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Integration of Rooftop Photovoltaic Systems in St. Paul Ford Site's Redevelopment Plans

Dan Olis and Gail Mosey

Produced under direction of the U.S. Environmental Protection Agency (EPA) by the National Renewable Energy Laboratory (NREL) under Interagency Agreement IAG-08-0719 and Task No. FE14.3524.

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Work for Others Report
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Executive Summary

The purpose of this analysis is to estimate how much electricity the redeveloped Ford Motor Company assembly plant site in St. Paul, Minnesota, might consume under different development scenarios and how much rooftop photovoltaic (PV) generation might be possible at the site. Because the current development scenarios are high-level, preliminary sketches that describe mixes of residential, retail, commercial, and industrial spaces, electricity consumption and available rooftop area for PV under each scenario can only be grossly estimated. These results are only indicative and should be used for estimating purposes only and to help inform development goals and requirements moving forward.

Table ES-1 shows the five different development scenarios contemplated for the site. Per the direction of personnel from the City of St. Paul, Scenarios 2–5 are considered in this analysis.

Table ES-1. Development Scenarios

Scenario	Name	Considered in This Analysis
1	Primary Industrial	No
2	Light Industrial/Flex Tech	Yes
3	Mixed Use: Office/Institutional	Yes
4	Mixed Use: Urban Village	Yes
5	Mixed Use: Transit Village	Yes

Table ES-2 shows estimates of PV capacity required to achieve 100% renewable electricity on a net-zero basis[1] by development scenario and estimates of what fraction of PV needed for net-zero can be installed on the development's rooftops. The analysis considers standard electricity consumption levels of the buildings and low electricity consumption (high efficiency) scenarios. The analysis also considers use of standard efficiency PV modules and best-in-class high efficiency modules to maximize total PV capacity on space-constrained roofs.

[1] The following references have a full discussion on the concept of net-zero energy:
Torcellini, P; Pless, S; Deru, M. (2006). *Zero Energy Buildings: A Critical Look at the Definition*. CP-550-39833. Golden, CO: National Renewable Energy Laboratory.
Carlisle, N.; Van Geet, O.; Pless, S. (2009). *Definition of a 'Zero Net Energy' Community.* TP-7A2-46065. Golden, CO: National Renewable Energy Laboratory.

Table ES-2. Estimates of PV Needed for Net-Zero Electricity and Rooftop Space Available

Scenario	Building Electricity Usage	PV Needed for Net-Zero Electricity (MW)	PV Module Efficiency	PV Needed for Net-Zero Met by Rooftop Capacity (%)	PV Shortfall (MW) of Rooftop Space
2	Low	12.1	High	57	5.2
			Mid	45	6.6
	Typical	16.6	High	46	8.9
			Mid	37	10.5
3	Low	9.1	High	50	4.6
			Mid	41	5.4
	Typical	12.1	High	44	6.8
			Mid	36	7.8
4	Low	6.8	High	63	2.5
			Mid	55	3.1
	Typical	9.0	High	62	3.4
			Mid	56	4.0
5	Low	6.5	High	49	3.3
			Mid	43	3.7
	Typical	8.9	High	44	5.0
			Mid	35	5.8

According to these estimates, under no scenario is the site able to achieve net-zero electricity with rooftop PV alone. Rooftop PV could provide approximately 63% of electricity under Scenario 4 with low building electricity usage (high efficiency buildings) coupled with a specification for high efficiency PV. In Scenario 5, mid-tier rooftop PV is estimated to meet approximately 35% of the net-zero goal with standard building electricity consumption estimates. These cases bracket the results.

Minnesota has a Solar Energy Standard and offers incentive programs that result in cost-effective PV for participating individuals and businesses. However, these incentives are available on a lottery basis. Program limits will not allow all home and building owners and tenants on the redevelopment site to benefit from them. Tables ES-3 and ES-4 show estimated levelized costs of electricity (LCOE) for PV and retail electricity for a 25-year analysis period starting in year 2019. In Table ES-3, ITC refers to the federal investment tax credit. The LCOE of PV does not include any Minnesota incentives. Based on projected PV cost reductions and utility retail electricity cost increases, net-metered PV systems are predicted to be near grid-parity in terms of costs in about 2020 when the site may be ready for occupancy.

Table ES-3. Nominal Levelized Cost of Electricity From PV Systems, $/kWh

	10% ITC	30% ITC
Residential Rooftop	$0.097–$0.142	$0.080–$0.116
Commercial Rooftop	$0.095–$0.139	$0.076–$0.110

Table ES-4. Projected Retail Cost of Utility Purchased Electricity Over 25-Year Analysis Period

	Levelized Cost ($/kWh)
Residential	$0.130
Commercial	$0.115

Incorporating energy goals into development requirements can help ensure that development proposals for this site meet expectations of the City of St. Paul.

To maximize the fraction of electricity loads that can be offset with renewable PV electricity, the city could consider the following options:

- Focus on energy efficiency in the design phase. This improves the prospect of meeting a higher portion of total electricity needs through PV and reduces the total size, and therefore cost, for PV systems needed to achieve net-zero electricity.
- Consider PV as part of the building infrastructure in the design phase, even if it is decided that it will not be installed during initial construction. This will ensure that sufficient, shade-free roof areas are available, the buildings are structurally prepared for PV loads, and that PV can be cost-effectively added if the building owner decides to add a system. This includes maximizing the PV-ready roof area by including building architectural features that allow sufficient roof exposure facing south and reducing building-on-building shading.
- Maximize rooftop PV capacity by specifying best-in-class efficiency PV modules.
- Expand on-site areas capable of hosting PV by adding over-parking shade structures that support PV systems. These systems can either directly tie to individual building meters if their location permits cost-effective interconnection or possibly be developed as Community Solar Garden systems with ownership shares dedicated to utility customers within the development. The Community Solar Garden program has capacity limits so achieving 100% renewable electricity this way is not assured.
- Allow development of a 0.6-MW Community Solar Garden on the parking lot covering the former Ford dump site.

