An Economic Analysis of Solar PV Microgrids:

Are They a Cost-Effective Option for Solar Deployment in Madison?

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ABSTRACT

This report examines the economic costs and benefits of using microgrids as the main technology to promote distributed renewable generation in the City of Madison. The study compares a baseline scenario under current policies, generation mixes and price assumptions from the Energy Information Administration (EIA) against four microgrid deployment scenarios that replace different percentages of traditional electricity provided by Madison Gas & Electric. The study identifies the costs associated with pursuing varying levels of microgrid deployment, renewable penetration, and assesses the cost burden on different stakeholders.

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Acknowledgements

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Abbreviations & Acronyms

ACEEE – American Council for an Energy Efficient Economy
CO_2 – Carbon dioxide
DER – Distributed Energy Resource
DOE – Department of Energy
EDM – Economic Dispatch Model
EEI – Edison Electric Institute
EIA – Energy Information Administration
EPA – Environmental Protection Agency
EPRI – Electric Power Research Institute
GHG – Greenhouse gases
GIS – Geographic Information System
IOU – Invest Owned Utility
kW – kilowatt
kWh – kilowatt-hour
MG - Microgrid
MGE – Madison Gas & Electric
MISO – Midwest Independent System Operator
mmBtu – Million British Thermal Units
MoDERN – Model for Distributed Energy Resource Networks
MW - Megawatt
MWh – Megawatt-hour
NO_x – Nitrogen oxide
NRDC – Natural Resources Defense Council
NREL – National Renewable Energy Laboratory
O&M – Operations and Maintenance
PCT – Particpant Cost Test
PSC – Public Service Commission
PUC – Public Utilities Commission
PV – Photovoltaic
RIM – Ratepayer Impact Measure
RMI – Rocky Mountain Institute
SCC – Social Cost of Carbon
SO_2 – Sulfur dioxide
T&D – Transmission and distribution
TRC – Total Resource Cost
UCT – Utility Cost Test
VOST – Value of Solar Tariff

1.1 - Project Overview

The goal of this report is to determine whether solar PV-based microgrids can be used to meet a portion of Madison Gas & Electric's (MGE) demand without reducing the utility's long-term net revenue. The report identifies several categories of benefits including: the ability to cost-effectively provide electricity to critical buildings in Madison, and to improve power quality, flexibility and reliability by integrating solar PV with backup generation from natural gas microturbines. Technological advances in power electronics have made microgrids an attractive option for multiple business sectors, military and government applications that require a high level of reliability and control over their power supply.

Combined with the dramatic cost reductions for solar PV, the traditional regulated monopoly business model for electric utilities faces both threats and opportunities. Utilities could choose to oppose the deployment of microgrids and distributed energy resources (DER) to preserve their monopoly status, or they can develop innovative new solutions to incorporate these technologies in a way that maximizes cost savings and other benefit to ratepayers without reducing their profitability.

This study compares the economic viability of using solar PV-based microgrids to offset varying levels of MGE's electricity demand in order to identify customer segments and saturation levels that result in positive net benefits for both the utility and customers. There are multiple levels to this analysis. First, the City of Madison's electricity density (kWh/ft^2) is mapped using geospatial analysis to identify energy hotspots and critical buildings that could benefit from the deployment of microgrids to reduce demand and improve reliability.

Second, the total amount of rooftop area that is suitable for solar PV is mapped in order to match energy hotspots with ideal locations for solar generation. Third, energy modeling using an independently developed tool in conjunction with the Wisconsin Energy Institute's IWEI) MyPower software is used to determine the long-term cost effectiveness of six microgrid deployment scenarios. The results of the modeling simulations are used to determine how many energy hotspots can be served by microgrids without negatively impacting MGE's net revenue over a 25-year period from 2015-2040.

The results of this analysis add to the rapidly evolving discourse surrounding the future of electric utility business models, regulatory treatment of microgrids and DER, and help identify pathways for building a more efficient and resilient electric distribution network without painful rate increases. These are achievable goals according to a recent report by the National Renewable Energy Laboratory (NREL), which concluded that the development of DER through resource planning could yield significant reliability and cost benefits for the whole system.

2.1 - Literature Review

There is a large number of technical, economic and policy studies covering all types of renewable energy and DER deployment strategies. Electric utilities in many states also perform Integrated Resource Planning (IRP) to create forecasts for different generation and consumption scenarios over long time periods. However, Wisconsin does not currently require utilities to conduct mandatory IRP processes and very few utilities have undertaken a holistic analysis that examines the feasibility of wide-scale microgrid deployment as an alternative to building large fossil-fuel power plants that require transmission expansion and other system upgrades.

This study will contribute to the literature by combining economic analysis of microgrid deployment scenarios with utility resource planning to determine whether a transition from the existing electric grid to a “smart grid” is economically feasible. The analysis incorporates a number of evolving regulatory frameworks to help inform policymakers and utilities of the benefits microgrids can provide to ratepayers, electric utilities and the environment. Ultimately, the results of this research will help utilities examine and adjust their business models to convert DER from a threat to a valuable asset that can provide new sources of revenue.

Recent studies by NREL and the Rocky Mountain Institute (RMI) have summarized the results of cost-benefit analyses across multiple states that quantify the value associated with solar PV and other DER technologies. NREL lists the following categories as benefits for solar PV; electricity generation and capacity, transmission and distribution (T&D) cost deferrals, reduced line losses, fuel cost hedging, emissions reductions and associated health benefits. Costs of solar and other DER technologies include the initial capital and debt financing costs, operations and maintenance (O&M), interconnection and grid integration, which vary depending on the degree of DER penetration into the existing electric grid.[1] These benefit and cost categories are echoed by RMI’s survey of regulatory proceedings in states like Colorado, New Jersey and Texas.

Legislation and regulations in Minnesota also provide a unique case study for this analysis. In March 2014, Minnesota adopted regulations that created a value of solar (VOS) tariff that utilities can choose to pay customers for power generated from solar PV on their homes and businesses as an alternative to net metering at the retail rate. Minnesota’s VOS process highlighted the range of methodologies used to calculate the most accurate value for the aforementioned cost and benefit categories. Minnesota’s VOS also required feedback on the value of economic development stimulated by increased deployment of renewables. The values used in Minnesota’s VOS methodology are used to calculate the benefits of microgrids built in MGE’s service territory.[2]

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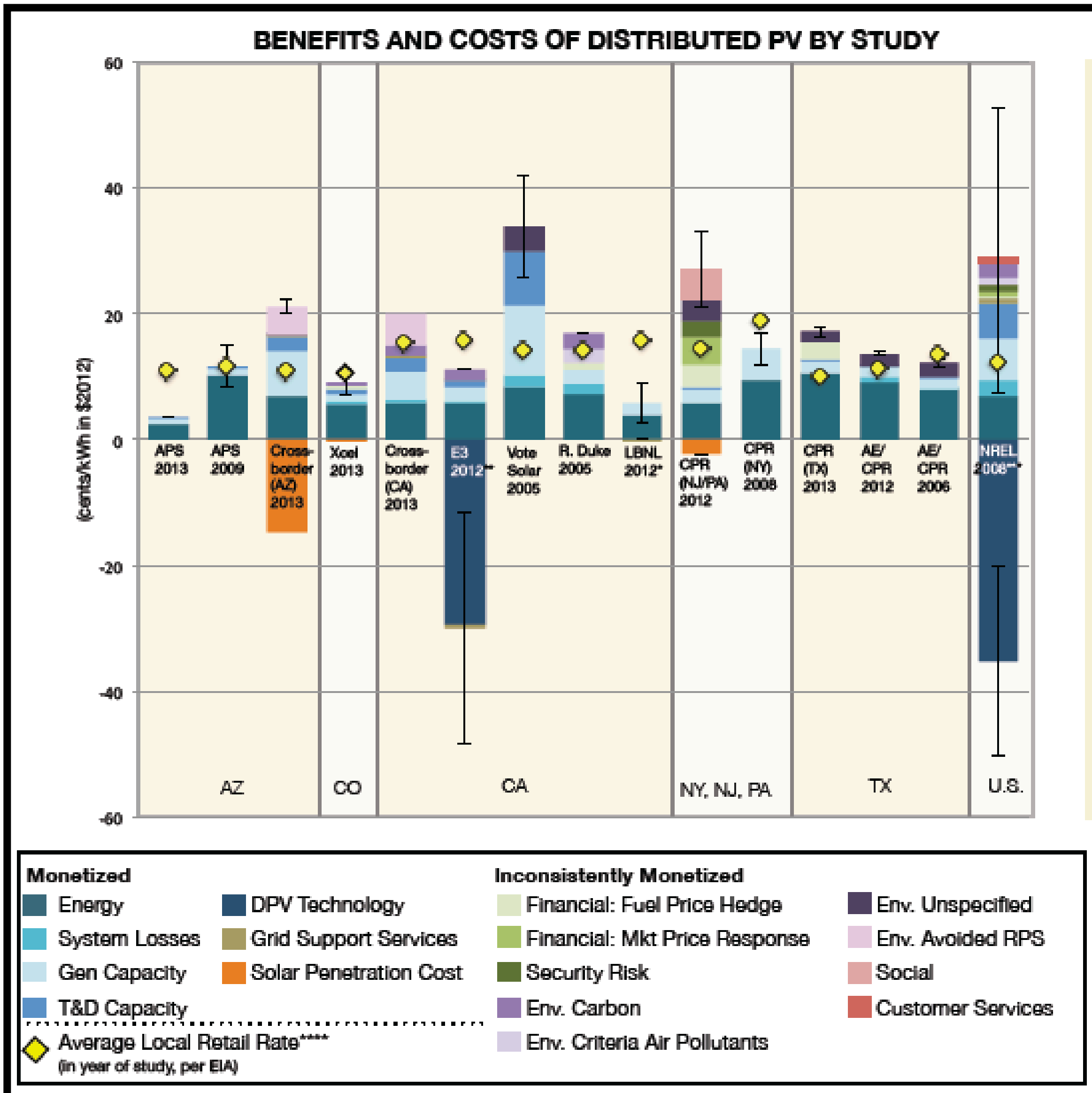
[1] *Regulatory Considerations Associated with Expanded Adoption of Distributed Solar.* NREL(2013) link.

[2] *Minnesota Value of Solar Tariff Methodology*. MN Department of Commerce (2014) link.

Figure 1: Results of RMI Survey of Solar Cost-Benefit Studies[3]



NREL also discusses business models and ratemaking options that could be employed to soften the impact of higher DER penetration from reducing utility revenues. In particular, the study notes that regulators may need to consider the balance between the role of traditional utilities and the dynamic benefits of a third-party service provider. This report examines microgrid deployment under two business models; one where MGE purchases, owns and operates all DER and microgrid equipment versus an alternative scenario where a third party developer purchases, owns and operates the DER and microgrid equipment. These represent two polar opposite cases and do not include provisions for revenue sharing, or

[3] *A Review of Solar PV Cost & Benefit Studies.* Rocky Mountain Institute (2013) link.

shared ownership of DER/microgrid assets. That is an area where additional research could help determine how utility business models can be modified to achieve the most efficient results at the lowest cost to ratepayers.

Dominion Virginia Power provides an example of how a traditional utility under the regulated monopoly business model can support solar PV using its own resources. In February 2012, Dominion filed an application with state regulators requesting permission to operate a five-year pilot program backed by $80 million in funding. The program is designed to support a mix of customer-owned distributed solar, and utility-owned solar projects. Solar projects can range from 500-2,000kW with a goal of installing 30MW of total solar capacity by the end of the five-year pilot period.

The microgrid deployment scenarios examined in this report range from 3-36MW of solar PV capacity (each microgrid uses 1,500kW of solar and 400kW of natural gas fired microturbines). Under the Dominion program, electricity from solar panels does not pass through the customers' meters. Instead, it is fed directly into Dominion's distribution grid and participating customers benefit from lease payment for the use of their property by the utility.[4] Dominion has also gained regulatory approval for an alternative to net metering for solar customers (more information on the program can be found in case number PUE-2011-00117). Under the Community Solar Power Program, participating customers can purchase all of their electricity at the current residential or commercial rate, while selling all of the electricity generated by qualifying solar projects at a fixed rate of 15 cents/kWh.[5]

An example of a utility working in tandem with a third party developer can be found in California where Pacific Gas & Electric (PG&E) formed a subsidiary to invest in distributed solar projects developed by SunRun and SolarCity. The PG&E subsidiary (Pacific Venture Capital) provided upfront financing for the solar projects and received revenue from lease payments by participating solar customers. PG&E was able to take advantage of federal tax credits, state and local rebates that reduced the overall cost of the solar systems. PG&E entered a $100 million agreement with SunRun and a $61 million agreement with SolarCity to finance an estimated 4,500 systems in 2010 and 2011.[6] This is an example of a creative revision to existing utility business models that transformed third party competitors into partners.

The integrated nature of this research project also incorporates an element of urban planning by using geographic information systems (GIS) to determine which locations in the City of Madison represent the best candidates for microgrid development. The best sites for microgrid development were selected by identifying census blocks that contain critical buildings (i.e. health and government buildings), that also contain enough rooftop area to support at least 1,500kW of solar PV

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4 *Regulatory Considerations Associated with Expanded Adoption of Distributed Solar.* NREL(2013) link.

5 Virginia State Corporation Commisson. Final Order in Case Number PUR-2012-00064. 22 March 2013 (link).

6 *Regulatory Considerations,* NREL (2013)

capacity. Solar PV potential was calculated using the assumption that half of each building's rooftop area could be used to support solar PV panels.

A more accurate assessment would require a detailed survey of each property to determine if shade, building orientation, or structural deficiencies would prevent solar from being a viable option. The methodology used in this study follows work done by researchers at Columbia University, which used publicly available data to map annual energy use in each city block of New York City.[7] Methods for quantifying solar PV potential were drawn from a study completed by UCLA's Luskin School for Public Affairs. The UCLA study uses census data to determine the amount of solar capacity that can be supported at different locations within Los Angeles County.[8]

Economic, technology and environmental incentives are changing the face of electricity generation and transmission. Centralized generating facilities are giving way to smaller, more distributed energy resources partially due to the loss of traditional economies of scale.[9] The high-voltage transmission network is reliable and controllable, but suffers from cascading failures. Its efficiency and use of resources are also poor, considering centralized power plants can only achieve 35-cy% efficient because of line losses and smoke stack waste. Revolutionary changes are not expected in the transmission network, but the distribution system provides major opportunities for smart grid development. DER-based distribution system can improve reliability, facilitate high penetration of renewable sources, operate in dynamic islanding mode during blackouts, and increase generation efficiencies.[10]

The best way to manage such a system is to break the distribution system down into small clusters, or microgrids, with distributed optimizing controls coordinating multi-microgrids in a given service territory. Microgrids are defined as an integrated energy system consisting of interconnected loads and DER, which can operate in parallel with the grid, or in an intentional island mode. Dynamic islanding is a key feature that can produce numerous benefits when the grid experiences power faults, voltage sags and outages that can damage expensive equipment and appliances. Smart islanding can greatly enhance the value proposition for the utility and customers alike.[11]

The major roadblock consists of system complexities associated with managing such a wide and dynamic set of resources and control points. One option for dealing with this problem is to create a two-way command and control system with "smart" meters to meet customers' demands. This approach is complex and costly and is not

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[7] Howard, B., Parshall, L., et all. *Spatial Distribution of Urban building Energy Consumption by End Use.* Energy & Buildings, 45, February 2012 (141-151) link.

[8] DeShazo, J.R., Callahan, C., and N. Wong. *Los Angeles Solar and Efficiency Report.* UCLA Luskin Center, November 2013 (link).

[9] Lassetter, R.W. "Smart Distribution: Couple Microgrids." *IEEE* (link)

[10] Ibid.

[11] Ibid.

necessary if DER are well integrated with the distribution system.[12] By contrast, microgrids use an interface switch to autonomously island themselves during faults, outages, or power quality events. DER units in the islanded microgrid use a power versus frequency droop controller to track the energy requirements of the loads contained in the microgrid system.[13]

Advanced system controllers can be used to optimize the internal operation of each microgrid as well as respond to system requests for real and reactive power flows between the microgrid and the distribution grid. These power controls can be used to create microgrids that can achieve three major objective; high power quality, multi-MW scale microgrids, and exporting high levels of solar PV.[14] The standard microgrid configuration used in this report will combine the attributes of multi-MW microgrids designed to export high levels of solar PV. Smarter distribution can be achieved through the fast control of hundreds of individual DER units, which requires real-time information on each DER unit and key loads. The control complexity and reliability of such a system is greatly reduced using coupled microgrids that aggregate multiple DER units into a single, dispatchable resource.

These technologies and operation strategies are been tested at the AEP/CERTS Microgrid Test Bed site in Ohio. The tests have demonstrated stable behavior at critical operations points and the ability to island and re-connect to the grid in an autonomous manner. All tests performed as expected and demonstrated a high level of robustness.[15] The results from the AEP/CERTS project show that coupled microgrids represent a viable alternative to the centralized power generation model that has existed for over a century in the US. MGE could become a leader in smart grid deployment by partnering with the University of Wisconsin-Madison, which operates a microgrid testing facility at the Wisconsin Energy Institute (WEI).

3.1 – Study Methodology

This analysis takes a multi-step approach to determine the best sites for microgrid development in the City of Madison at costs that allow MGE to continue operating at its regulated rate of return (ROR). The first step involved gathering data for electricity use across MGE's three main customer segments (residential, commercial and industrial) within the City of Madison. Data from the US Energy Information Administration's (EIA) Form 860 from 2012 provide MGE's retail sales for each of those three customer segments. A combination of tax assessor data from the City of Madison and GIS data from the Dane County Land Information Office is used to

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[12] Ibid.

[13] Lasseter, R.W., "Microgrid: A Conceptual Solution." PESC 2004 Aachen, Germany, 20-25 June, 2004.

[14] Lassetter, R.W. "Smart Distribution: Couple Microgrids." *IEEE* (link)

[15] Ibid.

determine the building footprint and indoor living area of buildings that fall into the three customer segments.

These datasets are then used to create energy density (kWh/ft^2) and PV potential (kW) maps that identify hotspots where microgrid development would be most beneficial. Each building's electricity use was calculated by dividing the total retail sales (kWh) by the total indoor living area (for residential buildings), or footprint area (for commercial buildings), to obtain electricity density factors. The electricity density factors are then multiplied by the square footage of each building to create a map of each building's annual energy use. MGE could not provide more detailed consumption data so this "backed in" method represents the best option. A similar methodology was used to calculate building level electricity consumption in New York City. This data was then used to plot the annual energy consumption of each tax parcel in New York City as shown in Figure 2.

Figure 2: Annual Energy Consumption in New York City[16]

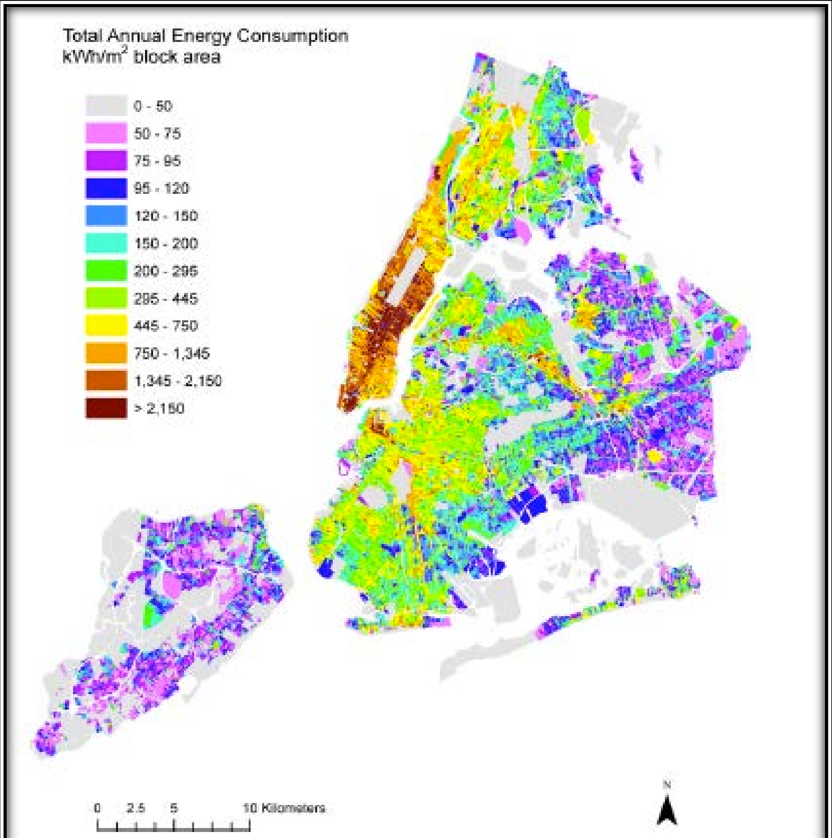
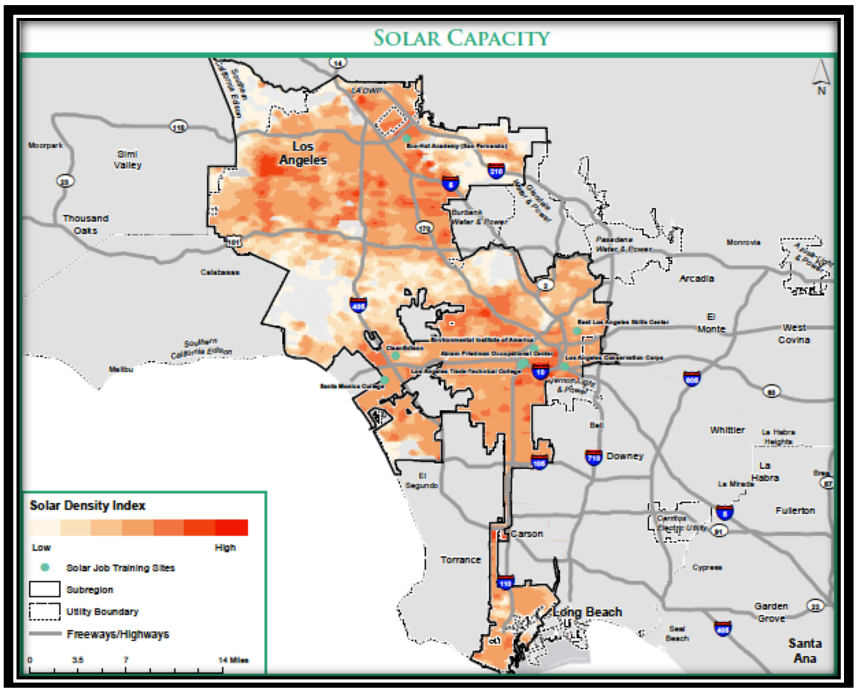


Fig. 6. Annual building energy consumption by block area (kWh/m^2), 2009.

[16] Howard et al. "Spatial Distribution of Urban Building Energy Consumption by End Use." *Energy and Buildings,* 45, 141-151, February 2012 (link).

Building footprint data was also used to create citywide estimates for the amount of available rooftop space suitable for solar PV in the City of Madison. Similar methods were used by researchers at UCLA's Luskin Center to identify optimal locations for distributed solar PV in California. NREL's PVWatts application was used to determine monthly generation and capacity factors for solar PV in Madison.[17]

Figure 3: Solar PV Potential in Los Angeles County



3.2 - Data Overview & Limitations

The most accurate form of topographical data that can be used to generate a solar resource map is Light Detection and Ranging data (LiDAR). LiDAR data can be used to create three-dimensional digital elevation models (DEMs) that analyze the impact of shading, roof tilt, and building orientation to produce highly accurate estimates for solar generating potential. The DEMs are used to estimate the amount of rooftop area that can support viable solar installations. In the absence of LiDAR data for the City of Madison, a combination of high-resolution orthophotography, building footprints, and parcel data for feature and building identification are considered an acceptable alternative.[18]

A comparison of four different solar mapping techniques found that applying a constant solar irradiation value to every building footprint, and assuming that every roof is flat, resulted in total solar potential that was 62% higher than the most

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[17] PVWatts, National Renewable Energy Laboratory (link)

[18] *Planning for Solar Energy, 2011 Compendium.* American Planning Association, 2011 (link).

accurate model.[19] To account for the tendency toward overestimating solar potential for the less complex GIS methodology used in this report, maximum solar potential was reduced by 50% for each building. While this reduces the citywide solar potential, it does not fully exclude buildings that are completely shaded, or lack the proper orientation to support viable solar projects. More detailed LiDAR surveys of the City of Madison are required to obtain more accurate solar potential maps like those created for Boston, Los Angeles and San Francisco.

The goal of the GIS analysis is to determine the annual electricity consumption and solar PV potential for each building within the City of Madison. Two datasets were used to accomplish this task; building footprint data from the Dane County Land Information Office, and tax assessor data from the City of Madison. The Dane County dataset included building footprint area, latitude/longitude coordinates, and some land use/building use identifiers. However, the Dane County dataset did not include footprints for all buildings in the City of Madison. Many residential buildings contained in the tax assessor dataset were not present in the Dane County GIS dataset. For example, there were nearly 68,000 residential properties in the tax assessor data compared to just 23,590 in the Dane County dataset. Thus, the tax assessor data was used to perform calculations for the residential sector.

The two datasets also produced different results for the number and area of industrial and commercial buildings. There were 6,017 commercial properties in the tax assessor dataset compared to 3,828 in the Dane County dataset. The total area of the commercial building footprints was just over 48 million square feet compared to 59 million square feet for the total area of commercial parcels in the tax assessor data. This presented another problem because the tax assessor dataset only included building area for residential properties, while commercial and industrial properties only included the land area of the tax parcel. Thus, the footprint data was used for commercial and industrial buildings from the Dane County dataset in combination with the footprint data for residential buildings from the tax assessor dataset. The table below provides a summary of the data used to calculate electricity use and solar PV potential in the City of Madison.

	Building Area (ft^2)	**Total Customers**	**Electricity Demand (kWh/year)**	**Electricity Intensity (kWh/ft^2)**	**Max PV (MW)**	**50% PV (MW)**
Commercial	48,022,319	19,491	2,272,398,000	47.32	480.2	240.1
Industrial	13,916,462	44	247,178,000	152.88	8.1	4.0
Residential	98,244,977	122,807	826,766,000	8.42	982.4	491.2
Total	160,183,757	142,342	3,346,342,000	-	1,470.8	735.4

EIA's Form 860 dataset provided the number of customers and annual electricity usage for the three major customer segments in MGE's service territory. The electricity intensity factor was calculated by dividing total annual consumption by

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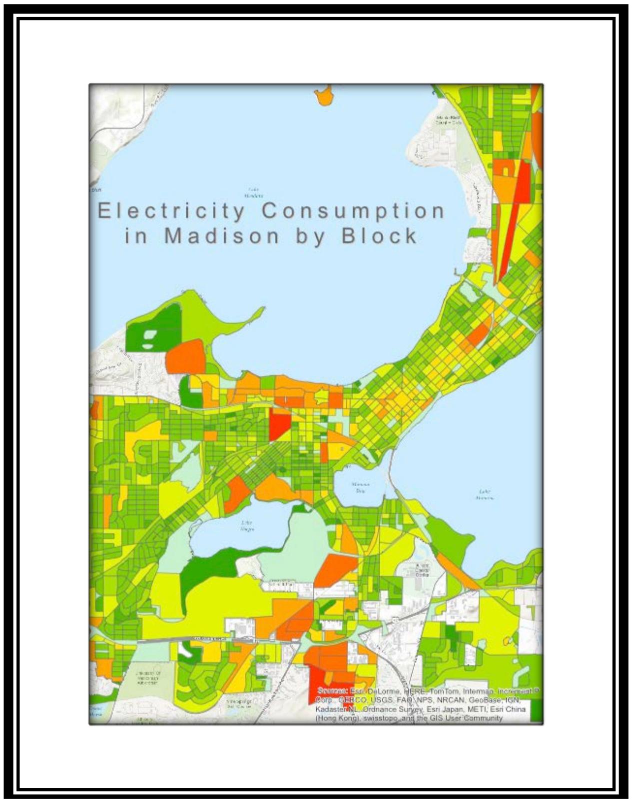
19 Jakubiec, Reinhart. "Toward Validated Urban Photovoltaic Maps." *MIT* (2012) link.

the total area of each customer segment. The electricity intensity factor is then multiplied across each building's total area in order to map estimated annual electricity consumption across the City of Madison. As a result, the amount of electricity consumption in each building and census block is directly correlated to the size of the building. This "backed in" calculation is the best estimate in the absence of more detailed consumption data from MGE. Figure 4 depicts the electricity intensity of census blocks in downtown Madison.

Figure 4: Electricity Density in Downtown Madison



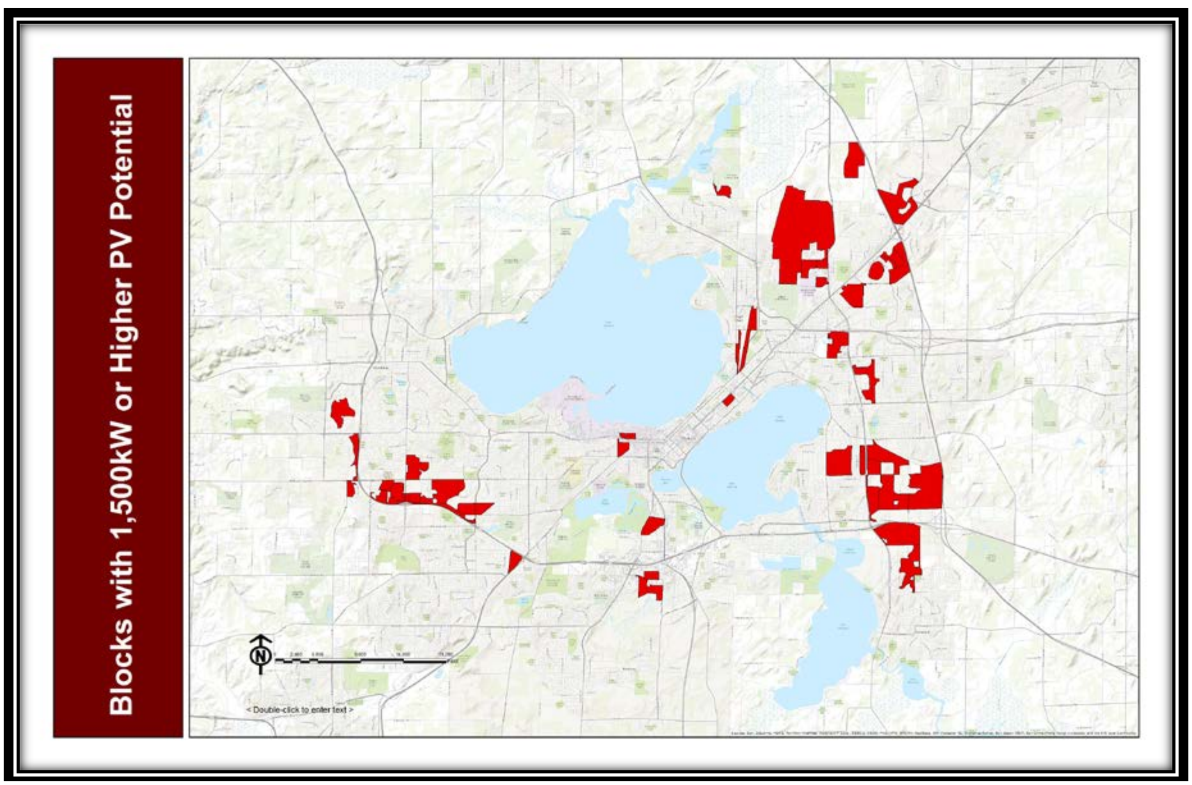
3.3 - Selecting Microgrid Sites

After using ArcMap to plot the electricity use and solar potential by building footprint and census block, the following screening process was used to select microgrid sites to fill the number required to replace 1.5% and 3% of MGE's retail sales in each customer group.

Buildings with less than 15kW of potential solar PV capacity were omitted and given zero values because of uncertainty about the orientation, roof tilt and shade affecting smaller buildings. Using a threshold of 15kW results in a building with a rooftop area of at least 3,000 square feet, which is considered large enough to assume that shade from other buildings will not affect a portion of the building's rooftop area large enough to support a solar PV array. The table below shows the amount of area required to support 1kW of solar PV capacity using different PV modules. The location of census blocks capable of supporting at least 1,500kW of solar PV capacity is shown in Figure 5.

Module	**Capacity (W)**	**Size (ft²)**	**ft²/kW**	**$/kW**
SunPower E20	435	23.8	54.7	NA
LG Mono X	250	17.8	71.2	$1,420
Kyocera KD140SX	140	10.8	77.1	$2,143
Suniva MVX 250	250	18.1	72.4	$1,180
Data from Wholesalesolar.com				
System Type	**Capacity (kW)**	**Size (ft²)**	**kW/ft²**	**$/kW**
Sloped Roof	1,500	116,000	77.3	$1,800
Flat Roof	1,500	174,000	116.0	$1,900
Data from SolarElectricSupply.com				

Figure 5: Census Blocks with at least 1,500kW of Solar PV Potential

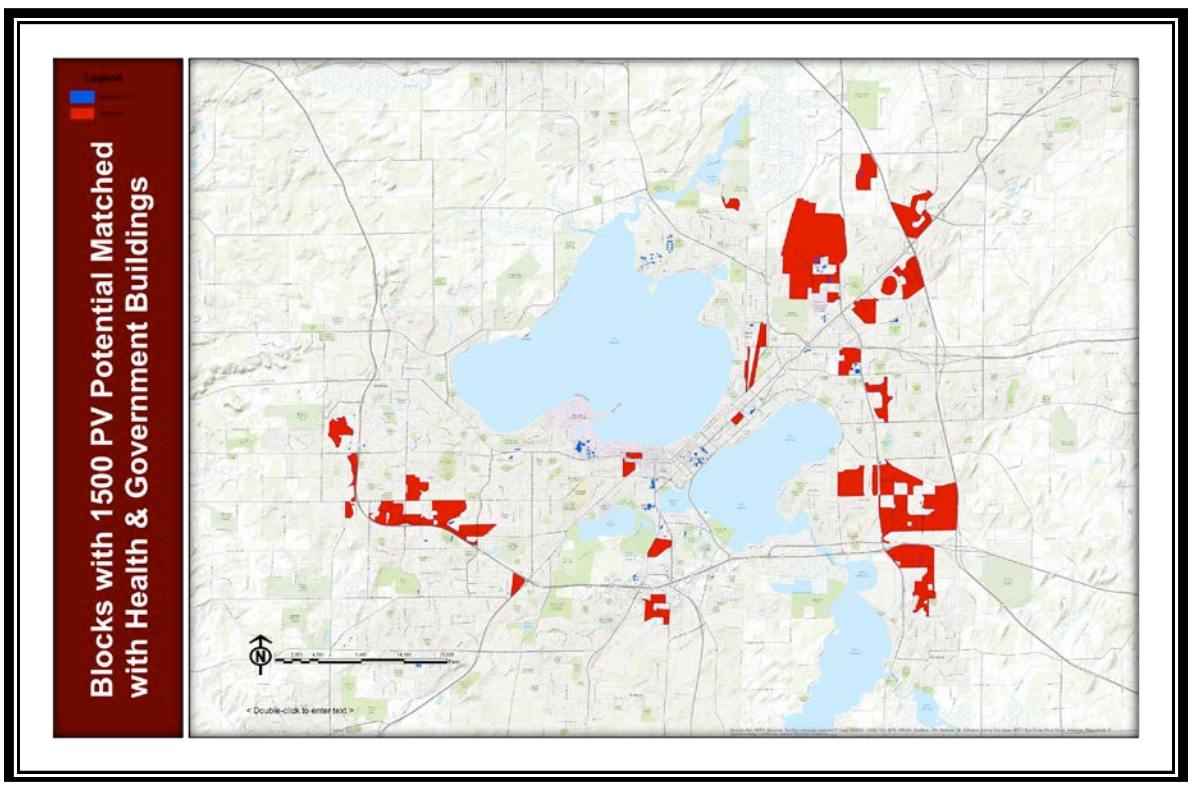


Out of 12,888 total census blocks within the City of Madison, 45 were capable of supporting at least 1,500kW of solar PV capacity using the screening process described above. These census blocks were then matched with the location of health and government buildings (colored blue in the map above) to identify the best sites for microgrid deployment. This selection process matches the highest PV potential with critical buildings that would continue to receive power when MGE's distribution grid experiences outages, faults or other power quality problems.

In total, there are 11 census blocks that contain critical buildings and are capable of supporting at least 1,500kW of solar PV. Those 11 potential microgrid sites are capable of supporting 32.7MW of solar PV and contain 29 health and government buildings. The amount of solar PV is only slightly higher than the 30MW Dominion Virginia Power is seeking develop under its five-year pilot program. The table and map below summarize their characteristics.

Block ID (GEOID)	PV Potential (kW)	Number of Critical Buildings
550250031003039	7,212.0	1
550250025001007	5,022.7	11
550250026032043	4,088.2	2
550250030014002	3,283.6	2
550250109011010	2,602.6	2
550250021004002	2,234.2	1
550250031003022A	2,031.0	3
550250105012000	1,598.5	1
550250109011096	1,584.4	1
550250112004025	1,578.0	2
550250025001014	1,523.0	3
Total	**32,758.3**	**28**

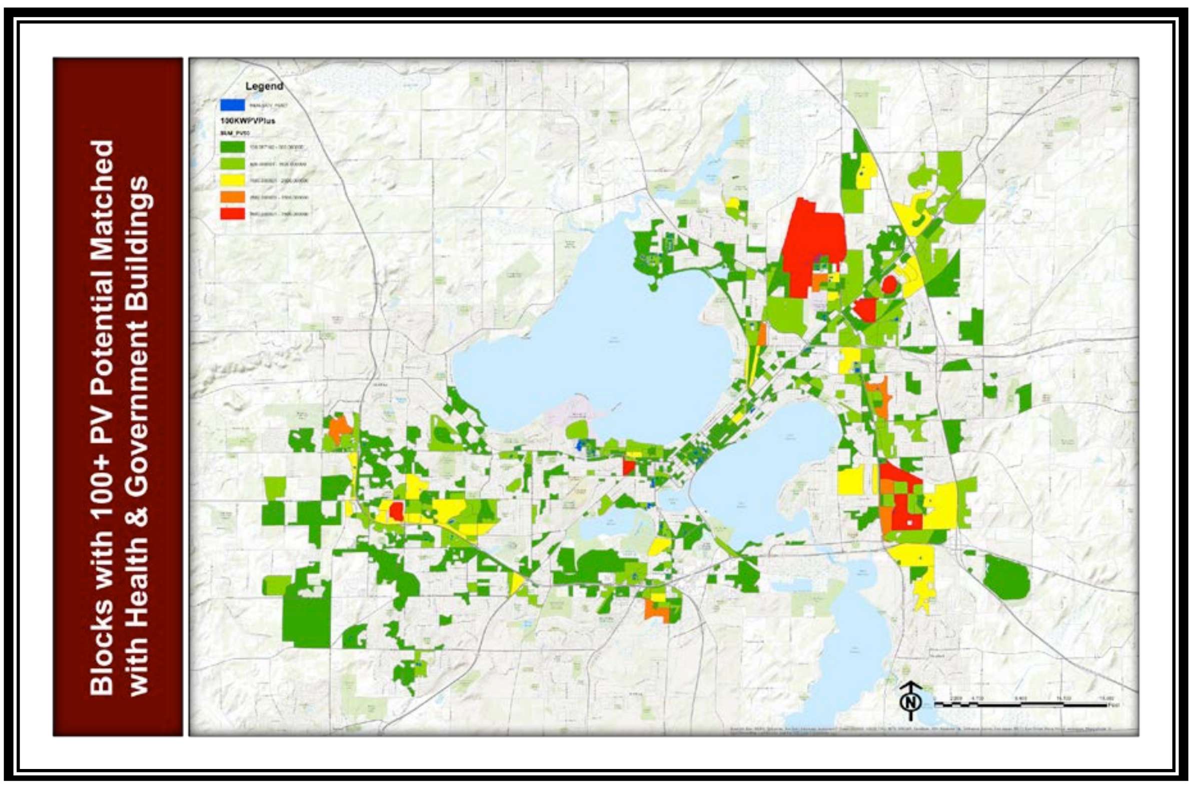
Figure 6: Eleven Optimal Microgrid Sites in Madison



The 11 census blocks that contain health and government buildings represent the best candidates for microgrid development in the City of Madison. But there are many other sites that could support microgrids if MGE were to pursue a more aggressive deployment strategy. In addition to the 45 census blocks capable of supporting at least 1,500kW of solar PV, another 38 could support at least 1,000kW, and 94 others could support at least 500kW. In total, these census blocks are capable of supporting an estimated 225MW of solar PV capacity. A summary of the solar PV potential and the location of the associated census blocks are shown in the table and map below.

PV Potential (kW)	# of Blocks	Total PV Potential (MW)
100-499	423	104.3
500-999	94	64.9
1,000-1,499	38	47.1
1,500+	45	113.0
Total	**600**	**329.3**

Figure 7: Census Blocks with at least 100kW of Solar PV Potential



The City of Madison has a large hypothetical potential for solar PV and microgrid deployment at the census block level. Microgrids could also be built to cover multiple census blocks to aggregate solar PV capacity and serve other critical buildings and customers closer to the downtown area. These areas were screened out mainly because of their small size compared to larger census blocks on the outskirts of the city. Another key siting consideration is the location of MGE's substations and feeder lines that reduce high voltage power to lower voltages for distribution to end use customers. MGE did not divulge the location of this equipment. Therefore, the microgrid sites are based solely on their ability to support solar PV and the types of buildings contained within those census blocks.

3.4 - Base Case Assumptions

The base case scenario uses MGE's historical retail sales data to predict demand growth and rate increases from 2015 to 2040. The base case scenario uses a 1% annual growth rate for total electricity demand, a 2% annual growth rate for electricity rates in all three customer segments, and the 2013 average MISO price of $30.85/MWh to calculate the cost of MGE's wholesale electricity purchases. The MISO price is also used as a proxy for MGE's fuel and operating costs for its own generation. This is a conservative assumption compared to the cost of power purchases reported by MGE in the utility's 2012 annual report, which listed net costs of $73.8 million (roughly $47/MWh or $0.047/kWh) for wholesale power purchases. MGE reported fuel costs of $46.5 million in 2012 ($14/MWh).[20]

The Wisconsin PSC approved new electricity rates and return on equity for MGE on December 22, 2011, according to the Wisconsin Citizen's Utility Board.[21] The PSC reduced MGE's return on equity to 10.3%, which is used to estimate MGE's costs that are not captured by the cost of wholesale purchases or fuel costs. These additional costs include deprecation of physical assets, administrative costs, debt financing and taxes. Using the 10.3% factor to back out these costs results in $255.6 million in 2012 compared to $264.2 million that MGE reported in it's 2012 annual report. Therefore, it is reasonable to use the 10.3% return on requity to calculate these costs in years 2015-2040.

The base case scenario uses the system-wide rates implied using EIA retail sales data for 2012. The rates increase by 2% per year from 2013-2015 when the microgrid deployment project is set to begin. The resulting sales revenue is then discounted to convert all revenue streams to their net present value using 2015 as the base year. The 2% annual increase in electricity rates reflects the lower end of historical trends observed from 1990-2012, according to EIA data shown on the following page. Sensitivity analysis is performed to account for uncertainty with rate increases ranging from 0% to 4% per year.

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[20] *Annual Report 2012*. Madison Gas & Electric (2013) link.

[21] MGE Cases. Wisconsin Citizen's Utility Board (2011) link.

