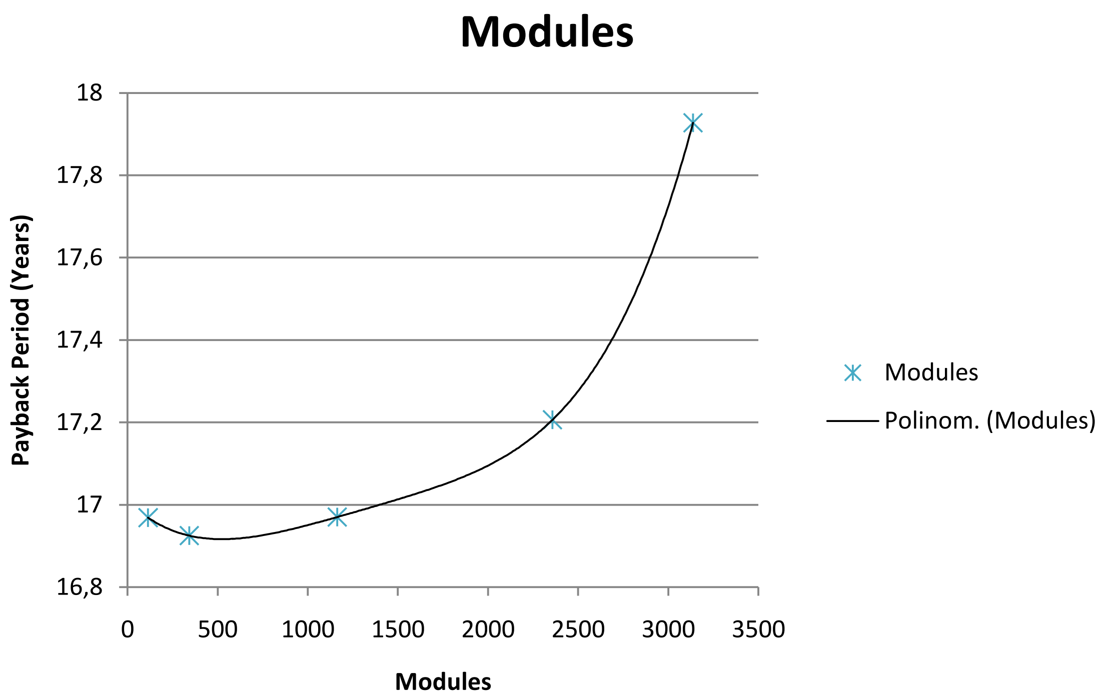

Fig.12. PV system optimization curve with 5 data points.

The assumption of 1100 modules was found to be somewhat inaccurate, as the line describing payback period versus system size was more complex than initially expected. Fig. 12 shows a modified approximation of actual system size versus payback period reflecting a fourth-order polynomial trend line that combines the 2.5x Rule with its quantified payback period. In this new chart, the ideal system size in modules appears to be rather closer to the system size originally created in the 4x Rule case. By including more data points, more precise optimal system capacity can be determined. However, the results of the system size and payback period analysis provide useful information on the likely range of system capacity that both maximizes system performance and minimizes the payback period. In this case study, a system size between 66 kW and 227 kW was determined to represent the optimized system for Turner Hall. We were also able to locate the PV system on the rooftop according to the suggested rule sets, as described in this study. Since the optimized payback and the system performance can be achieved using a system capacity in this defined range, we can select the most appropriate system size within this range that meets the electrical demands of the building.
A variety of new and innovative PV system technologies are being developed to improve module efficiency and performance. Bypass module connection, multiple diodes, and incorporating a micro inverter on each PV module are all strategies that are expected to minimize the impact of partial shading on future PV arrays. Although PV system types and roof conditions may vary for each case, the framework for determining ideal system size and optimizing PV system performance suggested here can be adapted for any PV system planning and development project. We strongly believe the suggested PV system design approach and the outcomes of this study can be utilized by PV system installers and developers to accurately determine the system size which optimizes both system performance and payback period.

CONCLUSIONS
It is well known that the electrical output of a PV system can be greatly reduced when rooftop objects overshadow even part of the PV array. Therefore, the installation of PV systems near rooftop objects is generally avoided. However, the magnitude of the actual impact of overshadowing on a system's annual electrical output is unclear.
In this study, we proposed a design approach that can be applied to determine both the appropriate area for PV system installation and the system capacity that optimize the overall PV system performance. The research methodology compared on-site data collection from the PV system installed on Turner Hall with a simulation of the same system modeled in System Advisor Model (SAM), which was developed by NREL to estimate annual

electrical energy production. The simulation tool was utilized to examine different case scenarios in order to suggest an optimal system for a given rooftop condition.
We identified the optimum system size for the study site to be between 66 kW and 227 kW, with a payback period of about 17 years. This study revealed that partial shading may not have a significant impact on the annual electrical output in all cases and can be tolerable within a certain range. With this suggested design approach, developers can enjoy more flexibility in terms of system capacity, allowing them to better meet the demands of the building's electrical consumption. The optimized PV system, which takes into account both the system capacity and location, can be identified using the suggested PV design approach developed in this study.

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