Table of Contents

1 Introduction

The purpose of this assessment is to consider photovoltaic (PV) electric systems as part of the planned infrastructure in the development on the site of the former Ford Motor Company assembly plant in St. Paul, Minnesota. This assessment looks at three elements:

1. Technical potential for providing some or all of the buildings' electricity with rooftop PV
2. Economics of PV
3. Development considerations to maximize PV potential.

The results of the technical potential and economic portions of this assessment are indicative, not conclusive, due to uncertainty in the development scenarios, levels of building efficiency ultimately specified and achieved, and uncertainty in PV costs and incentive programs that have a significant impact on economic viability.

The site is 135 acres located on the east bank of the Mississippi River, about 1 mile northeast of the Minneapolis - St. Paul International Airport. The site is mostly flat and completely scraped of all buildings and vegetation.

Currently, there are five development scenarios being considered.[2] Per the direction of the City of St. Paul, this analysis considers Development Scenarios 2–5. The scenario descriptions include an approximate mix of residential units, including the number of units of single-family homes, townhomes, and multi-unit housing structures and approximate square footage of retail space, commercial space, and light industrial space. The scenarios also describe an approximate number of floors of the building types for multi-family, retail, and commercial spaces.

[2] *Ford Motor Company Site, Phase 1 Summary Report: 5 Major Development Scenarios*, 2014. Accessed September 24, 2014: http://www.stpaul.gov/DocumentCenter/Home/View/16428.

2 Technical Potential

This section includes a general discussion and analysis that considers how much of the site's total electricity needs might be met with PV-generated electricity. Because the current development scenarios are only sketches of possible build-out scenarios that consider different amounts of residential, retail, commercial, and industrial space, electricity consumption and available rooftop area for PV under each scenario can only be grossly estimated. Electricity usage can vary significantly based on the building architectural design and mechanical systems and each building tenants' consumption requirements and habits. Available space for rooftop PV depends on roof orientations, pitches, areas free from penetrations and mechanical systems, a given roof's solar access, and relative roof area to total building floor area (higher-rise buildings have less relative roof space to support PV per occupied area than buildings with fewer floors). PV electricity production levels depend on details of the installation, including efficiency of the class of PV panels specified, the orientation of the installations, and shading levels. Due to all of these factors, the results of the technical potential have relatively large uncertainty and are indicative only. They should, however, help inform design decisions and drivers as development details are further refined and formed.

Details of the technical potential analysis follow, including an overview of the development scenarios, electricity requirement estimates, PV performance, and available rooftop analysis.

2.1 Development Scenarios

The development scenarios are described in *Redevelopment of the Ford Motor Company Site, Phase 1 Summary Report: 5 Major Development Scenarios*.[3] Table 1 shows a general description of each scenario. As directed by the City of St. Paul personnel, the analysts considered Development Scenarios 2–5, as described in the report.

Table 1. Development Scenarios

Scenario	Name	Considered in This Analysis?
1	Primary Industrial	No
2	Light Industrial/Flex Tech	Yes
3	Mixed Use: Office/Institutional	Yes
4	Mixed Use: Urban Village	Yes
5	Mixed Use: Transit Village	Yes

Descriptions of the relative mix of residential, retail, office/institutional, and light industrial spaces for each scenario are mixed; residential types are described by the number of units while retail, office/institutional, and light industrial types are described in terms of total square feet. These figures are shown in Table 2.

[3] *Ford Motor Company Site, Phase 1 Summary Report: 5 Major Development Scenarios*, 2014. Accessed September 24, 2014: http://www.stpaul.gov/DocumentCenter/Home/View/16428.

Table 2. Build-Out by Space Type for Each Site Development Scenario

	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Single Family	87 units	44 units	242 units	0
Townhome	36 units	74 units	206 units	0
Multi-Family, Low Rise	250 units	404 units	230 units	300 units
Multi-Family, Medium Rise	251 units	723 units	250 units	730 units
Multi-Family, High Rise	0	0	0	320 units
Office/Institutional	250,000 ft^2	750,000 ft^2	260,000 ft^2	375,000 ft^2
Retail	135,000 ft^2	200,000 ft^2	275,000 ft^2	194,000 ft^2
Industrial	590,000 ft^2	0	0	0

2.2 Estimating Site Electricity Requirements

Annual electrical energy use of the individual development scenarios was estimated by multiplying electricity use intensity (EUI) values in units of kilowatt-hours per square foot per year (kWh/ft^2/year) by the gross development square footage values for each building type based on the distribution of space types.[4]

EUIs are intended to be representative averages across building types and to be representative of Minnesota buildings. EUIs were taken from a variety of sources. Commercial building values are based on building models built per American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) codes while residential and industrial EUIs come from empirical data of existing facilities.

This analysis attempts to bracket EUIs between typical and efficient construction. However, actual values will depend on design and tenant usage requirements and behaviors. For achieving low energy intensity, energy use targets should be specified by project leaders and assured through design, bid, construction, and commissioning phases.

Table 3 lists the assumed EUIs.

Table 3. Electricity Use Intensities (kWh/ft^2-year)

	Residential	Office & Institutional	Retail	Industrial
Standard Efficiency Building	3.9	11.3	13.3	25.0
Low Energy Use, High Efficiency Building	2.4	8.9	12.9	18.0

Table 4 shows the references used for the values in Table 3.

[4] *Ford Motor Company Site, Phase 1 Summary Report: 5 Major Development Scenarios*, 2014. Accessed September 24, 2014: http://www.stpaul.gov/DocumentCenter/Home/View/16428.