WI Rates from 1990-2012	Residential	Commercial	Industrial
Average Annual Rate Increase	**3.21%**	**2.80%**	**2.87%**
Probability of 1% or Higher Rate Increase	77.27%	63.64%	68.18%
Probability of 2% or Higher Rate Increase	63.64%	59.09%	50.00%
Probability of 3% or Higher Rate Increase	54.55%	54.55%	50.00%
Probability of 4% or Higher Rate Increase	36.36%	40.91%	36.36%
WI Rates from 1997-2012	**Residential**	**Commercial**	**Industrial**
Average Annual Rate Increase	**4.45%**	**4.31%**	**4.67%**
Probability of 1% or Higher Rate Increase	100.00%	86.67%	93.33%
Probability of 2% or Higher Rate Increase	86.67%	86.67%	73.33%
Probability of 3% or Higher Rate Increase	80.00%	80.00%	73.33%
Probability of 4% or Higher Rate Increase	53.33%	60.00%	53.33%
WI Rates from 2002-2012	**Residential**	**Commercial**	**Industrial**
Average Annual Rate Increase	**4.79%**	**4.72%**	**4.89%**
Probability of 1% or Higher Rate Increase	100.00%	90.00%	90.00%
Probability of 2% or Higher Rate Increase	90.00%	90.00%	70.00%
Probability of 3% or Higher Rate Increase	80.00%	90.00%	70.00%
Probability of 4% or Higher Rate Increase	60.00%	70.00%	70.00%

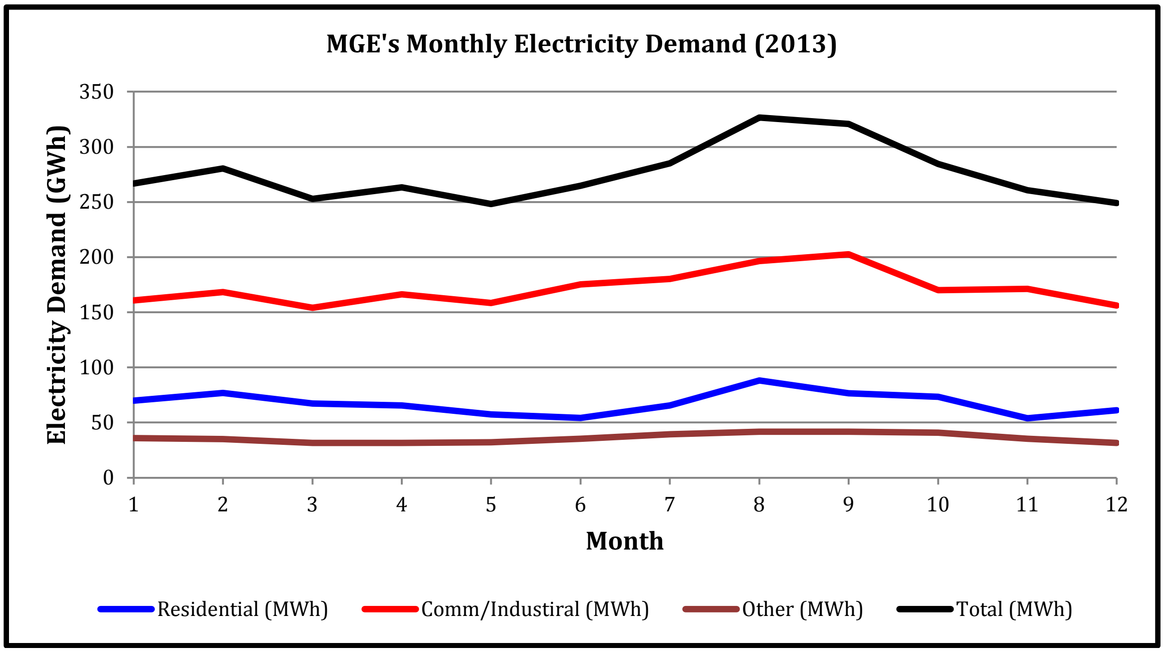
The Wisconsin PSC's most recent Strategic Energy Assessment states that fuel prices and purchased power cost increases, generation and transmission construction costs, and lost sales as a result of the recession are the significant drivers of recent rate increases.[22] The comparison of the base case against the four microgrid deployment scenarios calculates retail sales, less fuel costs and wholesale purchases. These two costs are calculated by multiplying the amount of electricity provided by MGE by the average MISO price from 2013. The MISO price is also set to increase at 2% per year to match the increase in MGE's customer rates.

Monthly Average Day-Ahead Prices for MISO ($/MWh and cents/kWh)		
January	$28.87	2.89
February	$27.68	2.77
March	$32.86	3.29
April	$35.29	3.53
May	$33.99	3.40
June	$31.27	3.13
July	$40.76	4.08
August	$27.86	2.79
September	$24.96	2.50
October	$27.64	2.76
November	$30.37	3.04
December	$28.59	2.86
Average	**$30.85**	**3.08**

[22] *Wisconsin Strategic Energy Assessment.* Wisconsin PSC (2012) link.

Figure 8 illustrate the seasonal variation in MGE's electricity demand throughout the year. These graphs are based on 2013 data from the Wisconsin Energy Office, but the figures were not complete (December figures were not finalized), so this analysis uses 2012 retail sales data from EIA for all other calculations. Peak demand is experienced in the summer months of July and August, but the highest average monthly demand is only 31.6% higher than the lowest monthly average. This indicates that MGE's electricity demand is not subject to extreme seasonal swings seen in other parts of the country where longer, hotter summers create much higher demand for air conditioning. The lower summer peaks coincide with the higher generation output from solar PV to provide valuable peak demand shaving during the summer months.

Figure 8: Seasonal Variation in Electricity Demand by Customer Segment



4.1 - Microgrid Deployment Scenarios

For this analysis, the Model for DER Networks (MoDERN) and MyPower were used to compare the base case scenario against six microgrid deployment scenarios under two financial structures. The total number of microgrids needed under each deployment scenario was determined by dividing the retail sales (kWh) for each customer group by the annual estimated generation of the standard microgrid, comprised of 1,500kW of fixed-axis solar PV modules and two Capstone CR200 (200kW) microturbines.

For example, electricity demand in the residential sector was 826 million kWh in 2012 and the annual estimated generation from the standard microgrid configuration is approximately 2.5 million kWh. This results in the need for at least five microgrids to replace 1.5% of MGE's residential demand, twelve microgrids to meet 1.5% of commercial demand, and two microgrids to meet 1.5% of industrial demand. The number of microgrids required under each deployment scenario is shown in the table below.

Customer Segment	Replace 3% of Retail Sales	Replace 1.5% of Retail Sales
Residential	9	5
Commercial	24	12
Industrial	3	2
Total	36	19

While the total amount of demand met by the microgrids is relatively small, their ability to reduce MGE's total costs is significant. Generation from solar PV arrays coincides with peak demand hours (10am to 4pm) when MGE may be forced to purchase power from the MISO wholesale market at inflated prices to meet demand. The portion of MGE's total demand served by wholesale power purchases is shown in the table below. Inefficient peaking units are also dispatched during periods of peak demand, which makes MGE vulnerable to volatile natural gas prices. Offsetting MGE's wholesale purchases with DER generation from a network of microgrids would reduce MGE's exposure to price volatility in the wholesale market and serve as a hedge against rising prices in future years.

	MGE Generation (MWh)	Wholesale Purchases (MWh)	Wholesale Purchases (%)	Cost of Wholesale Purchases
Annual	2,142,715	1,571,734	42.3%	$48,480,135
Monthly	178,560	130,978		$4,040,011
Daily	5,870	4,306		$132,822
Hourly	245	179		$5,534

The six deployment scenarios are outlined on the following page along with variables that were tested using sensitivity analysis for annual rate escalation and environmental compliance costs. Annual demand growth is set at 1% while the annual increase in electricity rates is set at 2% under the base case. Sensitivity analysis is performed for rate increases ranging from 0% and 4%. The low environmental compliance cost scenario uses current allowance prices for SO_2/NO_x and does not include a CO_2 compliance cost. The medium environmental compliance cost scenario uses current SO_2/NO_x allowance prices and a $10/ton price on CO_2 that does not escalate in future years. The high environmental compliance cost case uses current SO_2/NO_x allowance prices and a $35/ton price for CO_2 emissions that escalates at 2.1% annually.

This CO_2 price reflects the White House Office of Management and Budget's most recent guidance for regulatory impact analysis to reflect the social cost of carbon[23]. In the absence of a cap-and-trade program, the high CO_2 cost can be viewed as a proxy value for the cost of complying with other forms of federal and state regulations targeting CO_2 and other greenhouse gas emissions.

Business As Usual (no MG's)	**3% and 1.5% Deployment Scenarios**
Sensitivity	
Annual Rate Increase (2% annual)	Ranges from 1% to 4% per year
Low Env Compliance Cost (no CO_2) Medium Env Compliance Cost High Env Compliance Cost	Low Env Compliance Cost (no CO2) Medium Env Compliance Cost High Env Compliance Cost

4.2 - Scenario A: Cost-Benefit Categories

Under this scenario, MGE purchases all microgrid and DER equipment and does not charge customers for electricity generated by the renewable resources. To recover the upfront costs and loan payments, MGE charges microgrid customers higher rates for non-microgrid power during on-peak and off-peak periods. MGE also charges a fixed rate for electricity generated by the microgrid that is set at 25% above the LCOE for the microgrid. Selecting the right rates results in MGE recovering its investment, while customers enjoy lower total electricity purchases.

Tier I Cost & Benefits (MGE Customers Only)
Avoided Electricity Purchases Avoided Losses Due to Outages
Tier II Cost & Benefits (MGE)
MG/Generation Capital Costs Loan/Equity Payments Avoided Wholesale Purchases Lower SO_2 Allowance Purchases Lower NO_x Allowance Purchases Avoided Ancillary Services Costs Avoided T&D Costs (apply only to avoided wholesale purchases or all MG generation) Avoided Capacity Costs (only for future demand growth or also for current demand?) Fuel Price Hedging (renewables) Solar/Wind 30% Investment Tax Credit Microturbine 10% Investment Tax Credit Federal PTC for Renewables Wisconsin Solar PV Energy Rebate Salvage Value

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[23] *Technical Update of the Social Cost of Carbon for Use in Regulatory Impact Analysis.* Interagency Working Group on Social Cost of Carbon (2013) link.

Tier III Cost & Benefits (State of Wisconsin)
Lower SO_2 Environmental/Health Impacts Lower NO_x Env Impacts Lower CO_2 Environmental/Health Impacts
Sum of Tier I-III Yields Total Net Benefits to Wisconsin

** The sum of Tier I-III represents total net benefits to the state of Wisconsin. It subtracts the marginal excess tax burden (METB) associated with federal/state tax incentives as an opportunity cost for not allocating those taxes to other economic sectors. But since the federal tax incentives are at the national level and standing is limited to the state of Wisconsin, the incentives are still counted as benefits*

4.3 - Scenario B: Cost-Benefit Categories

Under this scenario, a third party developer purchases all microgrid and DER equipment. The third party company charges customers by consumption ($/kWh) to recover the capital costs in addition to revenue generated from net-metered electricity sales, REC sales, and monetization of federal tax credits. Under this scenario, MGE still enjoys the benefits of reduced wholesale purchases, ancillary services, T&D and capacity investment deferrals, but the utility is negatively affected by the loss of retail sales, which expand with the level of microgrid and DER market penetration.

Tier I Cost & Benefits (MGE Customers Only)
Avoided Electricity Purchases Avoided Losses Due to Outages
Tier II Cost & Benefits (MGE)
Avoided Wholesale Purchases Lower SO_2 Allowance Purchases Lower NO_x Allowance Purchases Avoided Ancillary Services Costs Avoided T&D Costs Avoided Capacity Investment Costs Fuel Price Hedging (all generation) Cost of increased REC purchases (omitted because the utility has a large supply) Cost of increased net metered purchases
Tier III Cost & Benefits (Externalities)
Lower SO_2 Environmental/Health Impacts Lower NO_x Environmental/Health Impacts Lower CO_2 Environmental/Health Impacts **Sum of Tier I-III Yields Total Net Benefits to Wisconsin**

5.1 - Uncertain Cost & Benefit Categories

The following benefit categories can be omitted from the calculation of net benefits under Tier II because methodologies for calculating their value are still being studied and validated by state and federal regulators. Additional research is needed in the following areas to ensure that the true value of these benefits is reflected in future studies and regulatory proceedings. These benefits are recognized by some utilities and disregarded by others due to the evolving and expanding nature of current literature. These Tier II benefits can be toggled on and off by the MoDERN user if they do not feel they should influence MGE's investment decisions. The value of these benefits cannot be ignored as microgrid and DER penetration increases.

5.2 - Deferral of Capacity and T&D Investments

Tier II benefits expand dramatically when microgrid deployment increases because the expansion of localized generation results in the deferral of investments in new generation capacity, and transmission and T&D expansion. These benefits cannot be ignored when microgrid deployment expands to a high level, which would deliver major cost deferrals for MGE. For example, the value of deferred capacity and T&D investments for a single microgrid ranged from $140,000 to $211,000 per year using a value of $0.055/kWh for avoided capacity and $0.018/kWh for avoided T&D (taken from Minnesota's VOS methodology). When these figures are expanded to the 3% deployment scenario, they increase to $15.6 to $23.3 million per year.

Xcel Energy, the largest regulated utility in Minnesota, submitted comments to the PUC in October 2013 stating the utility's perspective on the value of these benefits. Xcel reported a value of $0.006-$0.013/kWh for avoided capacity based on a cost of $5/kW-month for a new natural gas combustion turbine that would be needed in 2017. Xcel also placed a value of $0.004/kWh on avoided reserve capacity.[24] It is not clear whether MGE will need to build additional capacity during the 2015-2040 time period so the benefit of avoided capacity is only added to the net benefits calculation after 2025. The value is applied to the difference between total avoided generation from 2024-2025, growing larger each year thereafter as the customer base continues to expand.

There is also disagreement surrounding the estimated values for avoided T&D costs. Xcel proposed a value of $0.0001/kWh (based on 1.5% of its total generation costs) and $0.0005/kWh for avoided distribution costs. Xcel also reported a value of $0.004/kWh for avoided T&D line losses based on 7% average losses. Geronimo LLC, a solar developer in Minnesota, reported that its 100MW project would avoid approximately $3.24 million each year in T&D congestion costs. Geronimo expects the project to generate about 200,000 MWh/year, which translates into marginal benefit of $16.20/MWh or $0.0162/kWh.[25] That value is very close to the $0.01579/kWh figure from a study of MISO's proposed T&D upgrades and slightly less than the value contained in Minnesota final VOS methodology.

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[24] "Comments on Minnesota Value of Solar Tariff." Xcel Energy, 8 October 2014 (link).

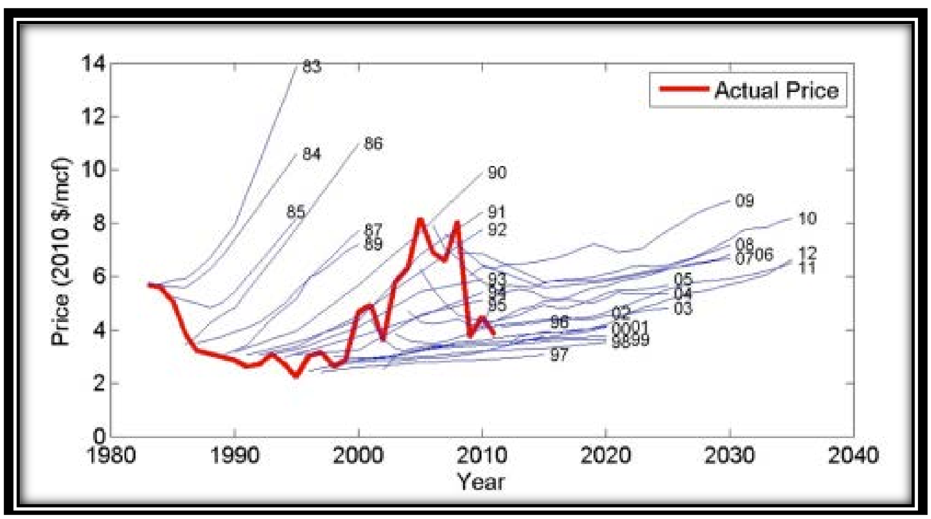
[25] Reply Brief of Geronimo Energy, LLC. MPUC Docket E002/CN-12-1240, 6 December 2013.

5.3 - Value of DER as a Hedge Against Fuel Price Volatility

The value of DER as a hedge against future price volatility can also be omitted from Tier II benefits using MoDERN. Multiple methods for calculating the true value of renewables as a hedging strategy have been proposed, but few have gained regulatory approval. Most studies derive the hedging value by comparing the fixed costs of renewables against financial or physical supply contracts for natural gas and coal. This can be difficult because of business confidentiality agreements and the lack of contracts longer than 5-10 years for natural gas. These contracts may include premiums that reflect lack of liquidity and counterparty risk.[26]

Renewables can also provide hedging, or insurance value, against rising wholesale electricity prices caused by unexpected spikes in natural gas prices, a CO_2 tax or cap-and-trade program, or other costly environmental regulations. NREL found that the effectiveness of DER as a price hedge declined in regions that do not have a diverse mix of renewables with market penetration lower than 20% of total capacity. Therefore, it may be inappropriate to include this benefit when evaluating single microgrid projects, but it should be included under the citywide deployment scenarios. Figure 9 shows the volatile nature of natural gas prices, illustrating the value of stability provided by renewables that do not have fuel costs.

Figure 9: Historical and Projected Natural Gas Prices[27]



A review of regulatory hearings in Colorado, Minnesota, New Jersey and Texas reveals multiple methods for calculating fuel hedging benefits along with a wide range of values for the reduction in volatility risk. For example, a study by the Commission for Environmental Cooperation used $5.50/MWh ($0.0055/kWh) to

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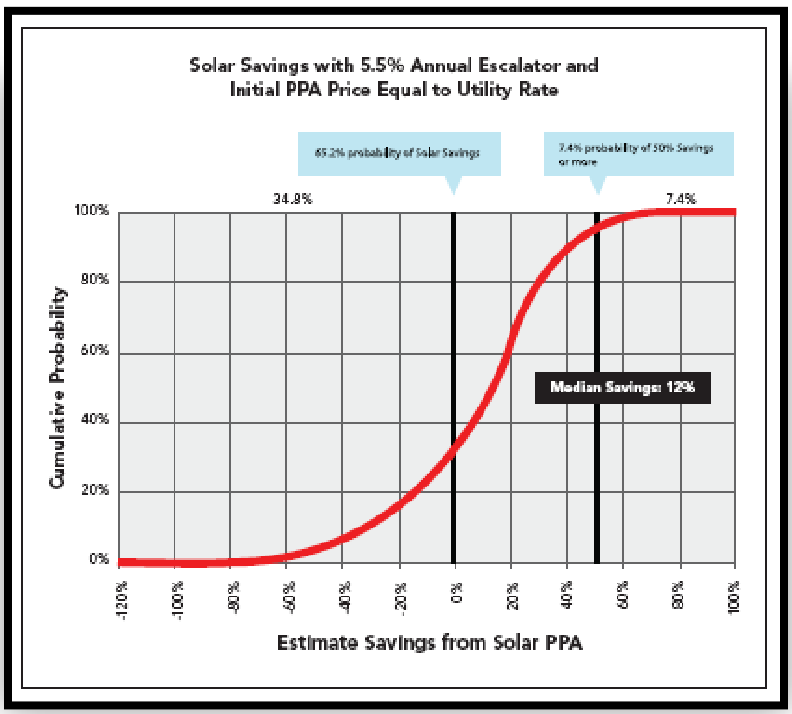
26 *The Use of Solar and Wind as a Physical Hedge Against Price Variability.* NREL (2013) link.

27 *The Use of Solar and Wind as a Physical Hedge Against Price Variability.* NREL (2013) link.

calculate fuel hedging benefits[28], while figures in New Jersey ranged from $24-$44/MWh.[29] The NREL study predicted the value of decreased volatility in electricity prices with 20-35% renewable penetration could range from $5-$30/MWh.

Multiple electric utilities have denied that there is any hedging value due to the intermittent nature of renewables, but Xcel placed a value of $0.0045/kWh for avoided fuel costs in the Minnesota VOS proceedings. Xcel did not place a value on "price guarantees" for solar (another term for hedging value). Applying the lowest value resulted in a range of benefits from $9,000-$12,000 per year for a single microgrid. Figure 10 illustrates the probability of customers achieving net savings from entering solar power purchase agreements offered by third party developers, the business model proposed under Scenario B.

Figure 10: Probability of Achieving Net Savings Under Solar PPA[30]



More research is needed in these areas to produce a widely accepted method for calculating these benefits, which have the potential to alter utility investment decisions and regulatory approval of capital-intensive projects. Minnesota's VOS methodology settled on a value of $0.056/kWh for fuel hedging.[31]

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28 *Renewable Energy as Hedge against Price Volatility.* CEC (2012) link.

29 *The Value of Distributed Solar to New Jersey & Pennsylvania.* Clean Power Research (2012) link.

30 "Hedging Against Utility Rate Fluctuations with a Solar PPA." Tioga Energy, June 2008 (link).

31 *Minnesota Value of Solar Tariff Methodology*. MN Department of Commerce, 1 April 2014 (link).

5.4 - Value of Power Quality and Avoided Outage Costs

While DER can provide significant energy savings, intermittent resources like solar PV cannot guarantee a reliable supply of high quality electricity. Businesses that require a very high level of reliability and power quality to protect valuable electronic equipment (i.e. military bases, data centers, prisons, hospitals) are willing to pay a premium for energy security to guard against power surges, voltage drops, frequency imabalance, or blackouts that affect entire cities or regions. The value of energy reliability is highly dependent on the type of customer served by the microgrid, and the frequency of expected power outages in a given year. In this study, it is assumed that each customer will experience one prolonged power outage each year (defined as 60 minutes in length), and ten power quality events each year.

The value of increased reliability to residential customers is calculated by multiplying the number of events in a given year, by the value placed one ach individual event. Based on the results of a survey the Lawrence Berkeley National Laboratory (LBNL), residential customers place a very low value on power quality events (this study sets the value at $0 per event), and power outages (set at $100 per event). Commercial customers expressed a wide range of values for the cost of power disruptions, from $230 for small public administration offices to $$17,000 for large financial firms that rely on electronic payments to complete transactions. This study uses $7,000 for each power quality event and $13,000 for each 60-minute outage with sensitivity analysis ranging from 10% to 200% of those values. For industrial customers, whose operations can be interrupted for hours following a minor power quality event, the value of power quality events is set at $22,000 and each 60-minute outage is set at $37,000.[32]

Interruption Length	Momentary (PQ Event)	One Hour
Industrial (Manufacturing)	$22,000	$37,000
Commercial (Trade & Retail)	$7,000	$13,000
Residential (Homes)	$0	$100

The assumptions and methodology that produced these core results are discussed in detail in Appendix E. Appendix K contains a description and user guide for MoDERN.

[32] Sullivan et al. *Estimated Value of Service Reliability for Electric Utility Customers.* LBNL, 2009 (link).

6.1 - Discussion of Variables

Electricity markets and power systems are extremely complicated systems with a vast number of variables that can affect the outcome of economic analyses. To account for uncertainty in the most important variables that affect the proposed microgrid deployment scenarios, Monte Carlo analysis with randomized values was used to simulate uncertainty in the annual capacity factor for solar, the CO_2 intensity of displaced electricity, prices for natural gas to fuel microturbines, average electricity consumption, average electricity rate changes, and the social cost of carbon.

The wide range for the price of carbon and the impact of increasing electricity rates had the most dramatic effect on net benefits in all three-stakeholder tiers. Sensitivity analysis was performed using fixed rate changes of 1%, 2% and 3% while holding the price of emissions allowances, health benefits of avoided emissions and the value of economic losses due to power outages constant. The MoDERN user can change these variables to conduct additional sensitivity analysis of other variables. The following tables summarize the randomized and fixed variables used in the MoDERN simulations.

Randomized Variables in Monte Carlo Analysis`				
Variable	**Min Value**	**Max Value**	**Mea n**	**Distribution**
Capacity Factor - Solar	12%	16%	14%	Triangular
Change in Average Electricity Consumption	80%	120%	100 %	Uniform
Average Electricity Growth Rate	0%	8.8%	3%	Uniform
Social Cost of Carbon	$1.90	$200	$35	Asymmetric Triangular
METB Rate	20%	30%	25%	Uniform

Fixed Variables in Monte Carlo Analysis`			
Variable	**Value**	**Variable**	**Value**
Discount Rate	3%	**REC Price ($/MWh)**	$1.00
Inflation Adjusted Interest Rate	4.90%	**WI Solar Rebate**	$2,400
Total Demand (kWh/year)	5,000,00 0	SO_2 **Permit Price ($/ton)**	$1.50
On-Peak Demand Purchases (%)	0%	NO_x **Permit Price ($/ton)**	$40
Off-Peak Purchases from Grid (%)	100%	SO_2 **Social Cost ($/ton)**	$2,754
Net Metered Sales Rate ($/kWh)	$0.07	NO_x **Social Cost ($/ton)**	$1,622
MISO Price ($/kWh)	$0.03	**Annual** CO_2 **Cost Increase**	2.10%
Avoided Ancillary Services ($/kWh)	$0.005	**Avoided Outage Cost**	Varies

MoDERN assumes all costs and benefits accrue at the end of each year. The net benefits are annualized and calculated out to 25 years, which reflects the typical lifetime of solar panels and other DER equipment. This is a relatively conservative assumption considering Clean Energy Collective (a third party solar developer based in Colorado) expects its solar PV projects to operate for up to 50 years. [33] The one-time federal investment tax credit (ITC) for solar equipment is realized in year two. Federal production tax credits (PTC) are included through the first 10 years.

The salvage value of microgrid equipment was calculated using a 10% annual depreciation rate. The depreciated value in year 25 is then discounted to reflect its' net present value. This captures the scrap value of equipment and also reflects the potential useful value of microgrid equipment beyond 25 years. All benefits are discounted at 3% per year, which reflects the rate of return on 30-year US Treasury Bonds.[34] This is an appropriate considering microgrid deployment is a very capital intensive project with social benefits spread across several stakeholder groups. A 3% discount rate is also used in California's Title 24 building code for evaluating energy efficiency projects (CPUC Presentation link).[35]

7.1 - Cost Effectiveness Parameters, Definitions & Tests

To determine whether microgrid deployment is a cost-effective strategy for DER expansion, measurable conditions and tests must be applied in order to compare each deployment scenario against the base case. Each deployment strategy will be analyzed from three different perspectives; the ratepayer (Tier I), MGE (Tier II), and the environment (Tier III). Determing cost-effectiveness must account for the interplay between all three of these groups. MGE would not invest in developing a microgrid that reduces annual energy costs for its' customers by if the utility incurs a net loss from financing and operating these systems. Similarly, the microgrid would not be cost-effective if the small subset of customers served by the system and MGE enjoy net benefits, while non-microgrid customers subsidize the system's development through higher electricity rates.

Thus, a four-step process was developed to determine whether each deployment scenario is cost-effective to all stakeholders. First, customers served by the microgrid must experience a minimum 10% return on investment (ROI), MGE must maintain is 10.3% ROR through revenue and cost reductions delivered by the microgrid, MGE cannot offset the cost of microgrid development by raising electricity rates on non-microgrid customers by more than 1% above the base case scenario. These tests ensure that microgrid customers experience net benefits over the 25-year life of the system, MGE enjoys net benefits from investing in the

[33] Clean Energy Collective. "Pagosa Springs Project Summary." Presentation, 8 October 2013 (link).

[34] U.S. Department of Treasury. "Treasury Yield Curve." (link), S&P 500 (link)

[35] *Time Dependent Valuation of Energy for Building Efficiency Standards.* E3 Consulting, 2011 (link).

microgrid system, and ratepayers not served by the microgrid do not face inequitable rate increases to support microgrid development.

7.2 - Step One: Ratepayer ROI Must Exceed 10%

Ratepayer ROI is calculated by dividing the net present value of total benefits (energy savings, increase reliability) by total costs (cost of energy services above the base case). The 10% ROI (equivalent to a 1.1 cost-benefit ratio) threshold for cost-effectiveness was chosen to reflect the low risk inherent in both microgrid development scenarios. The ratepayers are not asked to recover any initial investment in the microgrid system, therefore any scenario that produces positive net benefits should be prefereable to the base case, but the 10% threshold was chosen to prevent the utility from charging the highest possible rates for energy services provided by the microgrid. This approach is known as the participant cost test (PCT).[36]

7.3 - Step Two: Microgrid Energy Sales Must Cover Lifetime Costs

This test ensures that the volumetric rate charged for energy produced by the microgrid's solar PV array and microturbines is sufficient to cover the system's total lifetime costs without including the value of additional benefits (i.e. fuel price hedging, T&D/capacity investment deferrals). This test is performed by summing the net present value of electricity sales from the microgrid, and subtracting total lifetime costs. A net positive value indicates that the microgrid can support itself without additional revenue streams, subsidies, or other sources of external funding.

7.4 - Step Three: MGE Must Maintain a 10.3% Rate of Return (ROR)

The Wisconsin PSC allows MGE to earn a 10.3% ROR, which represents the threshold each microgrid deployment scenario must match in order to be considered cost-effective to the electric utility. MGE's ROR is calculated by dividing the net present value of total benefits included under Tier II by the net present value of total costs. This approach is known as the Utility Cost Test (UCT), which is the primary method for determining the cost-effectiveness of utility programs in California, Connecticut, Michigan, Oregon, Texas and Utah.[37]

Microgrid deployment reduces MGE's fuel costs for existing generating units, wholesale power purchases and environmental compliance costs, but the other costs (taxes, depreciation, administrative costs etc.) are held constant in this analysis. It is beyond the scope of this study to perform a full financial audit of each microgrid deployment scenario. If MGE's ROI matches or exceeds the 10.3% ROR granted by state regulators, then the microgrid scenario is considered cost-effective from the electric utility's perspective.

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[36] Gelling and Chamberlin. *Demand Side Management Planning.* Fairmont Press. Lilburn, GA (1993).

[37] Daykin et al. "Whose Perspective? The Impact of the Utility Cost Test." Cadmus Group, 2011 (link).

7.5 - Step Four: Average Non-Microgrid Rates Cannot Increase by More tan 1%

If MGE is unable to maintain its' 10.3% ROR through microgrid revenue and cost savings alone, the utility will be allowed to recover its lost revenue by increasing electricity rates for non-microgrid customers, or by reducing other costs. MoDERN calculates the amount of revenue required to maintain a 10.3% ROR and distributes that burden proportionally across each of the three customer segments that are not served by microgrids. The sample calculation below illustrates the application of this test, also known as the ratepayer impact measure (RIM) test.

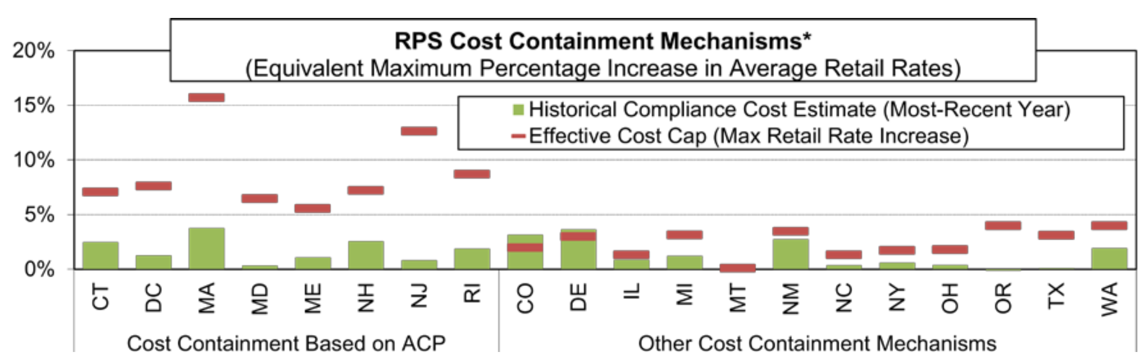
Equation for Calculating Rate Increases to Cover Microgrid Development Costs

= ($1M additional revenue) * (7E8 kWh of commercial demand / 1E9 kWh of total demand)
= $700,000 extra revenue needed from commercial customers
New Commercial Rate: ($700,000 / 7E8 kWh) = Original Rate + $0.001/kWh ($1/MWh)

If the additional cost of raising revenue to support microgrid development is less than 1% above the base case rate, then the deployment scenario is considered cost-effective by MGE and non-microgrid ratepayers. The 1% threshold was chosen because adding that percentage to the assumed annual rate increase of 2% yields a total increase of 3% per year. A 3% rate increase is lower than the annual average rate increase for all three customer groups in Wisconsin based on EIA data from 1997-2012.

Wisconsin currently does not have a rate impact cap on its Renewable Portfolio Standard (RPS), while many other states have cost containment caps well above 1%, as shown in Figure 11. Kansas and Missouri both have RPS cost caps set at 1% of average retail rates, while Illinois, Ohio, New York and North Carolina have caps below 2% of average retail rates. Thus, the 1% cap chosen for this study represents a conservative threshold that provides robust protection for ratepayers. The combination of the PCT, UCT and RIM tests ensure that each microgrid deployment scenario undergoes rigorous evaluation from each stakeholder perspective.

Figure 11: Cost Containment Caps for State-Level RPS Programs[38]



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[38] Heeter et al. *A Survey of State-Level Costs and Benefits of RPS.* NREL, 2014 (link).

The amount of additional revenue needed to offset microgrid development costs also represents the level of cost reductions MGE could pursue in order to maintain its' 10.3% ROR without raising rates on non-microgrid customers. MoDERN calculates the amount of divestment in existing coal-fired generation necessary to offset microgrid development at different levels of market penetration. According to MGE's 2012 Annual Report, the utility owns 22% of the Columbia Generating Station equivalent to 225MW of capacity, and 8.3% of the Elm Road Generating Station equivalent to 106MW of capacity. The depreciated value of MGE's share in the Columbia plant is $101.4 million ($451/kW), while MGE's share of the Elm Road plant is valued at $186.5 million ($1,759/kW).

The amount of divestment necessary to offset the initial capital costs (loan down payment) of microgrid deployment is illustrated in the table below.

# Microgrids	Coal Divestment	MG Capacity	MGE Total Capacity	% Capacity Reduction
1	-$2.01	1.9	803.9	-0.18%
2	-$4.01	3.8	802.4	-0.37%
5	-$10.0	9.5	798.0	-0.92%
10	-$20.1	19.0	790.5	-1.85%
20	-$40.1	38.0	775.6	-3.70%
30	-$60.2	57.0	760.7	-5.55%
40	-$80.2	76.0	745.8	-7.40%
50	-$100.3	95.0	730.9	-9.25%

8.1 – MoDERN Tool Description & Results

The Model for Distributed Energy Resource Networks (MoDERN) was developed in Microsoft Excel to align with the goals of this analysis. Excel has limitations compared to other more sophisticated energy modeling software packages, but MoDERN was built specifically to match the data available for MGE, and to address rapidly evolving regulatory questions that are not included in other publicly available models (i.e. the value of fuel hedging, avoided capacity, T&D deferrals etc).

MoDERN is also highly customizable. A user can select a wide range of generation technologies, vary the size of the microgrid system and change the amount of electricity they would like to offset. It also allows the user to change the price of many variables that affect the economic viability of each microgrid project. For example, the user can select various prices for environmental benefits like RECs, SO_2/NO_x allowances and the social cost of carbon. The user can also choose to omit the uncertain Tier II benefits discussed earlier. MoDERN is supplemented by the use of MyPower, an economic dispatch model (EDM) developed by researchers at the Wisconsin Energy Institute (WEI).[39]

[39] Meier, Paul. "MyPower Methodology Documentation." UW-Madison (link).

For Scenario B, the selected electricity rate charged to microgrid customers ensures the third party developer of a 15% ROI for all three customer segments. MGE's on- and off-peak rates for microgrid customers are raised to maintain their 10.3% ROR, and to prevent non-microgrid customers from experiencing rate increases greater than 1% above the base case. These are reasonable assumptions because the third party developer would not undertake the project unless it could earn a reasonable ROI, and the ratepayers would not accept microgrid deployment unless they experience positive net benefits. This illustrates the impact of third party development on MGE's revenue stream under the six deployment scenarios.

8.2 - Scenario A Rate Levels & Results

Under Scenario A, MGE purchases, owns and operates all of the microgrid equipment. The utility recovers its investments by charging different rates for customers served by microgrids compared to their flat or time-of-use rates for residential, commercial and industrial customers. MoDERN calculates energy savings and MGE's retail sales from microgrid customers by using time-of-use rates for each customer segment. The volumetric rate charged for electricity generated by the microgrid is set at 150% of the microgrid's LCOE, and raises off-peak rates to cover the cost of microgrid deployment. This is a simplified rate structure, but it supports economic incentives for customers to reduce consumption by retaining time-of-use pricing for electricity not provided by the microgrid. A summary of the rates charged by MGE under Scenario A is provided below.

Benefits Included	**MGE Includes Tier II Benefits**		**MGE Excludes Tier II Benefits**	
Customer Group	**1.5% Residential**	**1.5% Residential**	**3% Residential**	**3% Residential**
MGE Off-Peak Rate	$0.0750	$0.0825	$0.0750	$0.0825
MGE On-Peak Rate	$0.2463	$0.2709	$0.2463	$0.2709
MGE Rate for MG Power	$0.2158	$0.2158	$0.2158	$0.2158
Original LCOE ($/kWh)	$0.1323	$0.1323	$0.1323	$0.1323
Microgrid LCOE ($/kWh)	$0.1141	$0.1188	$0.1141	$0.1188
Benefits Included	**MGE Includes Tier II Benefits**		**MGE Excludes Tier II Benefits**	
Customer Group	**1.5% Commercial**	**1.5% Commercial**	**3% Commercial**	**3% Commercial**
MGE Off-Peak Rate	$0.0550	$0.0975	$0.0975	$0.1575
MGE On-Peak Rate	$0.1145	$0.2029	$0.2029	$0.3278
MGE Rate for MG Power	$0.2118	$0.2118	$0.2118	$0.2118
Original LCOE ($/kWh)	$0.0701	$0.0701	$0.0701	$0.0701
Microgrid LCOE ($/kWh)	$0.1047	$0.1221	$0.1221	$0.1468
Benefits Included	**MGE Includes Tier II Benefits**		**MGE Excludes Tier II Benefits**	
Customer Group	**1.5% Industrial**	**1.5% Industrial**	**3% Industrial**	**3% Industrial**
MGE Off-Peak Rate	$0.0550	$0.0600	$0.0600	$0.0600
MGE On-Peak Rate	$0.0841	$0.0918	$0.0918	$0.0918
MGE Rate for MG Power	$0.2124	$0.2124	$0.2124	$0.2124
Original LCOE ($/kWh)	$0.0582	$0.0582	$0.0582	$0.0582
Microgrid LCOE ($/kWh)	$0.0981	$0.1000	$0.1000	$0.1000

Under Scenario A, MGE's net benefits over the 25-year time period (2015-2040) range from $984 million under the 1.5% residential deployment scenario to $1.09 billion under the 3% industrial deployment scenario when electricity rates increase at 2% annually with low environmental compliance costs. The four industrial deployment simulations (1.5% and 3% with and without Tier II benefits) all produced net benefits for MGE that were higher than the base case scenario.

The industrial microgrid deployment scenarios produced 25-year net benefits ranging from $40-$44 million above the base case. The residential and commercial deployment scenarios were not far below the base case, ranging from $984 million to $1.03 billion and corresponding ROI's of 9.59% to 10.03% before raising rates on non-microgrid customers, or divesting coal ownership. The net shortfalls translate into annual additional revenue requirements, or cost reductions, of just $1.1 to $2.9 million annually. The divestment necessary to offset the development costs of the residential and commercial microgrid deployment scenarios ranges from $10-$50 million. The upper end of that range is rougly one-third the amount MGE is paying to upgrade the Columbia Generation Station's emissions controls.

MGE's net benefits fall to $827 million under the base case scenario when a $10/ton price is imposed on carbon emissions. The residential and commercial deployment scenarios help mitigate the new cost on carbon, but MGE's net benefits are still lower than the base case scenario at $759-$827 million, a difference of $68 million over the 25-year period, or $2.7 million per year. Microgrid deployment in the industrial sector results in higher net benefits for MGE when the carbon price is included, ranging from $858-$871 million.

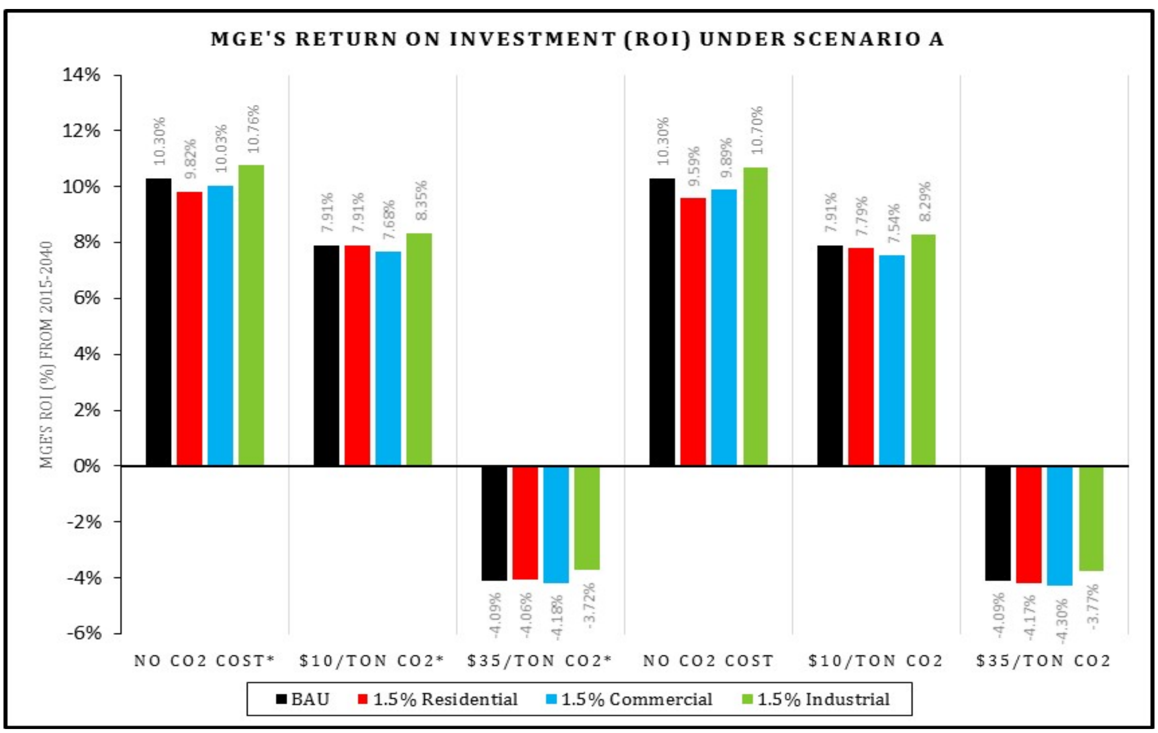
Under the high environmental cost scenario (a $35/ton carbon price that escalates at 2.1% per year), MGE's net benefits under the base case fall to negative $482 million compared to negative $507 million and negative $478 million under the residential and commercial deployment scenarios, respectively. Net benefits under the industrial deployment scenarios are still negative at $442 to $436 million, but there are slightly higher than the base case results. Clearly, a high price on carbon emissions creates the need for a major overhaul of MGE's current business model.