Table 4. References and Assumptions Used for Electricity Energy Use Intensities

	Residential	Office & Institutional	Retail	Industrial
Standard Efficiency Building	Value from KEMA report for local utility[5]	Analysis based on ASHRAE 90.1. Average of small, medium, and large office buildings in Minneapolis.[6]	Analysis based on ASHRAE 90.1, for retail buildings in Minneapolis.[7]	Industrial Assessment Centers Database[8,9]
Low Energy Use, High Efficiency Building	Assume 40% reduction[10]	Analysis based on ASHRAE 189.1.[11] This report uses values from that work but not published in the reference. Value is average of small medium and large office space in Minneapolis.	Analysis based on ASHRAE 189.1.[12] This report uses values from that work but not published in the reference. Value is for retail space in Minneapolis.	Industrial Assessment Centers Database[13]

This analysis assumes that space heating and water heating are not provided by electricity. Further, this analysis considers building electrical loads only. Additional loads within the development (e.g., street lighting) are not included and would require additional PV to offset their electricity consumption if those loads were included in the development's renewable goals.

Because the square footage of residential units was not provided in the *Ford Motor Company Site*,[14] the analyst assigned the values. Table 5 shows the assumed values.

Table 5. Assumed Total Floor Area of Residential Units

	2-Story Single-Family Home	2-Story Townhome	3-Story Multi-Family Unit	4-Story Multi-Family Unit	6-Story Multi-Family Unit	10-Story Multi-Family Unit
Unit Area (ft^2/unit)	2,500	1,600	1,100	1,100	1,100	1,100

[5] KEMA, Inc. *Xcel Energy Minnesota DSM Market Potential Assessment, Final Report – Volume 1*, 2012. Accessed November 5, 2014: http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-DSM/MN-DSM-Market-Potential-Assessment-Vol-1.pdf.
[6] DOE, New Construction – Commercial Reference Buildings. Accessed October 30, 2014: http://energy.gov/eere/buildings/new-construction-commercial-reference-buildings.
[7] DOE, New Construction – Commercial Reference Buildings. Accessed October 30, 2014: http://energy.gov/eere/buildings/new-construction-commercial-reference-buildings.
[8] Data for audited industrial facilities were taken from the reference. EUI values were calculated for Minnesota facilities. EUIs ranged from 10 to 200 kWh/sq. ft/year. Values were selected by the analyst at the low end of the distribution as representative 'standard light industrial' and 'low energy use light industrial.'
[9] Industrial Assessment Center Database. Accessed October 20, 2014: http://iac.rutgers.edu/database/.
[10] KEMA, Inc. *Xcel Energy Minnesota DSM Market Potential Assessment, Final Report – Volume 1*, 2012. Accessed November 5, 2014: http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-DSM/MN-DSM-Market-Potential-Assessment-Vol-1.pdf.
[11] Long, N.; Bonnema, E.; Field, K.; Torcellini, P. (2010). *Evaluation of ANSI/ASHRAE/USGBC/IES Standard 189.1-2009*. TP-550-47906. Golden, CO: National Renewable Energy Laboratory, 55 pp.
[12] Long, N.; Bonnema, E.; Field, K.; Torcellini, P. (2010). *Evaluation of ANSI/ASHRAE/USGBC/IES Standard 189.1-2009*. TP-550-47906. Golden, CO: National Renewable Energy Laboratory, 55 pp.
[13] Industrial Assessment Center Database. Accessed October 20, 2014: http://iac.rutgers.edu/database/.
[14] *Ford Motor Company Site, Phase 1 Summary Report: 5 Major Development Scenarios*, 2014. Accessed September 24, 2014: http://www.stpaul.gov/DocumentCenter/Home/View/16428.

2.3 PV Performance

PV installations require shade-free solar exposure for most daylight hours and roof layouts that permit cost-efficient installations. Section 4 includes discussion of development considerations for accommodating PV installations. In addition to the rooftops within the development, the 3-acre parking lot that caps a Ford dump site adjacent to the river is a possible site for additional PV that building owners could buy shares of under a Community Solar Garden (CSG) type of development (described in more detail later in this report).

This analysis assumes net metering is available so that PV electricity that may be exported to the grid is credited to the utility customer's electricity bill. Without net metering, PV produced during daylight hours that is not immediately consumed at the building would not provide any value to the PV system offtaker (e.g., on a home during the week when the homeowners are at work and on a school or commercial property that is not occupied during a weekend). Without net metering, exported electricity would either be surrendered to the utility or PV systems would require battery storage, which adds significantly to overall system costs. Minnesota law allows customers of investor-owned utilities (IOUs), including Xcel, which serves St. Paul, with systems up to 1 MW in size (1,000 kW) to net meter.

Additional PV can be developed over street-level parking and on the top level of parking garages. As the development scenarios did not describe space designations for these, they are not included in the technical potential figures. Canopy structures over parking for support of PV add to overall system costs so economics described in Section 3 would be negatively impacted. If parking is not located to readily allow cost-effective interconnection to building electricity meters, these systems could be developed as CSG systems. Section 3 also describes Minnesota's CSG program.

The energy produced by PV systems depends on the local solar resource, coincident ambient temperatures (efficiency decreases as PV panels become hot), and installation details. As mentioned above, energy production is sensitive to shading. For example, a shadow can reduce power levels from a PV system by as much as 30 times the shadow's physical size.[15] System designers can reduce the effect of shading in the design phase when shadow patterns are considered and PV electrical architecture is appropriately specified and configured. Additionally, ongoing advances of module-level power electronics (including microinverters) promise reduced impact of shading (among other factors); however, as PV requires sun to function, minimizing shading will maximize electricity production and will always be considered a best practice.

In addition to shading, the orientation of the PV panels relative to the sun's position in the sky has an effect on energy production. A PV installation with a tracking rack system will constantly adjust the position of the panels to better capture the solar resource. Rooftop systems are fixed-tilt as a general rule (i.e., they are not tracking systems). Ground-mounted systems can be fixed or tracking. The decision as to whether to specify tracking in the system design is based on the relative cost of the tracking system versus electricity production gain.