1.5% Residential Capacity, Generation & Cost Summary				
Generation Technology	**Capacity (MW)**	**Generation (kWh/yr)**	**Capital Cost**	**Annual O&M**
Solar PV	7.50	9,606,690	-$18,750,000	-$150,000
NG Microturbines	2.00	4,849,711	-$4,820,000	-$541,655
3% Residential Capacity, Generation & Cost Summary				
Solar PV	13.50	17,292,042	-$33,750,000	-$270,000
NG Microturbines	3.60	8,729,479	-$8,676,000	-$974,980
1.5% Commercial Capacity, Generation & Cost Summary				
Solar PV	18.00	23,056,056	-$45,000,000	-$360,000
NG Microturbines	4.80	12,466,236	-$11,568,000	-$1,335,421
3% Commercial Capacity, Generation & Cost Summary				
Solar PV	36.00	46,112,112	-$90,000,000	-$720,000

NG Microturbines	9.60	24,932,472	-$23,136,000	-$2,670,841
1.5% Industrial Capacity, Generation & Cost Summary				
Solar PV	3.00	3,842,676	-$7,500,000	-$60,000
NG Microturbines	0.80	2,053,938	-$1,928,000	-$221,331
3% Industrial Capacity, Generation & Cost Summary				
Solar PV	4.50	5,764,014	-$11,250,000	-$90,000
NG Microturbines	1.20	3,080,906	-$2,892,000	-$331,996

The table above summarizes the total capacity of solar PV and natural gas microturbines, capital costs, and annual O&M costs under each of the six deployment scenarios. Each scenario is quite feasible given the availability of about 160MW of solar potential in census blocks capable of supporting at least 1,00kW of PV capacity. The limiting factor would be finding clusters of customers who place a high value on the increased reliability offered by microgrids, and matching their electricity consumption to the generation provided by the standard microgrid.

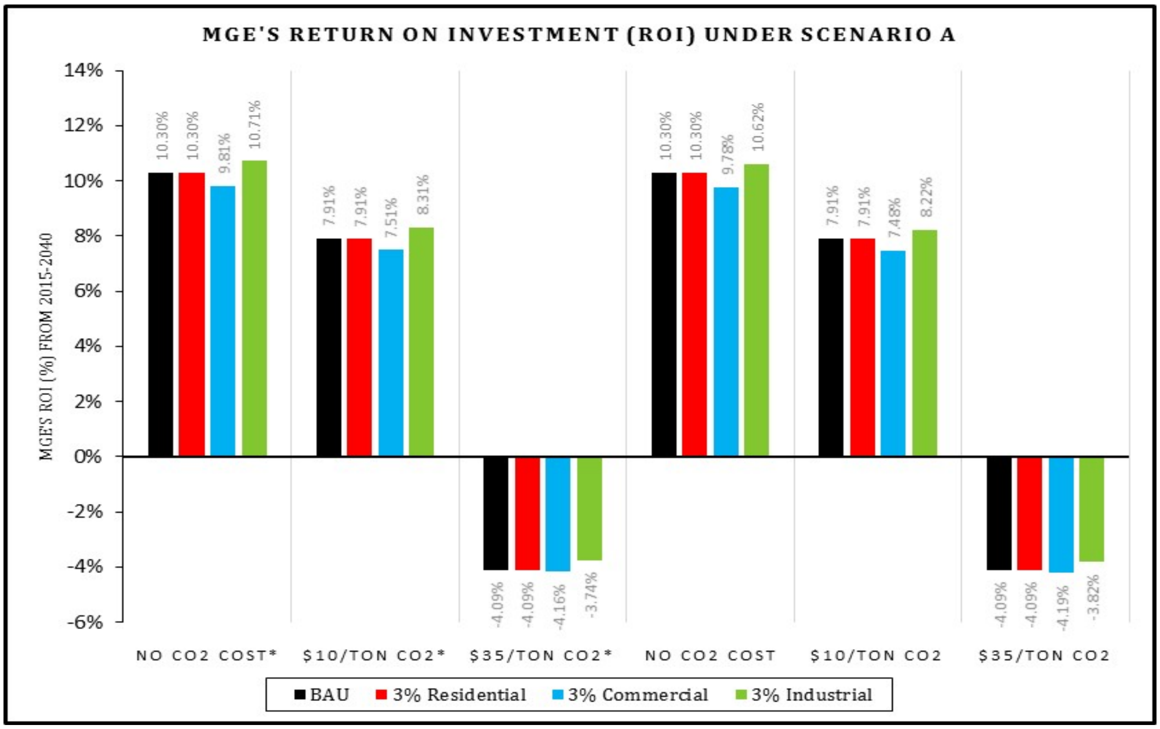
Figure 12: MGE's ROI Under 1.5% Microgrid Deployment



Figures 12 (above) and 13 (next page) illustrate MGE's net benefits under the two sensitivity cases tested under Scenario A. The first three sets of columns represents MGE's net benefits when the uncertain Tier II benefits (fueld hedging, T&D/capacity deferrals) are included in the utility's ROR calculation, while the three sets of columns on the right side of the chart display MGE's net benefits when those categories are not included in the ROR calculation.

The 1.5% deployment scenarios shown on the previous page result in minimal net losses for MGE and represent an economically feasible approach to building a "smart" distrubiotn network in Madison. The capital, financing, and O&M costs associated with microgrid development are nearly offset in each scenario by increased retail sales from microgrid customers, fuel cost reductions, reduced wholesale purchases, and other benefits. The results of the 3% deployment scenarios show similar trends that result in very manageable costs to MGE.

Figure 13: MGE's ROI Under 3% Microgrid Deployment



The difference in MGE's ROR and net revenue between Scenario A and Scenario B is relatively minor under each deployment scenario. MGE's 25-year net revenue never dips lower than $70 million, or $2.8 million per year, below the base case scenario. Only two of the 24 sensitivity cases produced results where MGE'srate increases for non-microgrid customers under Scenario B were lower than those under Scenario A.

This indicates that MGE could enjoy the benefits delivered by DER and microgrids without having to recover investment costs by contracting with a third party developer. MGE could further reduce its losses under the 1.5% and 3% deployment scenarios if the utility implements a revenue sharing agreement with the third party developer, or takes ownership of microgrid equipment once the third party developer has recovered their initial investment. This type of shared revenue model was not tested with in MoDERN and represents an important area where further research would be beneficial.

8.3 - Ratepayer Benefits Under Scenario A

Under the 1.5% deployment scenario, residential customers receive $8.6 million in net benefits over the 25-year life of the project when Tier II benefits are not included, and $12.2 million when those benefits are included. The net benefits are driven by savings achieved when the microgrid generates power during on-peak hours, while off-peak rates are raised from 7.3 cents/kWh to 7.5 cents/kWh. The volumetric rate for power generated by the microgrid is set at 21.6 cents/kWh, which is below MGE's time-of-use rates for all on-peak periods (these rates range from 23.9 to 29.1 cents/kWh). The 25-year LCOE for residential microgrid customers ranges from 11.4-11.8 cents/kWh compared to an LCOE of 13.2 cents/kWh under the base case. The long-term cost reductions stem from the fixed rates for microgrid customers, while rates for non-microgrid customers rise at 2% annually. The scenario results in a net revenue shortfall of $72 million for MGE, or $2.9 million per year.

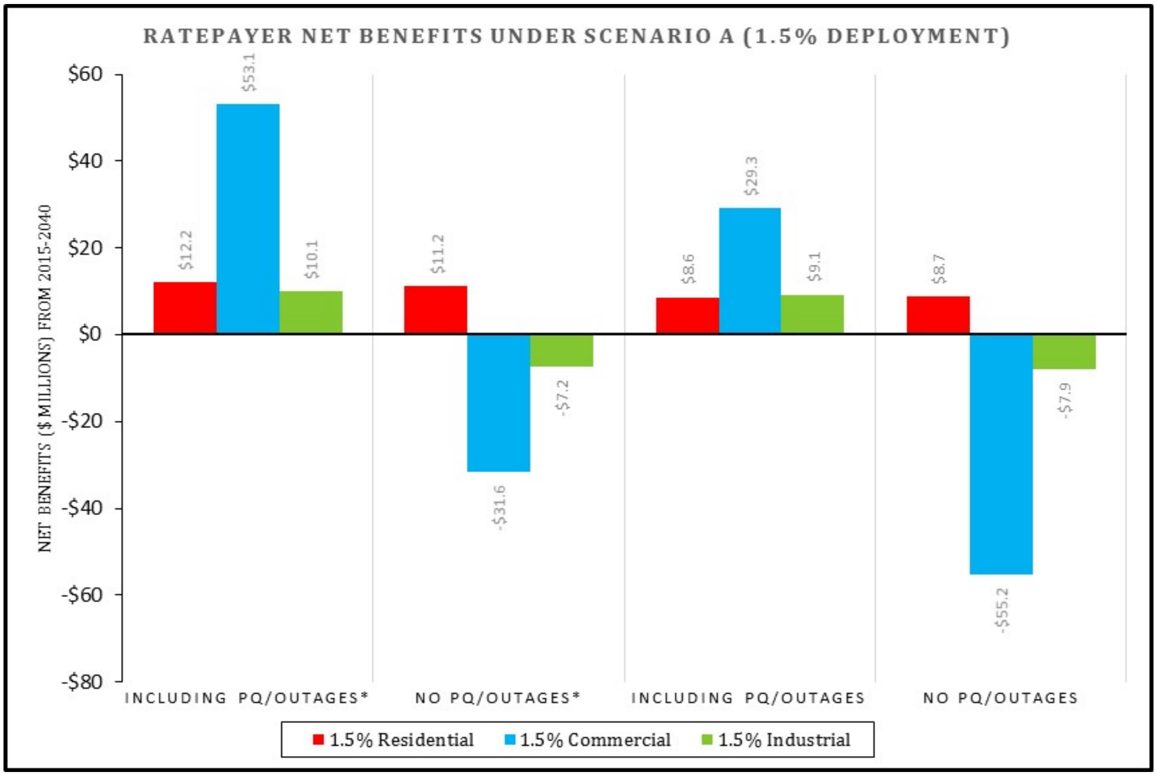
Commercial customers enjoy net benefits under Scenario A, but only when the benefits of avoided power outages and increased power quality are included. If the microgrid serves five commercial customers who value power quality at $7,000 per event, and outages at $13,000 per 60-minute event (the values reported by retail customers in the EPRI suvery), the total annual benefit for each microgrid rises to $415,000. Commercial customers also enjoy reduced demand charges, which decline from around $96,000 to $38,000 per year, for a microgrid with annual demand of 5 million kWh. Demand charges are incurred during on-peak hours when a fixed charge is applied to the highest 15-minute period of demand during each day.

The commercial off-peak rate rises from 5.4 cents/kWh to 9.5 cents/kWh when Tier II benefits are not included in MGE's revenue stream. The lifetime LCOE for commercial customers ranges from 10.5-14.7 cents/kWh compared to the base case LCOE of 7 cents/kWh. When the benefit of avoided power outages is included, commerciual customers experience $53-$59 million in net benefits. However, when the benefits of improved power quality and avoided power outages is omitted, commercial customers experience net costs of $56 to $93 million under the 1.5% deployment scenario, and $155 to $281 million under the 3% deployment scenario. Clearly, microgrids are only cost-effective for commercial customers who place a high value on power quality and reliability. Unlike residential customers, who can experience net energy savings, MGE cannot reduce the microgrid volumetric charges below current time-of-use rates resulting in net cost increases.

Industrial customers face a similar value proposition because their rates are the lowest of all of MGE's customer segments, but they make up a relatively small portion of MGE's total customer base. The LCOE for electricity purchased from MGE is 5.8 cents/kWh compared to 9.8-10 cents/kWh from the microgrid. This results in additional annual costs of about $315,000 for each industrial microgrid and $3.9

million in additional costs over the microgrid's 25-year operating life. Assuming that each microgrid serves two industrial customers who place a high value on power quality and reliability, the microgrid delivers $9.1 to $15.2 million in net benefits. Without including power quality and reliability benefits, industrial customers experience net costs of $12 to $13 million. As with commercial customers, the cost-effectiveness and economic viability of microgrids depends on the customers' value/willingness-to-pay for power quality and reliability.

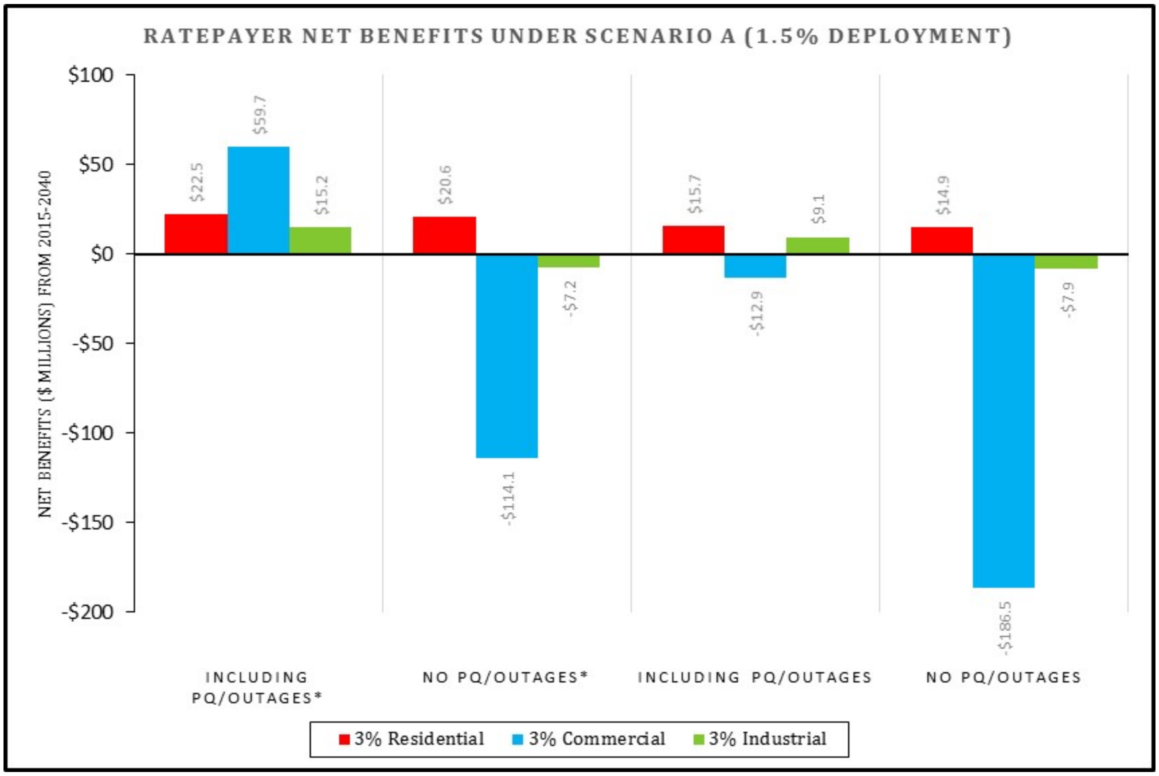
Figure 14: Ratepayer Benefits Under 1.5% Deployment Scenario from 2015-2040



Figures 14 (above) and 15 (next page) illustrate the distribution of net benefits for each customer group under the different sensitivity simulations. The first set of columns illustrates ratepayer net benefits when MGE includes the uncertain Tier II benefits in its ROR calculation, and the value of power quality/reliability are included in the Tier I benefit calculation. The second set of columns includes Tier II benefits, but omits the value of power quality and reliability. The third set of columns does not include Tier II benefits, but does include power quality and reliability benefits, while the fourth set of columns does not include Tier II benefits or the value of increased power quality and reliability.

The charts show that residential customers enjoy positive net benefits under both deployment scenarios regardless of whether Tier II benefits, or the value of power quality and reliability are included. By comparison, the microgrid value proposition for commercial and industrial customers hinges on the value of increased power quality and reliability.

Figure 15: Ratepayer Benefits Under 3% Deployment Scenario from 2015-2040



8.4 - Scenario B Rate Levels & Results

Under Scenario B, a third party developer builds, owns and operates the DER and microgrid equipment for the duration of the system's operational life. The developer charges a volumetric rate ($/kWh) that allows it to earn a 15% ROI. Typically, the rate is between 150-165% of the system's LCOE. MGE still enjoys benefits such as reduced fuel and wholesale electricity purchases, less exposure to environmental compliance costs, and investment deferrals, without incurring the initial capital costs to build the microgrid systems.

However, unlike Scenario A, MGE does not earn revenue from electricity generated by the microgrids and does not obtain physical assets, tax credits, or RECs generated by the microgrids' solar PV arrays. MGE raises its' on-peak and off-peak rates for microgrid customers to the point where non-microgrid customers experience average rate increases of less than 1%. The table on the next page summarizes the third party and MGE rates.

Benefits Included	MGE Includes Tier II Benefits		MGE Excludes Tier II Benefits	
Customer Group	**1.5% Residential**	**1.5% Residential**	**3% Residential**	**3% Residential**
MGE Off-Peak Rate	$0.0729	$0.0729	$0.0729	$0.0729
MGE On-Peak Rate	$0.2394	$0.2394	$0.2394	$0.2394
MGE Rate for MG Power	$0.2561	$0.2561	$0.2561	$0.2561
Original LCOE ($/kWh)	$0.1323	$0.1323	$0.1323	$0.1323
Microgrid LCOE ($/kWh)	$0.1253	$0.1253	$0.1253	$0.1253
Benefits Included	**MGE Includes Tier II Benefits**		**MGE Excludes Tier II Benefits**	
Customer Group	**1.5% Commercial**	**1.5% Commercial**	**3% Commercial**	**3% Commercial**
MGE Off-Peak Rate	$0.0550	$0.0550	$0.0650	$0.0650
MGE On-Peak Rate	$0.1145	$0.1145	$0.1353	$0.1353
MGE Rate for MG Power	$0.2224	$0.2224	$0.2224	$0.2224
Original LCOE ($/kWh)	$0.0701	$0.0701	$0.0701	$0.0701
Microgrid LCOE ($/kWh)	$0.1085	$0.1085	$0.1126	$0.1126
Benefits Included	**MGE Includes Tier II Benefits**		**MGE Excludes Tier II Benefits**	
Customer Group	**1.5% Industrial**	**1.5% Industrial**	**3% Industrial**	**3% Industrial**
MGE Off-Peak Rate	$0.0530	$0.0530	$0.0530	$0.0530
MGE On-Peak Rate	$0.0810	$0.0810	$0.0810	$0.0810
MGE Rate for MG Power	$0.2287	$0.2287	$0.2287	$0.2287
Original LCOE ($/kWh)	$0.0582	$0.0582	$0.0582	$0.0582
Microgrid LCOE ($/kWh)	$0.1007	$0.1007	$0.1007	$0.1007

The third party rates outlined above results in a modest 15% ROI for the developer over the 25-year simulation period. With rates set between 20-22 cents/kWh for each customer group, the third party developer receives about $1 million in total net benefits for each microgrid system it builds and operates. Their revnue could increase if the developer is able to sell RECs at a higher price than the $10/MWh value used in the MoDERN simulation. The average cost of RECs and renewable electricity procured by Wisconsin utilities to comply with the state's RPS was estimated at $40-$50/MWh.[40] Unlike MGE, the third party developer is not affected by the imposition of a price on carbon emissions, because EPA's proposed regulations under Section 111(d) of the Clean Air Act only apply to coal and gas-fired units larger than 25MW. The microturbines used in the standard microgrid configuration are only 200kW in size.

Scenario	Residential	Commercial	Industrial
Third Party ROI	15.12%	15.03%	15.10%
1.5% Deployment	$7.5	$18.8	$3.1
3% Deployment	$13.5	$37.8	$4.7

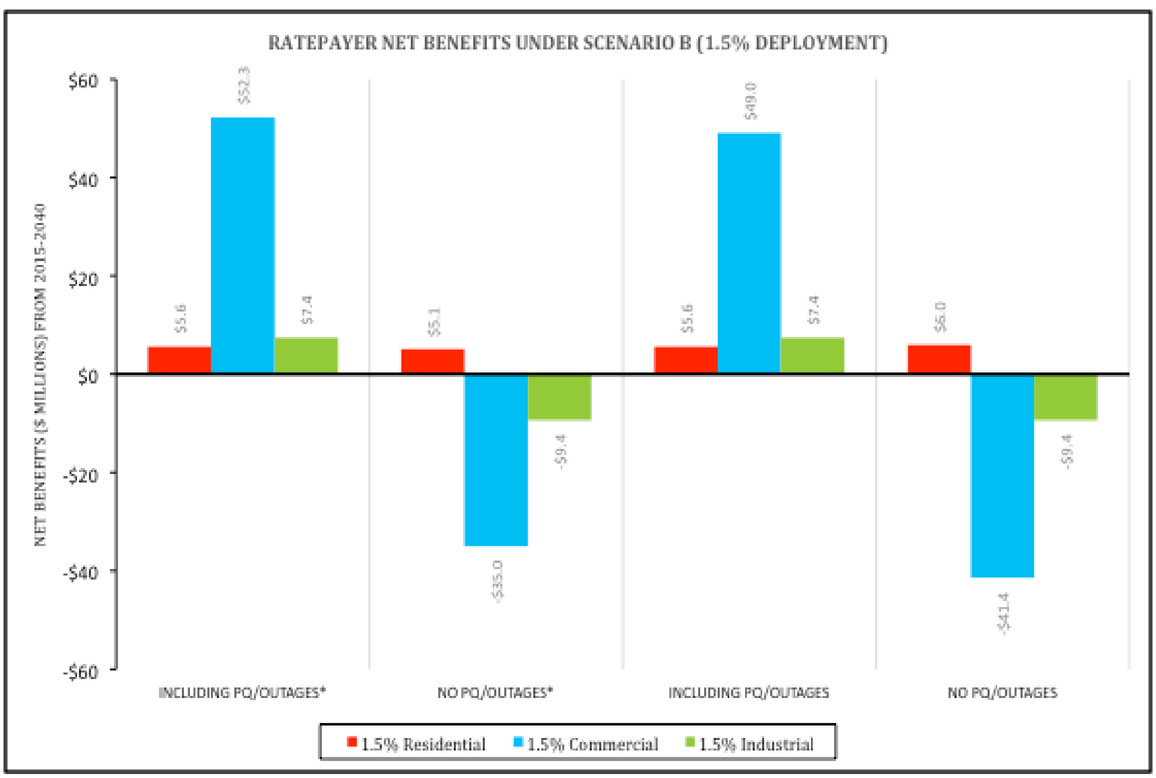
[40] Heeter et al. *A Survey of State-Level Costs and Benefits of RPS.* NREL, 2014 (link).

8.5 - Ratepayer Benefits Under Scenario B

Under the 1.5% deployment scenario, residential customers received an average of $5.6 million in net benefits over the 25-year life of the project (based on 1,000 simulations). The. The 25-year LCOE with the microgrid is 12.3 cents/kWh, slightlow lower than the base case LCOE of 13.2 cents/kWh. The developer must charge a fixed volumetric rate of 24.8 cents/kWh to earn a 15% ROI, which results in residential customers experiencing a 7.9% ROI. While simulated net benefits under this scenario are positive, and 65% of the simulated outcomes were positive, the residential ROI is below the 10% threshold used in the four-step cost-effectiveness process.

The ratepayer's savings and total net benefits would rise above the 10% threshold if the developer reduced their volumetric rates to 24 cents/kWh, but that would reduce the developer's ROI to 12.1%, below their 15% threshold. MGE does not need to raise rates above current levels for the microgrid customers in order to maintain their 10.3% ROI, while rates on non-microgrid customers rise by less than 1%. Under the 3% residential deployment scenario, total ratepayer benefits rise to $10.1 million.

Figure 16: Ratepayer Benefits under Scenario B (1.5% Deployment)



Commercial customers enjoy net benefits of $4.3 million for each microgrid when the value of power quality and increased reliability are included, compared to net costs of $2.9 million when those benefits are not included. When MGE omits the uncertain Tier II benefits from its revenue calculations, commercial net benefits decline to $3.6 million when power quality and reliability are included, and net costs of $3.5 milliion when those benefits are not included. Under the 1.5% deployment scenario, commercial benefits range from $49-$52 million, or costs of $25-$41 million when power quality and reliability benefits are not included. The 25-year LCOE under this deployment scenario is about 11 cents/kWh compared to 7 cents/kWh under the base case. MGE must raise it's rates for microgrid customers slightly in order to prevent non-microgrid customers from experiencing average rate increases grater than 1%.

Under the 3% commercial deployment scenario, MGE must raise rates for microgrid customers quite significantly in order to maintain their 10.3% ROI. When the uncertain Tier II benefits are included in MGE's revenue calculation, off-peak rates rise to 10 cents/kWh and on-peak rates rise to 20.8 cents/kWh resulting in a lifetime LCOE of 12.7 cents/kWh for commercial microgrid customers. When the Tier II benefits are not included, MGE must increase off-peak rates for commercial microgrid customers to 14.2 cents/kWh and on-peak rates to 29.6 cents/kWh. This results in a lifetime LCOE of 14.4 cents/kWh, more than double the base case LCOE of 7 cents/kWh. Less than 50% of the 1,000 MoDERN simulations produced positive net benefits when MGE includes the Tier II benefits. None of the simulations were positive when the value of power quality and reliability was omitted. Thus, microgrids are only cost-effective for commercial customers who place a high value on power quality and reliability to offset substantial rate increases.

The results for industrial customers are similar to those of commercial customers. MGE's rates for industrial customers are the lowest of the three major groups and result in a lifetime LCOE of 5.8 cents/kWh. The third party developer must charge a volumetric rate of 22.8 cents/kWh to earn a 15% ROI, which results in a lifetime LCOE of 10.1 cents/kWh for industrial microgrid customers. MGE is not forced to raise rates on microgrid customers under the 1.5% and 3% industrial deployment scenarios, because the microgrids produce a higher ROR than the base case. The two industrial microgrid scenarios are the only simulations that result in a higher ROR for MGE without raising rates on microgrid or non-microgrid customers. This is because only two microgrids are required under the 1.5% scenario, and just three for the 3% deployment scenario, meaning that MGE's total electricity sales decline by a much smaller amount than the commercial and residential scenarios.

When MGE includes Tier II benefits in it's revenue calculation, industrial microgrid customers enjoy average net benefits of $4.2 million for each microgrid when power quality and reliability are included. About 75% of the MoDERN simulations for the 1.5% and 3% deployment scenarios produced positive net benefits. When power quality and reliability benefits are excluded, only 2% of the simluations produced positive results, and the average cost to industrial customers is $4.7 million. Again, cost-effectiveness for industrial customers hinges on the value of reliability,

Figure 17: Ratepayer Benefits Under Scenario B (3% Deployment)

8.6 - MGE Benefits Under Scenario B

Under Scenario B, MGE experiences a small decrease in net revenue when microgrids and DER are used to displace 1.5% and 3% of the utility's retail sales in each customer group. MGE's lost retail sales during on-peak hours are slightly greater than the reductions in wholesale purchases, fuel costs and capacity investments. The lost revenue is recovered by raising rates for microgrid customers and non-microgrid customers (up to the 1% limit). Net revenue under Scenario B does not fall lower than $70 million below the base case, similar to Scenario A. Most of the simulaitons in Scenario A prouce slightly higher net revenue than Scenario B, MGE's ROI is slightly higher under Scenario B because the utility does not incur the additional costs of financing and operating microgrids.

In fact, MGE's ROR under the 1.5% residential and industrial deployment scenarios exceeds the 10.3% base case ROI when the uncertain Tier II benefits are included in MGE's revenue calculation. MGE's ROR under the 1.5% commercial deployment exceeds 10% and requires very modest rate increases from non-microgrid customers. When the Tier II benefits are not included, only the industrial deployment scenarios return an ROR that exceeds the 10.3% baseline. Figures 18 and 19 illustrate the results of the Scenario B simulations in MoDERN.

Figure 18: MGE's ROI Under Scenario B (1.5% Deployment)

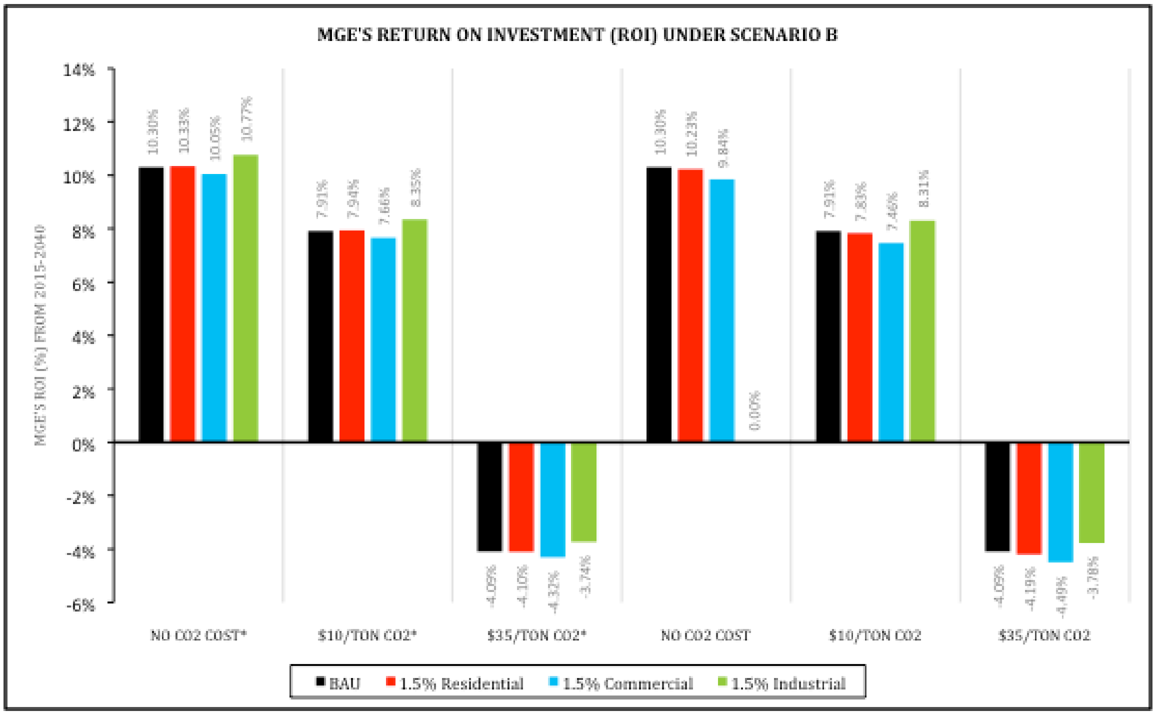
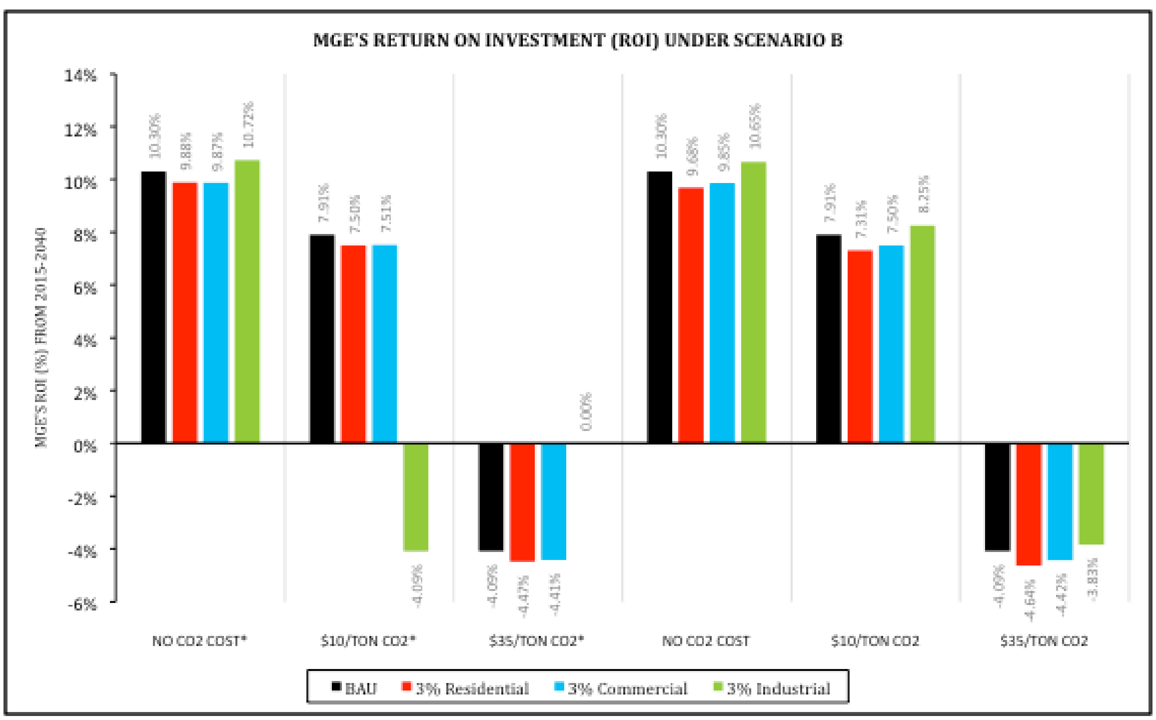
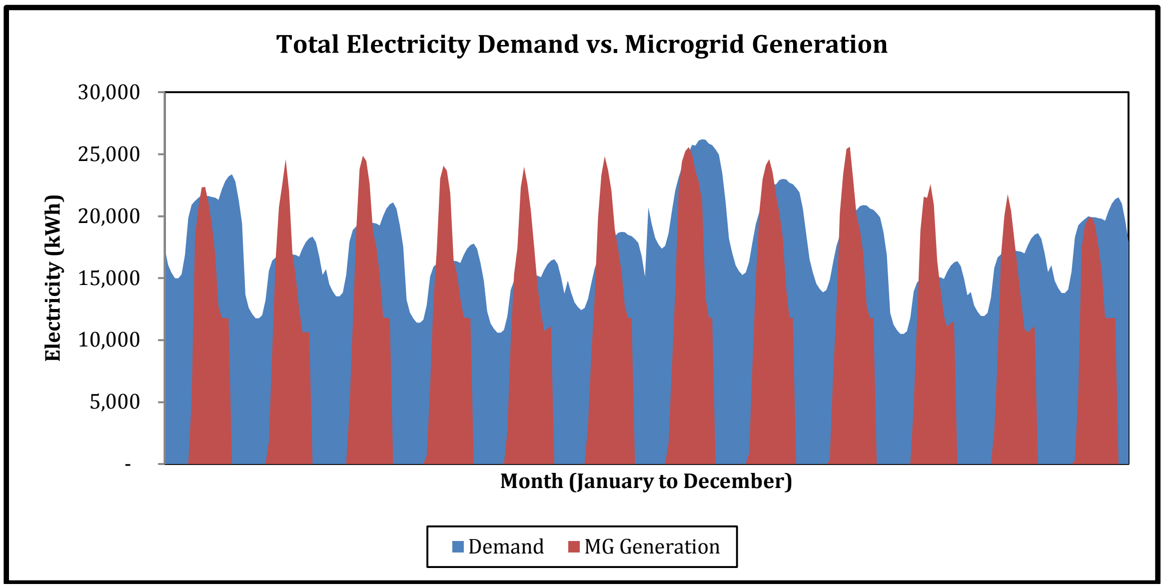


Figure 19: MGE's ROI Under Scenario B (3% Deployment)



Although on-peak hours only account for roughly 35% of total annual load served, on-peak sales accounted for about 70% of MGE's total revenue in 2012 because the rates (ranging from 19-29 cents/kWh for residential customers) are two to three times higher than the residential off-peak rate of 7.3 cents/kWh. Under the standard microgrid configuration, the combination of solar PV and microtubines is able to provide 95% of on-peak demand in areas where on-peak demand is around 1.6 million kWh. Microgrid generation reduces annual purchases from $485,000 to $20,000. Figure 20 compares annual energy demand against the amount of electricity produced by one microgrid when total annual demand is 5 million kWh.

Figure 20: Monthly Residential Demand vs. Microgrid Generation



The microgrid system is capable of meeting all customer demand during most on-peak hours, especially in the spring and fall when demand is relatively low, and solar generation is relatively high. When the red peaks rise higher than the blue, it means that the microgrid is generating excess power that is being sold back to MGE at the net metered rate. There is no energy storage capacity built into the standard microgrid, which would allow the operator to release excess energy during evening hours when solar generation fades, or when clouds cut into PV generation.

The blue areas represent the time when customers are purchasing electricity from MGE. This typically occurs during off-peak hours because it is cheaper to purchase from the grid than to generate power from the small natural gas-fired microturbines that serve as backup for solar PV. The MoDERN simulations show that MGE can maintain its' 10.3% ROR under Scenario B by implementing marginal rate increases on microgrid and non-microgrid customers. At the low deployment levels tested in this analysis, it appears that it would be more cost-effective for MGE to allow a third party developer to build and operate microgrids for interested customers.

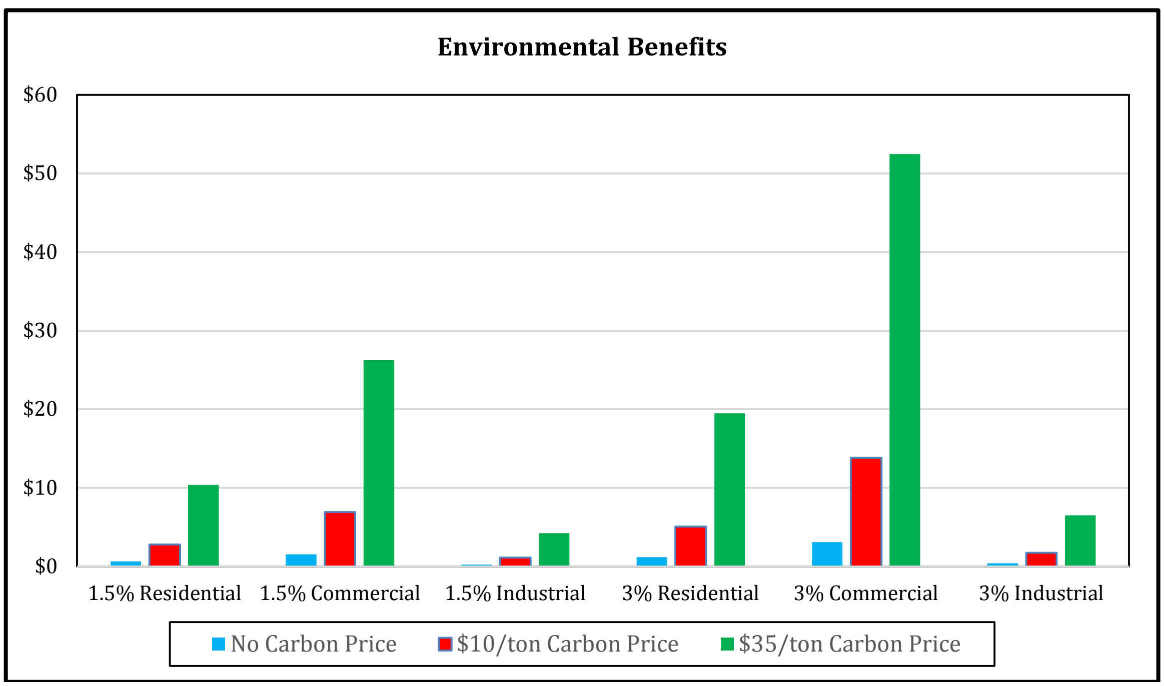
As discussed earlier, a split ownership or cost/revenue sharing model may be able to resolve this problem and provide net benefits to both MGE and the third party developer operating in the residential sector. Commercial and industrial customers who place a high value on reliability may also choose to pay higher prices for electricity generated by a network of microgrids. The MoDERN simulations show that MGE's net revenues are quite vulnerable to the inclusion of CO_2 compliance costs under baseline conditions. Further analysis of the impact of carbon pricing is necessary to evaluate the effectivess of microgrids against other generation types.

8.7 - Environmental & Social Benefits Under Scenario A & B

Environmental benefits not included under Tier I or Tier II include the avoided health and environmental costs associated with the displacement of electricity generated by fossil fuels. The value of avoided CO_2 , SO_2 and NO_x emissions is calculated based on figures used by the EPA in the agency's regulatory impact analysis for recent air pollution regulations. Under the 1.5% deployment scenario, total net social benefits from 2015-2040 range from $2.5 million to $33.5 million depending on the social cost of carbon.

Under the 3% deployment scenario, total benefits range from $3.2 million to $67.1 million. Social benefits increase dramatically under the hig deployment scenarios, ranging from $18.6 million to $327.6 million under the partial deployment scenario and $58.8 million to $773.4 million under the full deployment scenario. The highest values occur when the social cost of carbon is set at $35/ton in 2015 and increases at 2.1% annually.

Figure 21: Environmental Benefits of Microgrid Deployment



8.8 - Summary of Cost-Effectiveness Results in Scenarios A & B

Out of the 24 scenarios tested under Scenario A, 15 passed all four cost-effectiveness tests outlined in sections 7.1-7.5, while 6 passed all four tests under Scenario B (highlighted green in the following tables). All of the microgrid deployment scenarios deliver positive net benefits with a cost-benefit ratio higher than 1.0 for all customer segments when the value of increased reliability and power quality is included. Residential customers experience positive net benefits when reliability benefits are excluded because the microgrid can deliver electricity during on-peak periods at a lower cost than MGE's time-of-use rates.

Under Scenario A, MGE enjoys positive net benefits under the UCT when the microgrid is considered as an isolated entity, while maintaining a minimum 10.3% ROR without exceeding the 1% RIM limit. The 1.5% and 3% industrial deployment scenarios pass both tests and do not require MGE to raise rates on non-microgrid customers.

Tier II & Reliability	**PCT**	**UCT for Microgrids**	**RIM (%)**	**UCT Entire System**
1.5% Residential	1.162	1.372	0.00%	1.103
3% Residential	1.117	1.428	0.59%	1.103
1.5% Commercial	1.351	1.188	0.37%	1.103
3% Commercial	1.158	1.397	0.69%	1.103
1.5% Industrial	1.427	1.126	-0.31%	1.108
3% Industrial	1.400	1.149	-0.28%	1.107
Tier II, No Reliability				
1.5% Residential	1.160	1.372	0.00%	1.103
3% Residential	1.114	1.428	0.59%	1.103
1.5% Commercial	0.799	1.188	0.37%	1.103
3% Commercial	0.685	1.397	0.69%	1.103
1.5% Industrial	0.700	1.126	-0.31%	1.107
3% Industrial	0.684	1.149	-0.28%	1.107
No Tier II & Reliability				
1.5% Residential	1.162	1.372	0.21%	1.103
3% Residential	1.114	1.428	0.98%	1.103
1.5% Commercial	1.158	1.397	0.54%	1.103
3% Commercial	0.963	1.691	0.73%	1.103
1.5% Industrial	1.400	1.149	-0.27%	1.107
3% Industrial	1.400	1.149	-0.22%	1.107
No Tier II, No Reliability				
1.5% Residential	1.160	1.372	0.21%	1.103
3% Residential	1.114	1.428	0.98%	1.103
1.5% Commercial	0.685	1.397	0.54%	1.103
3% Commercial	0.570	1.691	0.73%	1.103
1.5% Industrial	0.684	1.149	-0.27%	1.107
3% Industrial	0.684	1.149	-0.22%	1.107

Under Scenario B, only 7 of 24 simulations passed all four cost-effectiveness tests. The third party developer enjoys a minimum 15% ROI under each scenario, while MGE is able to maintain a 10.3% ROR without increasing average rates for non-microgrid customers above the 1% RIM threshold. Unlike Scenario A, the residential deployment scenarios fail to achieve the minimum 1.1 score on the PCT because the third party developer must charge a higher rate than MGE for electricity generated by the microgrid to achieve a 15% ROI.

Scenario B scores slightly higher on the PCT for the 3% commercial scenario when reliability benefits are not included (1.256 to 1.158), but non-microgrid customers face higher rate increases (0.81% to 0.54%). The results show that MGE can develop microgrids across all customer segments more cost-effectively than a third party developer. But, if MGE is unwilling to pursue microgrid development, there are some scenarios where microgrids could be cost-effective for all stakeholders when built by a third party developer.

Tier II & Reliability	**PCT**	**UCT for Microgrids**	**RIM (%)**	**UCT Entire System**
1.5% Residential	1.079	0.344	0.03%	1.103
3% Residential	1.079	0.344	0.71%	1.103
1.5% Commercial	1.303	0.497	0.53%	1.103
3% Commercial	1.114	0.556	0.95%	1.103
1.5% Industrial	1.332	0.348	-0.30%	1.108
3% Industrial	1.332	0.348	-0.26%	1.107
Tier II, No Reliability				
1.5% Residential	1.077	0.344	0.03%	1.103
3% Residential	1.077	0.344	0.71%	1.103
1.5% Commercial	0.771	0.497	0.53%	1.103
3% Commercial	0.658	0.556	0.95%	1.103
1.5% Industrial	0.621	0.348	-0.30%	1.108
3% Industrial	0.621	0.348	-0.26%	1.107
No Tier II & Reliability				
1.5% Residential	1.079	0.344	0.17%	1.103
3% Residential	1.079	0.344	0.97%	1.103
1.5% Commercial	1.256	0.377	0.81%	1.103
3% Commercial	0.979	0.765	0.97%	1.103
1.5% Industrial	1.332	0.348	-0.27%	1.107
3% Industrial	1.332	0.348	-0.22%	1.106
No Tier II, No Reliability				
1.5% Residential	1.077	0.344	0.17%	1.103
3% Residential	1.077	0.344	0.97%	1.103
1.5% Commercial	0.742	0.377	0.81%	1.103
3% Commercial	0.579	0.765	0.97%	1.103
1.5% Industrial	0.621	0.348	-0.27%	1.107
3% Industrial	0.621	0.348	-0.22%	1.106

Evaluating microgrid deployment using the combination o the UCT, PCT and RIM tests is appropriate given that the UCT is used as the primary measure of cost-effectiveness in Michigan (a close neighbor to Wisconsin with a regulated electric utility sector) and several other states. The Wisconsin PSC currently uses the Total Resource Cost (TRC) test as the primary measure of cost-effectiveness, but reliance on this test alone can create biases against renewables, demand side management, and other energy conservation programs. The TRC, as commonly applied, has several fundamental problems. These include, the exclusion of non-energy benefits (i.e. environmental benefits), and the exclusion of ratepayer energy savings.[41] These concerns have also been raised in Wisconsin by a former manager of Focus on Energy's Solar Electric Program.[42]

Utah, like Michigan, has also switched from relying on the TRC to the UCT as the primary measure of cost-effectiveness because it can "put candidate demand-side resources on the same footing as supply-side resources."[43] A 2011 review of cost-effectiveness tests across multiple states determined that regulators should rely on the UCT as the threshold test for program approval and cost recovery because it accurately compares utility (and therefore customer) costs with supply-side alternatives. Based on the results of previous studies and the application of the UCT in other states, it is appropriate to evaluate the cost-effectiveness of microgrid deployment using the UTC as well as the PCT and RIM tests.

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[41] Neme and Kushler. "Is it Time to Ditch the TRC?" American Council for an Energy Efficient Economy, 2011 (link).

[42] Wolter. Email communication on 11 October 2011 (link).

[43] Daykin et al. "Whose Perspective? The Impact of the Utility Cost Test."

9.1 - MyPower Analysis & Results

In addition to using MoDERN to analyze the economic viability of microgrid deployment, the MyPower model developed at the Wisconsin Energy Institute (WEI) was used to compare microgrids against utility investment in other forms of generation capacity. The MyPower model is a long-term simulation of electricity supply and demand. The underlying model relies on a long-standing approach to power sector simulation termed a load duration curve (LDC) model.

The MyPower model is most similar to the Oak Ridge Competitive Electricity Dispatch model, which is used to evaluate competitive power markets. The data underlying MyPower is based largely on information from the US EPA's Integrated Planning Model (IPM), an LDC used for evaluating the cost of pollution reduction polices. The MyPower model was developed to provide a simple and transparent approach for building and comparing hypothetical scenarios for electricity supply and demand. It is well suited for the task of comparing microgrid deployment against the baseline scenario, as opposed to other models that use optimization algorithms to identify the lowest cost option for expanding generation capacity. The 1.5% and 3% microgrid deployment scenarios are developed in the MyPower framework to forecast changes in electricity demand, rates, and emissions.[44]

In MyPower, the default microgrid is set up with 5MW of solar PV and will be compared against 3.5MW of backup diesel generators over a 20-year time horizon (2015-2035). The 5MW solar PV array in MyPower is considered equivalent to 3.5MW of diesel generators based on the coincident capacity factor of solar PV during on-peak hours. NREL's PVWatts tool was used to obtain hourly capacity factors for solar PV in the City of Madison, which is illustrated in figure 22. PVWatts produces hourly solar generation estimates for locaitons within the U.S. based on 40km^2 resolution grid cells and solar irradiation data from the TMY2 dataset provided by NREL's National Solar Radiation Database.[45]

PVWatts calculates the solar radiation incident the PV array and the PV cell temperature for each hour of the year. The DC energy for each hour is calculated from the PV system's DC rating and the incident solar radiation, and then corrected for the PV cell temperature. The AC energy for each hour is calculated by multiplying the DC energy by the overall DC to AC derate factor and adjusting for inverter efficiency as a function of load. Hourly values of AC energy are then summed to calculate monthly and annual AC energy production. The TMY2 data was collected from 1961-1990 and represents typical, rather than extreme, conditions and is therefore not suited for modeling worst-case scenarios.

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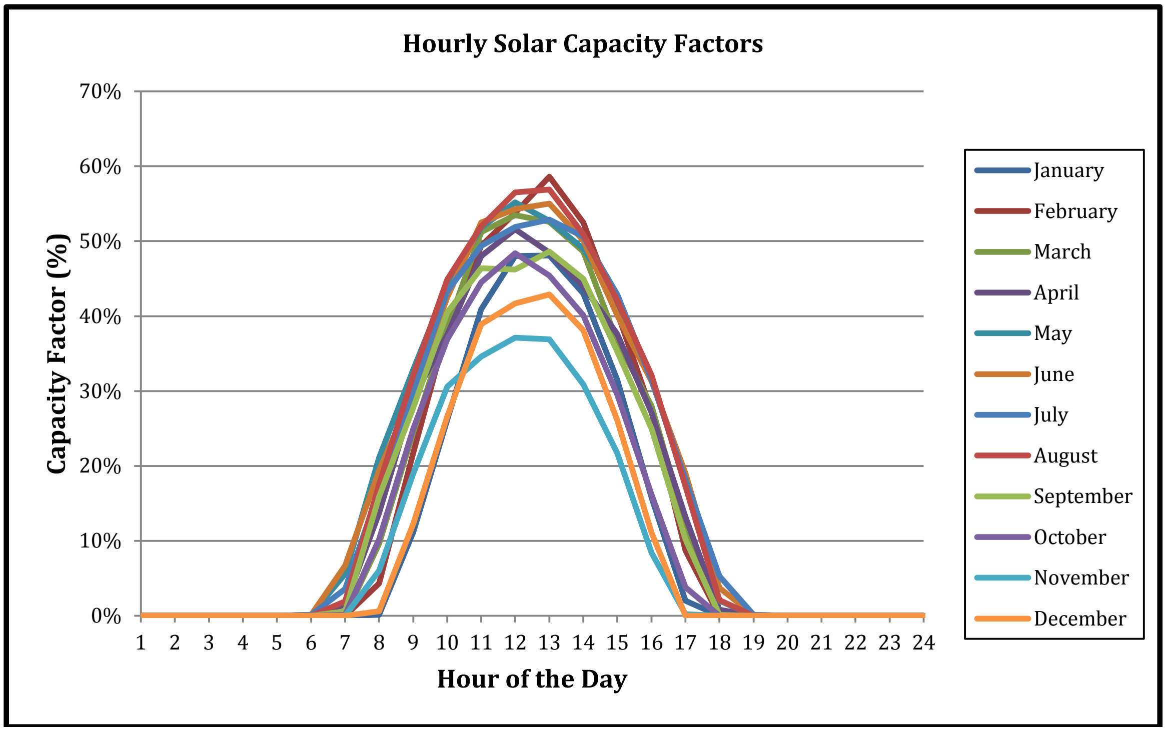
[44] "MyPower Methodology Documentation." Meier Engineering & Research (link).

[45] Marion, B., et al. "PVWATTS Version 2 - Enhanced Spatial Resolution for Calculating Grid-Connected PV Performance." NREL, 2001 (link or website).

Figure 22: Average Hourly Solar PV Capacity Factors in Madison, Wisconsin



The PVWatts results show that a fixed axis PV system in Madison is capable of generating power at 40% to 60% of its total nameplate capacity between the hours of 11am and 2pm. Thus, the capacity value of a 1.5MW solar PV system is approximately 600-900kW. An NREL survey of methodologies used to calculate the capacity value of solar PV produced values ranging from 56% to 72% depending on the project's location.[46] Xcel Energy, the largest utility in Minnesota and Colorado, reported solar PV capacity values of 59% to 63% for fixed-axis systems.[47]

Based on these sources, it is reasonable to use a 60% capacity value for the fixed-tilt PV systems contained in the standard microgrid. Thus, each 5MW solar PV microgrid that is added to the MyPower simulation will be compared against a 3.5MW diesel genset in the alternative simulation. This method effectively compares the lifetime costs of solar PV against the most likely alternative form of fossil generation.

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[46] Denholm, Paul. *Comparison of Capacity Value Methods for Photovoltaics in the Western US.* National Renewable Energy Laboratory, July 2012 (link).

[47] "Comments on Xcel Energy's Distributed Solar Generation Study." Vote Solar Initiative, 9 September 2013 (link).

PV Capacity Values (% of Nameplate PV Capacity)		
Location	**ECP Method**	**ELCC Method**
Albuquerque, NM	72.6%	67.4%
Bartsow, CA	64.2%	59.7%
Boise, ID	71.1%	66.0%
Cheyenne, WY	55.8%	51.8%
Congress, AZ	75.1%	69.7%
Denver, CO	64.6%	60.0%
Hanover, NM	61.0%	56.7%
Las Vegas, NV	64.6%	60.0%
Los Angeles, CA	56.0%	52.0%
Phoenix, AZ	69.4%	64.4%
Salt Lake City, UT	65.7%	61.0%
San Francisco, CA	60.1%	55.8%
Seattle, WA	62.0%	57.6%
Yucca Flat, NV	61.0%	56.6%

The 1.5% residential scenario utilizes five microgrids (1.5MW of solar PV and 400kW of natural gas-fired microturbines) for a total of 13.5MW of solar PV and 2MW of microturbines, 15.5MW of total microgrid generation. The MyPower model compares three 5MW solar PV arrays against an alternative scenario that deploys diesel generators equivalent to 60% of the microgrid's solar capacity. The diesel generators in MyPower are 3MW units. The comparison of the 1.5% residential scenario utilizes three diesel generators installed in 2015. The 3% commercial scenario requires 24 microgrids, or 36MW of solar PV and 9.6MW of microturbines. The MyPower simluaiton compares seven 5MW microgrids against seven 3MW diesel generators.

Deployment Scenario	Total PV Capacity (MW)	MG's Built in MyPower	Diesel Capacity in MyPower (MW)
1.5% Residential	15.5	3	9
3% Commercial	36	7	21

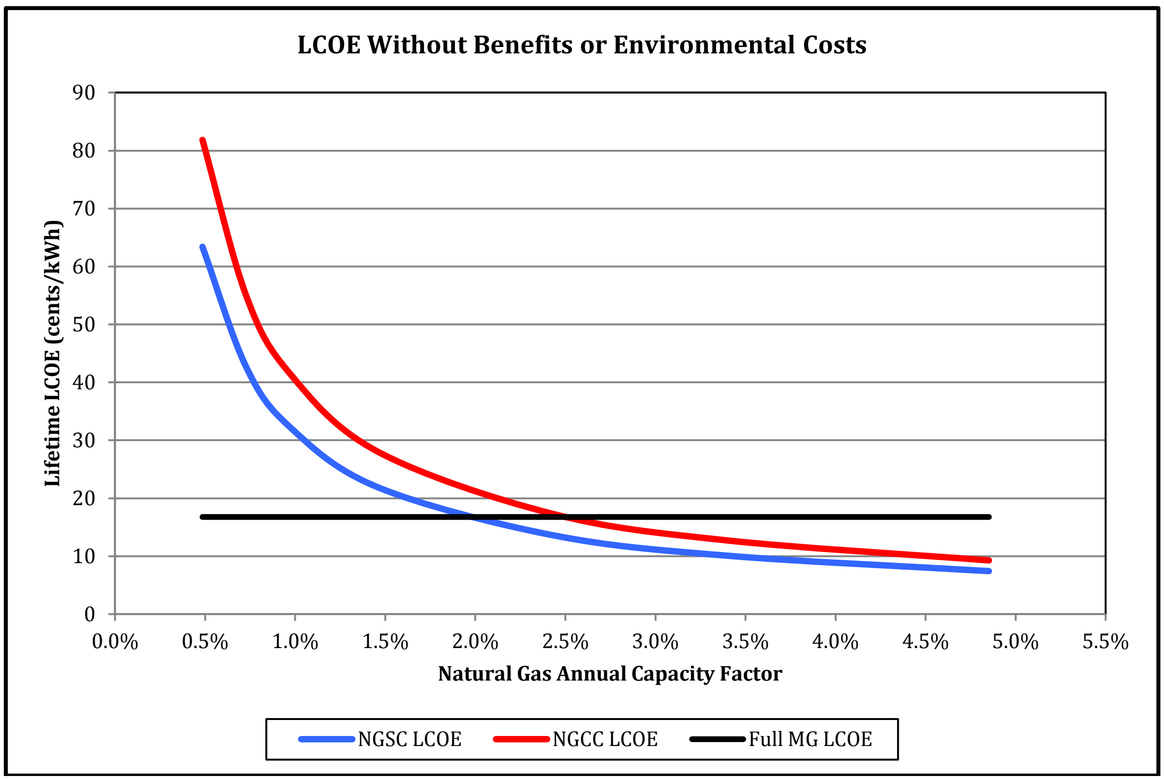
Results of MyPower Simulations

The four scenarios are: 1.5% Residential Diesel, 3% Commercial Diesel, 1.5% Residential PV, and 3% Commercial PV. In both cases, the diesel generators did not run at all in 2015, 2020 or 2030. While the diesel generators provide backup capacity and a measure of increased reliability, none of their initial or annual costs are recovered through actual sales of electricity. The LCOE for the diesel generators was extremely high at $0.61/kWh in 2020, declining to $0.32/kWh in 2025 and $0.26/kWh in 2030. By comparison, the PV systems generated power 1,211 hours in each year, producing 18,171MWh, and the LCOE declined steadily from 30 cents/kWh in 2015 to 19 cents/kWh in 2030.

The MyPower modeling results clearly show that solar PV-based microgrids offer attractive, long-term economic returns when compared to diesel generators. The cost-competitiveness of PV-based microgrids can also be shown against natural gas peaking units by comparing the LCOE of each option at different capacity factors for a natural gas unit. For this example, a 25MW natural gas unit is compared against the standard microgrid system (1.5MW of solar P and two 200kW microturbines) at capacity factors ranging from 1% to 5%.

In 2012, the average capacity factor of natural gas units in Wisconsin was just 5.6%, and only two of the nineteen plants operated at capacity factors above 20% (EIA Form 861, 2012). The capital cost for simple cycle and combined cycle gas turbines is set at $900/kW and $1,200/kWh, respectively, based on Minnesota's VOST methodology. Figure 23 shows that the standard microgrid's LCOE is lower than the simple cycle turbine until it reaches a capacity factor of 2%, while the combined cycle turbine must operate at around 2.5-3% to be competitive with microgrids.

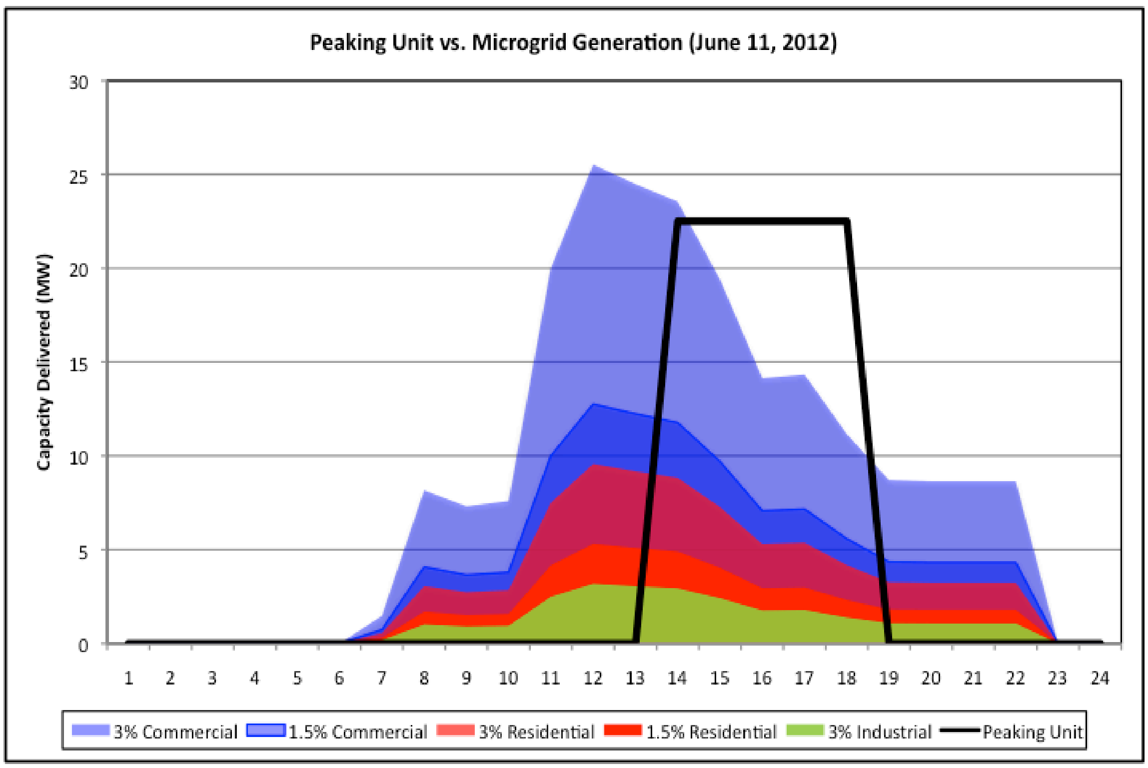
Figure 23: LCOE of Microgrids vs. 25MW Natural Gas Peaking Unit



When environmental costs are included in the LCOE calculation, the microgrid outperforms the natural gas units by a wide margin. The microgrid LCOE ranges from $89-$94/MWh, while the natural gas LCOE ranges from $50/MWh at a 20% capacity factor to $595/MWh at a 1% capacity factor. Environmental costs are calculated using the $18/MWh value adopted by the Minnesota VOS methodology. The microgrid LCOE also includes the value of fuel hedging and investment deferrals included in the Minnesota methodology. When the full range of costs and benefits are considered, microgrids represent a very attractive option for MGE and other utilities compared to diesel generators and natural gas peaking units that operate at very low capacity factors. In 2012, fourteen of the eighteen natural gas units smaller than 100MW operated at a capacity factor of 5% or lower (EIA Form 861, 2012).

However, comparing the annual generation and capacity factor of a peaking unit and microgrid system fails to account for hourly variations in peak demand that may require the peaking unit to operate at a high capacity factor during short time periods. While the annual generation of a 25MW gas-fired unit with a 5% capacity factor can be matched by nine microgrids, the microgrids cannot match hourly demand spikes. For example, if the 25MW peaking unit operates at a 90% capacity factor to meet critical peak demand on a hot summer afternoon, the microgrids would not be able to match this output. Figure 24 illustrates the hourly generation profile of a 25MW peaking unit operating at a 90% capacity factor from 1pm to 6pm, and the hourly generation of microgrids under each deployment scenario.

Figure 24: Hourly Peak Capacity, 25MW Gas Turbine vs. 20 Microgrids



In this scenario, microgrid generation peaks at 1pm when solar PV reahes a maximum capacity factor of 55% and the microturbines are ramped up to a 90% capacity factor. Solar PV generation peaks at 7.2MW and the microturbines provide 3.1MW of hourly capacity until 9pm when the peak demand period ends. By comparison, the 25MW peaking unit provides 45MW of hourly capacity throughout the 8-hour period, resulting in a capacity shortfall of 35-42MW as solar PV generation tapers off in the evening hours. This shortfall could be mitigated by the microgrid's ability to facilitate demand response and load shaving by MGE or the third party system operator. The combination of peak shaving capacity provided by the microgrid and effective implementation of demand response could eliminate the need for the 25MW peaking unit, which would only be dispatched during periods of extremely high demand, resulting in high LCOE and long payback period.

Of the eighteen gas-fired power plants in Wisconsin smaller than 100MW, only four operated at a capacity factor higher than 5% and eleven operated at a capacity factor of 1% or lower (EIA Form 861, 2012). A 25MW peaking unit would need to operate at a 90% capacity factor from 1-9pm on 54 days (438 total hours) to achieve a 5% annual capacity factor, and 11 days (88 total hours) to achieve a 1% annual capacity factor. The average number of critical peak hours reported by Wisconsin Public Service Co., from 2007-2013 is 63 and the annual total has only exceeded 88 hours once during that time period.[48]

Assuming the 25MW peaking unit is dispatched for the average number of critical peak hours results in an annual capacity factor of just 0.75%. At that low level, the LCOE for the peaking unit rises to $580-$770/MWh compared to an LCOE of $137/MWh for the nine microgrid systems required to meet 3% of MGE's residential demand. This comparison shows that meeting peak demand with microgrids and demand response is far more economical than building gas-fired peaking units or diesel generators that operate less than 100 hours per year (eleven of Wisconsin's nineteen gas plants smaller than 100MW operated less than 100 hours in 2012).

MGE's 22MW Fitchburg peaking plant provides an illustrative example in the MyPower model. During the 2015-2030 simulation period, the Fitchburg plant is never dispatched and carries fixed O&M costs of $240,000/year, resulting in total stranded costs of $3.8 million. By comparison, the 35MW of solar PV required under the 3% commercial deployment scenario is projected to generate 653,000 MWh from 2015-2030 at a total cumulative cost of $172 million, resulting in a 15-year LCOE of 26.4 cents/kWh. The simulations show that future deployment of solar PV-based microgrids can produce electricity at a lower levelized cost than existing natural gas-fired peaking units. Including additional microgrid benefits, such as increased reliability, reduced emissions, fuel price hedging and T&D investment deferrals would further improve microgrid cost-competitiveness when compared against natural gas peaking units.

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[48] Wisconsin Public Service Company, Critical Peak Hours (link)

Summary of MyPower Simulation Results

Generation Simulated	Lifetime Costs ($M)	Lifetime Generation (MWh)	LCOE (cents/kWh)	LCOE (3% Disc. Rate)
1.5% Microgrid	$73.89	281,144	26.4	16.9
3% Microgrid	$172.41	652,951	26.4	16.9
1.5% Diesel	$4.99	0	N/A	N/A
3% Diesel	$11.67	0	N/A	N/A
Fitchburg Peaking Unit	$3.84	0	N/A	N/A

A survey of demand response performance in the PJM region found that each request for at least 20MW of load reduction was matched with a minimum of 89% of the specified reduction, even with short lead times. Requests ranged from 24MW to 1,046MW, indicating that demand response can effectively eliminate the need for peaking units described above.[49] Five of the twenty-six utilities that reported more than 100MW of peak demand reductions in 2012 share borders with Wisconsin and WPSC ranked sixth nationally with 372MW of peak reductions through demand response (EIA Form 861).

The extremely low dispatch rates for small diesel generators and natural gas peaking units raises questions as to why MGE or other utilities would deploy these units instead of renewables and DER. Utilities may dispatch small diesel generators during periods of extremely high demand under demand response programs. This strategy (dubbed dirty DR) does not actually reduce load, it merely shifts generation from larger units to smaller units that face less stringent emissions control regulations.[50] The EPA has proposed regulations for backup generators that would impose strict emissions limits on particulate matter and NO_x emissions from generators larger than 19kW if they are dispatched more than 100 hours in a given year.[51]

The 100-hour exemption from emissions standards faces legal uncertainty following a May 2014 federal court ruling, which determined that diesel generators cannot receive payments for demand response under FERC Order 745. A group of utilities, environmental advocates and state agencies have urged the DC Circuit Court of Appeals to strike down the entire rule, which could further restrict the viability of diesel generators.[52] Thus, the PV microgrid represents a cleaner, more economical option for demand response programs with less regulatory risk and zero restrictions on the amount of time it could be dispatched.

[49] *Emergency Demand Response Performance Report 2012-2013.* PJM, December 2012 (link)

[50] Haugen, Dan. "Will EPA Proposal Shift Load to Dirty Generators?" *Midwest Energy News,* 26 July 2012 (link).

[51] US EPA. "Nonroad Technical Amendments." *Federal Register,* 6 February 2014 (link).

[52] Parker, S. "Clean Utilities City DR Ruling to Bolster Suit Over EPA Generator Air Rule." *Inside EPA.* 23 September 2014 (link).

10.1 - Policy Considerations

The results of economic modeling discussed in the previous section show that MGE could pursue smart grid development by building a network of microgrids to serve critical buildings in the City of Madison without severely impacting the utility's regulated ROR. The 1.5% and 3% microgrid deployment scenarios reduce MGE's net revenue by less than 1% compared to the baseline projection, but higher penetration of DER-based microgrids operated by a third party developer represent a potential threat to the current regulated monopoly business model. The future viability of the traditional regulated monopoly is unclear, as DER and other technologies chip away at the economies of scale that have supported natural monopolies in the electric power sector since the early 20th century.

A number of important policy and regulatory issues must be addressed in order for DER and microgrid deployment to move forward without causing regulated monopolies like MGE to descend into financial insolvency. One of the key issues related to increasing penetration of DER is how to allocate the fixed costs of upgrading and maintain the electric grid, and how to recover those costs. For MGE, the costs of building new T&D infrastructure is recovered through a mixture of volumetric charges ($/kWh) and fixed charges on each customer's monthly electricity bill.

Residential customers, for example, must pay a fixed charge of 34.3 cents per day and 3 cents per kWh for distribution services.[53] If a large number of customers switch to a third party developer, MGE's ability to recover the fixed costs of its distribution network will become more difficult. As more customers defect, and as total sales decline, MGE would be forced to seek higher rates from the PSC, which in turn could cause more customers to defect. The Edison Electric Institute (EEI) summarizes the daunting challenges faced by the electric industry (dubbed the "utility death spiral" by the Wall Street Journal[54]) in the following passage. [55]

> *As DER and demand side management (DSM) programs continue to capture market share, utility revenues will be reduced. Adding the higher costs to integrate DER, increasing subsidies for DSM and direct metering of DER will result in the potential for a squeeze on profitability and credit metrics. While the regulatory process is expected to allow for recovery of lost revenues in future rate cases, tariff structures in most states call for non-DER customers to pay for lost revenues. As DER penetration increases, this cost-recovery structure will lead to political pressure to undo these cross subsidies and may result in utility stranded cost exposure.*

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53 MGE Residential Rates link

54 Denning, Liam. "Lights Flicker for Utilities." *Wall Street Journal,* 22 December 2013 (link).

55 Kind, Peter. *Disruptive Challenges: Financial Implicaitons and Strategic Responses to a Challenging Retail Electric Business.* Edison Electric Institute, 2013 (link).

In addition to the risk of declining revenue and stranded infrastructure costs, EEI and its member utilities (comprising about 70% of all IOUs in the US) argue that net-metering laws do not accurately reflect the cost of integrating DER into the existing grid. Under most net metering programs electric companies are required to purchase excess power from DER systems at the full retail rate, which includes all of the fixed costs of the poles, wires, meters, advanced technologies, and other infrastructure that makes the grid safe, reliable, and able to accommodate intermittent DER systems. EEI argues that net-metered customers effectively are avoiding paying these costs, which are shifted to customers without DER systems through higher utility rates.[56] Four major policy concerns are listed below with further discussion and possible solutions outlined in the following sections.

- **Declining electricity sales**
- **Cost recovery and allocation**
- **Net-metering and the cost of integrating DER systems**
- **Alternative utility business models**

While the utility "death spiral" has gained considerable attention, there are opposing viewpoints that question the credibility of the threat DER poses to traditional electric utilities. A key argument by electric utilities is that higher penetration of DER will result in lower investment ratings by firms like Moody's or Standard & Poors that would increase the cost of capital that would be passed through to customers in the form of higher electricity rates.[57]

However, Moody's Investor Service revised its ratings of utilities in November 2013 to reflect reduced volumetric and commodity risk. The Moody's credit rating upgrade affects approximately $400 billion of utility debt. MGE was one of 167 utilities on the Moody's list of companies scheduled to receive credit rating upgrades, which indicates that utilities may not be as susceptible to the death spiral as previously thought.[58]

10.2 - Declining Revenue & Cost Recovery

As described earlier, increasing penetration of DER reduces the amount of electricity sold to customers and thereby reduces utility revenue that is used to pay for the fixed costs of maintaining electric grid infrastructure and dispatchable generation to backup intermittent renewables. The current regulatory response to declining sales is to raise the volumetric rate over a shrinking rate base, which drives up the price of electricity and could force accelerate customer adoption of DER or systems owned and operated by third party developers.

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[56] Edison Electric Institute: Distributed Generation and Net Metering Policies, 2014 (link).

[57] Pentland, William. "Why the Utility Death Spiral is Dead Wrong." *Forbes,* 6 April 2014 (link).

[58] "Moody's Places Ratings of Most US Regulated Utilities on Review for Upgrade." Moody's Investor Service, 8 November 2013 (link).

An alternative response to this problem would be the adoption of a fixed charge for each customer that is proportional to their share of system fixed costs, while retaining a volumetric charge for truly variable costs like fuel and electricity purchases from the wholesale market. Under this approach, the load lost to DER would lead to revenue losses for the utility equal to the costs they actually avoid in the short run. On net, the utility would be kept whole when load declines. This approach to ratemaking would also address the problems associated with net-metering by providing volumetric credits for the actual avoided costs realized by the utility instead of receiving the full retail rate for excess generation that includes fixed costs in the volumetric rate.[59]

However, switching to a billing system with relatively high fixed charges and relatively low volumetric charges results in far weaker economic price signals to end use consumers. This rate design may reflect historical system costs, but those are not the metric of interest in economic terms. Forward-looking marginal cost is the relevant benchmark. Forward-looking marginal costs include both internalized costs and externalities, such as the social cost of air emissions and water use. Increasing the fixed charge and lowering the volumetric charge exacerbates the problem by reducing the incentive for customers to conserve energy.[60] The high fixed-charge method also raises questions about fairness because it prevents low-income customers from reducing their energy costs through conservation.[61]

Attempts by utilities across the US to implement higher fixed-charges have been largely unsuccessful. Arizona Public Service Co., requested a monthly fixed-charge of $50-$100 for solar ownership, but state regulators only granted a $0.70/kW ($7/month for a 10kW system) monthly fee that took effect at the beginning of 2014.[62] In Wisconsin, MGE requested a 40% increase to its monthly fixed-charges and received approval for a 20% increase in January 2013.

Escaping the "death spiral" of declining revenues leading to increasing volumetric rates that stimulate accelerated customer defection and adoption of DER is a very complex problem. Striking the right balance between recovering fixed costs through monthly fixed-charges and variable costs through volumetric charges represents the solution that is most compatible with the traditional regulated monopoly business model.
However, a customer's fixed-charges should vary with their energy use and include exemptions for low-income customers to preserve economic fairness. Instead of assigning a fixed $/kW charge for solar, utilities could create tiers of fixed-charges

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[59] Kihm, Steve and Joe Kramer. "Third Party Distributed Generation: Issues and challenges for Policymakers." *Energy Center of Wisconsin,* March 2014 (link).

[60] Edison Electric Institute. *2010 Financial Review: Annual Report of the US Shareholder- Owned Public Utility Industry* (link).

[61] Wolfram, John, *Straight Fixed Variable Rate Design*, Catalyst Consulting, 2013.

[62] Montgomery, James. "Arizona Keeps Net-Metering , But Levies Smaller Solar Fee." *Renewable Energy World,* 15 November 2013 (link).

for customers with DER systems based on their monthly or annual energy consumption. Utilities could also shift the larger fixed-charges to large consumers who maintain a steady demand for power, while reducing volumetric charges for those customers and providing incentives for DSM during peak periods.

10.3 - Net-Metering & Integration Costs

The debate over net-metering shares many characteristics with the debate surrounding the allocation and recovery of fixed costs. In most states, excess electricity generated by DER systems must be purchased by the electric utility at the full retail rate. As discussed, earlier, the retail rate includes volumetric charges that are used to recover a portion of the fixed costs to build and maintain long lived grid infrastructure. Unless customers with DER are completely self-reliant, they are still responsible for paying for a portion of the T&D and backup generating capacity that is needed to integrate DER into the grid. Current net metering policies allow customers or third party developers to sell excess electricity at the full retail rate without paying for access to the grid, which provides reserve capacity, voltage/frequency control and other ancillary services.

Minnesota Value of Solar (VOS) methodology provides an alternative to standard net-metering policies. Utilities can choose to pay customers the VOS rate instead of the full retail rate for excess solar electricity. The VOS is currently estimated at 14.5 cents/kWh compared to Minnesota's average statewide retail rate of 11.5 cents/kWh. But the VOS could decline over time and become more attractive to utilities as retail rates increase. Participating customers will receive the VOS rate for 25-years and must forfeit any excess generation to the electric utility. By comparison, net-metered customers receive the full retail rate for systems smaller than 40kW, or the utility's avoided cost of generation for systems smaller than 1,000kW. Both policies limit total solar capacity to 120% of the host customer's annual energy consumption.[63]

Utilities stand to benefit from the VOS because it is uncoupled from retail rates and it provides free acquisition of solar renewable energy credits (RECs) from VOS projects. Solar RECs, which must be submitted for compliance with the state's RPS law, carry high prices in other states with deregulated solar REC trading markets like New Jersey, Maryland, Pennsylvania and Massachusetts. Preliminary analysis suggests that the VOS may cost utilities slightly more in the short run than net metering, but quite a bit less in the long run if retail rates continue to escalate at historical rates of 4-5% annually.[64]
Another alternative to full retail price net-metering policies can be found in New York where the Long Island Power Authority (LIPA) has implemented a feed-in-tariff program based on competitive renewable energy auctions. Under LIPA's Clean

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[63] Farrel, John. *Minnesota's Value of Solar: Can a Northern State's Solar Policy Defuse Distributed Resource Battles?* Institute for Local Self Reliance, April 2014 (link).
[64] Farrel, *Minnesota's Value of Solar: Can* (link).

Solar Initiative program, customers must offer 100-2,000kW of solar capacity and cannot participate in New York's separate net-metering program. Participating customers submit bids at annual auctions that set a market clearing price for solar electricity. The winning bids are paid the market clearing price under a 10-year PPA with LIPA.

A total of 150MW of solar capacity was authorized under the first two feed-in-tariff auctions and LIPA has requested authority to purchase an additional 20MW of non-solar DER, which is expected to provide 115 million kWh of electricity annually.[65] The results of the second LIPA auction, made public in April 2014, resulted in a clearing price of 16.8 cents/kWh for 78 solar projects with a total nameplate capacity of 100MW.[66] The market price is about 5 cents lower than New York's average retail electricity price for February 2014.[67]

The VOS and LIPA feed-in-tariff programs represent alternatives to full retail price net-metering that may be attractive to utilities and DER customers alike. Both programs provide a sales price that is higher than the wholesale price of electricity, but lower than the full retail rate, which allows electric utilities to recover some of the fixed costs for upgrading and maintaining T&D infrastructure and reserve capacity.

10.4 - Alternative Utility Business Models

As the cost of DER, microgrids and other technologies continues to fall, electric utilities will face increased competition on multiple fronts. It appears unlikely that the traditional regulated monopoly business model will survive in its current form, though it is not doomed to complete extinction. A survey of senior executives from more than 50 power companies revealed that our survey shows that many in the industry expect the existing utility business model in their market to transform or even be unrecognizable by 2030. Despite opposition on net-metering policies in some states, 82% of the survey respondents saw DER as an opportunity as opposed to a threat. About half of the survey respondents from North America felt that DER could spell "death for the current energy retailing business model" with a "medium" or "high" probability.[68] With such high expectations for transformation in coming decades, it is important to gain an understanding of potential alternatives to the current electric utility business model.

The results of economic modeling described in this report show that MGE would be less affected by greater DER penetration if the utility chooses to build, own and

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65 McMahaon, John. "Clean Solar Initiative Feed-in-Tariff." Long Island Power Authority, 27 March 2014 (link).

66 Public Service Electric & Gas. "100MW of Solar Coming to Long Island." 2 April 2014 (link).

67 Energy Information Administration: Electric Power Monthly. 22 April 2014 (link).

68 PwC Consulting. *Energy Transformation: The Impact on the Power Sector Business Model,* October 2013 (link).

operate the DER systems instead of opposing their growth and risking competition with a third party developer. However, MGE's investors may not support large capital expenditures in DER-based microgrid deployment and the Wisconsin PSC may not grant rate increases to recover the cost of microgrid deployment. When this regulatory and investor risk is considered, MGE may be best served by a partnership with third party developers that includes some level of cost and revenue sharing.

For example, MGE may contract with a third party developer to design and build the DER-based microgrids, but all the power would be sold to MGE. In exchange for these services, MGE would share a portion of the microgrids' electricity sales with the third party developer until their costs are recovered. Once the third party developer has recovered their costs, MGE would take full ownership of the microgrid systems and receive 100% of the sales from their power generation. This concept is a scaled up version of the third party leasing model that is driving solar growth in states like Colorado, California and Arizona.

MGE and other vertically integrated, regulated utilities could obtain revenue on investments in third party developers if the utility is able to show regulators that it has invested in DER that are part of its resource supply, and that its ownership share should be placed in the rate base. The utility could own the assets (for which it could recover its investment costs and a return), and the third-party developer would be compensated for providing development and maintenance services. Working with a third-party developer could provide the utility with an opportunity to build competency and gain experience with DER projects and financing.[69]

Exelon chief executive Chris Crane envisions a future where DER systems are built and operated by competing third party developers who sell power back to the grid, which is operated by traditional regulated utilities. "We create the grid situation where they can sell power back out onto the system," Crane said in May 2014.[70] Former US energy secretary Steven Chu has offered similar advice to utility executives. Chu's solution to the threat of a utility death spiral is to have utilities purchase and own DER equipment to take advantage of their extremely low borrowing costs, and partner with local companies to install the systems. The utility would own and operate the DER system and charge participating customers a lower rate that reflects the systems LCOE, mimicking the third party business model.[71]

In addition to the partnership approach, NREL has also touted the virtual power plant operator and energy services utility as alternative business models that utilities could use to incorporate DER into their revenue stream. As a virtual power plant operator, the utility would aggregate the generation from all of the DER units on its system to help balance loads with supply and relieve congestion within the

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[69] Bird, Lori, Heeter, Jenny and Joyce McLaren. *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* NREL, 2013 (link).

[70] McMahon, Jeff. "What Death Spiral?" *Forbes,* 13 May 2014 (link).

[71] McMahon, Jeff. "Steven Chu Solves Utility Companies' Death Spiral." *Forbes,* 21 March 2014 (link).

distribution system. This strategy would both improve reliability and delay the need for broader system upgrades.

Under the electric service utility model, pricing is not based on the amount of energy provided but on the value of services provided by the utility. Customers select from a menu of services that they require and pay according to the value of those services, much like a cable television or internet service provider. This model increases equitability across utility customers (whether they invest in DG or not) and ensures that utilities and DG owners are appropriately compensated for the services each provides.[72] Additional research is needed to analyze this shared ownership structure, and pilot programs will provide important test beds for these alternative business models.

[72] Bird, Lori, Heeter, Jenny and Joyce McLaren. *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* NREL, 2013 (link).

11.1 - Conclusion & Areas for Further Research

Solar PV-based microgrids can deliver substantial benefits to both MGE and ratepayers, but new financial and regulatory structures must be implemented to ensure that these benefits are fully realized and fairly distributed. MGE and other utilities hold the exclusive right to serve customers in their service territory and earn a reasonable ROR on their investments. However, solar PV, other DER, and smart grid technologies are replacing the passive energy consumer with a much more engaged energy "prosumer." DER and microgrids represent a cost-effective option for MGE to harness the prosumers' desire to have more control over their energy supply, into load shifting, peak shaving, and deferrals of costly T&D upgrades.

These benefits for MGE can be passed through to all ratepayers, while microgrid customers would see net energy savings (in the residential sector), and increased reliability. However, the cost-effectiveness of microgrids in the commercial and industrial sectors is contingent on the value those customers place on increased power quality and reliability. Of the 24 deployment scenarios tested under Scenario A (MGE builds, owns and operates all microgrid equipment), 15 passed all four cost-effectiveness tests described in section 7.1-7.5. Under Scenario B (a third party developer builds, owns and operates all microgrid equipment), only 7 of the 24 scenarios passed all four cost-effectiveness tests. This is because the third party developer must charge a higher volumetric rate or service fee for electricity generated by the microgrid.

The results show that MGE can maintain its current 10.3% ROR without raising average rates in any customer sector by more than 1%, while providing positive net benefits across all customer segments. Microgrid deployment in strategic areas where ratepayer benefits are maximized represents an economically feasible strategy for MGE to begin building a "smart grid" in Madison that can facilitate the integration of increased solar PV generation, and insulate the utility against current and future environmental regulations.

Planning for future environmental regulations is crucial considering EPA's proposal of existing source performance standards (ESPS) for carbon emissions from the electric power sector in June 2014. Utilities that are heavily reliant on fossil fuels are extremely vulnerable to price shocks resulting from the implementation of a carbon tax or cap-and-trade program. Imposing a $10/ton price on CO_2 emissions would reduce MGE's 25-year ROR from 10.3% to about 7.9%, and a $35/ton price would result in net costs over the 2015-2040 time frame. Modest, incremental development of solar PV microgrids and other DER can help MGE meet this regulatory challenge, as opposed to wasting money in protracted legal battles.

EPA intends to finalize the Clean Power Plan by June 2015 and states will have two years to develop their own plans to meet the federal guidelines. Although the program will is destined to face a deluge of legal challenges, utilities could be required to make steep cuts to carbon emissions by 2018-2020. The Clean Power Plan is designed to give states flexibility to implement "outside the fence" measures such as energy efficiency programs and RPS programs that reduce emissions outside of the physical property of existing coal and natural gas plants.[73] Pursuing microgrid deployment will help MGE transition to a cleaner, more decentralized generating fleet that can also offer increased reliability and system resilience during extreme weather events.

States and utilities can work together to create a variety of strategies to cut carbon emissions that meet the EPA's guidelines, but renewables and energy efficiency will likely play a prominent role in most states. Wisconsin's 10% by 2015 RPS will not drive additional renewable energy growth, so utilities will need to invest in DER and other efficiency measure to comply with the federal program. The Natural Resources Defense Council (NRDC) estimates that implementing a flexible program could reduce national carbon emissions 531 millions below 2012 levels by 2020. State level analysis found that annual household electricity expenditures in Illinois, Iowa, Minnesota and Michigan could decrease by $70-$105 under the EPA program by 2020.[74] DER and efficiency gains made possible through the deployment of microgrids could become a key component of MGE's carbon compliance strategy.