[15] Deline, C. (2009). "Partially Shaded Operation of a Grid-Tied PV System." [Proceedings] 34th IEEE Photovoltaic Specialists Conference (PVSC '09), 7-12 June 2009, Philadelphia, Pennsylvania. CP-520-44874. Piscataway, NJ: Institute of Electrical and Electronics Engineers, Inc. (IEEE), pp. 001268-001273. Accessed December 22, 2014: http://dx.doi.org/10.1109/PVSC.2009.5411246.

Power production is reduced from maximum values if the sun's rays do not strike the panels at 90 degrees. However, because PV panels are able to convert both direct as well as diffuse sunlight, power production is less sensitive to the angle between the sun and the panel surface than it is to shading.

For fixed-tilt systems installed in the northern hemisphere, panels are installed generally facing south (as the sun in the northern hemisphere travels across the southern sky). Annual maximum PV production is achieved when the panels have a tilt angle set to the installation's latitude. The latitude in St. Paul is 45 degrees so PV production for a fixed-tilt system would achieve an annual maximum with the azimuth set to south and the panel tilt set to 45 degrees. However, the energy production penalty for not meeting these optimal guidelines is not too severe. Table 6 shows the impact of azimuth (angle from due south) and tilt on annual energy production in St. Paul. The table shows annual energy production is relatively insensitive to moderate deviations of these two parameters from optimal. NREL's PVWatts[16] was used to model PV production levels for this table. The analysis assumes crystalline silicon modules. At optimal tilt and azimuth, the model predicts a PV system would produce about 1,400 kWh per year for each 1 kW-DC of nameplate installed capacity.

Table 6. Impact of Tilt and Azimuth on Annual PV Energy Production in St. Paul[17]

Tilt Angle (degrees)	45 Deg. West of South	30 Deg. West of South	15 Deg. West of South	Due South	15 Deg. East of South	30 Deg. East of South	45 Deg. East of South
20	92%	94%	96%	96%	96%	94%	92%
33	94%	97%	99%	100%	99%	98%	95%
45	94%	97%	99%	100%	99%	98%	95%

On flat roofs, the greater the panels are tilted, the larger the spacing needed between PV rows to eliminate shading of one row of panels on the row behind it. Also, greater tilt angle adds more material necessary for the racking system and results in an increased profile to the wind, which can increase wind loads, potentially adding to the strength requirements of the rack system, and subsequently more material, and increasing loads to the building structure for roof-mounted systems.

On flat roofs, it is relatively easy to set the azimuth to due south, and a 20-degree tilt angle is often specified, providing reduced overall system costs, good roof-packing density, and minimal penalty on annual energy production. On pitched roofs, systems are typically installed parallel to the roofline to minimize racking hardware and maximize packing density. Maximum annual energy production is achieved if the pitched roofs face south, but as Table 6 shows, roofs facing southeast and southwest can also be reasonably used.

In Minnesota, system designers should also consider the impact of tilt on accumulation of snow on the PV panels. Snow on the panels will greatly reduce electricity production and steeper tilted panels will shed snow better than panels with lower tilt angles. In snowy climates like St. Paul,

[16] NREL, PVWatts photovoltaic system model; http://pvwatts.nrel.gov/.
[17] Values in the table are deviation from maximum production (100%) with a 45-degree tilt and azimuth set to due south.

impact of snow is another consideration in the overall optimization of costs and benefits in the design.

For the purposes of this analysis, PV installations are assumed to be an even mix of tilts and azimuths, as shown in Table 6.

2.4 Available Rooftop Area Analysis

To estimate the maximum capacity of PV that each building could hold, an estimate of the rooftop area available for PV is first needed. This requires the number of stories for each building and an estimate as to how much of that roof could be used for PV. For pitched roofs, this analysis assumes 50% of the total roof is available for PV. This assumes a standard gable-type roof and that rooftop penetrations for plumbing vents, heating system vents, and any skylights are limited or located on the portion of the roof that tilts to the north. This analysis assumes that single-family homes, townhomes, and 2- and 3-story multi-family units have pitched roofs while all other buildings have flat roofs. For a flat roof, 70% of the roof is assumed to be available for PV installation. Additionally, this analysis assumes that the above-stated roof area fractions are not further reduced by shadows from trees or other buildings.

For each build-out scenario described in the *Ford Motor Company Site*,[18] the analyst studied the text accompanying each description to make an informed assumption on the number floors for some of the building types. Some descriptions have specific values while others have ranges (e.g., under Scenario 3, the build scheme describes "3–6 story condominiums/apartments/senior housing"). In this case, it was assumed that the (404) Multi-Family Low Rise units described in Development Scenario 3 are 3-story and the (723) Multi-Family High Rise are 6 stories high. In other cases, the analyst assumed an average number of stories by inference from the accompanying images of each scenario. Some of these designations were arbitrarily chosen by the analyst as the report lacks specificity.

Table 7 includes the number of stories used in the analysis for the residential unit types described in the *Ford Motor Company Site*.[19]

Table 7. Assignment of Number of Residential Units in [1] to Stories of Building in This Analysis

Scenario	2-Story Single Family Home	2-Story Townhome	3-Story Multi-Family Unit	4-Story Multi-Family Unit	6-Story Multi-Family Unit	10-Story Multi-Family Unit
2	87	36	250	251		
3	44	74	404		723	
4	242	206	230		250	
5			300	730		320

[18] *Ford Motor Company Site, Phase 1 Summary Report: 5 Major Development Scenarios*, 2014. Accessed September 24, 2014: http://www.stpaul.gov/DocumentCenter/Home/View/16428.
[19] *Ford Motor Company Site, Phase 1 Summary Report: 5 Major Development Scenarios*, 2014. Accessed September 24, 2014: http://www.stpaul.gov/DocumentCenter/Home/View/16428.

2.5 Residential Results

Table 8 shows a breakdown of the residential units to provide better insight into general approach and drivers. General results are that single-family homes and townhomes have sufficient roof area to allow enough PV to meet 100% of electricity needs for higher EUI of standard construction and lower efficiency PV panels. At 3 and 4 stories, there may be a slight shortfall in meeting 100% of electricity needs with PV unless units or unit occupants manage energy use or higher efficiency PV panels are specified. The table indicates that residential housing that exceeds 4 stories is unlikely to be able to provide 100% of electricity needs with rooftop PV.