Solar-based microgrids represent an alternative investment option for MGE can pursue as environmental regulations and changing customer preferences impose new challenges on the traditional regulated monopoly business model. This report illustrates that solar-based microgrids are economically superior to diesel generators, and natural gas peaking units that operate at annual capacity factors below 4-5%. However, the Wisconsin PSC's use of the Total Resource Cos (TRC) test for cost-effectiveness places solar, DER and energy efficiency at a disadvantage during the regulatory approval process.

The TRC only accounts for the value of avoided generation and fails to consider the value of retail energy savings delivered to end-use customers. The American Council for an Energy Efficient Economy (ACEEE) states that the TRC is "has significant flaws" because of the unequal treatment of demand-side to supply-side resources.[75] Wisconsin should therefore consider re-evaluating its regulatory policies with the goal of developing new frameworks that incentivize utilities to expand renewables and efficiency programs, rather than build new fossil fuel plants and protect their monopoly status.

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73 US EPA. "Flexible Approach to Cutting Carbon Pollution." 2 June 2014 (link)

74 Yeh et al. *Retail Electric Savings and Energy Efficiency Job Growth from NRDC's Carbon Standards: Methodology Description.* Natural Resources Defense Council, May 2014 (link).

75 Kushler and Neme. "Is it Time to Ditch the TRC?" ACEEE, 2011 (link).

Third party developers can pose a threat to MGE and other utilities, but the threat can be defused and transformed into a beneficial partnership through cost and revenue sharing business models that have been implemented in California and Virginia. Dominion Virginia Power launched a pilot program aimed at installing 30MW of distributed solar PV at commercial, industrial and public buildings by the end of 2015 using the solar leasing business model that has fueled the rise of third party developers like SunRun and SolarCity. Dominion's 30MW goal for the Solar Partnership Program is 35% than the total amount of solar installed in Wisconsin. As the cost of solar and other DER technologies continue to fall, more customers will look to defect from traditional utilities. MGE must incorporate these disruptive technologies into their business model or risk a steady decline into financial despair.

Additional research is needed to develop a more technical methodology for integrating multiple microgrids into existing distribution networks, establishing a fair and legally defensible value for the benefits provided by DER and microgrid systems, testing more complex and dynamic utility business models, and determining the effectiveness of solar PV-based microgrids as a major component of state plans to comply with current and future environmental regulations.

List of Appendices

Appendix A: Standard Microgrid Assumptions

The calculations in this study are based off the use of a standard microgrid system comprised of 1,500kW of fixed axis solar PV and two 200kW Capstone CR200 microturbines for a total nameplate generating capacity of 1,900kW. The calculations assume that the microgrid operator will attempt to cover as much on-peak demand as possible, while purchasing electricity from the grid during off-peak hours. Under this operational structure, the microgrid customers will accept electricity generated by the solar array during off-peak hours and use the microturbines to offset as much on-peak demand as possible with any shortfall being made up by purchases from MGE's distribution grid.

The microgrid system is sized to meet 5,000,000 kWh of annual electricity demand with an average hourly load of 570kW and a peak hourly load of 1,630kW. Seasonal variation is factored in to the calculations using hourly data from MGE's feeder lines provided by the utility for 24-hour load profiles during each month of 2012.[76] The load factor was determined by dividing each hourly demand value by the maximum hourly load during 2012, which was 4,260kW. The variation in hourly demand is depicted in Figure A.1 below with values ranging from 1,240kW to 4,260kW and an average of 2,210kW. Table A.1 shows a breakdown of the hourly demand from two distribution feeders provided by MGE.

Table A.1: Hourly Demand at MGE Feeders

	Feeder 1 MW	% of Total	Feeder 2 MW	% of Total
1st Quartile Average	1.55	12.8%	1.73	10.4%
2nd Quartile Average	1.99	38.2%	2.19	34.7%
3rd Quartile Average	2.24	62.8%	2.45	64.2%
4th Quartile Average	3.08	89.2%	3.12	92.7%
1st Half Average	1.78	22.9%	1.97	24.3%
Median	2.12	52.1%	2.31	52.1%
2nd Half Average	2.67	84.0%	2.80	88.2%
1st Half Average	1.84	25.3%	2.01	26.7%
Mean	2.21	61.1%	2.37	57.6%
2nd Half Average	2.79	86.1%	2.86	88.5%

[76] Day, Martin. Personal E-mail Communication, 19 October 2013.

The data shows that the standard microgrid has enough nameplate capacity to meet hourly demand for just under 38% of the hours for MGE Feeder 1 and 21% of the hours for MGE Feeder 2. Deploying two of the standard microgrids for each feeder would provide enough nameplate capacity to meet demand for over 90% of the hours reported by MGE. However, each microgrid only contains 400kW of dispatchable capacity, meaning that eight microgrids would be needed to cover 90% of the hourly demand for MGE Feeder 1 and 2 (3.1MW divided by 0.4MW of microturbine capacity).

Figure A.1 illustrates the monthly variation in load factor for MGE Feeder 1, whose data was used in MoDERN to calculate hourly variation in customer demand based on the annual consumption entered on the MoDERN homepage. Thus, the max load of 1,630kW is multiplied by the associated load factor for each hour of the year to produce an annual demand curve with monthly variations.

Figure A.1: Monthly Demand & Load Factors from MGE Feeder 1

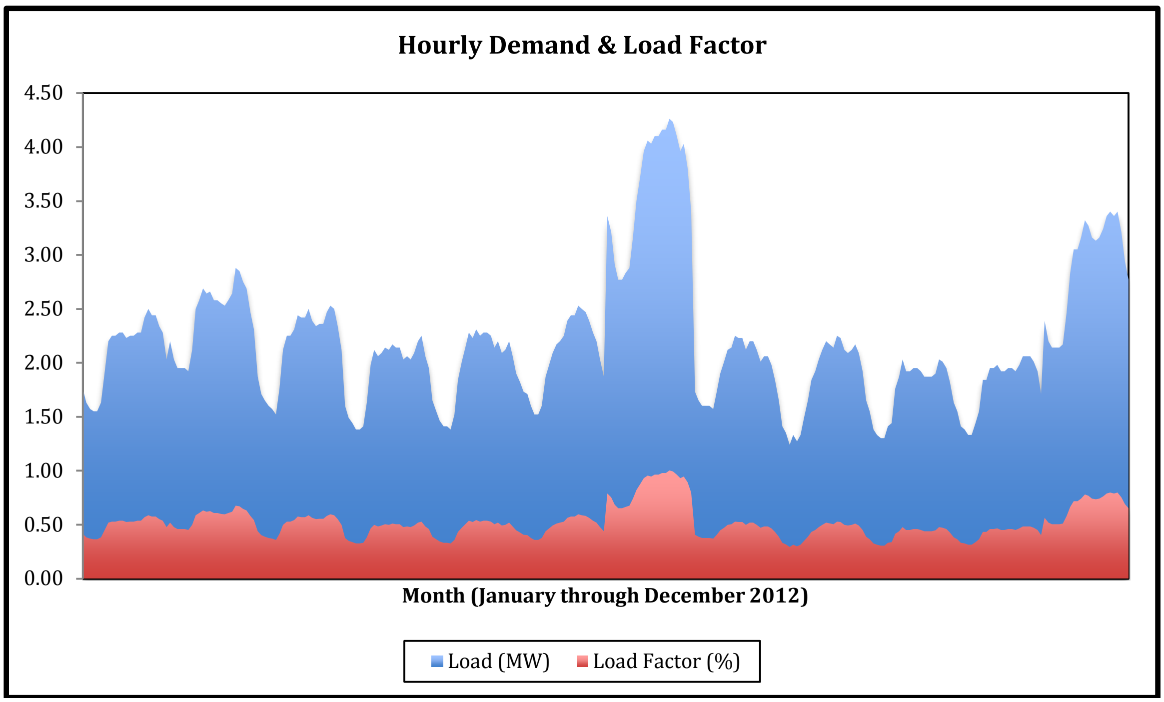
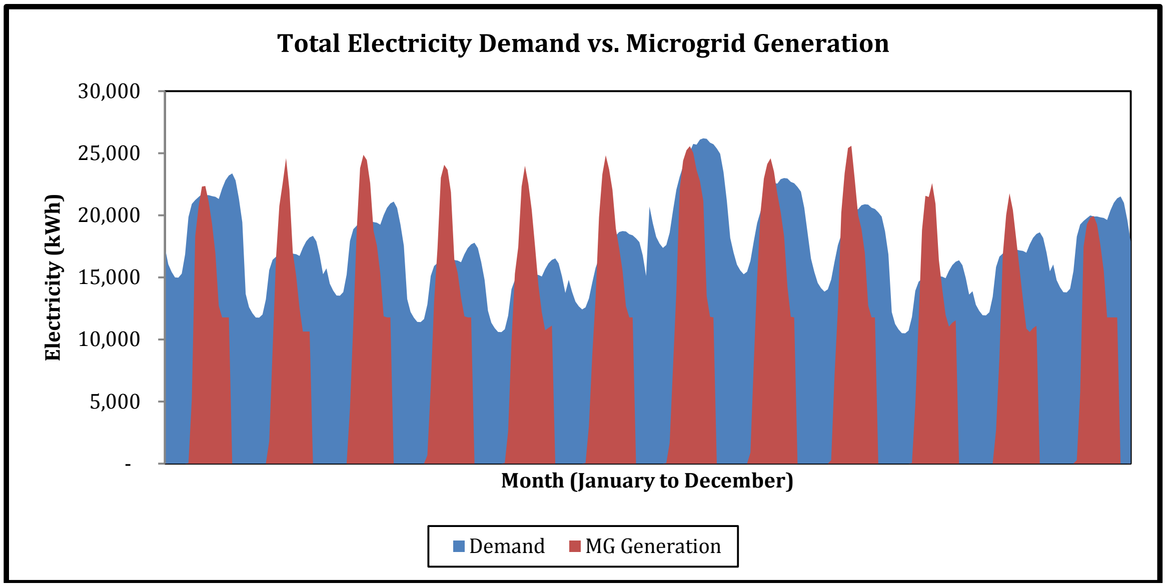


Figure A.2 compares the annual demand against the annual generation from the standard microgrid system. Anytime the red peaks rise higher than the blue peaks, it indicates a period of time when microgrid generation exceeds demand with the excess power being sold back to MGE at the net metered rate. The demand profile is based off of annual consumption of 5,000,000 kWh with a 35 average load factor adjusted for seasonal variation. The standard microgrid is able to offset 95% of annual on-peak demand, 21% of annual off-peak demand, and generate 57,000kWh of net metered electricity.

Figure A.2: Microgrid Generation vs. Demand



The solar PV arrays operate at an annual capacity factor of 14.5%, which varies from 0% to 60% depending on the hour of the day and month. Figure A.3 compares the hourly solar generation against hourly demand for a day in June 2012. The microturbines operate at an 18% annual average capacity factor with fuel costs calculated based on specifications provided by the manufacturer, Capstone. The standard microgrid system will carry about $95,000 in fuel and O&M costs.

Figure A.2: Average Hourly Solar Generation vs. Average Hourly Demand

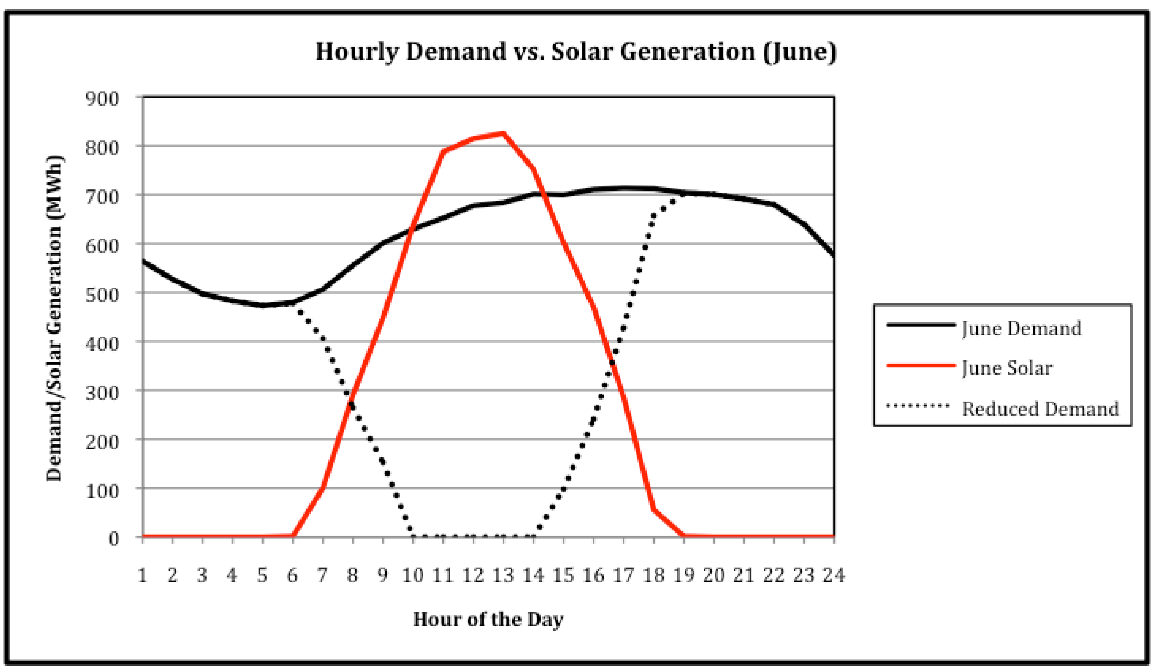


Table A.2: Summary of Standard Residential Microgrid Costs & Benefits

Microgrid Costs	Capacity (kw)	Capacity Factor (%)	Generation (kWh)	O&M Cost	Capital Cost
Solar PV	1500	14.61%	1,921,338	-$30,000	-$3,750,000
Microturbines	400	27.66%	969,942	-$108,331	-$964,000
600 Amp Static Switch					-$75,092
Other System Components					-$1,732,500
Construction Costs ($/ft3)					-$1,500,000
Total Costs			**2,891,280**	**-$138,331**	**- $8,021,592**

Microgrid Generation Summary	kWh/year	$/year
On-Peak Avoided	1,332,695	$335,408
Off-Peak Avoided	903,705	$65,880
Grid Purchases	2,763,600	$327,008

Benefit Categories	Test Case	Average	Minimum	Maximum
CO2 Reductions	$0	$0	$0	$0
SO2 Allowance Reduction	$3	$3	$3	$3
NOx Allowance REductions	$52	$52	$45	$58
Avoided Ancillary Services	$14,456	$18,263	$6,299	$32,019
Deferred T&D Costs	$52,043	$38,622	$126	$87,232
Deferred Capacity Costs	$159,020	$119,582	$302	$260,523
Net Metered Sales	$32,744	$33,736	$0	$84,020
Salvage Value	$301,408	$301,408	$301,408	$301,408
Avoided T&D Losses ($/kWh)	$4,459	$4,610	$3,809	$5,355
Value of RECs	$19,213	$12,728	$1,366	$23,332
Solar/Wind 30% Tax Credit	$1,125,000	-	-	-
Microturbine 10% Tax Credit	$8,000	-	-	-
Federal PTC for Renewables	$0	$0	$0	$0
Avoided Outage Costs	$2,000	$2,296	$0	$7,494
SO2 Health Impacts Avoided	$5,376	$5,367	$4,655	$6,076
NOx Health Impacts Avoided	$2,042	$2,038	$1,768	$2,308
Fuel Price Hedging Value ($/kWh)	$10,567	$7,978	$24	$17,261

Table A.3: Summary of Standard Commercial Microgrid Costs & Benefits

Microgrid Costs	Capacity (kw)	Capacity Factor (%)	Generation (kWh)	O&M Cost	Capital Cost
Solar PV	1500	14.61%	1,921,338	-$30,000	-$3,750,000
Microturbines	400	29.63%	1,038,853	-$111,285	$964,000
600 Amp Static Switch					-$75,092
Other System Components					-$1,732,500
Construction Costs ($/ft3)					-$1,500,000
Total Costs			**2,960,191**	**-$141,285**	**-$8,021,592**

Microgrid Generation Summary	kWh/year	$/year
On-Peak Avoided	1,473,937	$170,524
Off-Peak Avoided	1,125,216	$60,053
Grid Purchases	2,400,847	$162,195

Benefit Categories	Test Case	Average	Minimum	Maximum
CO2 Reductions ($)	$0	$0	$0	$0
SO2 Allowance Reductions	$3	$3	$3	$3
NOx Allowance Reductions	$52	$52	$45	$58
Avoided Ancillary Services	$14,801	$18,904	$6,238	$33,472
Deferred T&D Costs	$53,283	$40,182	$36	$90,733
Deferred Capacity Costs	$162,811	$122,414	$337	$268,940
Net Metered Sales	$18,052	$22,767	$0	$69,799
Salvage Value	$301,408	$301,408	$301,408	$301,408
Avoided T&D Losses	$4,565	$4,452	$3,709	$5,163
Value of RECs	$19,213	$15,731	$4,276	$26,678
Solar/Wind 30% Tax Credit	$1,125,000	-	-	-
Microturbine 10% Tax Credit	$8,000	-	-	-
Federal PTC for Renewables	$0	$0	$0	$0
Avoided Outage Costs	$415,000	$462,597	$1,774	$1,482,381
SO2 Health Impacts Avoided	$5,376	$5,381	$4,693	$6,086
NOx Health Impacts Avoided	$2,042	$2,044	$1,782	$2,312
Fuel Price Hedging Value ($/kWh)	$10,567	$7,824	$13	$17,275

Table A.4: Summary of Standard Industrial Microgrid Costs & Benefits

Microgrid Costs	Capacity (kw)	Capacity Factor (%)	Generation (kWh)	O&M Cost	Capital Cost
Solar PV	1500	14.61%	1,921,338	-$30,000	-$3,750,000
Microturbines	400	29.29%	1,026,969	-$110,665	-$964,000
600 Amp Static Switch					-$75,092
Other System Components					-$1,732,500
Construction Costs ($/ft3)					-$1,500,000
Total Costs			**2,948,307**	**-$140,665**	**-$8,021,592**

Microgrid Generation Summary	kWh/year	$/year
On-Peak Avoided	1,474,770	$124,824
Off-Peak Avoided	1,003,223	$53,402
Grid Purchases	2,522,006	$143,295

Benefit Categories	Test Case	Average	Minimum	Maximum
CO2 Reductions ($)	$0	$0	$0	$0
SO2 Allowance Reductions	$3	$3	$3	$3
NOx Allowance Reductions	$52	$52	$45	$58
Avoided Ancillary Services	$14,742	$18,776	$6,636	$33,166
Deferred T&D Costs	$53,070	$39,806	$46	$89,545
Deferred Capacity Costs	$162,157	$124,093	$1,294	$275,085
Net Metered Sales	$23,516	$25,943	$0	$75,543
Salvage Value	$301,408	-	-	-
Avoided T&D Losses	$4,547	$4,206	$3,477	$4,902
Value of RECs	$19,213	$14,755	$3,045	$25,963
Solar/Wind 30% Tax Credit	$1,125,000	-	-	-
Microturbine 10% Tax Credit	$8,000	-	-	-
Federal PTC for Renewables	$0	$0	$0	$0
Avoided Outage Costs	$514,000	$588,136	$32,477	$1,841,368
SO2 Health Impacts Avoided	$5,376	$5,369	$4,678	$6,073
NOx Health Impacts Avoided	$2,042	$2,039	$1,777	$2,307
Fuel Price Hedging Value	$10,567	$8,120	$26	$17,440

Appendix B: GIS Data & Methodology

This appendix includes an overview of the data sources and processes used in ArcGIS to perform spatial analysis of Madison's electricity consumption, PV potential, and optimal locations for microgrid development. The first step involved gathering data for electricity use across MGE's three main customer segments (residential, commercial and industrial). Data from EIA's Form 860 for 2012 provided MGE's retail sales broken down into these three customer segments, shown below.

Table B.1: MGE Customer Data from 2012

Customer Segment	Total Customers	Annual Demand (million kWh)	Annual kWh per Customer	MGE Retail Sales ($ million)	Customer Rate ($/kWh)
Commercial	19,491	2,272.4	116,587	$246.9	$0.1086
Industrial	44	247.2	5,617,682	$19.4	$0.0786
Residential	122,807	826.8	6,732	$130.6	$0.1579
Total	142,342	3,346.3	23,509	$396.9	$0.1186

A combination of tax assessor data from the City of Madison and GIS data from the Dane County Land Information Office was used to determine the building footprint and indoor living area of buildings that fall into the three customer segments. These datasets where then used to create energy density (kWh/ft^2) and PV potential (kW/ft^2) maps that identify hotspots where microgrid development would be most beneficial. Each building's electricity use was calculated by dividing the total retail sales (kWh) by the total indoor living area (for residential buildings), or building footprint area (for commercial buildings), to obtain electricity density factors.

The electricity density factors were then multiplied by the square footage of each building to create a map of each building's annual energy use. MGE could not provide more detailed consumption data so this "backed in" method represents the best available option. As a result, the annual energy consumption for each individual building is solely dependent on its size, which ignores the wide variability between building types. Large office buildings, for example, have energy densities that range from 6.8 kWh/ft^2 to 41.9 kWh/ft^2, according to MGE data summarized in table B.2 on the following page.[77] The results of electricity consumption at the census blocks level could change dramatically if building level consumption data were available.

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[77] Building Energy Use Comparions. Madison Gas & Electric (link)

Table B.2: Electricity Density for Different Building Types

Business Category	Average	Minimum	Maximum	Notes
Bakery	27.54	9.11	45.97	
Bowling Alley	16.17	7.18	25.15	
Child Care	6.43	2.32	10.53	
Church	7.73	0.76	14.69	
Clinics	40.98	13.82	68.14	2 of 15 were above 31 kWh/ft2
Cold Storage	46.89	10.81	82.96	1 of 7 was below 23 kWh/ft2
Community Centers	11.95	5.42	18.48	1 of 6 was below 10 kWh/ft2
Convenience Stores	75.71	11.89	139.52	1 of 5 was below 44 kWh/ft2
Distribution	8.34	1.71	14.97	2 of 7 were below 5 kWh/ft2
Fitness Centers	15.32	4.14	26.50	2 of 9 were above 21 kWh/ft2
Grocery	54.44	29.66	79.21	1 of 7 was above 60 kWh/ft2
Group Homes	16.25	11.21	21.29	
Laboratories	58.51	11.80	105.21	14 of 18 were btw 18=68 kWh/ft2
Manufacturing	44.09	1.91	86.26	4 of 44 were above 33 kWh/ft2
Small Office	20.16	0.95	39.36	3 of 40+ were above 24 kWh/ft2
Medical Office	11.73	4.75	18.70	
Large Office	24.25	6.63	41.86	3 of 35 were above 25 kWh/ft2
Printing	18.92	4.65	33.19	
Restaurants	87.90	10.83	164.97	Very wide distribution
Retail	23.17	1.27	45.06	
Schools	17.66	4.19	31.13	2 of 11 were above 14 kWh/ft2
Auto Repair	14.73	0.90	28.55	11 of 16 were between 6-25 kWh/ft2
Warehouses	11.01	0.71	21.30	4 of 23 were above 12 kWh/ft2
Average	**28.69**	**6.81**	**50.57**	

Two datasets were used to calculate electricity density and solar PV potential; building footprint data from the Dane County Land Information Office, and tax assessor data from the City of Madison. The Dane County dataset included building footprint area, latitude/longitude coordinates, and some land use/building use identifiers. However, the Dane County dataset did not include footprints for all buildings in the City of Madison. Many residential buildings contained in the tax assessor dataset were not present in the Dane County GIS dataset. For example, there were nearly 68,000 residential properties in the tax assessor data compared to just 23,590 in the Dane County dataset. Thus, the tax assessor data was used to complete calculations for the residential sector.

The two datasets also produced different results for the number and area of industrial and commercial buildings. There were 6,017 commercial properties in the tax assessor dataset compared to 3,828 in the Dane County dataset. The total area of the commercial building footprints was just over 48 million square feet compared to 59 million square feet for the total area of commercial parcels in the tax assessor data. This presented another problem because the tax assessor dataset only included building area for residential properties, while commercial and industrial properties only included the land area of the tax parcel. Thus, I used the footprint data for commercial and industrial buildings from the Dane County dataset in combination with the footprint data for residential buildings from the tax assessor dataset. Table B.3 summarizes the differences between the two datasets and Table B.4 describes the data used in the final GIS analysis.

Table B.3: Tax Assessor vs. Dane County GIS Building Footprint Data

Sector	# of Buildings (GIS)	# of Properties (Assessor)	GIS Footprint (ft^2)	Assessed Land (ft^2)	Assessed Footprint (ft^2)
Commercial	3,828	6,017	48,022,319	59,726,135	0
Industrial	717	161	13,916,462	1,616,760	0
Residential	23,590	67,942	46,610,358	129,864,517	98,244,977
Total	28,135	74,120	108,549,139	191,207,412	98,244,977

Table B.4: Summary of GIS Data Sources

	Footprint Data Source	kWh/ft^2 Value	Max PV Area	Max PV (kW)	75% PV (kW)	50% PV (kW)
Commercial	GIS footprint	47.32	GIS footprint	480,223	360,167	240,112
Industrial	Assessed Area	152.88	50% of Assessed Area	8,084	6,063	4,042
Residential	Assessed Living Area	8.42	Assessed Living Area	982,450	736,837	491,225
Total				1,470,757	1,103,068	735,378
	Building Area (ft^2)	**Total Customers**	**Electricity Demand (kWh/year)**	**Electricity Intensity (kWh/ft^2)**	**Max PV (MW)**	**50% PV (MW)**
Commercial	48,022,319	19,491	2,272,398,000	47.32	480.2	240.1
Industrial	13,916,462	44	247,178,000	152.88	8.1	4.0
Residential	98,244,977	122,807	826,766,000	8.42	982.4	491.2
Total	160,183,757	142,342	3,346,342,000	-	1,470.8	735.4

ArcGIS Analysis Process

The raw data was imported from Microsoft Excel (.xlsx format) into ArcGIS (.dbf format). Several columns were added to base building footprint database to add MAXPV (dividing total footprint area by 100 square feet/kW of solar capacity), and KWHANN (annual electricity demand) by multiplying the footpring by 47 kWh/square foot (the figure derived by dividing MGE's 2012 commercial retail sales by total footprint area).

The buffer tool was used to convert the residential and industrial (RES/IND) point files into shape files using a 10 feet linear boundary between polygon shapes. The resulting polygons are small circular dots that do not represent the actual shape of the building footprint, but the visual geometry is irrelevant because data attached to each point is what will be used to calculate annual electricity consumption and PV potential across each census block. The Dane County data for commercial building footprints was merged with all of the RES/IND files into one layer called "foot_all." A sub-layer of building footprints that have at least 20kW of solar PV potential was created and named "20KWPV_Foot". The "20KWPV_Foot" layer was then joined with the Dane County Census Blocks (MadBlocks) layer to sum the total PV capacity and annual kWh consumption in each census block using the spatial join and dissolve tools in ArcGIS.

Dissolving the PV50 data across GEOID in the "MadBlocksPVKW" layer produced 12,888 datasets (matching the number of blocks in the "MadBlocks" layer). The resulting "PVDiss1" layer sums the total PV capacity of all buildings capable of supporting at least 20kW of solar PV across the block they reside in. For example, the block containing Camp Randall has total PV capacity of 3,800kW with the stadium making up 1,630kW of that total, the UW-Madison engineering building adds another 680kW, and the athletic building adjacent to Camp Randall adds another 970kW. Annual kWh from the "foot_all" layer was dissolved onto the "MadBlocks" layer to create "MadBlocksKWH." This layer contains all electricity consumption for every building attached to the GEOID that represents each census block.

Microgrid Selection Process:

After using ArcGIS to plot the electricity use and solar potential by building footprint and census block, the following screening process was used to determine microgrid sites to fill the number required to replace 1.5% and 3% of MGE's retail sales under the low deployment scenarios.

Buildings with less than 15kW of potential solar PV capacity were omitted and given zero values because of uncertainty about the orientation, roof tilt and shade affecting smaller buildings. Using a threshold of 15kW results in a building with a rooftop area of at least 3,000 square feet, which is large enough to assume that shade from other buildings will not affect a large portion of the building's rooftop area. Table B.5 shows the eleven census blocks that contain critical buildings and are capable of supporting at least 1,500kW of solar PV. Table B.6 shows census blocks capable of supporting at least 1,000kW of solar PV, which can meet at least 25% of that block's annual electricity demand. Table B.7

Table B.5: Census Bocks with 1,500+ PV Potential & Critical Buildings

Census Block GEOID	PV Potential (kW)	Critical Buildings
550250021004002	2,234.2	1
550250025001007	5,022.7	11
550250025001014	1,523.0	2
550250026032043	4,088.2	2
550250030014002	3,283.6	2
550250031003039	7,212.0	1
550250105012000	1,598.5	3
550250109011010	2,602.6	1
550250109011096	1,584.4	1
550250112004025	1,578.0	2
550250031003022A	2,031.0	3

Figure B.1: Location of Eleven Optimal Microgrid Sites in Madison

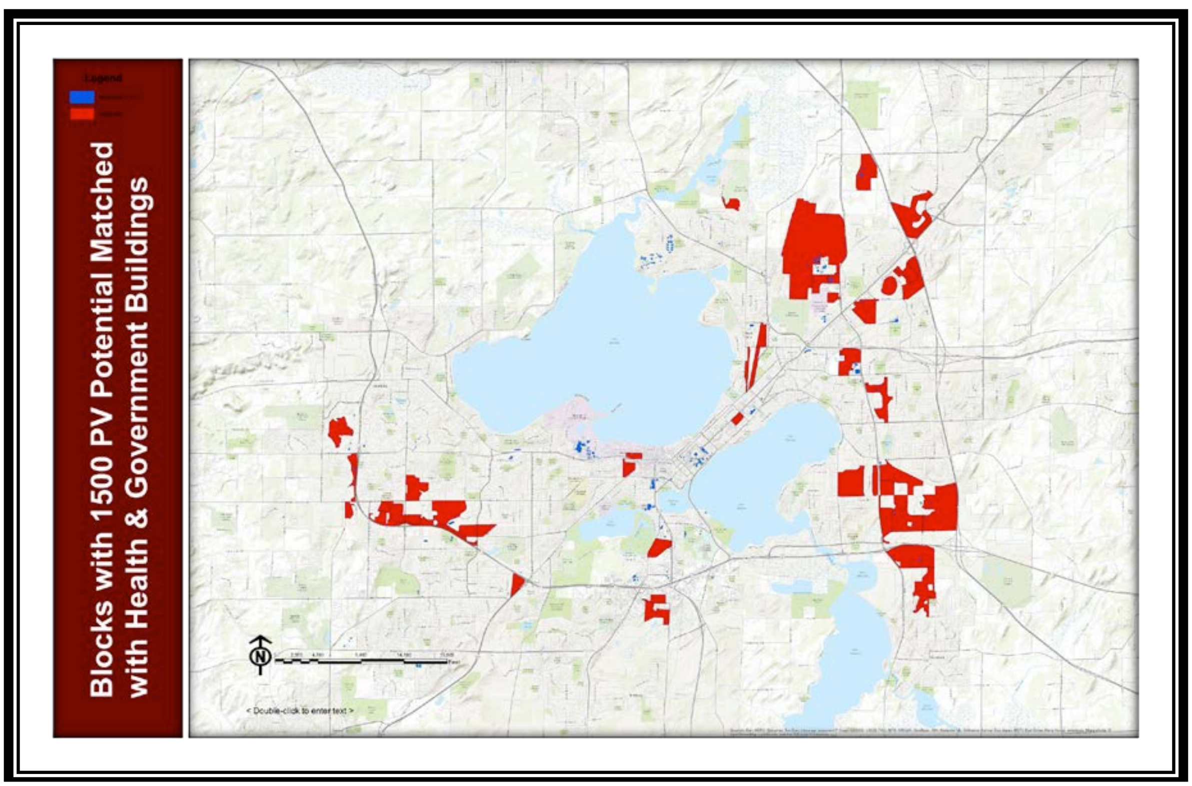


Table B.6: Census Blocks with at least 1,000kW PV Capable of Meeting 25% Load

GEOID	Building Area	Max PV (kW)	Annual Demand (kWh)	50% PV (kW)	PV Generation (kWh/year)	PV % of Demand
550250109031035	235	3,110	2,505,037	1,555	2,044,801	81.6%
550250002012000	0	2,704	2,262,614	1,352	1,777,745	78.6%
550250015011004	460	2,455	2,161,468	1,227	1,613,908	74.7%
550250031003006	17,394	3,217	3,293,659	1,609	2,115,280	64.2%
550250107021005	0	2,078	2,144,279	1,039	1,365,918	63.7%
550250005043005	0	2,372	2,511,324	1,186	1,559,471	62.1%
550250002042003	2,540	3,909	4,225,626	1,954	2,569,841	60.8%
550250002052004	1,846	2,055	2,278,028	1,028	1,351,323	59.3%
550250004054000	2,506	2,222	2,834,425	1,111	1,460,722	51.5%
550250112004074	244	3,891	5,147,450	1,946	2,558,401	49.7%
550250022003010	9,481	2,191	2,912,467	1,096	1,440,736	49.5%
550250004061022	28,105	2,196	2,951,950	1,098	1,444,023	48.9%
550250002051023	51,911	3,431	4,721,992	1,715	2,255,448	47.8%
550250109011061	28,161	2,366	3,502,077	1,183	1,555,264	44.4%
550250002053009	48,000	3,353	5,196,669	1,677	2,204,561	42.4%
550250031003012	87,677	2,784	5,553,427	1,392	1,830,078	33.0%
550250026021005	74,366	2,403	4,990,563	1,202	1,579,852	31.7%
550250023021011A	86,663	2,541	5,498,225	1,270	1,670,449	30.4%
550250031001000	107,890	2,401	6,074,942	1,200	1,578,274	26.0%
550250031004001	153,129	3,455	8,763,022	1,728	2,271,753	25.9%
550250005011017	97,919	2,080	5,472,275	1,040	1,367,233	25.0%

Table B.7: Annual Demand by Census Block & PV Potential

Annual Demand	# of Blocks	% Total Demand	Total PV Potential (MW)
40+ GWh	5	6.7%	26.6
20-40 GWh	19	12.1%	50.8
10-20 GWh	59	20.5%	87.4
5-10 GWh	101	16.5%	79.5
1-5 GWh	476	26.9%	178.5
0.1-1 GWh	2,258	17.2%	307.1
Total	**2,918**	**100.0%**	**729.9**

In the City of Madison, 184 of the 2,918 census bocks, or 6.3%, account for 55.9% of the city's annual electricity consumption. Those same blocks are capable of supporting 244MW of solar PV capacity, or 33.5% of Madison's total potential. This methodology represents a rough estimate of solar potential that does not account for shading from vegetation, other buildings, roof angle, building orientation, or local solar insolation (kWh/m^2/year). A more accurate approach to mapping solar potential is outline on in the following section.

Solar Mapping Using LiDAR Datasets

LiDAR data for the City of Madison could not be obtained for this analysis, but this section will provide a brief discussion of the process for creating a solar potential map in the future. After obtaining raw LiDAR data, the LAS files The LAS files must be converted to multipoint feature class files using the average spacing from the point file information tool. The multipoint files can then be converted into raster files that include a field for "z values" that describe the height of objects in the three dimensional map. A cell size of 5-8ft^2 is applied to differentiate larger objects (i.e. buildings) from treetops and other non-building objects. The mosaic-to-new-raster tool can then be used to combine the multiple layers into a single file.

Once the maximum elevation layer is created, a digital elevation model (DEM) for the underlying terrain can be subtracted from the maximum elevation layer to serve as the "ground-level" that will serve as the base of building polygons. After this step has been completed, the solar radiation tool in ArcMap's spatial analyst toolbox can be used to calculate the amount of solar energy reaching the surface over the course of a day, month, or year. The solar radiation tool requires several inputs, including the latitude of the area, the number of cycles (hourly), the diffuse proportion (a measure of cloudiness), and radiation transmissivity. The results of the solar radiation tool can then be extracted to building shapefiles. The building shape layer will include an attribute table with a column holding values for solar radiation (kWh/m^2/year).

The best rooftops can be determined using methods developed for the Los Angeles Solar Atlast. The most desirable sites receive higher amounts of solar radiation, which will result in higher energy production and a quicker payback period for the homeowner, utility, or third party developer. This guide will use LG's 250 Black Mono polycrystalline solar panel to provide an example of the calculations used to identify the most economical sites for solar deployment. The LG 250 is a 250 watt panel with 15.5% module efficiency that occupies 18.33 ft^2 (1.07 m^2) of rooftop area. The LG 250 has a list price of $355, which translates into $1.42/watt, $331.78/m^2, and $232.24/m^2 when the 30% federal investment tax credit (ITC) is applied. Dividing the original panel cost by 25 years results in annual energy savings of $14.20/year to repay the investment in 25 years. Achieving this level of annual energy savings would cover the ITC-adjusted investment in 17-18 years.

The minimum amount of energy required to deliver the minimum amount of annual energy savings depends on the retail electricity price charged by the utility. MGE's fixed residential rates range from 13.5-14.5 cents/kWh depending on the time of year. At this rate level, the single solar panel would need to generate an average of 101 kWh/year based on the formula shown below.

[System Cost] / [System Lifespan] / [Cost/kWh] / [System Efficiency] / [Panel Efficiency] / [Daily]
[$355 / 25 years] / $0.14/kWh] / [85%] / [15.5%]

The amount of solar insolation needed to produce the minimm amount of electricity can be calculed by dividing the minimum electricity generation by the system efficiency and solar panel efficiency (101 kWh / 85% / 15.5%). This calculation results in a minimum solar insolation of 770 kWh/m^2/year, or 2.11 kWh/m^2/day. This minimum solar insolation can then be used to filter out buildings in the three-dimension map that do not receive adequate sunlight to support an economically viable solar PV system. From that point, additional analysis can be performed to determine the total economically viable PV capacity within the City of Madison.

Table B.8 provides a summary of the minimum solar generation and solar insolation levels required to payback initial solar investment at different electricity rate levels. Annual average solar insolation for a fixed-tilt solar array in Madison (35 degree roof angle with an orientation of 180 degrees south) is 4.6 kWh/m^2/day, based on NREL's PVWatts tool. A 250 Watt fixed-tilt panel would produce 340 kWh/year, according to the PVWatts analysis, enough to offset panel costs at very low rates.

Table B.8: Minimum Energy Savings, Solar Generation, and Solar Insolation

MGE Rate Level	Minimum Energy Savings Needed ($/year)	Minimum Generatio (kWh/year)	Solar Insolation Needed (kWh/m^2/year)	Solar Insolation Needed (kWh/m^2/day)
$0.0500	$14.20	284.00	2,155.6	5.91
$0.0600	$14.20	236.67	1,796.3	4.92
$0.0700	$14.20	202.86	1,539.7	4.22
$0.0800	$14.20	177.50	1,347.2	3.69
$0.0900	$14.20	157.78	1,197.6	3.28
$0.1000	$14.20	142.00	1,077.8	2.95
$0.1100	$14.20	129.09	979.8	2.68
$0.1200	$14.20	118.33	898.2	2.46
$0.1300	$14.20	109.23	829.1	2.27
$0.1400	$14.20	101.43	769.9	2.11
$0.1500	$14.20	94.67	718.5	1.97
$0.1600	$14.20	88.75	673.6	1.85
$0.1700	$14.20	83.53	634.0	1.74
$0.1800	$14.20	78.89	598.8	1.64
$0.1900	$14.20	74.74	567.3	1.55
$0.2000	$14.20	71.00	538.9	1.48

References

1. LG Mono X 250. Retrieved from http://www.wholesalesolar.com on 11 September, 2014.
2. Leitelt, L. *Developing a Solar Energy Potential Map for Chapel Hill, North Carolina.* University of North Carolina-Chapel Hill, Master's Thesis, 2010 (link).

Appendix C: Solar Assumptions

Solar Capacity Factor: Capacity factor is the ratio of the actual system energy output to the potential maximum output. The capacity factor for a solar PV system depends on its location and meteorological conditions. The latitude of the project site determines the amount of solar radiation that reaches the PV panels. The longitude, time, environment and weather determine the actual energy output that the PV panels generate. To determine the capacity factor for PV project in Madison, NREL's PVWatts database was used to calculate monthly electricity generation and capacity factors for the City of Madison. Table C.1 presents the geographical data for Madison and the PVWatts inputs.

Table C.1: Site Identification Information and Specifications (Simon 2013)

PV System Specifications		Station Identification	
DC Rating	1.0 kW	City	Madison
DC-to-AC Derate Factor	0.77	State	Wisconsin
AC Rating	0.8 kW	Latitude	43.13° N
Array Type	Fixed Tilt	Longitude	89.33° W
Array Tilt	43.1°	Elevation	262 m
Array Azimuth	180.0°		

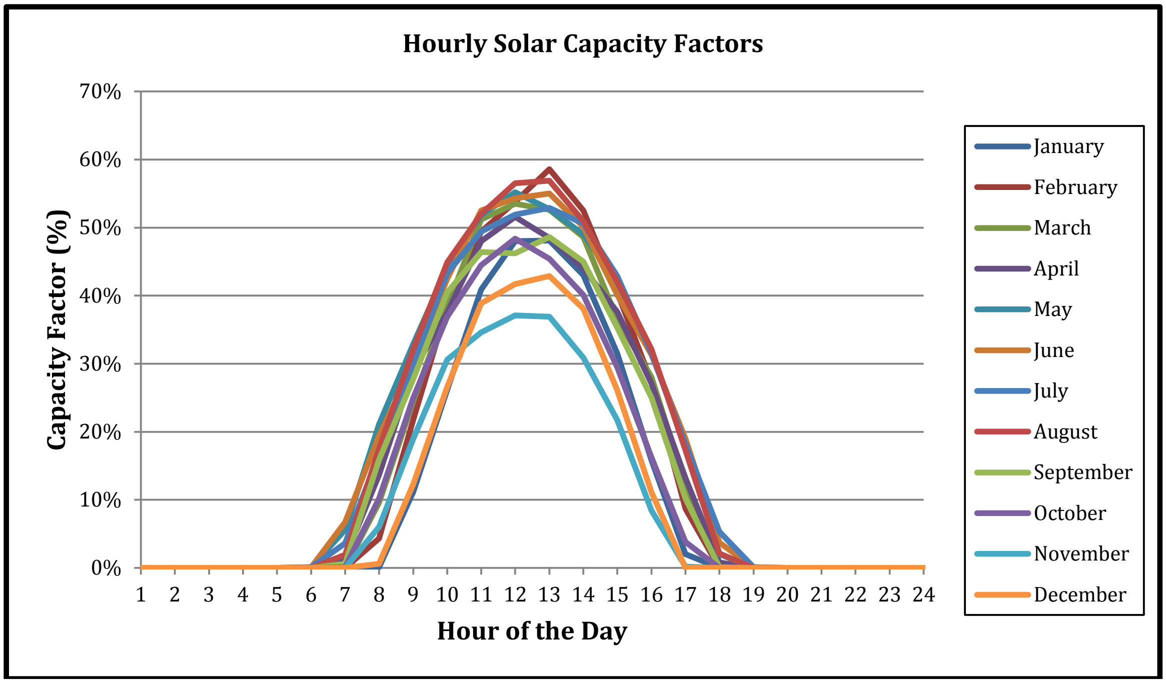
The PVWatts tool estimated that a 1kW PV panel would produce 1,231 kWh/year in Madison. Dividing this amount by the maximum potential energy output for a 1kW system (8,766 kWh/year) results in an annual average capacity factor of 14% in Madison. This capacity factor was used for macro-level analysis with a range of +/- 2% in a triangular distribution for the Monte Carlo analysis to reflect variable weather conditions and other performance uncertainties.

Table C.2: Monthly PV Generation for a 1kW System

Month	Jan	Feb	March	April	May	June
Solar Radiation (kWh/m^2/day)	3.25	4.39	4.56	4.78	5.56	5.81
AC Energy (kWh)	83	99	110	106	126	121
Month	**July**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Solar Radiation (kWh/m^2/day)	5.81	5.87	4.78	4.09	2.96	2.97
AC Energy (kWh)	123	126	102	93	68	74

The MoDERN model calculates hourly solar output based on the output of the PVWatts tool, which provides average hourly capacity factors for each hour of each month. The model accurately reflects the daily generating pattern of solar PV where capacity factors rise above 50% during the mid-afternoon and fall to 0% during the night. The highest PV capacity factors occur in the early afternoon, which coincides with peak demand, thereby enhancing the value of solar generation to the consumer and the utility. Figure C.1 illustrates the average hourly capacity factor for each month of the year.

Figure C.1: Average Hourly Solar PV Capacity Factors



Microgrid Solar Panel System Assumptions

Each microgrid system is made up of a 1.5MW fixed tilt solar PV array. Based on an NREL feasibility study for a solar project in Eau Claire, Wisconsin, a range of installed costs from $2,700-$3,500/kW was used for economic analysis. Rooftops must be checked for shadows cast by trees or adjoining builds, particularly from the south where solar generation is maximized. A detailed three-dimensional model in GIS would provide the most accurate estimates for the City of Madison, but LiDAR data for Madison was not readily available. Thus, the amount of solar capacity in Madison was calculated based on the footprint of each building in the city. To account for buildings without suitable orientation or shading, this total was divided in half to provide a conservative estimate for citywide solar capacity.

Capital Cost, Operation & Maintenance costs:

The total installed cost of the solar PV system was calculated by multiplying the system size by a cost factor of $2,500/kW based on a survey of utility-scale power purchase agreements during the first quarter of 2014. Annual O&M costs are set at $20/kW per year.

Table C.3: Microgrid Solar System Assumptions & Capital Costs

Minimum Rooftop Area Required (ft^2)	3,000
Solar PV (kW/100 ft^2)	1
Solar PV System Size (kW)	1,500
Solar PV Capacity Factor	14.61%
Hours per year	8,760
Annual Solar Generation (kWh/year)	1,901,436
Solar PV Capital Costs ($3,000/kW)	$3,750,000
Annual O&M Costs ($20/year)	$30,000

The amount of solar capacity each building could support was determined using the specifications for SunPower's 435 watt E20 monocrystalline silicon panel. The E20 module has a maximum generating capacity of 435 watts and measures 82x42 inches for a total area of 23.8 square feet. This translates to 55 square feet/kW, but a more conservative figure of 100 square feet/kW was used for this analysis.

Table C.4: Area Required for Solar Panels (ft^2/kW)

Module	**Capacity (W)**	**Size (ft^2)**	**ft^2/kW**	**$/kW**
SunPower E20	435	23.8	54.7	NA
LG Mono X	250	17.8	71.2	$1,420
Kyocera KD140SX	140	10.8	77.1	$2,143
Suniva MVX 250	250	18.1	72.4	$1,180
Data from Wholesalesolar.com				
System Type	**Capacity (kW)**	**Size (ft^2)**	**kW/ft^2**	**ft^2/kW**
Sloped Roof	1,500	116,000	77.3	$1,800
Flat Roof	1,500	174,000	116.0	$1,900
Data from SolarElectricSupply.com				

References

1. Simon, J., and M. Gail. *"Feasibility Study of Economics and Performance of Solar Photovoltaics at the Sky Park Landfill Site in Eau Claire, Wisconsin."* Golden, CO: National Renewable Energy Laboratory (NREL), 2013.
2. Solar Electric Supply Inc. *"Commercial, Utility, Government Solar Power Systems."*
3. Honeyman, Corey. "Utility-Scale Solar is Back from the Dead." Greentech Media, 5 August 2014 (link).

Appendix D: Additional Hardware and Construction Costs

The upfront cost of advanced metered infrastructure (AMI) ranges from $1,620 to $5,650 with one-time installed costs ranging from $20 to $65. The cost of the electricity management system (EMS) ranges from $50,000 to $100,000 and $170 to $350 for the EMS customer interface and display. The cost of the equipment and software that enables the microgrid to communicate with demand response and price signals from the utility range from $5,000 to $24,000. Total costs for microgrid power electronics not included in the installed cost of generation equipment range from $56,810 to $134,065. The mean of $95,437 was used for this report [1].

Smart switches allow seamless disconnection and reconnection of microgrid loads and generation sources to the macrogrid. The Cyberex 600 Amp static switch included in our urban microgrid is estimated to cost $75,092.

Beyond the installed costs of the solar equipment, there will be some additional costs associated with wiring and installing the fully integrated microgrid system. The feasibility study for the Madison Sustainable Commerce Center used an estimate of $18/ ft^2 for electrical construction costs [2]. This report assumed there would be approximately 100,000 ft^2 of additional area that would need wiring work.

Table D.1: Additional Hardware Costs

Additional Hardware Costs	
Microgrid Power Electronics	$95,437
Cyberex 600 Amp Static Switch	$75,092
Additional Electrical Construction Costs ($18/ft^2 – 10,000 ft^2)	$180,000
TOTAL	**$350,519**

References

1. Gellings, C. *"Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid."* Palo Alto, CA: Electric Power Research Institute (EPRI), 2011.
2. MSCC Feasibility Study Study
3. *Microgrids – Benefits, Models, Barriers and Suggested Policy Initiatives.* Prepared by DNV Kema for the Massachusetts Clean Energy Center, February 2014 (link).

Appendix E: MGE Electricity Rates, Load and Generation Assumptions

The table below summarizes MGE's rate structure and the revenue stream generated by solar PV systems.

Table E.1: MGE's Residential Time-Of-Use Electricity Rates

Time-of-Use Rate Category	$/kWh	Percent of Load (%)
Off Peak – Winter (8 Months) – Weekends, Holidays, 9pm – 10am	0.0729	44%
On Peak 1-3 - Winter (8 months) – 10am – 9pm	0.2394	23%
Off Peak - Summer (4 months) – Weekends, Holidays, 9pm – 10am	0.0729	22%
On Peak 1 - Summer (4 months) – 10am – 9pm	0.2679	3%
On Peak 2 - Summer (4 months) – 10am – 9pm	0.2911	5%
On Peak 3 - Summer (4 months) – 10am – 9pm	0.2679	3%

To arrive at the percent of load distribution shown in Table D.1, electricity consumption was allocated across MGE's time-of-use rate categories based on load profiles for two feeder lines that were provided by MGE. These data were used to generate hourly load profiles for winter and summer. The profiles were generated by taking the amount of electricity used in the hour of highest demand and increasing this amount by 50% (it is assumed that even on the highest demand day of a single year, the potential peak load was not likely being reached). This peak load amount was used as the denominator and divided all hourly loads by this amount to get an hourly load factor for each month. The average of the winter months and summer months were then used to calculate the average seasonal load profiles.

Finally, each load profile was normalized by dividing each average hourly load factor by the average seasonal load factor. This allows us to apply the seasonal load factor "shape" to any desired average load factor. For this study, it is assumed that an average load factor of 25% taking the load profile "shape" derived from the MGE data shown in table D.2. The hourly load factors were then used to determine the hourly kWh of electricity use and combined this with assumptions about which days and hours were on and off peak throughout the year (see table D.3).

Table E.2: MGE Feeder Data & Seasonal Load Profile

Hour of Day	Load Profile Winter - Load Factor (%)	Load Profile Summer - Load Factor (%)
1	22%	23%
2	20%	21%
3	19%	20%
4	19%	19%
5	19%	19%
6	19%	19%
7	21%	20%
8	25%	22%
9	26%	24%
10	27%	25%
11	27%	26%
12	27%	27%
13	27%	28%
14	27%	28%
15	27%	28%
16	27%	29%
17	27%	29%
18	28%	29%
19	29%	28%
20	29%	28%
21	29%	28%
22	29%	27%
23	27%	26%
24	24%	23%
Average	**25%**	**25%**

Table E.3: Off Peak and On Peak Assumptions

OFF PEAK - Winter	Count of Holidays - Winter	7
OFF PEAK - Summer	Count of Holidays - Summer	3
OFF PEAK - Winter	Count of Weekend Days - Winter	69
OFF PEAK - Summer	Count of Weekend Days - Summer	35
ON & OFF PEAK - Winter	Count of winter days (less holidays and weekends)	167
ON & OFF PEAK - Summer	Count of summer Days (less holidays and weekends)	84
	TOTAL DAYS PER YEAR	**365.25**

Comparing Peaking Units to DER/Microgrids

To compare the standard microgrid against natural gas or diesel peaking units, the hourly generation of the microgrid is compared to actual hourly output from existing and hypothetical peaking units. Using a hypothetical 25MW natural gas peaking unit, the number of microgrids is calculated based on the output of the peaking unit at different capacity factors. For example, a 25MW unit that operates at a 5% annual capacity factor generates 21.9 million kWh, while one standard microgrid generates 2.5 million kWh. Thus, nine microgrids are needed to match the annual output of the 25MW peaking unit. MGE's 83MW West Marinette peaking unit provides an illustrative example. The natural gas-fired unit generated 19.4 million kWh in 2012, which translates into an annual capacity factor of just 2.7% and just 260 operating hours (assuming the plant operated at a 90% capacity factor when dispatched).

Only five of nineteen natural gas units smaller than 100MW operated at annual capacity factors higher than 5% in 2012, as shown in Table E.4 (MGE units are in bold). MGE's Sycamore (41.6MW) and Fitchburg (57.6MW) peaking units both operated below a 1% annual capacity factor in 2012. At a 1% capacity factor, the LCOE of the peaking units ranges from $440-$460/MWh compared to $140/MWh for the two microgrids needed to match the annual output from the natural gas peaking units.

Table E.4: Generation and Capacity Factors for Wisconsin Natural Gas Plants

Plant Name	Capacity (MW)	Fuel Used	MWh	CF %	Op Hours
Stevens Point Mill	7.6	1,055,683	9,993	15.0%	1,315
Domtar Paper Co. Rothschild	9.4	511,493	31,935	38.8%	3,397
Nine Springs	16.2	5,740	186	0.1%	11
Northern States Flambeau	16.3	32,929	1,523	1.1%	93
Arcadia Electric	16.9	2,195	163	0.1%	10
Kaukauna Gas Turbine	18.0	6,402	383	0.2%	21
Cumberland	21.9	5,266	33	0.0%	2
Custer Energy Center	24.5	7,247	425	0.2%	17
Rhinelander Mill	25.3	756,373	51,171	23.1%	2,023
MMSD Jones Island	35.0	827,772	38,042	12.4%	1,087
Sycamore	**41.6**	**41,003**	**2,215**	**0.6%**	**53**
Sheepskin	41.7	36,657	1,938	0.5%	46
Combined Locks	53.0	1,208,528	6,835	1.5%	129
Fitchburg	**57.6**	**2,083,634**	**4,138**	**0.8%**	**72**
Marshfield Utilities Gas Plant	60.4	1,633,790	5,322	1.0%	88
Island Street Peaking Plant	60.5	1,601,819	2,206	0.4%	36
Elk Mound	71.0	2,318,653	21,083	3.4%	297
West Marinette 34	**83.0**	**2,391,316**	**19,367**	**2.7%**	**233**
Blount Street	**100.0**	**3,193,345**	**47,668**	**5.4%**	**477**

Table E.5 shows the annual generation and LCOE ($/MWh) for a hypothetical 25MW peaking unit and standard microgrids under annual capacity factors ranging from 1% to 4%. The LCOE for simple cycle (NGSC) and combined cycle (NGCC) peaking units is based on installed costs of $900/kW for NGSC and $1,200/kW for NGCC, which were taken from Minnesota's VOS methodology. Even at a 4% annual capacity factor, which only one unit outside of the milling industry achieved in 2012, the microgrid's LCOE (including all Tier II benefits) of $119/MWh is comparable to the NGCC's LCOE of $113/MWh. The NGSC's LCOE is about 25% lower at $89/MWh. Adding the environmental costs/benefits into the LCOE calculation raises the NGSC to $100/MWh and $123/MWh for NGCC at a 4% annual capacity factor.

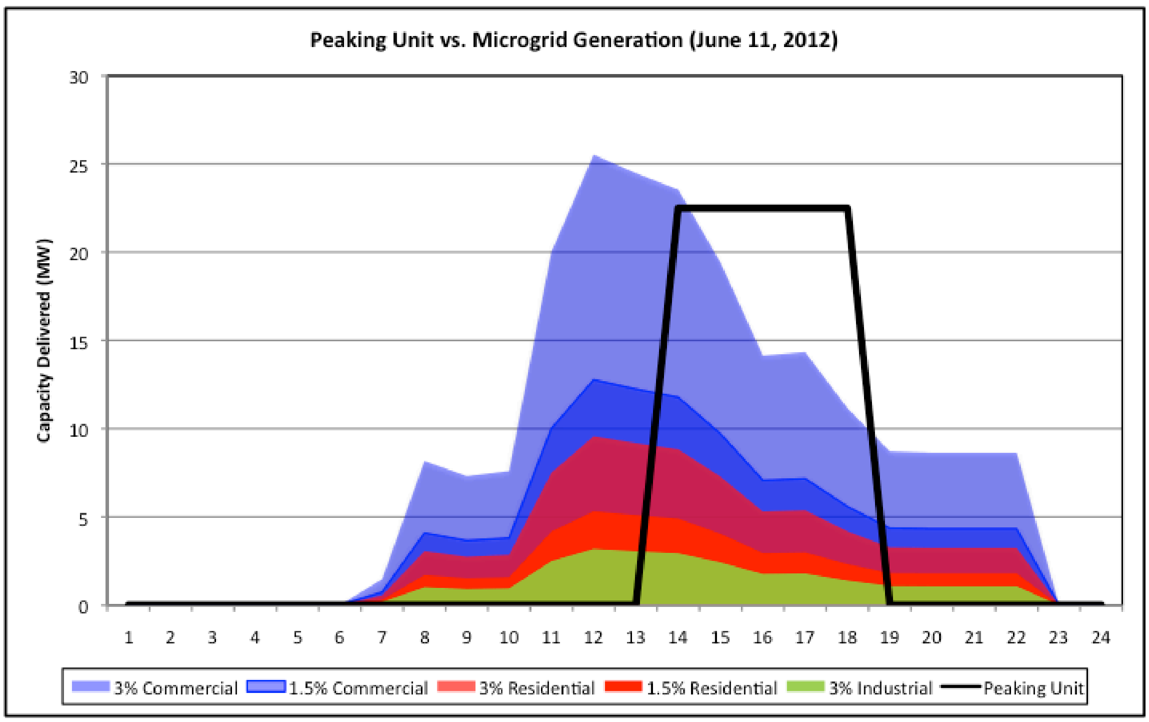
Table E.5: Generation and LCOE for 25MW Peaking Units vs. Microgrids

Generation Type	**NGSC**	**NGCC**	**Equivalent MG**
Hours of Operation	100	100	
Capacity Factor	0.97%	0.97%	
LCOE w/out Env Costs	$0.3230	$0.4153	$0.1677
LCOE w/ Env Costs	$0.3336	$0.4259	$0.1196
Payback w/out Benefits	50+	50+	21.6
Payback w/ Benefits	50+	50+	11.5
Generation Type	**NGSC**	**NGCC**	**Equivalent MG**
Hours of Operation	200	200	
Capacity Factor	1.94%	1.94%	
LCOE w/out Env Costs	$0.1676	$0.2137	$0.1677
LCOE w/ Env Costs	$0.1782	$0.2243	$0.1189
Payback w/out Benefits	50+	50+	18.8
Payback w/ Benefits	50+	50+	9.9
Generation Type	**NGSC**	**NGCC**	**Equivalent MG**
Hours of Operation	300	300	
Capacity Factor	2.91%	2.91%	
LCOE w/out Env Costs	$0.1157	$0.1465	$0.1677
LCOE w/ Env Costs	$0.1263	$0.1571	$0.1189
Payback w/out Benefits	41.0	50+	18.8
Payback w/ Benefits	50+	50+	9.9
Generation Type	**NGSC**	**NGCC**	**Equivalent MG**
Hours of Operation	400	400	
Capacity Factor	3.88%	3.88%	
LCOE w/out Env Costs	$0.0898	$0.1129	$0.1677
LCOE w/ Env Costs	$0.1004	$0.1235	$0.1189
Payback w/out Benefits	24.0	38.0	18.8
Payback w/ Benefits	30.4	50+	9.9

The annual comparisons show the economic viability of DER/microgrids, but they fail to account for the need for capacity needed during peak demand hours. The microgrids may be capable of matching annual output at a lower cost than peaking units, but they cannot provide the dispatchable capacity MGE and other utilities may need to meet peak demand during hot summer afternoons. The hypothetical peaking unit can provide up to 25MW of firm capacity, while a single microgrid can only offer 0.4MW of firm capacity from the microgturbines. But, solar PV can generate up to 60% of nameplate capacity in the early afternoon hours of June, July and August.

Under the 3% residential deployment scenario, which requires nine microgrids composed of 13.6MW of solar PV and 3.6MW of microturbines, the microgrids can provide up to 10.6MW of peak capacity around 1-2pm. WPSC, operates a demand response program that offers incentives for customers to reduce demand during critical peak hours. Figure E.1 compares the generation from a 25MW peaking unit during a critical peak demand event occurring from 1-6pm on June 19, 2012 against the hourly output from microgrids under each deployment scenario.

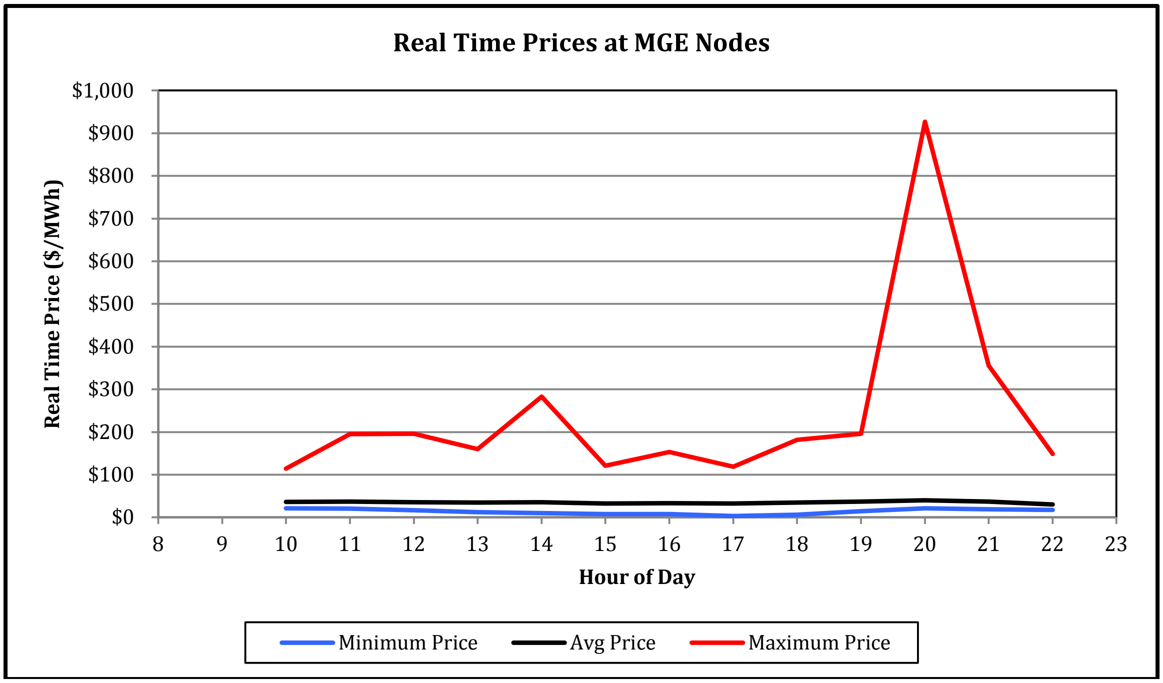
Figure E.1: Hourly Generation, Peaking Units vs. Microgrids



During this particular event, the 3% residential microgrids provide 3.2MW-10.6MW of peak shaving, but MGE still faces a net capacity shortfall of 34.3MW-41.8MW. The microgrid also provides demand shaving during morning and late afternoon hours when the critical peak period has ended. Reducing the peak demand during these critical hours can save large amounts of money for MGE, which may be required to pay extremely high prices for electricity purchased from the wholesale market.

Data provided by MGE for its 2014 rate case shows that locational market prices (LMP) in the MISO market spiked above $100/MWh 54 times between 10am-10pm in 2013 with a high point of $926/MWh on April 1. Figure E.2 compares the average LMP at MGE's generation nodes to maximum and minimum real-time prices during on-peak hours. If the microgrids were able to reduce peak demand by 10MW during an hour period when MISO prices spiked above $900/MWh, MGE would avoide $9,000 in wholesale purchases.

Figure E.2: Average, Minimum and Maximum LMP's at MGE Nodes in 2013



The value of DER/microgrids for peak shaving can be enhanced by their ability to reduce customer demand as well as providing generation capacity. The PJM grid operator runs a well functioning demand response market that pays customers the corresponding wholesale price ($/MWh) for each MWh of demand they reduce during critical peak periods. Analysis of an event occurring on July 18, 2012, shows that all demand response requests larger than 10MW with a short notice period were fully subscribed. This indicates that DER/microgrids in combination with demand response programs could eliminate the need for peaking units that rarely operate.

Table E.6: PJM Demand Response Performance on July 18, 2012

MW Requested	MW Reduced	Excess/Shortfall	% Subscribed	Utility	Notice
11	16	5	141%	METED	Short
24	31	7	129%	JCPL	Short
32	36	4	112%	AECO	Short
47	48	2	103%	DPL	Short
90	91	1	101%	BGE	Short
107	137	29	127%	PEPCO	Short

Source: MISO Emergency Demand Response Performance Report (link)

Table E.7: Wisconsin Public Service Co., Critical Peak Hours (2007-2013)

Year	2007	2008	2009	2010	2011	2012	2013
Hours	67	75	58	98	45	50	50
CF %	0.69%	0.77%	0.60%	1.01%	0.46%	0.51%	0.51%

** Capacity Factor calculated for a 25MW peaking unit*

Figure E.3: Hourly Generation at MGE's Fitchburg Plant in 2012

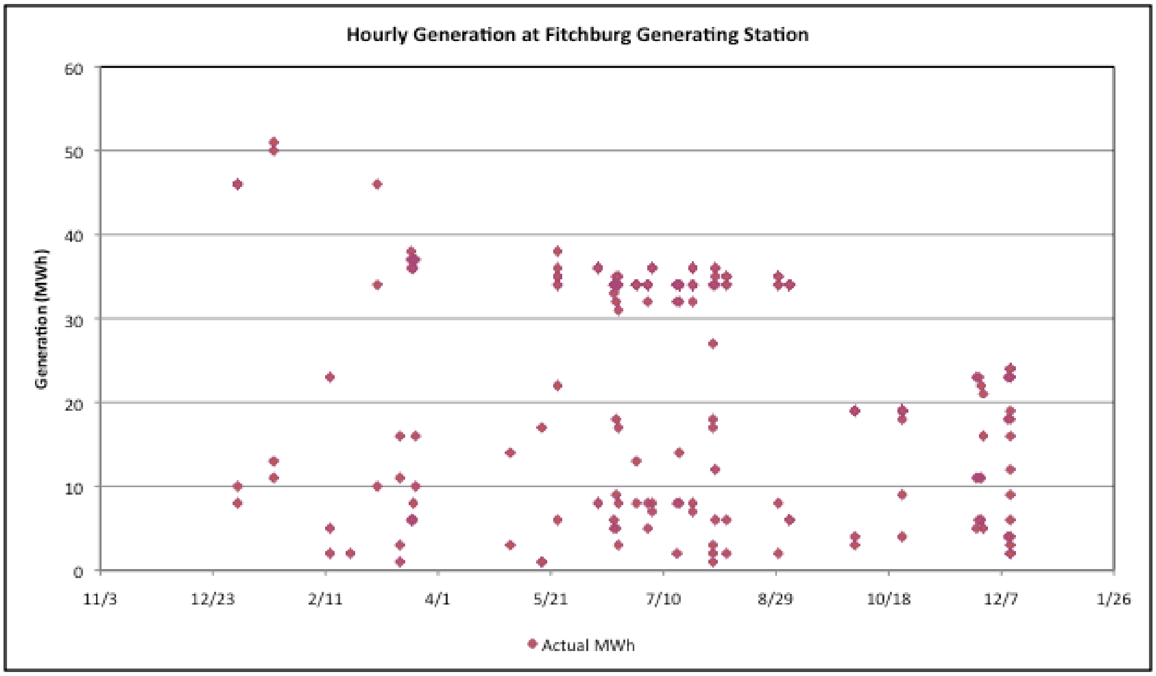
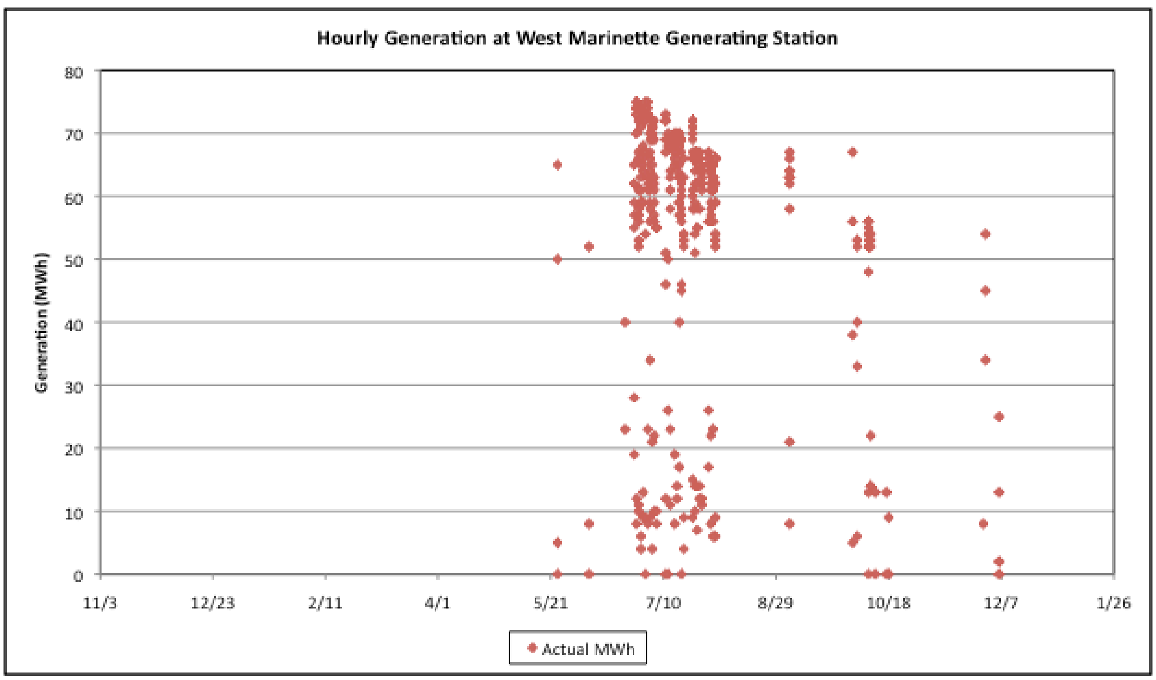


Figure E.4: Hourly Generation at MGE's West Marinette Plant in 2012



The hourly generation profiles were created using data retrieved from EPA's Air Markets Program Data online portal (link). West Marinette operated for 383 hours, 330 of which occured when the MISO price was above the unit's marginal operating cost. Fitchburg operated for 197 hours, 195 of which occurred when the MISO price was above the unit's marginal cost. West Marinette operated at a 70% average capacity factor, while Fitchburg operated at a 38% average capacity factor.

Table E.8: Wisconsin Average Electricity Prices by Customer Segment, 1992-2012

Year	Residential	% change	Commercial	% change	Industrial	% change
2012	$0.1319	1.31%	$0.1051	0.86%	$0.0734	0.14%
2011	$0.1302	2.92%	$0.1042	4.41%	$0.0733	7.01%
2010	$0.1265	5.95%	$0.0998	4.28%	$0.0685	1.78%
2009	$0.1194	3.74%	$0.0957	3.13%	$0.0673	3.38%
2008	$0.1151	5.89%	$0.0928	6.54%	$0.0651	5.68%
2007	$0.1087	3.43%	$0.0871	4.06%	$0.0616	5.30%
2006	$0.1051	0.00%	$0.0837	0.00%	$0.0585	0.00%
2006	$0.1051	8.80%	$0.0837	9.13%	$0.0585	8.53%
2005	$0.0966	6.50%	$0.0767	5.94%	$0.0539	9.33%
2004	$0.0907	4.61%	$0.0724	3.87%	$0.0493	4.67%
2003	$0.0867	5.99%	$0.0697	6.57%	$0.0471	6.32%
2002	$0.0818	3.54%	$0.0654	3.15%	$0.0443	1.61%
2001	$0.0790	4.91%	$0.0634	5.14%	$0.0436	7.92%
2000	$0.0753	3.01%	$0.0603	2.55%	$0.0404	3.86%
1999	$0.0731	1.95%	$0.0588	0.17%	$0.0389	0.78%
1998	$0.0717	4.22%	$0.0587	4.82%	$0.0386	3.76%
1997	$0.0688	0.00%	$0.0560	-1.41%	$0.0372	1.64%
1996	$0.0688	-1.29%	$0.0568	-1.73%	$0.0366	-3.17%
1995	$0.0697	-1.55%	$0.0578	-1.53%	$0.0378	-2.83%
1994	$0.0708	0.71%	$0.0587	-1.34%	$0.0389	-2.26%
1993	$0.0703	1.74%	$0.0595	0.68%	$0.0398	-0.50%
1992	$0.0691	2.67%	$0.0591	1.55%	$0.0400	-0.74%
WI Rates from 1992-2012		**Residential**		**Commercial**		**Industrial**
Average Annual Increase		**3.21%**		**2.80%**		**2.87%**
Monte Carlo Average		**4.39%**		**5.50%**		**4.34%**
1% or Higher Rate Increase		77.27%		63.64%		68.18%
2% or Higher Rate Increase		63.64%		59.09%		50.00%
3% or Higher Rate Increase		54.55%		54.55%		50.00%
4% or Higher Rate Increase		36.36%		40.91%		36.36%
WI Rates from 1997-2012		**Residential**		**Commercial**		**Industrial**
Monte Carlo Average		**4.45%**		**4.31%**		**4.67%**
1% or Higher Rate Increase		100.00%		86.67%		93.33%
2% or Higher Rate Increase		86.67%		86.67%		73.33%
3% or Higher Rate Increase		80.00%		80.00%		73.33%
4% or Higher Rate Increase		53.33%		60.00%		53.33%
WI Rates from 2002-2012		**Residential**		**Commercial**		**Industrial**
Monte Carlo Average		**4.79%**		**4.72%**		**4.89%**
1% or Higher Rate Increase		100.00%		90.00%		90.00%
2% or Higher Rate Increase		90.00%		90.00%		70.00%
3% or Higher Rate Increase		80.00%		90.00%		70.00%
4% or Higher Rate Increase		60.00%		70.00%		70.00%
Source EIA Electricity Data						

Appendix F: Financial Assumptions & Cost Effectiveness Paramters

To finance each microgrid project, it is assumed that MGE or the third party developer would use a 20-year loan with a 25% down payment and 5% interest rate adjusted for 2% inflation. This is slightly higher than the cost of debt for electric utilities surveyed by New York University (2.26%), and slightly lower than their cost of capital, which ranged from 3.13% to 3.55%.

Table F.1: Standard Microgrid Financial Assumptions

Loan Term (years)	20
Inflation Rate	2.00%
Loan Interest Rate	5.00%
Real Interest Rate	2.94%
Total loan amount	$6,016,194
Down Payment (20%)	($1,858,629)
Annual Loan Payment ($/year)	($402,187)

A 3% discount rate was used to reflect the rate of return on 30-year US Treasury Bonds. The user of MoDERN can conduct sensitivity analysis using other discount rates. At the 3% discount rate, the net present value of each microgrid loan exceeds the original principal. No project developer would rationally accept a loan with a higher net present value than the amount borrowed, , but if the developer does not have access to any other loans, and their highest investment rate of return is the 30-year Treasury Bond rate, the 3% discount rate is appropriate.

To accurately compare the value of the loan payments in present terms, the discount rate should be at least as high as the loan's real interest rate of 2.94%. The difference between the amount borrowed and the net present value can be viewed as a premium that the developer is paying for cash flow assistance. The net present value of the total loan payments depends significantly on the discount rate. A higher discount rate can make the loan appear more attractive, but a higher discount rate also reduces the net present value of benefits.

Summary of Cost-Effectiveness Tests

There are five widely accepted methods for determining the cost-effectiveness of utility programs and investment decisions. The Wisconsin PSC bases its cost-effectiveness determinations primarily using the Total Resource Cost (TRC) test, but this analysis uses a four-step process using multiple tests to take multiple stakeholder perspectives into consideration. This section includes an overview of the five major cost-effectiveness tests, and examples of the calculations used to determine cost-effectiveness in this analysis. The description of the cost-effectiveness tests and calculations is taken from a 2011 report by the Cadmus Group, and staff training guide provided by the California PUC.

Ratepayer Impact Measure Test (RIM): Originally known as the Non-Participant Test, RIM is also known as the "no losers test." The RIM tests from the viewpoint of a utility's customers as a whole, measuring distributional impacts of conservation programs. The test measures what happens to average price levels due to changes in utility revenues and operating costs caused by a program. A benefit/cost ratio less than 1.0 indicates the program will influence prices upward for all customers. For a program passing the TRC but failing the RIM, average prices will increase, resulting in higher energy service costs for customers not participating in the program.

Formula:
(Lifetime Increased Energy Sales / 25 Years) / Original Energy Sales
If the increase is less than 1%, the scenario passes the test in this analysis

Utility Cost Test (UCT): Also known as the Program Administrator Test (PACT), this test measures cost-effectiveness from the viewpoint of the sponsoring utility or program administrator. If avoided supply costs exceed costs incurred by the program administrator,average costs decrease.

Formula:
(Energy Sales with Microgrid – Lifetime Microgrid Costs) / (Lifetime Microgrid Costs)
If the result is positive, the microgrid's lifetime revenue exceeds lifetime costs

Participant Test (PCT): This test measures benefits and costs to customers participating in demand-side management (DSM) programs. The test compares bill savings against incremental costs of the efficient equipment. It measures a program's economic attractiveness to customers, and can be used to set rebate levels and forecast participation.

Formula:
(Avoided Outage Costs + Net Energy Savings) / Total Energy Costs with Microgrid
If the result is at least 1.1, the participant experiences a 10% ROI and the test is met

Total Resource Cost Test (TRC): Originally known as the All-Ratepayer Test, this test examines efficiency from the viewpoint of an entire service territory. This test compares the program benefits of avoided supply costs to costs for administering a program and the cost of upgrading equipment. When a program passes the TRC, this indicates total resource costs will drop, and the total cost of energy services for an average customer will fall.

Societal Cost Test (SCT): A variation of the TRC, this test expands the point-of-view from the service territory to society's perspective. The TRC and the SCT differ in two important ways: 1) while the TRC uses an average cost of capital discount rate, the SCT uses a societal discount rate; and 2) the SCT also includes all quantifiable benefits attributable to a program, such as avoided pollutants, water savings, detergent savings, and other non-energy benefits.

Summary of Components Included in Common Cost-Effectiveness Tests

Benefits	**PCT**	**RIM**	**TRC**	**SCT**
Primary Fuel Avoided Supply Costs		X	X	X
Secondary Fuel Avoided Supply Costs			X	
Primary Fuel Bill Savings (Retail Price)	X			
Secondary Fuel Bill Savings (Retail Price)	X			
Other Savings (i.e. water)	X		X	
Environmental Benefits				
Other Non-Energy Benefits				
Costs				
Program Administration		X	X	X
Measure Costs				
Program Financing Incentives		X	X	X
Customer Contributions	X		X	
Utility Lost Revenues		X		

Source: Kushler and Neme. "Is it Time to Ditch the TRC?" ACEEE, 2011 (link)

RIM Calculation Example:

If microgrids require MGE to raise $10 million in additional revenue over 2015-2040 ($400,000 per year), and total annual demand is 100 million kWh with 60 million kWh in the commercial sector, 30 million kWh in the residential sector and 10 million kWh in the industrial sector. And original rates are 10 cents/kWh in the commercial sector, 15/kWh cents in the residential sector, and 8 cents/kWh in the industrial sector.

$400,00)*(60% commercial load) = ($240,000)/60 million kWh = $0.4 cents/kWh

The revenue adjusted commercial rate is then 10.4 cents/kWh. The percent increasese is 4%, which exceeds the RIM cap of 1% used in this study. If the 25- year total revenue required were only $1 million, then the rate increase in the commercial sector would be 0.4%, which would pass the RIM test.

$400,00)*(30% residential load) = ($120,000)/30 million kWh = $0.4 cents/kWh

$400,00)*(10% industrial load) = ($40,000)/10 million kWh = $0.4 cents/kWh

The revenue adjustred residential rate is 15.4 cents/kWh, a 2.66% increase from the original rate of 15 cents/kWh. The revenue adjusted industrial increase is 8.4 cents/kWh, a 5% increase over the original rate of 8 cents/kWh. Again, if the total addition revenue required was $1 million, then the rate increases in the residential and industrial sectors would pass the RIM test as applied in this study.

UCT Calculation Example:

The UCT is used in two ways in this analysis. The first application measures the cost-effectiveness of a microgrid as an individual investment, while the second application measures the cost-effectiveness of microgrid deployment in the context of MGE's total business operations over 2015-2040.

For the first application, assume that the microgrid system costs $8 million with a $2 million down payment, $$8 in discounted loan payments over the term of the loan, total discounted O&M costs of $3 million, a $1 million return from the federal Investment Tax Credit (ITC), a $100,000 salvage value, and $12 million in total discounted revenue from electricity generated by the microgrid.

UTC = NPV of lifetime revenue / NPV of lifetime costs

(ITC+salvage value+annual sales)/(down payment+loan payments+O&M costs)

($$13.1 million) / ($11 million in total costs) = 1.19, which passes the UTC test.

Under Scenario B, MGE does not incur any costs for constructing, financing, or operating the microgrid system. Under this scenario, the UTC is calculated by dividing the NPV of retail sales to microgrid customers by the NPV of original retail sales. In this way, MGE's lost retail sales represents the only "cost" incurred by the utility, and the UTC ratio will always be less than 1.0 unless MGE dramatically increases rates for electricity delivered to microgrid customers. A UTC below 1.0 under Scenario B is considered acceptable if the system-wide UTC is at least 1.103.

For the system-wide UTC test, the basic principle is the same, but the calculation includes all revenue divided by all costs to MGE. MoDERN calculates MGE's ROR before, and after, the non-microgrid rate increases are applied. The final results discussed in this analysis focus on the ROI/UTC after those rate increases are included in MGE's lifetime net revenue calculation.

(Retail Sales+ITC+RECs+Investment Deferrals+Fuel Hedging)
(Fuel Costs+MISO Purchases+Environmental Costs+Taxes/Depreciaion/Admin)

If the ratio of lifetime system revenue to lifetime system costs is at least 1.103, then MGE maintains it's regulated ROR of 10.3%. If both UTC tests, and the RIM test results in rate increases of less than 1% for each customer segment, then the microgrid deployment scenario is considered cost-effective from the perspective of MGE and non-microgrid customers (non-participants).

PCT Calculation Example:

The participant cost test (PCT) measures the cost-effectiveness of microgrid deployment to the customers who are served by the system. It is calculated by dividing the NPV of energy purchases + net energy saving/costs by the NPV of net energy costs.
If a commercial customer pays $10 million over 2015-2040, $12 million when served by a microgrid, and they experience lifetime savings from increased power reliability of $4 million, the PCT is calculated as follows:

1 + [(reliability benefits + (original purchases – MG purchases) / (MG purchases)]

1 + [($4 million +($10 million - $12 million) / ($12 million)] = 1.16

The expression within the brackets calculates the microgrid customer's ROI, so adding 1 to that number produces the final PCT score. A negative ROI would produce a PCT score below 1.0, while a positive ROI produces a PCT score above 1.0. This analysis used a PCT threshold of 1.1 (a 10% ROI) to prevent the utility from raising rates for microgrid customers to the point where they receive very minimal benefits. Ratepayers would likely not be willing to accept microgrid service and a new rate structure unless they see substantive net benefits. The 1.1 PCT/10% ROI threshold was selected based on guidance from NREL's *Manual for Economic Evaluation of Energy Efficiency Technologies* (link).

Appendix G: Description & Methodology for Cost-Benefit Categories

Benefit Categories	Proposed Measurement Methodology
1. Environmental Benefits	
a. **Reduced Greenhouse Gas (GHG) Emissions**	Using renewable energy sources, each microgrid project can reduce negative externalities associated with GHG emissions from the combustion of fossil fuels (coal, petroleum and natural gas). The White House Office of Management and Budget's (OMB) social cost of carbon, which is set at \$35/ton in 2012 and rises at 2.1% per year through 2050, was used in the high environmental cost scenario [1, 2]. Other alternatives would be the price of CO_2 allowances in the Regional Greenhouse Gas Initiative (RGGI) market and the most recent auction-clearing price for California Carbon Allowances (CCA) under that state's AB32 climate law. For Monte Carlo analysis, carbon prices ranged from \$1.90/ton (the minimum value of Regional Greenhouse Gas Initiative CO_2 allowances) to \$190/ton (the maximum value from OMB's Interagency Panel on setting the SCC). OMB's social cost of carbon was multiplied by the amount of CO_2 emissions offset by the microgrid's solar array by finding the CO_2 emissions rate (tons of CO_2/kWh) for Wisconsin's electric generation fleet (EPA Acid Rain Program Data). Emissions from burning natural gas in the microgrid's microturbines are subtracted from the offset macrogrid generation by applying a 0.0006 ton/kWh CO_2 rate for natural gas and biogas as defined by the US Energy Information Administration.
b. **Reductions of Criteria Air Pollutants**	By reducing energy use from fossil fuels that produce harmful pollutants like SO_2 and NO_x, microgrids can achieve additional health and environmental benefits. Pollution reductions for SO_2 and NO_x were calculated using the same emissions rate method mentioned above (EPA Acid Rain Program). For purely financial value of SO_2 and NO_x reductions, the price of allowances issued under EPA's federal SO_2 and NO_x trading programs as reported by the IntercontinentalExchange (ICE) was used. These prices were cross-referenced with brokerage firm Evolution Markets to check for consistency. The allowance price is then multiplied by Wisconsin's emissions rate for each pollutant and the amount of renewable power generated by the microgrid.