Table 8. PV Needed for Net Zero and Available Space for PV by Residential Unit Type

	Single Family	**Townh ome**	**3-Story Multi-Family Unit**	**4-Story Multi-Family Unit**	**6-Story Multi-Family Unit**	**10-Story Multi-Family Unit**
Unit Area (ft^2/unit)	2,500	1,600	1,100	1,100	1,100	1,100
Stories	2	2	3	4	6	10
Roof Area Per Unit (ft^2/unit)	1,250	800	367	275	183	110
Roof Fraction for PV	50%	50%	50%	70%	70%	70%
Avail. Roof Area for PV (ft^2/unit)	625	400	183	193	128	77
Electricity Usage, Standard Efficiency Building (kWh/unit-yr)	9,861	6,311	3,850	3,850	3,850	3,850
Electricity Usage, High Efficiency Building (kWh/unit-yr)	5,917	3,787	2,200	2,200	2,200	2,200
PV Needed to Serve Load (kW/unit), Standard Construction	7.3	4.7	2.8	2.8	2.8	2.8
PV Needed to Serve Load (kW/unit), High Eff. Construction	4.4	2.8	1.6	1.6	1.6	1.6
Max. PV Installed Per Unit, 15.5% Eff. (kW)	9.0	5.8	2.6	1.5	1.0	0.6
Max. PV Installed Per Unit, 20% Eff. (kW)	11.6	7.5	3.4	2.1	1.4	0.8
PV Shortfall (kW/unit), Standard Eff. Bldg, 15.5% Eff. Module	-	-	0.2	1.3	1.8	2.2
PV Shortfall (kW/unit), Standard Eff. Bldg, 20% Eff. Module	-	-	-	0.8	1.5	2.0
PV Shortfall (kW/unit), Eff. Bldg, 15.5% Eff. Module	-	-	-	0.1	0.6	1.0
PV Shortfall (kW/unit), Eff. Bldg, 20% Eff. Module	-	-	-	-	0.3	0.8

2.6 Technical Potential Summary

This analysis uses the "net-zero energy" concept to quantify how much PV is needed to offset all of the electricity a building uses in one year.[20] In this report, net-zero electricity means on-site renewable systems produce as much as or more electricity than the building uses annually. This concept considers renewable electricity exported to the utility as an offset against non-renewable power purchased from the utility. If total renewable electricity exports equal or exceed total utility purchases on an annual basis, the building is considered net-zero electric.

The analysis estimates that 7–17 MW of PV are needed to make all of the buildings on the development at the Ford Motor site net-zero renewable electric depending on the development scenario and level of electrical energy use required. Table 9 shows these results. Scenarios with higher electricity usage requirements need proportionally more PV to offset their electricity consumption than development scenarios with lower electricity demands. Development Scenarios 4 and 5 have the lowest overall electricity use and are estimated to require 7– 9 MW of PV depending on the level of energy efficiency specified by building construction. Development Scenario 2 would require the most PV for net-zero renewable electricity—approximately 12 MW under a low electricity (high efficiency) scenario and 17 MW with typical electricity consumption estimates. Scenario 2 is estimated to have high electricity usage requirements due to the light industrial component of this scenario; the other development scenarios do not have this industrial element.

Table 9. Estimates of PV Needed for Net-Zero Electricity and Rooftop Space Available

Scenario	Building Electricity Usage	PV Needed for Net-Zero Electricity (MW)	PV Module Efficiency	PV Needed for Net-Zero Met by Rooftop Capacity (%)	PV Shortfall (MW) of Rooftop Space
2	Low	12.1	High	57	5.2
			Mid	45	6.6
	Typical	16.6	High	46	8.9
			Mid	37	10.5
3	Low	9.1	High	50	4.6
			Mid	41	5.4
	Typical	12.1	High	44	6.8
			Mid	36	7.8
4	Low	6.8	High	63	2.5
			Mid	55	3.1
	Typical	9.0	High	62	3.4
			Mid	56	4.0
5	Low	6.5	High	49	3.3
			Mid	43	3.7
	Typical	8.9	High	44	5.0
			Mid	35	5.8

[20] The following references have a full discussion on the concept of net-zero energy:
Torcellini, P; Pless, S; Deru, M. (2006). *Zero Energy Buildings: A Critical Look at the Definition*. CP-550-39833. Golden, CO: National Renewable Energy Laboratory.
Carlisle, N.; Van Geet, O.; Pless, S. (2009). *Definition of a 'Zero Net Energy' Community.* TP-7A2-46065. Golden, CO: National Renewable Energy Laboratory.

The estimates of rooftop areas available for PV do not follow any trend based on electricity needs. Although Development Scenario 2 has the highest estimated electricity needs, and therefore would require the most PV of all development scenarios, the roof space can support 37%–57% of PV required to achieve net-zero renewable electricity. By this metric, Scenario 4 comes in first place with up to 63% of electricity demand being offset by rooftop solar. Scenarios 3 and 5 are approximately tied in last place in terms of the fraction of PV needed for net-zero that can be met by rooftop PV.

The results in Table 9 assume high-efficiency modules have 20% efficiency while mid-efficiency modules have 15%. To maximize the fraction of electricity loads that can be offset with renewable PV electricity, the following options can be considered:

- Drive reduced electricity loads by including aggressive energy intensity use targets for all building types.
- Maximize use of roof areas for PV by including building architectural features that allow sufficient roof exposure facing south and reducing building-on-building shading.
- Maximize rooftop capacity on space-constrained roofs by specifying best-in-class efficiency PV modules. For example, a given roof can support about 33% more PV in terms of [kW] nameplate rating if a 20% efficient PV module is specified instead of a 15% module.
- Expand on-site areas capable of hosting PV by adding over-parking shade structures that support PV systems. These systems can either directly tie to individual building meters if their location permits cost-effective interconnection or possibly be developed as CSG systems with ownership shares dedicated to utility customers within the development. The CSG program has capacity limits so achieving 100% renewable electricity this way is not assured.
- Allow development of a 0.6-MW CSG on the parking lot covering the former Ford dump site. This is not sufficient to make up the PV deficit needed to achieve net-zero under any development scenario but would contribute to the overall goal.