	To monetize the value of health and environmental benefits resulting from emissions reductions, values recommended in studies contained in Boardman et al.'s *Cost Benefit Analysis: Concepts & Practice (4th Edition)* textbook were used. For sensitivity analysis, figures from EPA's technical support document for the Cross-State Air Pollution Rule, which included a range of values that were many orders of magnitude greater than SO_2 and NO_x allowance prices were used. To avoid double counting, the value of allowance prices was subtracted from health and environmental benefits when both benefit categories were included in Tier II analysis.
2. Stability & Reliability of Power Supply	
a. **Protection from Blackouts and Other Outages**	Microgrids offer resiliency when the macrogrid experiences a blackout and therefore can reduce economic losses incurred by businesses or vital services (i.e. hospitals, food storage and gas stations). To monetize the value of avoided power outages, the results of a Lawrence Berkeley National Laboratory survey of different businesses that placed value on the economic losses incurred from outages of different lengths was used. These values were then multiplied by the number and duration of outages that occur in MGE's service territory. MGE reported that its customers typically experience one 30-minute outage every two years. It is assumed that customers served by MGE would experience one outage per year, while this is more frequent than the reported figures, it also serves to encompass power quality episodes that do not result in outages. Estimates based on the expected value resulting from the probability of future power outages was not included in the Monte Carlo analysis. Future studies could use the System Average Interruption Frequency Index (SAIFI) to shape Monte Carlo analysis of the likelihood of blackouts and other power failures that are based on sophisticated algorithms and statistical analysis. A 2008 EPRI survey found that the average annual cost of power outages across businesses is $23,318 but ranges from $10,598 for digital service companies to $61,828 for continuous process manufacturing (page 31). A figure on page 30 of the EPRI survey shows that outages longer than` 1-hour account for 28% of all outages in any given year. Table 1 provides a summary of the annual cost of power outages for various lengths to different businesses. EPB, the

	municipal utility for the City of Chattanooga, Tennessee reported that reduced outages from deployment of smart switches resulted in 58 million fewer minutes of outages following a severe wind storm in June 2013 (link). EPB said these reductions translated to $1.4 million in savings or $0.024/minute (2.4 cents per minute).
c. **Reduced Investment in Generating Capacity, T&D and Ancillary Services**	A key aspect of maintaining macrogrid reliability is ensuring that electricity remains "in phase", meaning that alternating current cannot fluctuate very far beyond a 60-hertz (1/60 second) wave frequency. Imbalances in AC phasing can cause power surges that may damage appliances and other electronic devices, and in severe cases, can threaten the stability of the entire grid. Microgrids can isolate themselves from these imbalances to protect customers' electronic devices, and they could also help support power quality if the proper equipment is installed. Utilities pay for these "ancillary services" which are reduced if the microgrid can balance its own power when it is operating in island mode. MGE participates in the Midwest Independent System Operator (MISO), which operates real-time power markets that include day-ahead markets for ancillary services that were used as the basis for monetizing this benefit to utilities. The amount of avoided ancillary services costs to MG&E were found by taking 1% of the microgrid's avoided costs through self-generation as cited by the California ISO. An alternative method would be multiplying the microgrid's annual generation by the 12-month average MISO day-ahead price for ancillary services (voltage regulation and spinning reserve) purchased by utilities in its territory. The average price ranged from $4-$12/MWh from 2009-2011. To calculate the avoided cost of building new generation capacity, DOE's LCOE figure for a new simple and combined cycle natural gas plant ($0.357/kWh for simple cycle and $0.071/kWh for combined cycle) was used. For the avoided cost of T&D, values ranged from $9.63/MWh for MGE ($0.00963/kWh) to $15.79/MWh (0.01579/kWh) for ITC Midwest from MISO's Transmission tariff. Other values were presented by MISO in the grid operator's most recent report on transmission upgrades being pursued in its service territory [4], which is $8.91/MWh or $0.00891/kWh. Page 86 of the 2011 MISO report shows T&D accounting for 0.0363 cents/kWh of its current rates, while page 22 of the Synapse study shows the new MVP project will include

	$3.34/MWh or 0.00334/kWh. From Minnesota administrative law judge's report on the 100MW Geronimo Solar proposal (100MW expected to generate approximately 200,000MWh/year); using MISO's rate for network integration service, the avoided transmission capacity benefits are approximately $3.24 million/year (which works out to $16.20/MWh or $0.0162/kWh). The source report for these figures is in Minnesota PUC docket 12-1240 at this link. Xcel Energy and the Minnesota Department of Commerce ignored the value of SRECs which could reduce the net present costs of Geronimo's project by $10-$38 million, according to the company's rebuttal. The Geronimo rebuttal also estimates the reduced transmissions capacity and line losses at $9-$33 million (here).
3. Electricity Savings & Potential Revenues	
a. **Avoided Electricity Purchases**	Microgrid customers can decide when they want to purchase electricity from the grid (if any) to avoid higher electricity costs that occur during on-peak hours (typically between (8am-8pm). MoDERN is designed to analyze the costs and benefits of installing enough generating capacity to offset a specified amount of on-peak and off-peak demand. Any excess generation is sold back to MGE through net-metering agreements. We compare the total electricity costs incurred by a customer who purchases 100% of their power from MGE during all hours against the standard microgrid systems. Savings are treated as costs to MGE, but innovative regulations could make energy efficiency and demand reduction more attractive (i.e. North Carolina program where 88.5% of savings are given to the customer while utility earns 11.5% return on the lost sales [5]. The link between electricity demand and profit would also be eliminated if the utility received rates based on number of customers served rather than electricity generated (i.e. the Energy Trust of Oregon).
b. **Net Metered Electricity Sales**	Depending on the utility, customers with renewable energy sources can sell excess generation back to the macrogrid or earn credits on their monthly bills. Customers may also be able to earn additional revenue from selling renewable energy certificates (RECs) to utilities that need to source a certain percentage of their total power sales from qualified renewable sources.

	Wisconsin has a 10% by 2015 RPS that most utilities are already meeting, but RECs can also be sold in voluntary markets such as Green-e where prices are hovering around $1/MWh ($0.001/kWh) according to Deb Erwin of the Wisconsin PSC (personal communication). To be conservative MGE's off-peak rate was used for net-metered sales based on conversations with Monte Lamer of Clear Horizon Power, LLC. Other states offer higher rates for specific renewable generation types and more aggressive REC markets have much higher prices than the $1/MWh for voluntary Green-e RECs, which could drastically improve the financial benefits to microgrid owners.
c. **Increased Efficiency - Reduced T&D Line Losses**	Approximately 7% of the electricity generated at large power plants is lost in the transmission and distribution network, representing a sunk cost implicit in centralized power generation. Microgrids can have shown losses of just 2-3% [6] because generation sources are located in close proximity to major loads**.** An additional benefit of local generation is the ability to productively use the waste heat from local electricity production to provide heat from a Combined Heat and Power (CHP) system. This efficiency gain is one of the major benefits of local energy production over traditional methods; more than 60% of the energy produced in standard coal power plants is lost as waste heat.
4. Financial Incentives	This analysis included federal investment tax credits (ITC) and production tax credits (PTC) for eligible renewable technologies. The federal ITC is a 30% credit on the total cost of wind and solar and 10% for high efficiency microturbines. MGE offers a $0.25/kWh rate for PV solar systems 1-10kW in size but the program has reached its 1MW capacity. Wisconsin also offers a $600/kW of DC capacity rebate for solar thermal, PV and geothermal systems with a maximum rebate of $2,400. The program's funds have been exhausted for 2014 so the $2,400 rebate for solar PV is applied in year two of the microgrid's operational life [7]. There are many other state and utility level programs that the microgrid owner/operator could apply for in future years, but these programs were not included in this analysis. Value added by solar and wind energy systems are exempt from property taxes in Wisconsin so additional costs from taxes were not included in this analysis [7].

Cost Categories	Proposed Measurement Methodology
1. Capital Costs	This cost category includes construction, generation systems, and power electronics (DC-AC inverters, net metered/interconnection equipment, wiring, and engineering/consulting fees).
2. Operation and Maintenance (O&M)	These annual costs include inspections and changes, equipment replacement, depreciation and labor fees to maintain the microgrid systems.
3. Fuel Costs	Fuel costs are zero for renewable energy resources. Natural gas prices in the Excel Tool are based on EIA historical averages for Wisconsin customers.
4. Finance Costs	A 2.94% real interest rate (5% nominal) was applied to the capital costs with a 25% down payment. The annual loan payment was discounted in each period to create a total cost of loan payments that was used to calculate the Tier I and Tier II benefits for each scenario.
5. Marginal Excess Tax Burden	An METB rate of 20 – 30% was used to account for the cost to society of raising the funds for renewable tax credits via taxation.

Table G.1: Annual Cost of Power Outages for Various Business Sectors

Medium-Large C&I Businesses	**Momentary**	**30 Minutes**	**1 Hour**	**4 Hours**	**8 Hours**
Agriculture	$4,382	$6,044	$8,049	$25,628	$41,250
Mining	$9,874	$12,883	$16,366	$44,708	$70,281
Construction	$27,048	$36,097	$46,733	$135,383	$214,644
Manufacturing	$22,106	$29,098	$37,238	$104,019	$164,033
Telecommunications & Utilities	$11,243	$15,249	$20,015	$60,663	$96,857
Trade & Retail	$7,625	$10,113	$13,025	$37,112	$58,694
Financial Institutions & Real Estate	$17,451	$23,573	$30,834	$92,375	$147,219
Services	$8,283	$11,254	$14,793	$45,057	$71,997
Public Administration	$9,360	$12,670	$16,601	$50,022	$79,793
Small Commercial & Industrial Businesses					
Agriculture	$293	$434	$615	$2,521	$4,868
Mining	$935	$1,285	$1,707	$5,424	$9,465
Construction	$1,052	$1,436	$1,895	$5,881	$10,177
Manufacturing	$609	$836	$1,110	$3,515	$6,127
Telecommunications & Utilities	$583	$810	$1,085	$3,560	$6,286
Trade & Retail	$575	$760	$2,383	$4,138	
Financial Institutions & Real Estate	$597	$831	$1,115	$3,685	$6,525
Services	$333	$465	$625	$2,080	$3,691
Public Administration	$230	$332	$461	$1,724	$3,205

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17.

Appendix H: Microturbine Calculations & Assumptions

Microturbines burn gaseous and liquid fuels (natural gas in this study) to create high-speed rotation that drives a generator to produce electricity. In particular, microturbines can be used in stand-alone power generation or combined heat and power (CHP) systems. The general size of microturbine ranges from 30 to 200kW.

The natural gas powered microturbines used in this study are manufactured by Capstone, an industry leaders in the microturbine market. Three sizes of microturbines used in this study are Capstone CR30 - 30kW, Capstone CR65 - 65kW and Capstone CR200 - 200kW. The natural gas powered microturbine is used to fill the electricity generation gap when intermittent renewables are unable to produce enough electricity to meet the microgrid customer's demand. The characteristics and prices are listed in tables G.1 and G.2.

Table H.1: Typical Performance Parameters of Capstone CHP-equipped Microturbines

Model	**CR30 w/ CHP**	**CR65 w/ CHP**	**CR200 w/ CHP**
Power Rating (kW)	30	65	200
Unit Heat Rate	14,433	13,119	11,545
Fuel Flow HHV (BTU/hr)	433,000	842,000	2,280,000
Max Fuel Consumption (cf/hr)	419	825	2,233
Electrical Efficiency (LHV)	23%	25%	33%
NO_x emissions (lb/MWh)	0.64	0.46	0.40
CO_2 Emissions (lb/MWh)	1,736	1,597	1,377
Fuel Consumption (cf/kWh	13.96	12.69	11.17
Capital Costs	$51,600	$105,300	$320,000
O&M ($/kW of capacity)	$11,213.10	$17,379.70	$32,198.00
Installation	$36,600	$54,600	$162,000

[a]The usable energy content of fuels is typically measured on a higher heating value (HHV) basis. In addition, electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content of natural gas is 1,034 Btu/scf on an HHV basis or about a 10% difference.
[b]Electrical efficiencies are net of parasitic and conversion losses. Fuel gas compressor needs based on 1 psi inlet supply

The estimated capital cost for microturbine systems represents the costs for early market entry products. Estimation of equipment-only cost, installation cost and of the three different size microturbine systems are listed in table G.2. For *Capstone M330*, the cost of the genset package is $1,290/kW while the cost of other equipment including heat recovery system is $430/kw. The capital cost of equipment is $1,720/kW and $51,600 (calculated from $1720 /kW multiplies by 30kW) for the whole system. The installation cost includes labor and material fees ($710/kW), project and construction management fees ($210/kW), engineering fees ($210/kW) and project contingency ($90/kW).

For *Capstone C65*, the cost of genset package is $1,280/kW while the cost of other equipment including heat recovery system is $340/kw. Therefore, the total capital cost of equipment is $1,620/kW and $105,300 (calculated from $1,620 /kW multiplies by 65kW) for the whole system. The installation cost includes labor and material fees ($360/kW), project and construction management fees ($200/kW), engineering fees ($200/kW) and project contingency ($30/kW).

For *Capstone CR200*, the cost of the genset package is $1,410/kW while the cost of other equipment including heat recovery system is $190/kw. The total capital cost of equipment is $1,600/kW and $400,000 (calculated from $1,600 /kW multiplies by 250kW) in total. The installation cost includes labor and material fees ($350/kW), project and construction management fees ($190/kW), engineering fees ($190/kW) and project contingency ($80/kW).

Table H.2: Estimated Cost for Capstone CHP-equipped Microturbines

Costs	CR35	CR65	CR200
Equipment Cost ($/kW)[a]	$1,720	$1,620	$1,600
Capital Cost	$51,600	$105,300	$320,000
Installation Cost ($/kW)	$1,220	$840	$810
Total Installation Cost	$36,600	$54,600	$202,500
Annual O&M Costs ($/kW)[b]	0.015 - 0.025	0.013 - 0.022	0.012 - 0.020
Annual O&M	$11,213	$17,380	$32,198

[a]Total equipment cost here includes cost of gen set package, heat recovery and other equipment
[b]Based on full service maintenance contracts provided by the manufacturer. Normal maintenance includes periodic air and fuel filter inspections and changes, igniter and fuel injector replacement, and major overhauls of the turbine itself.
[c] Capstone also cites a cost of $185,000 ($2,000/kW) for two CR65's in a case study (link)
[d] Caterpillar 980kW Model G3516 is listed at $375,000 ($385/kW) on Utility Warehouse and its specs can be found at this link.
[e] Capstone sales representative Justin Rathke confirmed that these cost estimates were accurated in a personal communication received September 3, 2014

Fuel Consumption & Costs

Natural gas heat content of 1,034 Btu/cf was taken from EIA data (link) for the energy content of natural gas delivered to consumers in Wisconsin. Capstone's performance ratings were used to calculate fuel consumption (cf per hour / kW capacity rating). The fuel consumption rate is then multiplied by total generation (kWh) and EIA's average price of natural gas for Wisconsin customers to determine total fuel costs for each microturbine. The average price is divided by the fuel consumption rate to produce a $/kWh figure for fuel use associated with each microturbine. Table G.4 illustrates EIA's average natural gas prices for residential consumers over the past 12 months.

Regulatory Considerations

The US EPA adopted final regulations for non-road engines (which includes electric generators) in February 2014 (link). The limits for generators larger than 560kW are 0.1 grams/kWh for particulate matter and 3.5 grams/kWh for NO_x for engine model years 2015-2018. This fact sheet from CPower also discusses standards for diesel generators (link). Stationary generators are only allowed to provide peak shaving under demand response programs for up to 50 hours in a given year (EPA regulations discussed by Titan Energy link).

This provision is set to expire on May 3, 2014. EnerNOC (a demand response bundler) says the value of short-term energy savings provided by DR and on-site generators went up in 2012 because of a federal rule that forced utilities to pay the same wholesale price for "negawatts" as they would for megawatt-hours generated by merchant power plants. This webpage contains information about EPA's emissions controls for reciprocating internal combustion engines (RICE).

Table H.3: EIA Monthly Prices for Natural Gas in Wisconsin

Customer Type	**Residential**	**Commercial**	**Industrial**
Month	**$/1,000cf**	**$/1,000cf**	**$/1,000cf**
January	$8.28	$7.21	$6.35
February	$7.96	$6.99	$6.05
March	$8.14	$7.05	$6.21
April	$9.00	$7.38	$6.59
May	$9.85	$7.19	$6.11
June	$11.39	$7.58	$6.01
July	$12.66	$7.26	$5.39
August	$12.76	$6.98	$5.16
September	$10.78	$6.62	$4.61
October	$8.21	$5.97	$4.84
November	$8.99	$7.43	$6.38
December	$8.88	$7.62	$6.62
Average	**$9.74**	**$7.11**	**$5.86**

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Appendix I: *Battery Storage Technologies*

Battery storage was not included in MoDERN due to relatively high costs and the difficulty of accurately modeling their dispatch characteristics. However, background research on several battery technologies is included as a reference for future studies.

Currently, the macrogrid must balance consumer demand with generation by maintaining reliability and spinning reserves. These terms refer to power plants that are kept online and running, but not generating power so they can be called upon to quickly ramp up electricity generation when demand spikes above normal daily and seasonal levels. Reliability and spinning reserves are a cost that electric utilities incorporate in customer rates and wholesale prices as a type of ancillary service. Reserve generating capacity typically comes at a very high marginal cost, so the use of batteries to store excess energy generated during off-peak hours is an attractive alternative to building additional power plants that operate at very low capacity factors.

Batteries are also a natural complement to intermittent renewable energy sources like wind and solar. Those technologies cannot be ramped up and down by the grid operator, so they may produce excess power during off-peak hours and not be available when demand spikes and a shortfall in generation could result in system damage and potential brownouts. Incorporating battery storage into a microgrid would smooth out the unpredictable generation curves of renewable energy technologies to make them more reliable and attractive to both the microgrid operator and utilities who may purchase excess generation from the microgrid.

Despite the notable benefits of deploying battery storage, most battery technologies are too expensive to displace traditional spinning reserve power plants that are typically single or combined cycle natural gas-fired units. This cost-benefit analysis (CBA) used the results of an extensive industry survey conducted by the US Department of Energy (DOE) and the Electric Power Research Institute (EPRI) to examine the economic feasibility of including energy storage in urban and rural microgrids. The DOE/EPRI study included a review of numerous battery technologies, but we chose to focus on lead acid, zinc bromine and lithium-ion because they are the most commercially viable technologies at this point in time. The table below summarizes the DOE/EPRI costs and key specifications for these three battery technologies.

Table I.1: Overview of Battery Storage Performance Metrics

	Lead Acid	Zinc Bromine	Lithium Ion
Power Rating (kW)	50	500	500
Depth of Discharge	80%	100%	100%
Round Trip AC/AC Efficiency	90%	60%	90%
Energy Capacity (kWh)	250	2,500	1,000
Battery Replacement (years)	8	5	5
Daily Storage Time (hours)	5	5	2
Incremental Capacity Cost ($/kW)	$2,782	$2,584	$3,034
Balance of Systems Cost	$76,600	$667,000	$737,000
Total Capital Cost (per battery)	$139,100	$1,292,000	$1,517,000
Energy Cost ($/kWh)	$445	$517	$1,517
Annual O&M costs ($/kW per year)	$26.80	$11.70	$11.70
Source: DOE/EPRI 2013 Energy Storage Guidebook			

All three battery technologies appear cost competitive when compared to the present value of lifetime costs associated with building a new simple or combined-cycle natural gas-fired turbine, but the levelized cost of electricity (LCOE) is extremely high by comparison. According to the DOE/EPRI Handbook, the life cycle costs associated with natural gas-fired generation range from $2,225-$5,150/kW while the LCOE is drastically lower at $0.071-0.357/kWh. The economic feasibility of including battery storage in a microgrid depends on how the storage system is used to offset high value costs.

Lead Acid Battery Technology

Lead-acid batteries are the oldest and most commercially mature rechargeable battery technology, originally invented in the mid-1800s. They are used in a variety of applications, including automotive, marine, telecommunications, and uninterruptible power supply systems. Traditional batteries use a positive electrode made of lead-dioxide, a negative electrode composed of metallic lead and an electrolyte composed of a sulfuric acid solution that is usually around 37% sulfuric acid by weight when the battery is fully charged.

Xtreme Power systems has developed batteries for use in wind and solar photovoltaic smoothing applications. The Xtreme Power PowerCell is a 12-volt, 1kWh, advanced dry cell battery utilizing a solid-state battery design and chemistry. The uniform characteristics of the PowerCells allow thousands to be assembled in massive parallel and series arrangements that can be used for grid-scale utility applications. The table below compares the different lead-acid technologies examined in the DOE/EPRI study for commercial and residential projects aligned with the size of 500kW-2MW microgrids.

Table I.2: Lead-Acid Battery Performance Metrics

Power Rating (kW)	50	200	1,000
Depth of Discharge	80%	60%	80%
Round Trip AC/AC Efficiency	90%	75%	90%
Energy Capacity (kWh)	250	800	10,000
Battery Replacement (years)	8	8	8
Daily Storage Time (hours)	5	4	10
Incremental Capital Cost ($/kW)	$2,782	$5,995	$5,023
Balance of Systems Cost	$76,600	$399,000	$1,398,000
Total Capital Cost (per battery)	$139,100	$1,199,000	$5,023,000
Energy Cost ($/kWh)	$445	$1,050	$399
Annual O&M costs ($/kW per year)	$26.80	$16.50	$9.20
Source: DOE/EPRI 2013 Energy Storage Guidebook			

Lithium-Ion (Li-ion) Battery Technology

Li-ion batteries have emerged as the fastest growing platform for stationary storage applications. It is already the leading battery technology for hybrid electric and all-electric vehicles, which use larger-format cells and packs with capacities up to 50 kWh. A large manufacturing capacity (estimated at 30GW/year by 2015) could lead to reduced costs for large battery packs suitable for electric grid support services that require less than 4 hours of storage. AES Energy Storage LLC has deployed more than 50 as an independent power producer for frequency regulation and spinning reserve services. Utilities are also deploying megawatt-scale units for solar PV integration and distribution grid support that correlate with microgrid applications. The table below compares the different lead-acid technologies examined in the DOE/EPRI study for commercial and residential projects aligned with the size of 500kW-2MW microgrids.

Table I.3: Lithium-ion Battery Performance Metrics

Power Rating (kW)	100	250	500
Depth of Discharge	100%	100%	100%
Round Trip AC/AC Efficiency	90%	90%	90%
Energy Capacity (kWh)	400	1,000	1,000
Battery Replacement (years)	5	5	5
Daily Storage Time (hours)	4	4	2
Incremental Capital Cost ($/kW)	$5,804	$5,464	$3,034
Balance of Systems Cost	$268,400	$586,000	$737,000
Total Capital Cost (per battery)	$580,400	$1,366,000	$1,517,000
Energy Cost ($/kWh)	$2,173	$1,366	$1,517
Annual O&M costs ($/kW per year)	$23.70	$13.20	$11.70
Source: DOE/EPRI 2013 Energy Storage Guidebook			

Zinc Bromine Battery Technology

This technology is a type of flow battery in the early stages of field deployment. Electric utilities plan to conduct early trials of 500-1,000 kW systems for grid support and reliability by 2014. The zinc is solid when charged, dissolved when discharged, and the bromine is always dissolved in the aqueous electrolyte solution. Each cell is composed of two electrode surfaces and two electrolyte flow streams separated by a film. The table below compares the different lead-acid technologies examined in the DOE/EPRI study for commercial and residential projects aligned with the size of 500kW-2MW microgrids.

Table I.4: Zinc-Bromine Battery Performance Metrics

Power Rating (kW)	125	500	1,000
Depth of Discharge	100%	100%	100%
Round Trip AC/AC Efficiency	60%	60%	60%
Energy Capacity (kWh)	625	2,500	5,000
Battery Replacement (years)	15	15	15
Daily Storage Time (hours)	5	5	5
Incremental Capital Cost ($/kW)	$2,808	$2,584	$2,286
Balance of Systems Cost	$194,750	$667,000	$1,036,000
Total Capital Cost (per battery)	$351,000	$1,292,000	$2,286,000
Energy Cost ($/kWh)	$562	$517	$562
Annual O&M costs ($/kW per year)	$19.00	$11.70	$9.20
Source: DOE/EPRI 2013 Energy Storage Guidebook			

Optimal Dispatch Strategies

As show above, battery storage has far higher LCOE than natural gas-fired power plants, but storage can be economically viable if the system is used to offset costs of high value electricity services. For example, an EPRI analysis submitted to the California Public Utilities Commission in July, 2013 found that battery storage could provide cost-effective frequency regulation (a component of ancillary services) with a breakeven capital cost of $1,678/kW or $6,712/kWh. MISO also operates ancillary services markets with day-ahead pricing, but we were not able to model the potential benefits to a microgrid customer providing ancillary services due to time constraints.

EPRI's analysis also found that distributed energy storage at the transformer level produced break-even costs ranging from $2,745-3,464/kW and $686-1,509/kWh, which are within the range of costs reported in the DOE/EPRI survey. Distributed storage systems were marginally more costly than bulk energy storage systems, but significant additional value was derived from the deferral of investments to upgrade existing distribution infrastructure. Analysis performed by consulting firm DNV KEMA also found that using battery storage for distributed generation was use of storage for deferral at a single location was cost-effective where alternative costs were high and the battery size was optimized (neither too large or too small). Avoided distribution investments were included in the CBA to reflect the value of the microgrid although storage was found uneconomical in both the urban and rural case studies.

Due to the complex nature of building energy models to accurately reflect the charging and dispatch of electricity from battery storage systems, we did not include batteries in our microgrid architecture. Instead, we relied on natural gas-fired microturbines to provide backup generation in scenarios where renewables did not provide adequate generation to cover the microgrid's on-peak energy demand. Energy storage could become more attractive if prices for technology decline, or regulations that set a price on CO_2 emissions is implemented that would increase the LCOE of fossil fuel generation.

Eos Energy Storage (source) is developing a zinc-based system that touts low-capital costs of $1,000/kW and an LCOE of $160/kWh. Urban Electric Power, a New York City-based company, claims to have a zinc-manganese dioxide battery (known as the GreenCat) capable of achieving LCOE below $100/kWh and will begin filling commercial orders in 2014 (source). The commercial viability of these new technologies could not be proven and were therefore not considered in this analysis.

Appendix J: Sensitivity Analysis

Table J.1: Scenario A Sensitivity Analysis for MGE's Net Revenue & ROI

1.5% Residential	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Results	**Net Revenue**	**25-Year ROI**	**Net Revenue**	**25-Year ROI**
Monte Carlo Median	$1,058,097,304	10.36%	$1,048,088,552	10.26%
Monte Carlo Average	$1,056,553,963	10.33%	$1,048,866,740	10.26%
Monte Carlo Minimum	$910,172,791	8.86%	$896,664,201	8.70%
Monte Carlo Maximum	$1,197,174,667	11.79%	$1,240,249,733	12.19%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		53.60%		45.70%
3% Residential	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,012,380,243	9.88%	$1,000,604,807	9.76%
Monte Carlo Average	$1,014,344,601	9.89%	$1,001,410,430	9.77%
Monte Carlo Minimum	$817,854,856	7.92%	$828,571,922	8.00%
Monte Carlo Maximum	$1,164,300,932	11.45%	$1,155,769,715	11.35%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		22.00%		13.70%
1.5% Commercial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,040,649,678	10.13%	$1,041,799,496	10.14%
Monte Carlo Average	$1,042,755,715	10.15%	$1,041,372,776	10.13%
Monte Carlo Minimum	$850,156,067	8.21%	$910,571,926	8.81%
Monte Carlo Maximum	$1,187,064,411	11.61%	$1,196,093,409	11.67%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		40.50%		39.60%
3% Commercial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,036,560,973	10.00%	$1,041,951,513	10.04%
Monte Carlo Average	$1,037,366,438	10.00%	$1,041,357,856	10.04%
Monte Carlo Minimum	$867,425,154	8.29%	$870,136,386	8.32%
Monte Carlo Maximum	$1,178,278,426	11.42%	$1,195,735,978	11.65%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		38.10%		39.40%
1.5% Industrial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,096,368,351	10.74%	$1,097,124,749	10.76%
Monte Carlo Average	$1,096,658,550	10.75%	$1,097,253,127	10.76%
Monte Carlo Minimum	$931,252,864	9.07%	$938,908,469	9.15%
Monte Carlo Maximum	$1,263,656,555	12.47%	$1,251,205,044	12.35%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		80.70%		80.10%
3% Industrial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,099,509,345	10.76%	$1,091,767,419	10.69%
Monte Carlo Average	$1,097,993,613	10.76%	$1,090,310,856	10.68%
Monte Carlo Minimum	$947,012,214	9.25%	$929,980,247	9.05%
Monte Carlo Maximum	$1,253,329,709	12.35%	$1,274,883,674	12.58%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		81.00%		74.20%

Figure J.1: Distribution of MGE's Net Revenue Under Scenario A (1.5% Residential)

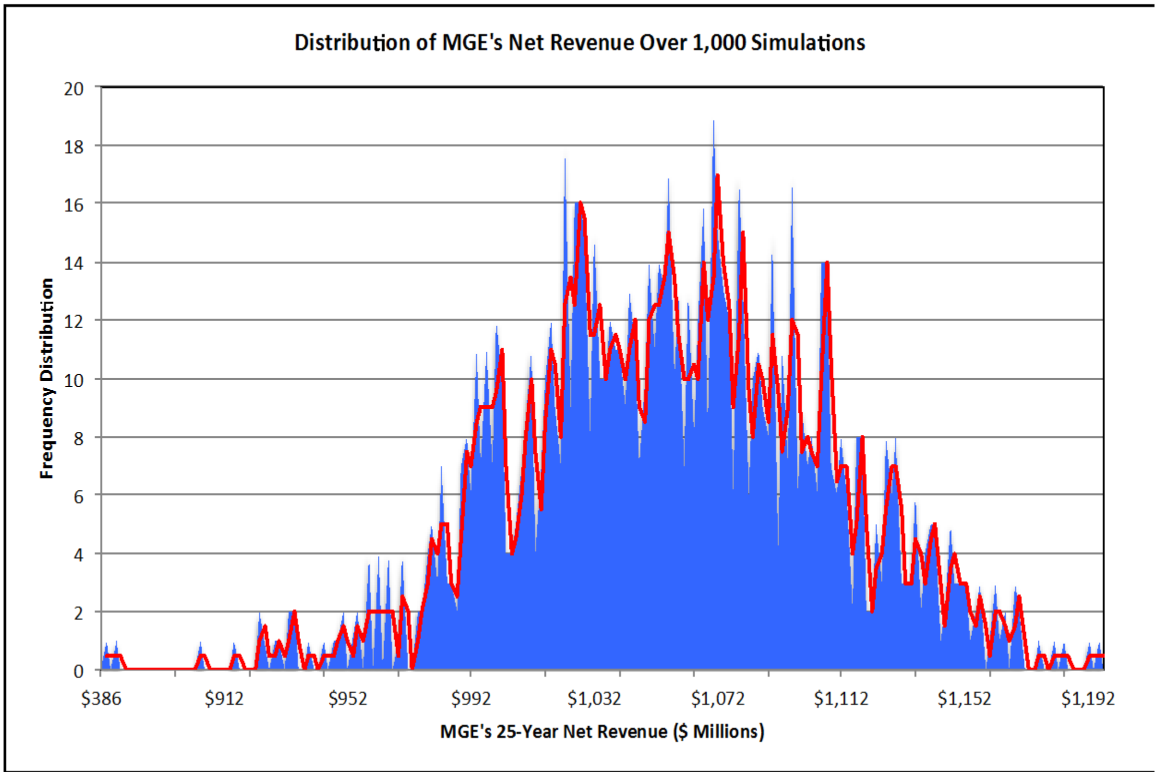


Figure J.2: Distribution of MGE's Net Revenue Under Scenario A (3% Residential)

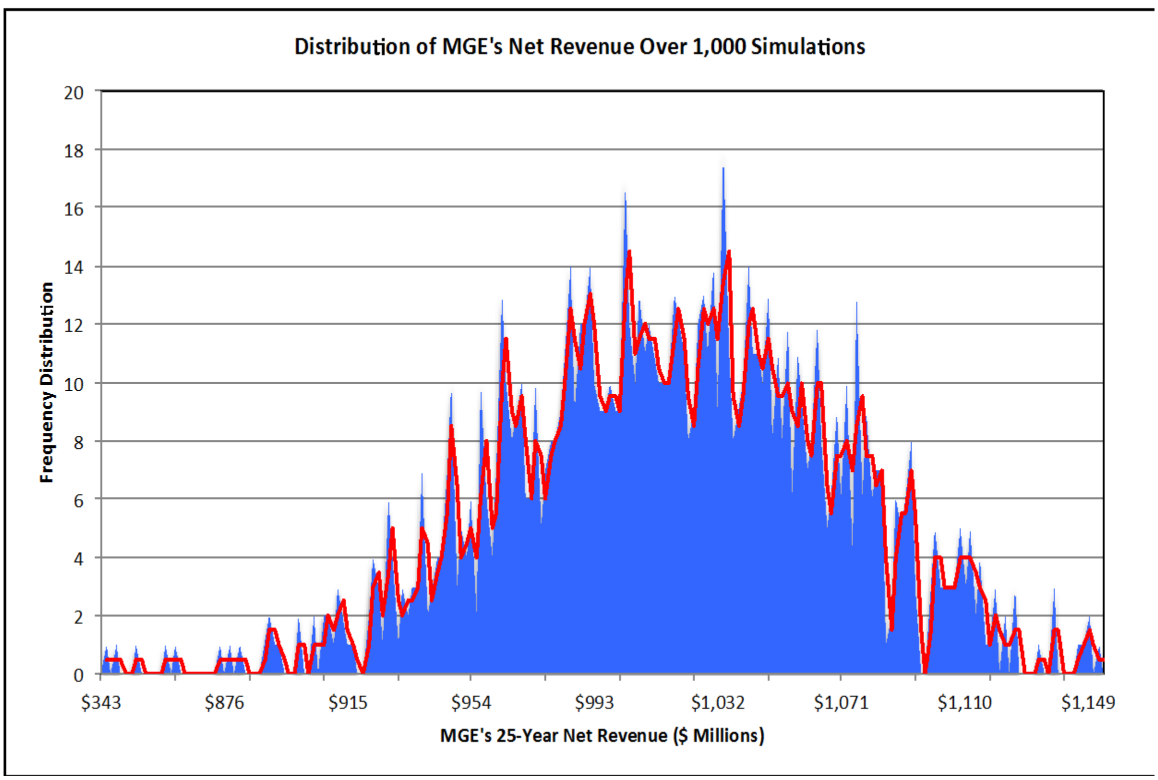


Figure J.3: Distribution of MGE's Net Revenue Under Scenario A (1.5% Commercial)

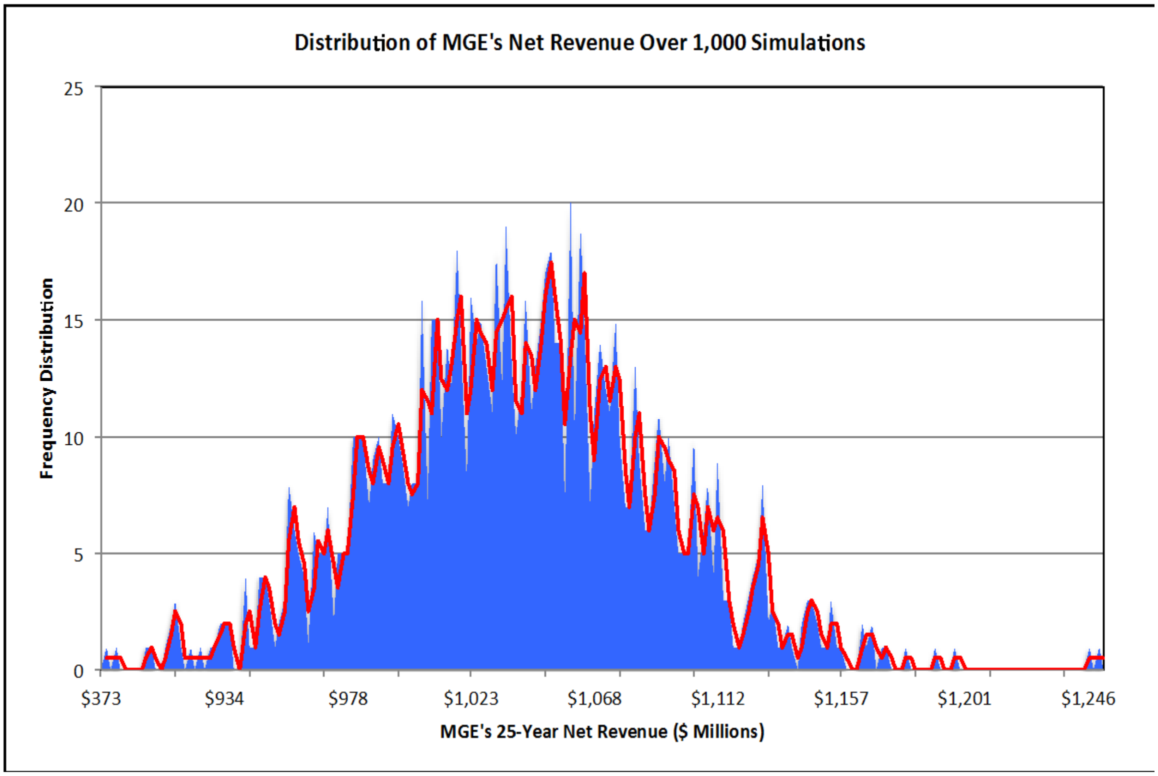


Figure J.4: Distribution of MGE's Net Revenue Under Scenario A (3% Commercial)

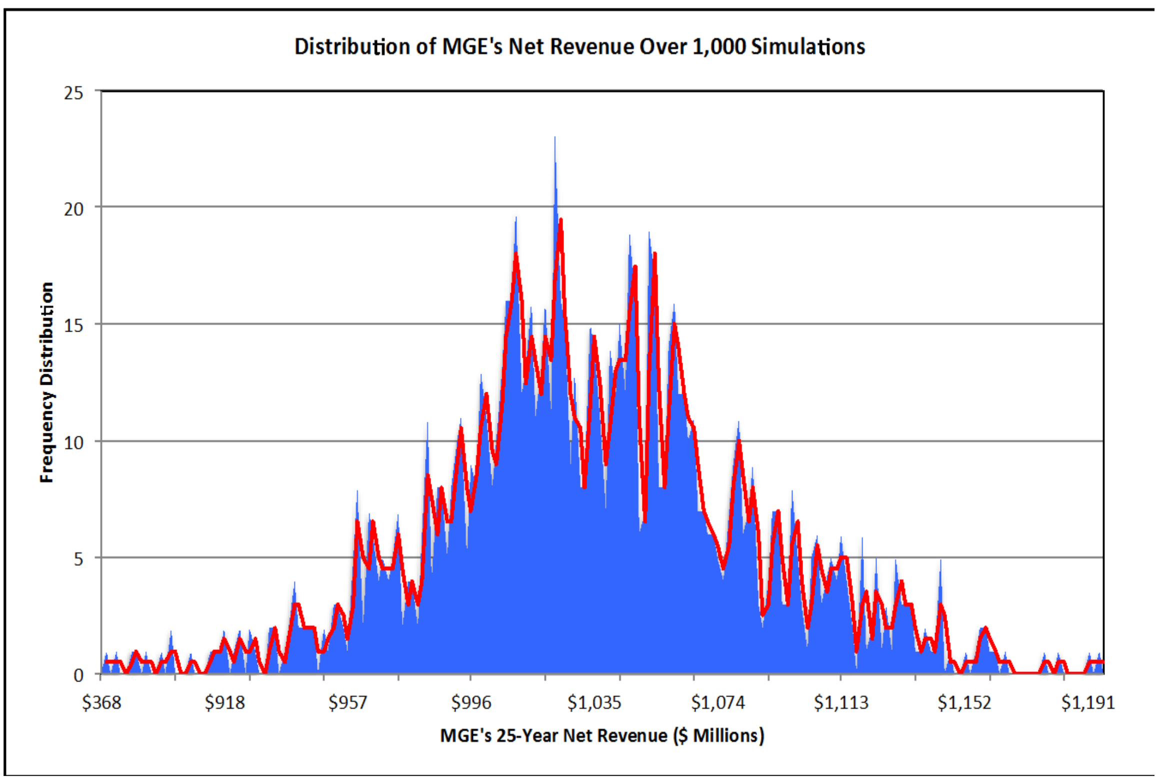


Figure J.5: Distribution of MGE's Net Revenue Under Scenario A (1.5% Industrial)

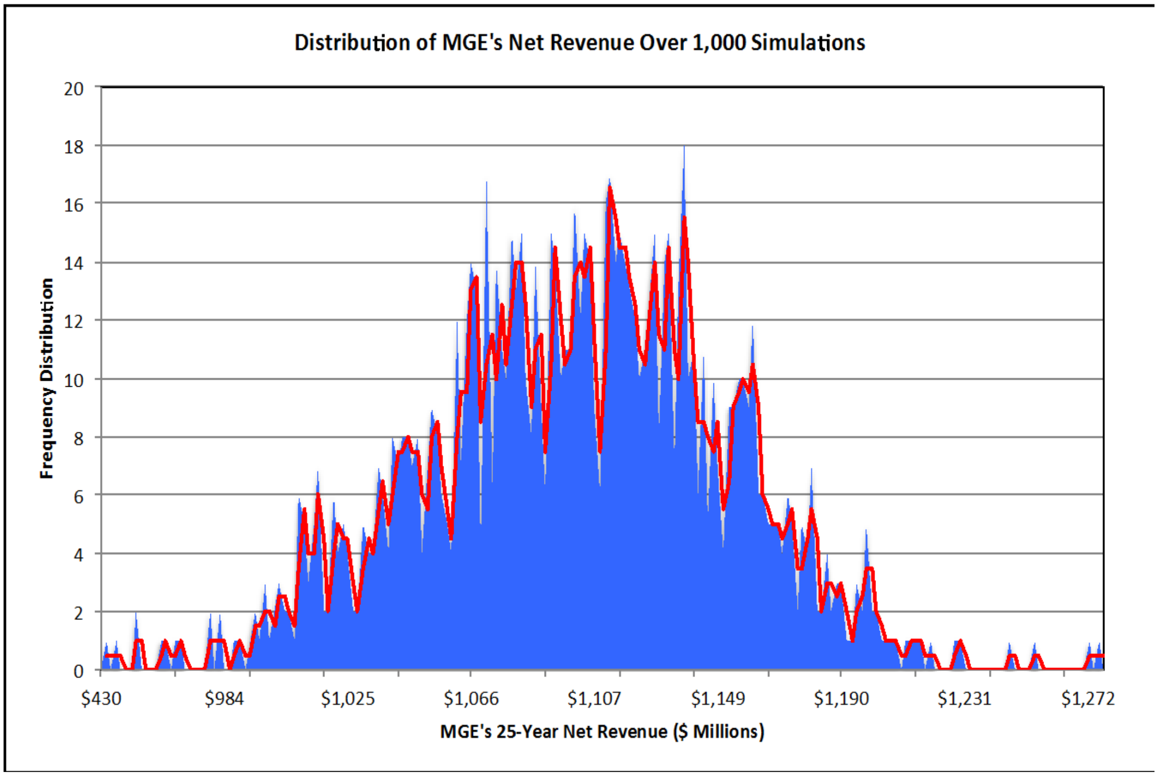


Figure J.6: Distribution of MGE's Net Revenue Under Scenario A (3% Industrial)