3 Economic Outlook

The economics of PV is influenced by installed costs, available incentives, cost of utility electricity, and PV performance based on installation and climate conditions described above. Because development of the site is still a number of years away, this adds uncertainty to an economic assessment due to uncertainty in projected PV costs, retail electricity rates, and incentives.

A discussion of current available incentives follows. Projected solar costs and utility rates are then presented with a general economic outlook for PV in St. Paul.

In Minnesota, the state's Solar Energy Standard currently requires IOUs to have 1.5% of total electricity sales be provided by PV by 2020.[21] For Xcel, this is approximately 400 MW. Legislation and program rules require that 10%, or approximately 40 MW, come from distributed, small-scale solar. This small-scale PV carve-out is driving three current incentive programs:

1. Xcel Solar Rewards Program[22]—This program is a production-based incentive (PBI) for systems up to 20 kW in size. A PBI is an incentive that the system owner receives for each unit of electricity that the PV system produces. Currently, the PBI is $0.08/kWh, and system owners who are accepted into the program will receive this payment for 10 years. However, the program expires in 2018 and therefore will not be available by the time the Ford site is redeveloped.
2. Made in Minnesota (MiM) Program[23]—MiM is also a PBI that is paid to system owners over 10 years for systems with modules that are made in Minnesota. This is a 10-year program; the last year systems will be accepted into the program is 2023. Therefore, the MiM program should be an option for the redevelopment at the Ford site as construction is completed and units begin to be purchased and occupied. The legislation requires that MiM PBI levels be set sufficiently high to ensure that participants receive a "reasonable return on their investment."[24] As implemented, PBI payments ensure systems achieve a simple payback typically in 6–8 years and a return on investment of approximately 8%–11% over 25 years. There are currently two Minnesota module manufacturers approved under this program, and the PBI varies depending on the module costs for each company and the utility sector of the system owner (i.e., residential customer versus commercial customer). Residential systems up to 10 kW and commercial systems up to 40 kW are eligible. The current PBI for residential systems is $0.20/kWh for systems with modules manufactured by tenKsolar and $0.27/kWh for Silicon Energy Cascade Modules, and $0.13/kWh and $0.18/kW for commercial systems, respectively. Program funding is $15 million per year, and last year the program was fully subscribed. Program funds for PV (MiM also includes solar thermal systems) are split 50/50 between residential and commercial customers. Roughly 90% of residential customers who applied for the

[21] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN14R&re=0&ee=0.
[22] http://www.xcelenergy.com/Save_Money_&_Energy/Rebates/Solar*Rewards_-_MN.
[23] Information on this program was found at http://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/made-in-minnesota/what-is-made-in-minnesota.jsp and as explained by Kim Havey from MN Dept. of Commerce during a telephone call on November 21, 2014.
[24] https://www.revisor.mn.gov/statutes/?id=216C.414.

program were selected in the lottery while about 40% of commercial customers won awards due to higher demand in this sector.

3. Community Solar Gardens—For utility customers who do not want to host a project or who do not have an opportunity to host one (e.g., insufficient roof space, roof access, or access to solar resource; not the building owner), the CSG program allows the utility customers to buy shares of PV systems installed as CSGs. For buying into a system, the utility customer receives a financial credit (not electricity credit) on their utility bill for their share of the project's monthly electricity production. The credit for each unit of electricity includes the retail value of electricity that the system exported to the electrical grid plus a payment for the solar renewable energy credit (SREC) associated with that energy. An SREC represents the environmental attributes associated with the PV-generated electricity. In Minnesota, utilities demonstrate compliance with the state's Solar Energy Standard by accumulating SRECs. For commercial electricity customers the total payment is approximately $0.12/kWh inclusive of the SREC and $0.15/kWh for residential customers. Based on current retail electricity costs, the SREC payment is approximately $0.04–$0.06/kWh of the total payment.

In terms of life cycle economics, participants in the MiM program are assured a return on investment of 8%–11% by program design. This is a generous program although the award is through a lottery and therefore not assured. Relatively high rates of awards were seen in the first year of the program, but as the program becomes more widely known, chances of successful awards may greatly diminish by the time the Ford site redevelopment begins occupancy. Perhaps 10%–40% of all electric utility customers within the development could be awarded MiM program PBIs; therefore, a good fraction of total electricity could be provided by a program that assures cost-effective PV.

Utility customers can also purchase CSG shares instead of buying their own systems. As CSG share owners receive utility credits for retail value of electricity produced plus SREC payments from the utility, the value of the solar energy is higher than the cost of the electricity they consume. Further, the credit from the utility increases as utility costs increase over time. CSGs less than 40 kW in size that use certified made-in-Minnesota panels can also apply to the MiM program. MiM CSGs would receive a higher price for the SREC under the PBI established for commercial systems, which is currently $0.13–$0.18/kWh.

It is important to note that both the MiM and CSG programs are driven by the Minnesota Solar Energy Standard, which requires IOUs to demonstrate compliance through sufficient accumulation of SRECs. To that end, the serving utility receives all of the SRECs for systems participating in these programs. This is important in that the owner of the SREC has claim to the "green" renewable power that is generated by the PV systems. Homeowners and businesses essentially sell SRECs to participate in these programs and cannot claim that they are consuming renewable power. For a homeowner, it may not matter, but for businesses, it could impact their decision making if positive public relations is one of the motivators. One could say they are hosting a PV system or that they have a PV system on their roof, but they could not state that they are consuming renewable power if they do not own the SRECs generated by the system. However, once the PBI payments cease after 10 years, the system owner once again becomes the owner of the SRECs produced for the remainder of the system life, perhaps 15–20 years.

For utility customers who are unable to participate in either the MiM or CSG programs, an economic analysis was performed to calculate the cost of the electricity produced from PV systems without those programs' benefits. Without SRECs, economics are driven by installed costs, federal tax incentives (if the system owner has sufficient tax basis to benefit from them), PV electricity production, and retail electricity costs. For simplicity, the economic metric reported here is the levelized cost of electricity (LCOE). It includes the initial total installed system cost and lifetime maintenance costs and is an indicator of how much each unit of electricity produced by the system costs over the system lifetime. The results are shown in Table 10. NREL's System Advisor Model (SAM) was used to generate these results.[25] The results assume the federal tax incentives are captured by the system owner. The federal investment tax credit (ITC) is currently 30% but will revert to 10% in 2017 unless extended by legislative action. This analysis considers both possible ITC levels to show the impact each could have on PV LCOE. In addition to the ITC, the modified accelerated cost recovery system (MACRS) depreciation tax credit is applied to commercial systems as this is an income deduction that businesses can take for investments in tangible property. LCOEs are based on a 25-year analysis period.

Table 10. Nominal Levelized Cost of Electricity From PV Systems, $/kWh

	10% ITC	30% ITC
Residential Rooftop	$0.097–$0.142	$0.080–$0.116
Commercial Rooftop	$0.095–$0.139	$0.076–$0.110

Table 11 shows the projected costs for utility-purchased electricity over the same analysis period. The utility costs are reported in the same metric to allow easy comparison of the cost of PV-generated electricity versus buying electricity from the utility. If PV LCOE is less than retail-projected LCOE, PV is cost effective. If it is more, the system owner is paying a cost premium for renewable energy. Comparison of the costs for PV electricity in Table 10 and utility-purchased electricity in Table 11 shows PV electricity is projected to be in the same range as retail rates based on the stated assumptions and even cost competitive depending on assumed installation costs.

Table 11. Projected Retail Cost of Utility Purchased Electricity Over 25-Year Analysis Period

	Levelized Cost ($/kWh)
Residential	$0.130
Commercial	$0.115

These results do not consider existing or possible future state incentives. As stated above, the MiM program as designed assures investments are economically beneficial under that program. The CSG program includes an SREC payment that is currently approximately $0.04–$0.06/kWh in addition to on-bill credits at retail electricity rates. So the SREC for shareholders in a CSG system can be considered to reduce the cost estimates in Table 10 for PV electricity by SREC payment amount, or $0.04–$0.06/kWh. For those that are able to take advantage of these two programs, the economics are positive.

[25] NREL, System Advisor Model (SAM) performance and financial model; https://sam.nrel.gov/.

Although PV can be cost-effective, it is a high-cost investment (e.g., a 5-kW residential PV system may cost $10,000 in 2019). If net-zero or near net-zero is a goal of the City of St. Paul for this site, it needs to be expressed in development requirements, or it is probable that it is often "value-engineered" out of the development plans in the experience of NREL personnel who have worked on projects with similar goals.

Both PV and utility LCOEs assume a 5% nominal discount rate for the residential sector and 8% for commercial. Retail utility costs in Table 11 assume current electricity retail rates are $0.09/kWh for residential and $0.08/kWh for commercial and that electricity costs will increase 2.5%/year over the analysis period.[26] The utility costs presented are calculated using a 25-year period starting in year 2019, as that is the same assumed installation year for the PV systems.

These and other assumptions are included in Table 12.

Table 12. Economic Analysis Assumptions

	Discount Rate	Investment Tax Incentive	Modified Accelerated Cost Recovery System	PV Total Installed Costs (Projected)
Residential	5%	10% and 30%	Not eligible	$1.60–$2.45/Watt
Commercial	8%		Yes	

Because the development of the old Ford plant site has not yet started, installation of PV systems may occur more than 5 years from now. PV installed costs have come down 200%–300% over the last 5 years and, although costs are not expected to drop as significantly over the next 5 years, some further cost reductions are projected.[27]

Projected installed costs for PV systems used in this analysis are compared with current national costs in Table 13.[28] Feldman et al. include a range of cost projections for 2016.[29] For this analysis, because the installation dates would be closer to 2019, a range of possible costs is estimated here, assuming continued cost declines after 2016 and the opposing force of lower PV market activity in St. Paul relative to other more active U.S. markets (which dominate and therefore tend to skew cost data and projections to those markets). Although Minnesota is not currently a very active market for PV, the state's Solar Energy Standard may change that. The 2019 projections are based on these factors and should be considered estimates only for a general discussion of economic outlook in St. Paul. More in-depth research and possible modeling for

[26] These assumptions were suggested to be reasonable estimates during a conversation with K. Havey at the Minnesota Department of Commerce on November 21, 2014.
[27] Feldman, D.; Barbose, G.; Margolis, R.; James, T.; Weaver, S.; Darghouth, N.; Fu, R.; Davidson, C.; Booth, S.; Wiser, R. (2014). *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections*. PR-6A20-62558. Sunshot, U.S. Department of Energy (DOE), 32 pp.
[28] These costs are based on NREL internal cost models and Feldman, D.; Barbose, G.; Margolis, R.; James, T.; Weaver, S.; Darghouth, N.; Fu, R.; Davidson, C.; Booth, S.; Wiser, R. (2014). *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections*. PR-6A20-62558. Sunshot, U.S. Department of Energy (DOE), 32 pp.
[29] Feldman, D.; Barbose, G.; Margolis, R.; James, T.; Weaver, S.; Darghouth, N.; Fu, R.; Davidson, C.; Booth, S.; Wiser, R. (2014). *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections*. PR-6A20-62558. Sunshot, U.S. Department of Energy (DOE), 32 pp.

improved accuracy in cost projections would be needed to improve uncertainty but is beyond the scope of this analysis.

Table 13. Rooftop PV Installed Costs Assumed in This Analysis

Current Prices	$2.94/Watt
2019 Projected Prices	$1.60–$2.45/Watt

Rooftop systems for the build-out scenarios can range in size from a few kilowatts for a single-family home to hundreds of kilowatts for a commercial rooftop system. Economy of scale typically results in lower costs for larger rooftop systems (i.e., commercial systems); however, as this analysis assumes the development includes rooftop PV as part of the original build, economy of scale is assumed to apply equally to all types as multiple projects can be bid and installed concurrently, reducing installers' overhead and mobilization costs. The rooftop cost of PV in Table 13 is intended to represent the average of all rooftop systems.

These cost estimates include significant uncertainty due to, among others, the uncertainty of timing, building architectural details, local PV market competitiveness that may exist in 4 years, and how PV projects may be bundled for improved economy of scale.

A summary of economic model inputs and assumptions follows:

- Analysis period, 25 years
- Discount rate, 8% nominal for commercial, 5% for residential
- General inflation rate, 2% (applies to operations and maintenance costs)
- ITC, 10% and 30% sensitivities
- MACRS, 5-year depreciation for commercial systems
- Federal income tax rate, 30%
- State income tax rate, 9.8%[30]
- Operations and maintenance costs, $20/kW-DC/year
- Insurance, 0.5% total installed costs/year
- PV installations are assumed to be an even mix of tilts and azimuths, as shown in Table 6
- PV system energy production degradation rate, 0.5%/year.

[30] http://www.taxadmin.org/fta/rate/corp_inc.pdf.

4 Development Considerations to Maximize PV Potential

Design for sustainability is a large and growing discipline, and its principles are already being considered by St. Paul for the redevelopment of the Ford assembly plant site. The needs, functional specifications, aesthetics, design goals, and cost targets, as well as many other factors, will influence the final design of the development. With respect to PV integration, designs of individual structures and the overall development plan will impact how much PV can be installed, what fraction of total development electricity needs the PV can provide, and the economics for integration within the development.

A summary of concepts for PV integration considerations is presented here and a list of references for planners and architects is provided.

Overall, some design decisions complement development goals while others compete against each other. For example, trees provide beauty and serve a cooling function during summer months by both shading buildings and minimizing heat absorption of streets, sidewalks, and parking surfaces. However, PV requires shade-free solar access. Development design can work toward balancing or merging energy, aesthetic, and economic requirements.

1. Community planning
    - A. Street layouts can facilitate access of buildings to the solar resource. In general, blocks oriented east to west will allow buildings to exploit the energy services that the sun can provide. These include:
        - i. Daylighting to significantly reduce daytime use of electrical lighting
        - ii. Passive solar heat gain to reduce building heating requirements for electricity, natural gas, or other sources
        - iii. South-facing orientation for pitched roofs to accommodate efficient capture of solar energy through PV. As mentioned in the technical potential part of the report, PV production diminishes as panel orientation deviates from an optimum 45-degree tilt and 180-degree azimuth (facing south) orientation. However, small deviations are tolerable while shading considerations are far more important.
    - B. Strategic grouping of buildings to minimize building-on-building shading can help control solar gain and maximize daylighting opportunity.
    - C. Considering potential rooftop shading from vegetation during landscape design can help ensure long-term performance of PV systems. Tree growth projections over 50 years or more should be included in this analysis.
2. Solar-ready buildings
    - A. Minimize electrical loads through design that includes energy efficiency targets greater than current building codes. Consider passive solar heating and daylighting strategies, as described above.

B. Increase shadow-free rooftop area by locating and minimizing building structures that protrude above roofline (e.g., locating roof access doorways and mechanical systems at the north end of a roof will increase shade-free available space for PV).

C. Consider ability to host PV during design of roofs, including total area with southern exposure and roof tilt.

D. Include fire-code requirements when estimating available roof space for PV. Code requirements for roof access might impact system layouts.

E. Make buildings solar-ready by pre-engineering loads of PV into the building structure to eliminate additional design review and possible structural bolstering that might otherwise be required for retrofit. On pitched roofs, a PV system will add about 3 pounds/ft^2 of additional load. On flat roofs, PV systems may be bolted to the roof deck, or more typically, held in place by ballast (loaded down with concrete pavers). Depending on which method is used, rooftop dead-loads and live loads due to wind (and in some areas seismic considerations) are impacted. A ballasted system typically weighs 4–6 pounds/ft^2.

F. Consider impact/interaction of PV with roofing materials. Roofing material companies may have specific requirements when installing PV so that the roof warrantee is not voided.

G. Identify location of PV system electrical routing from roof to service panel and provide areas for mounting PV electrical components, including inverters, meters, and disconnects. Make sure electrical service panel has room for additional breakers for interconnection of PV.[31]

[31] This information was taken in part from the following references. They should be consulted for additional details.
Minnesota Solar Ready Construction Specification (To be used in conjunction with the *Solar Ready Building Design Guidelines*). Accessed December 22, 2014: http://mn.gov/commerce/energy/images/Solar-Ready-Construction.pdf.
Solar Ready Building Design Guidelines: Solar Ready Building Design Guidelines for the Twin Cities, Minnesota (September 2010). Accessed December 22, 2014: http://mn.gov/commerce/energy/images/Solar-Ready-Building.pdf.
Renewable Energy Ready Homes (RERH); developed by the U.S. Environmental Protection Agency (EPA) for residential buildings. Accessed December 22, 2014: http://www.energystar.gov/index.cfm?c=rerh.rerh_index.
Lisell, L.; Tetreault, T.; Watson, A. (2009). *Solar Ready Buildings Planning Guide*. TP-7A2-46078. Golden, CO: National Renewable Energy Laboratory; 33 pp.
Watson, A.; Guidice, L.; Lisell, L.; Doris, L.; Busche, S. *(2012). Solar Ready: An Overview of Implementation Practices*..TP-7A40-51296. Golden, CO: National Renewable Energy Laboratory; 42 pp.