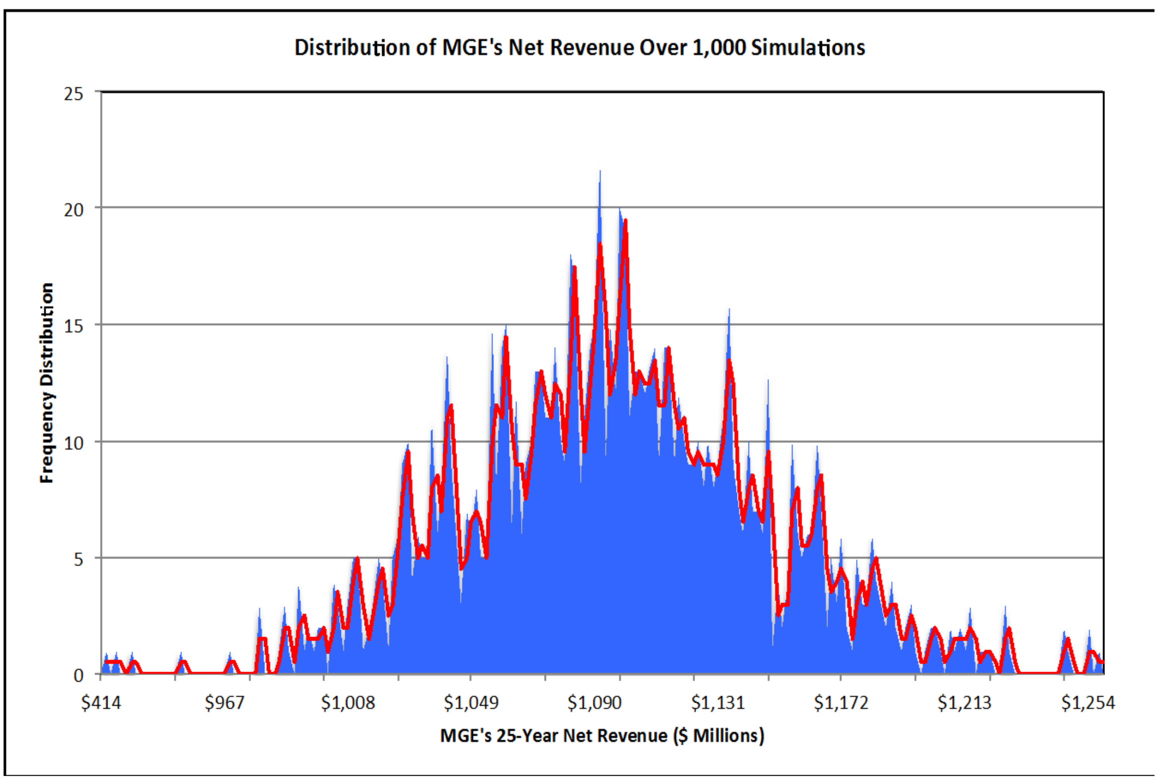


Table J.2: Scenario B Sensitivity Analysis for MGE's Net Revenue & ROI

1.5% Residential	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Results	**Net Revenue**	**25-Year ROI**	**Net Revenue**	**25-Year ROI**
Monte Carlo Median	$1,050,314,891	10.31%	$1,044,904,578	10.26%
Monte Carlo Average	$1,050,122,526	10.32%	$1,044,158,887	10.26%
Monte Carlo Minimum	$884,536,751	8.65%	$865,450,407	8.42%
Monte Carlo Maximum	$1,217,777,510	12.04%	$1,216,033,327	12.03%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		47.20%		42.20%
3% Residential	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,005,311,512	9.89%	$982,403,124	9.66%
Monte Carlo Average	$1,007,730,648	9.91%	$985,419,180	9.69%
Monte Carlo Minimum	$868,656,905	8.51%	$840,396,329	8.24%
Monte Carlo Maximum	$1,145,269,863	11.35%	$1,126,117,724	11.17%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		17.60%		9.20%
1.5% Commercial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,024,049,955	10.08%	$1,002,675,071	9.87%
Monte Carlo Average	$1,022,792,246	10.07%	$1,002,016,207	9.86%
Monte Carlo Minimum	$855,819,950	8.40%	$849,463,962	8.33%
Monte Carlo Maximum	$1,179,315,806	11.70%	$1,129,461,902	11.17%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		27.50%		14.60%
3% Commercial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,004,924,617	9.91%	$1,005,713,801	9.92%
Monte Carlo Average	$1,006,502,062	9.93%	$1,004,742,507	9.91%
Monte Carlo Minimum	$854,376,547	8.35%	$848,298,178	8.32%
Monte Carlo Maximum	$1,162,842,267	11.56%	$1,181,342,478	11.75%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		18.30%		15.60%
1.5% Industrial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,096,021,334	10.77%	$1,091,252,356	10.72%
Monte Carlo Average	$1,096,744,524	10.77%	$1,092,719,685	10.73%
Monte Carlo Minimum	$940,716,792	9.20%	$945,214,091	9.21%
Monte Carlo Maximum	$1,272,703,535	12.63%	$1,244,998,420	12.27%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		79.50%		77.90%
3% Industrial	**Tier Benefits Included**		**Tier II Benefits Excluded**	
Monte Carlo Median	$1,095,264,501	10.76%	$1,087,882,999	10.69%
Monte Carlo Average	$1,093,935,870	10.75%	$1,087,834,205	10.69%
Monte Carlo Minimum	$941,694,477	9.18%	$918,896,910	8.95%
Monte Carlo Maximum	$1,265,633,852	12.56%	$1,241,081,352	12.27%
Rate Increases Above 1%		0		0
% Above BAU Net Benefits		77.80%		74.40%

Figure J.7: Distribution of MGE's Net Revenue Under Scenario B (1.5% Residential)

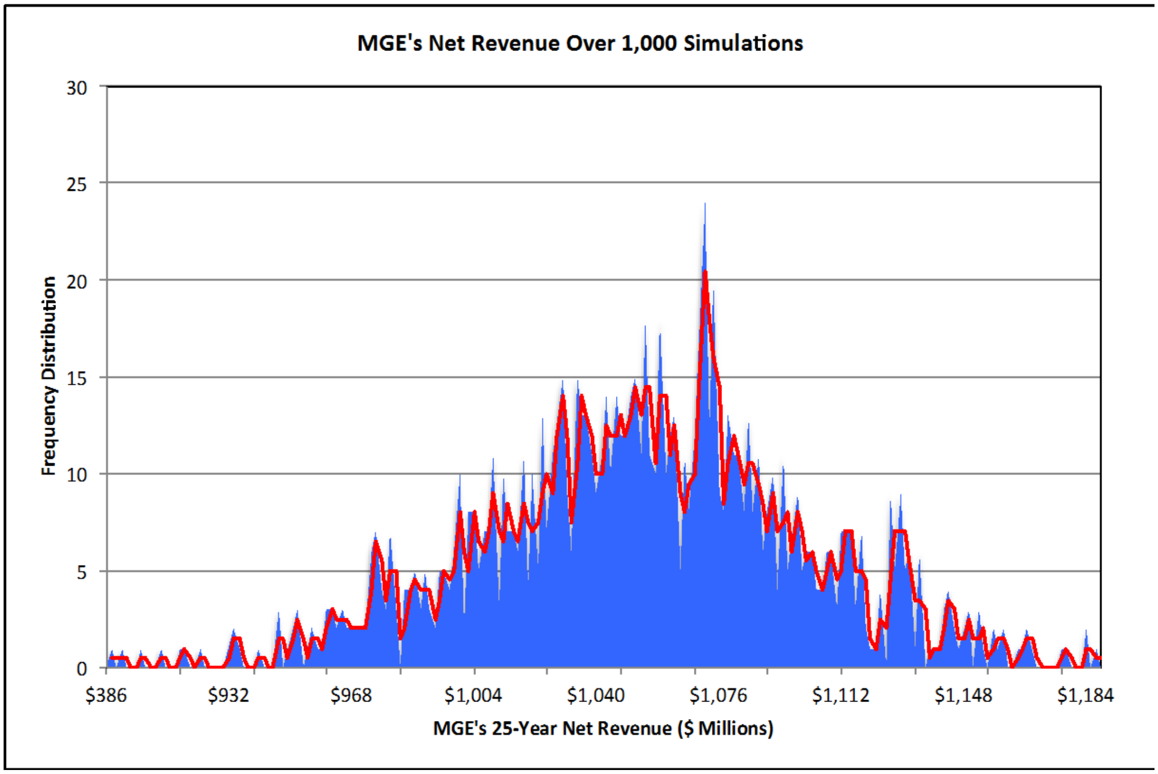


Figure J.8: Distribution of MGE's Net Revenue Under Scenario B (3% Residential)

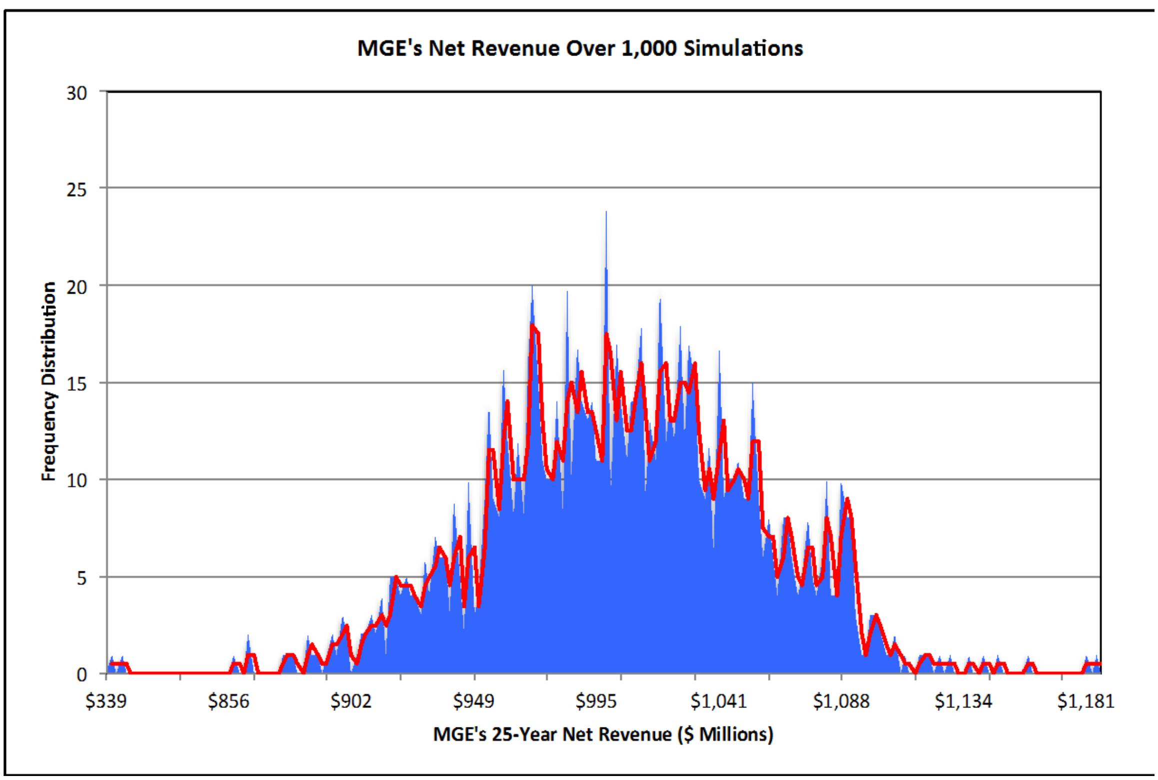


Figure J.9: Distribution of MGE's Net Revenue Under Scenario B (1.5% Commercial)

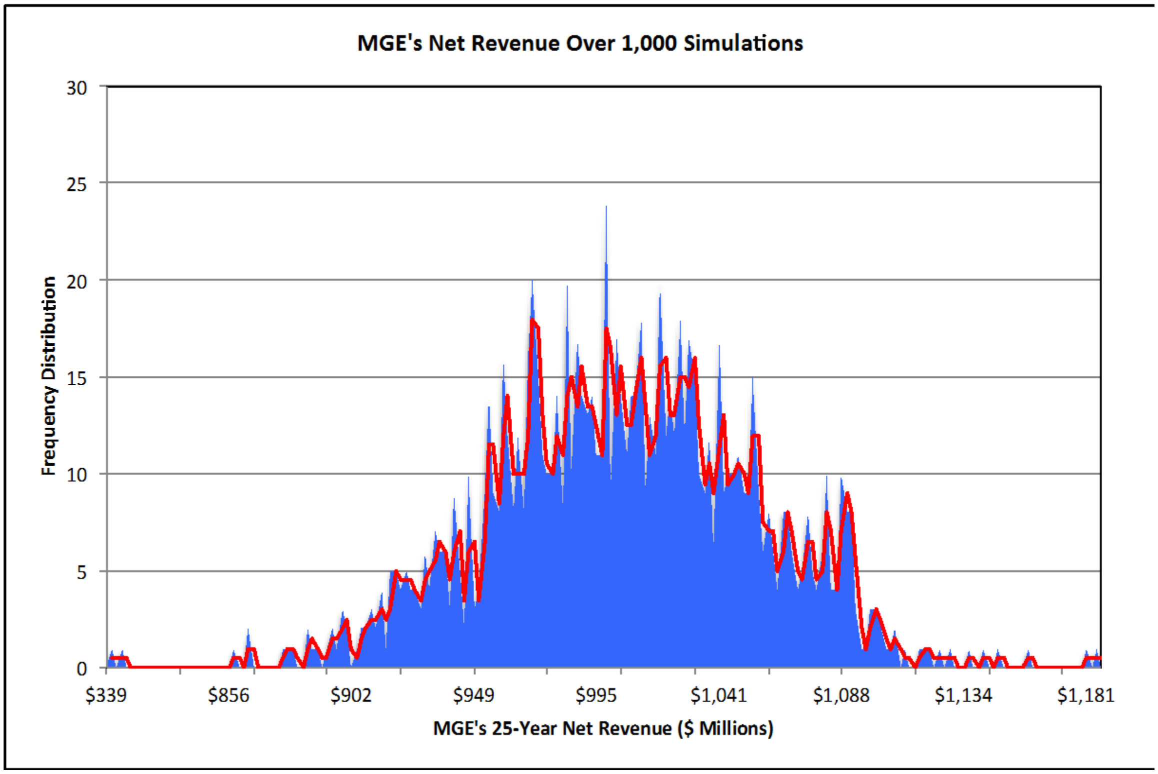


Figure J.10: Distribution of MGE's Net Revenue Under Scenario B (3% Commercial)

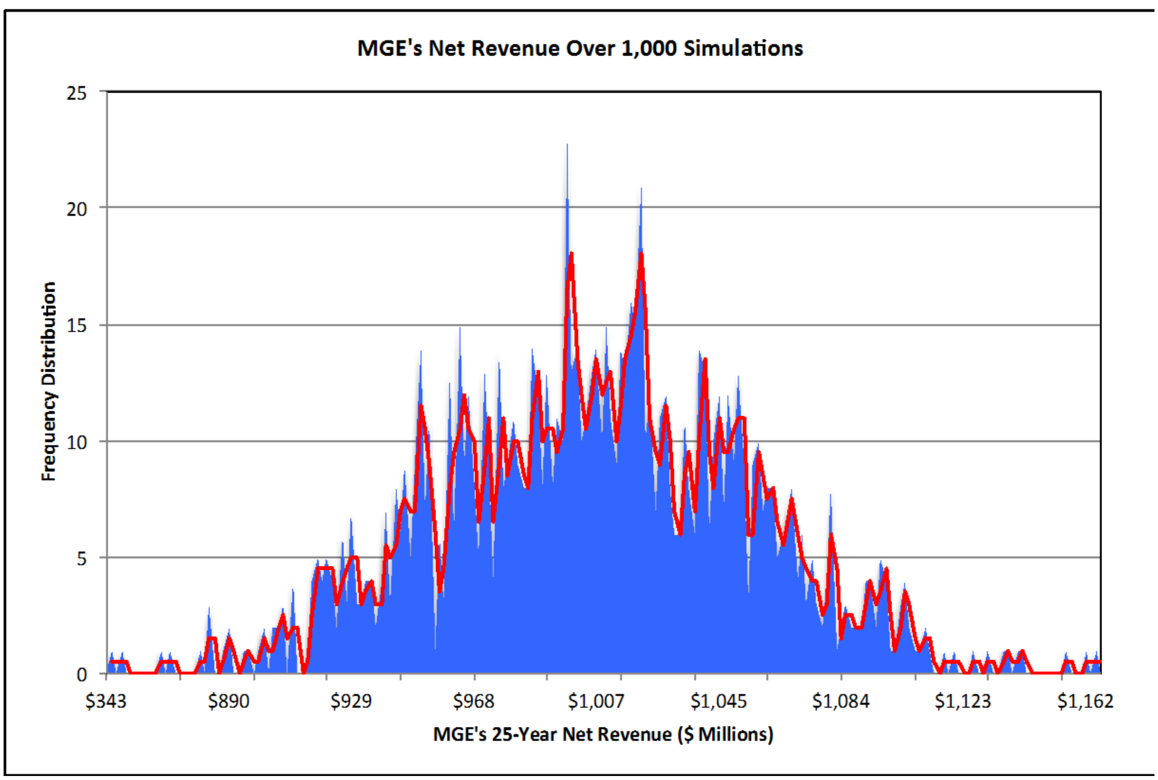


Figure J.11: Distribution of MGE's Net Revenue Under Scenario B (1.5% Industrial)

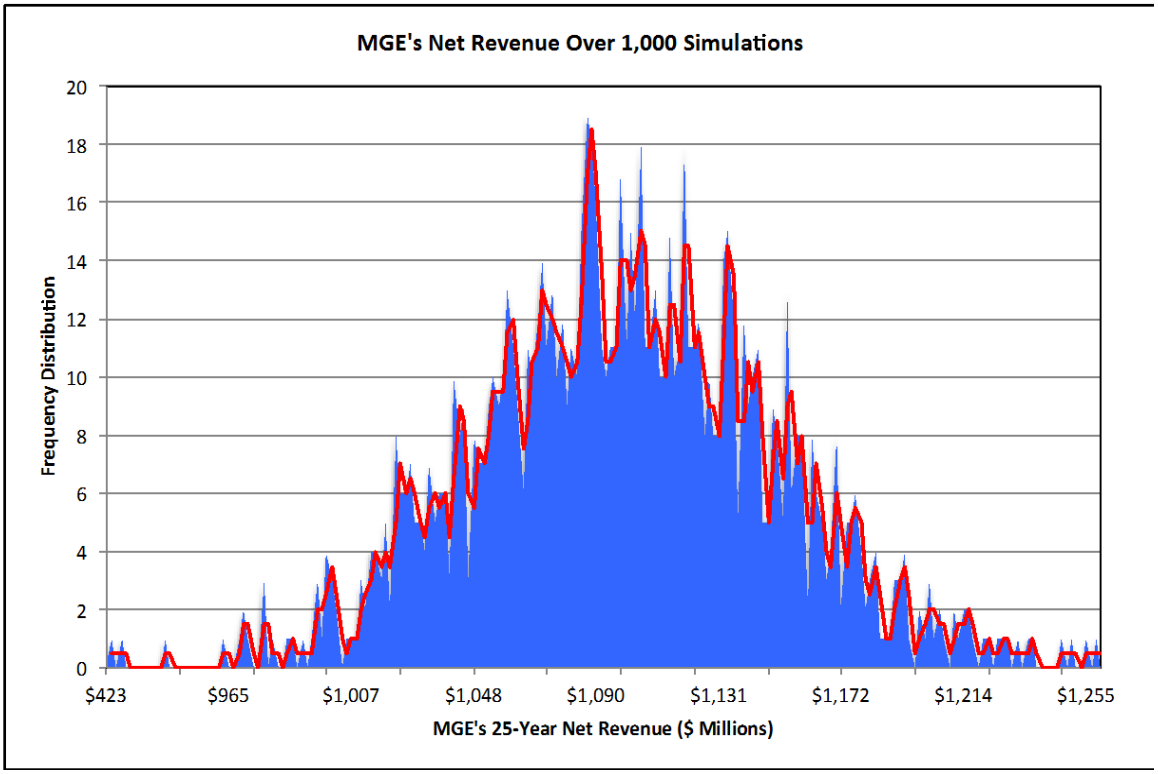
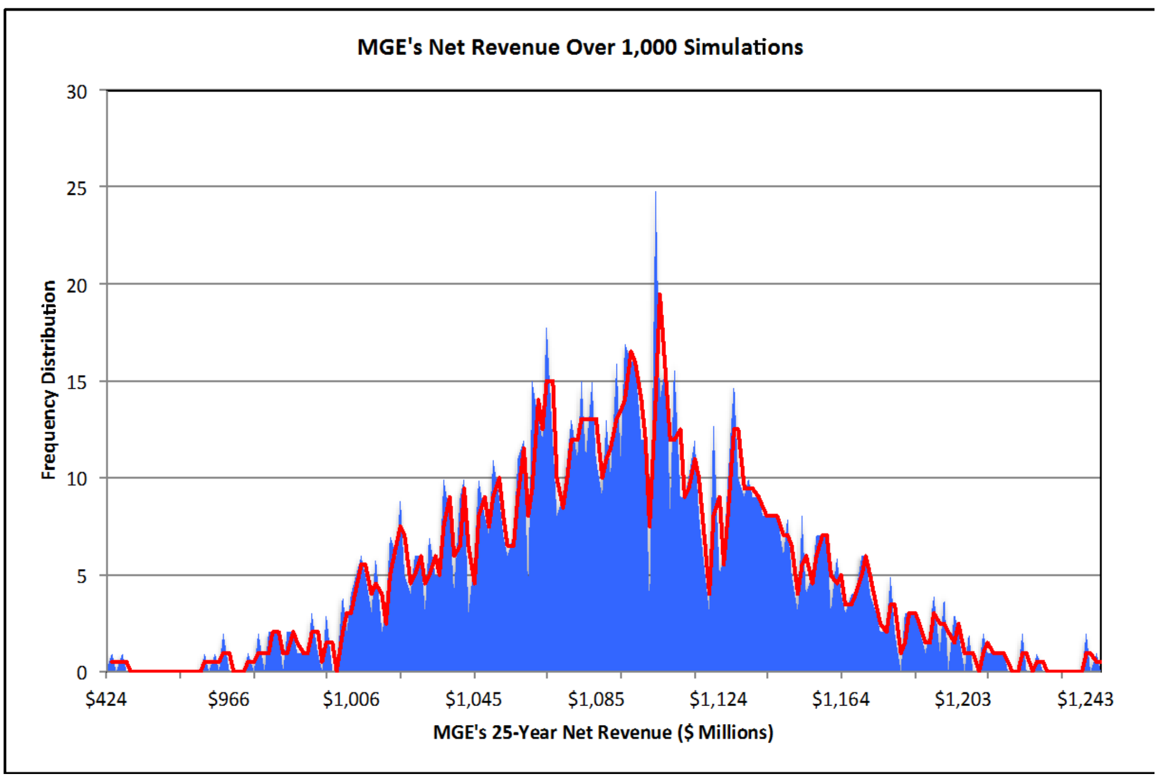


Figure J.12: Distribution of MGE's Net Revenue Under Scenario B (3% Industrial)



Appendix K: Limitations & Areas for Future Research

Due the software limitations of Microsoft Excel (compared to a more sophisticated energy modeling tools), MoDERN does not capture all of the complex processes that shape power markets with complete accuracy. For example, MoDERN uses average hourly capacity factors for solar power to estimate annual electricity generation during on and off-peak hours. However, actual generation can fluctuate widely every 5 to10 minutes depending on weather conditions, which means the microgrid owner may be forced to purchase some power during on-peak times even though the system was designed to generate enough power to cover the customer's full demand. The variability of solar energy is reflected by the use of a range of capacity factors in the Monte Carlo component of MoDERN.

Battery storage was not included in the MoDERN model for Madison because it serves as both a source of power generation and a load that consumes electricity. Without having precise, hourly power usage data from MGE, I did not feel comfortable including battery storage in MoDERN. The technologies reviewed in Appendix L are also very capital intensive and would dramatically increase the cost of each microgrid. However, battery storage could become a vital component of future microgrid systems if prices continue to decline. Storage systems would smooth the shape of intermittent renewable generation and help prevent microgrid owners from purchasing power when generation drops due to poor weather conditions.

The method for calculating the benefit of avoided power outages and power quality disruptions (i.e. voltage surges) could be expanded. The method simply assumes that each customer would experience an average outage of 30 minutes, based on MGE's annual report, with an associated cost of lost economic production based on surveys performed by EPRI and the Lawrence Berkeley National Laboratory. A more robust analysis could assign probabilities to different outage lengths in each year with a range of costs associated with each outage length. Electronic equipment could also be damaged from power surges that would be eliminated by the microgrid's sophisticated power electronics. Creating a more detailed model for the potential benefits associated with reduced outages and improved power quality require the use of more advanced engineering tools that I did not have access to.

Appendix L: MoDERN Tool Calculations & User Guide

We constructed a comprehensive spreadsheet tool using Microsoft Excel that serves as the basis for our cost-benefit calculations. The tool allows the user to input different values for a wide range of variables that affect the project's financial viability and net social benefits. This document serves as a guide to using the Excel tool and explains our calculations. The Excel calculations were cross-referenced with results from STATA calculations that accompany the Excel-based calculations.

The main tab the user will work with is the 'MG Tool' tab located at the far left of the scrollbar. All cells highlighted in yellow can be changed by the user to customize their microgrid size, system components and annual electricity use. Cells C5-C19 contain the first set of user inputs as illustrated in figure 1 below:

Figure L.1: Screenshot of User Input Cells in 'MG Tool' Tab

Microgrid Variable Inputs		Cells are user inputs
Scenario (Urban/Rural)	Urban	
Electric Utility	MGE	
** Not yet tied to Test CBA Tab **	User Inputs	Maximum
Discount Rate	3.00%	7.00%
Electricity Rate Increases (%/yr)	0.00%	6.00%
Inflation Rate (%/yr)	2.00%	5.00%
Microgrid System Size (kW)	500	500
Max Consumption (kWh/yr)	4,380,000	8,760,000
Annual Consumption (kWh)	1,095,000	8,760,000
Summer Load Factor (actual kWh/max kWh)	25%	100%
Electric Consumption Variance (% of baseline/yr)	80%	120%
Winter Load Factor (actual kWh/max kWh)	25%	100%
Natgas Price Increase (% of current price)	-50%	200%
Off-Peak Power Purchased (%)	100%	100%

Once the user has entered values in these cells, they can move on to the next set of variables located in cells C23 through D31. These cells allow the user to modify the size and number of generation sources that will provide electricity to the microgrid. Based on these inputs, cells F23-F31 will display annual power generation, cells G23-G31 will show total capital cost and cells H23-H31 will show annual O&M costs. A screenshot of the user interface is shown below in figure 2.

Figure L.2: Screenshot of Generation Input Cells in 'MG Tool' Tab

Microgrid Components	Unit Size	Number
Solar PV (kW)	590	1
Small Wind (kW)	100	0
Biogas Generator (kW)	0	1
Capstone CR30 Mictroturbine (kW)	30	0
Capstone CR65 Mictroturbine (kW)	65	0
Capstone CR200 Mictroturbine (kW)	200	0
600 Amp Static Switch	1	1
EMS, Smart Meter and System Controls	1	1
Construction Costs ($/ft^3)	$18.00	10,000

Cells C37-C41 show how much electricity is generated by the microgrid, how much electricity is purchased from the utility. The associated cost savings are displayed in cells D37-D41. Cells E37-G41 show the mean. Minimum and maximum values from 1,000 Monte Carlo simulations pulled from the 'Monte carol' tab. Cells D45-G63 show the mean, minimum and maximum results of all benefit categories pulled from the 'Monte carol' tab.

Cells D65-D67 show the net present value of benefits drawn from the test case results in the 'Test CBA' tab for our three stakeholder tiers. The mean, minimum and maximum values from the 'Monte carol' tab toggle based on the dropdown value (Tier I, Tier II or Tier III) in cell B68. Selecting "Tier III" will populate the Monte Carlo results in cells E67-G67, selecting Tier II will populate cells E66-G66 and selecting Tier I will populate cells E65-G65. A screenshot of these cells is shown in figure 3 below:

Figure L.3: Screenshot of Monte Carlo Results in 'MG Tool' tab

Tier I (Fiscal Net Benefits)	-$487,545.51	-$437,794.94	-$766,776.65	-$122,116.85
Tier II (MG & Utility Net Benefits)	-$463,906.14	-	-	-
Tier III (Net Social Benefits)	-$869,011.87	-	-	-
NPV Tier I	From Test CBA	Pulled from Monte Carlo Results (monte carlo tab)		

* The $/year values remain fixed because they are the baseline values that the Monte Carlo simulation is based on

Cell D71 calculates the net present value of benefits simply attributed to installing a microgrid system at a project site that already has existing generation equipment. It compares the cost of power electronics (smart switch, smart meter, user interface and construction costs) against the benefit of avoided power outages. The user can select different values for the avoided cost of power outages in cells E120 to perform their own sensitivity analysis.

Cells C78-C87 allow the user to change the project financing variables. Selecting "No" in cell C78 will run the cost-benefit calculations assuming that all capital costs will be paid upfront without loan financing. Selecting "Yes" will tell the tool to run calculations using loan financing according to the user's inputs in the following cells. Cell C79 is the percentage of the total capital cost that will be paid upfront and cell C82 is the loan interest rate (which is adjusted to a real interest rate based on the inflation percentage entered in cell C11). Cell C85 will calculate the annual loan payment and automatically change the Tier I, Tier II and Tier III results displayed in cells D65-G67. Cell C87 allows the user to input a value for external financing (government loans, private financing etc) to decrease the amount of capital costs paid by the project developer. A screenshot of the financial input cells is provided below in figure 4.

Figure L.4: Screenshot of Financial Input Cells in 'Test CBA' Tab

Financial Inputs	
Is the project financed with a loan?	Yes
Loan Downpayment (% of total costs)	20%
Amount Financed	-$1,695,215.20
Loan Term (years)	20
Loan Interest Rate (%)	7.00%
Inflation (%) to Calculate Real Rate	2.00%
Inflation Adjusted Rate (%)	4.90%
Annual Loan Payment	-$134,899.98
Include Omitted Tier II Benefits?	No
External Funding ($)	$0.00
Social Cost of Carbon ($/ton)	$35.00
Carbon Price Growth Rate (%/year)	2.10%
Hold CO2 Price Constant?	No

The green cells in the 'Test CBA' tab are directly tied to the user inputs in the 'MG Tool' tab. This tab runs the calculations that create the test case, which serves as the basis for the 1,000 Monte Carlo simulations in the 'Monte carol' tab. The user can also select the social cost of carbon, the annual carbon price growth rate and whether or not they would like to hold the carbon price constant in the Monte Carlo analysis. A screenshot of the cells tied to the 'MG Tool' user input cells is provided in figure 5 below.

Figure L.5: Screenshot of User Input Cells in 'Test CBA' Tab

		Cells are tied to MG Tool user input cells	
	Minimum	Maximum	
Discount Rate	3.00%	7.00%	
Electricity Rate Increases (%/yr)	0.00%	5.00%	
Inflation Rate (%/yr)	2.00%	5.00%	
Max Load (kW)	500	<--- User Defined	
Max Consumption (kWh/yr)	4,380,000	4,380,000	<--- Max Load*
Annual Consumption (kWh)	**1,095,000**	**4,380,000**	<---- lock cells
Summer Load Factor (actual kWh/max kWh)	25.00%	100.00%	Actual kWh/Ma
Electric Consumption Growth (%/yr)	0.00%	5.00%	
Winter Load Factor (actual kWh/max kWh)	25.00%		
Wind Capacity Factor (%)	10.00%	30.00%	
Natgas Price Increase (%/yr)	0.00%	10.00%	
Off-Peak Power Purchased (%)	100%	100%	
Loan Rate/Real Rate (%)	7.00%	4.90%	
Loan Term (years)	20	20	
Net Metering Sales (kWh/yr @ $0.07/kWh)	$24,323.61	$367,261.86	
** SCENARIO CHOICE **	Urban		

Here the user can change the discount rate, annual electricity rate increases, the size of the microgrid (kW), the average annual load factor (average load / max load), capacity factors for renewable energy sources, off-peak power purchases and loan borrowing terms. To begin creating a microgrid scenario, the user will select a size (kW in cell B6), which then automatically calculates the maximum annual consumption (kW * 8,766 hours per year). The Annual consumption is calculated by multiplying the maximum consumption by the load factor, which can be selected in cell B9. We used feeder line data provided by MGE to distribute energy consumption over the different on and off-peak periods using the 'CALCULATIONS' tab. That tab applies observed capacity factors across the different times of day by weighting certain periods more than others, but the total amount of electricity consumption will equal the value in B8.

Avoided Electricity Purchases

This is the most important benefit category for the microgrid customer. Our tool is set up so that the microgrid's generation sources will offset all of the customer's on-peak demand. The total cost of on and off-peak power purchases is found by multiplying the total annual consumption by the appropriate time-of-use rate (cells E23-E30, and the associated load factor from the 'CALCULATIONS' tab. Cells J31 shows the total annual power purchases under the MGE rate structure under the baseline scenario where the customer purchases all of their power from the macrogrid.

Cell F3 calculates the total amount of on-peak purchases avoided by using the microgrid's generation resources (summing cells J24-J26 and J28-J30. Cell F4 sums the total amount of off-peak consumption (kWh), cell F5 sums the total amount of off-peak purchases. Cells F6 and F7 calculate the amount of avoided off-peak consumption (kWh) and purchases by multiplying total those sums by the user-defined amount of off-peak power they wish to offset (the percentage in cell B14). So, if the user selects 100% in cell B14, the avoided off-peak purchases will be $0 because they will purchase all of their off-peak power from the utility. Avoided off-peak consumption and purchases will increase as the percentage in cell B14 is reduced because the customer will be using more microgrid generation to replace power purchases from the utility. Cell F9 sums the total avoided costs each year, which are then projected forward over 20 years in cells P102-AJ102. The total avoided power purchases are also multiplied by the value in cells Q20-AJ20, which varies, based on the user selected percent change in electric power rates (user input cell B4). This method assumes that all time-of-use rates change by a uniform rate.

Figure L.6: Screenshot of Main Calculation Cells in the Excel Tool

hours	Year 1	Total/NPV	
On-Peak Demand Avoided (kWh)	380,025	7,600,496	
On-Peak Costs Avoided	$96,023.02	$1,428,580.11	
Off-Peak Demand (kWh)	571,980	11,439,604	
Off-Peak Purchases ($)	-$41,691.64	-$775,332.82	
Off-Peak Avoided Consumption (kWh)	142,995	2,859,901	
Off-Peak Costs Avoided	$10,422.91	$0.00	
Total Avoided Power Purchases (kWh)	523,020	10,460,396	<--- Amount of MG generation needed
Total Avoided Costs ($)	$106,445.93		
Total Renewable Generation (kWh/yr)	665,339	13,306,788	
Generation Gap/Surplus (kWh/yr)	-142,320	(2,846,392)	
Percent Renewable Generation	127.2%		
Tons of CO2 Avoided/yr	586	11,711	
Tons of SO2 Avoided/yr	0.64	13	
Tons of NOx Avoided/yr	0.43	9	
WI eligible RECs/RRCs generated	665	13,307	
Loan Financed?		No	
Net Fiscal Benefits		$463,457.27	

	Year 1	Total/NPV
Social Cost of Carbon ($/tonne)	$35.74	
Avoided CO2 Costs	$21,143.43	$368,396.88
Avoided Capacity Costs ($/yr)	$37,134.41	$569,040.20
Avoided T&D Costs ($/yr)	$8,258.48	$126,551.33
Avoided Ancillary Services ($/yr)	$1,064.46	$16,311.56
Avoided T&D Losses ($/yr)	$806.63	$12,360.59
LCOE for MG Generation ($/kWh)		$0.18
LCOE for MG Operation ($/kWh)		$0.24

Changing Microgrid Generation Sources

Once the user has input values to determine total annual consumption, microgrid size and the amount of off-peak consumption they wish to avoid, they can begin adding generation sources in cells D45-D91 that are highlighted in green. Changing these cells adds wind turbines (cells D45, d48 and D51), natural gas-fired microturbines (cells D55, d61, D67), solar PV (cell D73), biogas digesters (cell D77), batter storage (cells D85, D88 and D91). When those cells are left with zero values, they will not pull any information from the 'Genset' tab and produce zero values for cost and generation (kWh). For the urban case, we determined that solar PV and natural gas microturbines were the only viable generation technologies, but installing a 550kW solar PV array would cover all of the customer's on-peak and some off-peak demand. Under the urban case, the 550kW system size is multiplied by a marginal capital cost factor of $3,930/kW to generate total capital costs, and an annual marginal O&M cost of $20/kW for annual costs for $11,000.

The user can change capacity factors for wind and solar (which are intermittent), but we held them constant at 24% for wind and 14% for solar PV based on the results of studies done by NREL and DOE. Our Monte Carlo analysis allowed the capacity factors of wind and solar to vary in order to model the unpredictable nature of these renewable energy sources. Cell F10 sums the total amount of renewable generation (from wind, solar, biogas and battery storage) and cell F11 shows the total shortage or surplus of microgrid generation to meet the user's on-peak and off-peak demands.

Net Metering Sales and REC Sales

A negative value in cell F11 means the microgrid is producing excess energy that could either be used to offset off-peak demand by reducing the percentage value in cell B14, or selling the excess generation back to the utility at the net metering rate (we used the off-peak rate for MGE). Cell B17 calculates the value of annual net metered sales by multiplying the amount of excess generation by MGE's off-peak electricity rate. Renewable energy certificates (RECs) represent 1MWh (1,000kWh) of electricity generated by qualifying renewable energy sources under Wisconsin RPS law. Utilities must meet RPS obligations by building their own renewable generation or by purchasing RECs from renewable projects owned by at third party. The microgrid customer could apply to become a registered REC generator with the PSC if the microgrid utilizes wind, solar or biogas generation. Deb Erwin of the Wisconsin PSC said prices for Wisconsin RECs are around $1/MWh, which is the same price as RECs sold into the voluntary Green-e market.

Cell F16 simply divides the total renewable generation in the microgrid by 1,000 to come up with the number of RECs the system will generate each year. That value is then applied across cells Q112-AJ112 and multiplied by the REC price (in this case $1/MWh) to calculate the net present value of REC sales over a 20-year period. Microgrid revenue could increase if REC prices rise above $1/MWh but we determined that was unlikely because the Wisconsin RPS is already oversupplied and not very aggressive. The voluntary Green-e REC market is also over supplied and prices are not expected to rise above the $1/MWh level.

Avoided CO_2 Emissions

Cell F13 calculates avoided CO_2 emissions by multiplying the amount of renewable generation in the microgrid system (cell F10) by the CO_2 intensity (tons/kWh) of the Wisconsin generation fleet (average value is 0.0009 tons/kWh found in cell L83 of the 'Emissions Pricing' tab). The value of avoided CO2 emissions is calculated in cells Q103-AJ103 by multiplying the amount of CO2 avoided (tons/year) by the federal government's official social cost of carbon. The social cost of carbon was set at $35/ton in 2012 and increases by 2.1% annually. The increasing social cost of carbon is incorporated in cells Q103-AJ103 and discounted to a net present value in cell O103 using the selected discount rate selected in cell B3.

Avoided SO_2 Emissions

Cell F14 calculates avoided SO_2 emissions by multiplying renewable generation by the SO_2 emissions intensity (tons/kWh) of the Wisconsin generating fleet (found in cell F83 of the 'Emissions Pricing' tab. This figure is then multiplied by the price of SO_2 allowances issued under EPA's Acid Rain Program to determine the value of avoided compliance costs for MGE. SO_2 allowance prices are set at $1.50/ton according to the most recent daily settlement prices taken from the IntercontinentalExchange (cell B21 of the 'Variables' tab). Allowance prices spiked to over $2,000/ton in the mid-2000's due to regulatory uncertainty, but we held prices flat at current levels for this analysis. A spike in allowance prices could drastically change the net benefits to MGE. The net present value of avoided SO_2 compliance costs are calculated in cell O104. The avoided social costs of reducing SO_2

emissions are calculated in cells Q119-AJ119 by multiplying the value in F14 by a user selected price located in cell E119. The different values for avoided SO_2 emissions are drawn from EPA studies and David Weimer's textbook (page 400 something). We used the figures in Weimer's textbook for our analysis.

Avoided NO_x Emissions

Cell F15 calculates avoided NO_x emissions by multiplying renewable generation by the NO_x emissions intensity (tons/kWh) of the Wisconsin generating fleet (found in cell H83 of the 'Emissions Pricing' tab. This figure is then multiplied by the price of NO_x allowances issued under EPA's Acid Rain Program to determine the value of avoided compliance costs for MGE. NO_x allowance prices are set at $40/ton according to the most recent daily settlement prices taken from the IntercontinentalExchange (cell B22 of the 'Variables' tab). Allowance prices spiked to over $3,000/ton in the mid-2000's due to regulatory uncertainty, but we held prices flat at current levels for this analysis. A spike in allowance prices could drastically change the net benefits to MGE. The net present value of avoided NO_x compliance costs are calculated in cell O105. The avoided social costs of reducing NOx emissions are calculated in cells Q120-AJ120 by multiplying the value in F15 by a user selected price located in cell E120. The different values for avoided SO_2 emissions are drawn from EPA studies and David Weimer's textbook (page 400 something). We used the figures in Weimer's textbook for our analysis.

Avoided Capacity Costs

Cell J4 calculates the avoided investments in new generation capacity by MGE that are offset by microgrid generation. This value is found by multiplying the microgrid's annual generation (kWh) in cell I94 by a cost factor of $0.071/kWh that was reported by DOE in the agency's 2013 Energy Storage Guidebook. The cost factor is the marginal cost of building a new natural gas combined cycle power plant, which is the typical type of new generation built by utilities to meet growing customer demand.

Avoided Transmission & Distribution Costs

Cell J5 calculates the avoided investments in transmissions and distribution infrastructure by MGE that are offset by microgrid generation. This value is found by multiplying the microgrid's annual generation (kWh) that is used onsite (sum of cells F2 and F6) by a cost factor of $0.01579/kWh. The cost factor was found in a report by the Midwest Independent Systems Operator (MISO) that described the marginal cost of T&D investment and upgrades that could be avoided by privately developed microgrids that serve as an independent distribution system. The cost factor was not applied to microgrid generation that is sold through net metering agreements because that electricity will still utilize the existing T&D network, which carries O&M costs.

Avoided Ancillary Services Costs

Ancillary services include voltage and frequency control to maintain grid stability and several forms of capacity reserves. Utilities incur costs to provide these vital services that are not directly sold to end use customers, but are crucial in supporting the overall electric grid. MISO operates day-ahead markets for ancillary services with prices that range from $0.20-$20/MWh. It was unclear which price we should apply to our analysis so we deferred to a simple method used by the California Independent System Operator where the value of ancillary services is calculated by taking 1% of the customers total consumption. In our case, the microgrid provides ancillary services to the customer during all on-peak and some off-peak hours so the value of avoided ancillary services is calculated by multiplying the microgrid's total avoided costs (F3 plus F7) by 1%.

Avoided Transmission & Distribution (T&D) Losses

Cell J7 calculates the value of avoided T&D losses by multiplying the microgrid's total onsite consumption (kWh) by MISO's wholesale electricity cost ($/kWh). According to Martin Day, MGE's director of forecasting and marketing, about 5% of the power generated by the utility's power plants is lost during delivery to end-use customers. Microgrid losses have been shown to be as low as 1-2%. Therefore MGE avoids the cost of generating excess electricity to transmit over the T&D system because microgrids provide generation in such close proximity to demand that losses are minimized. We multiply total microgrid avoided consumption (cell F8) by 1.05 and then subtract F8 to find the amount of excess power the utility would have to produce or purchase from the MISO market in order to cover line losses. That value is then multiplied by the 12-month average MISO wholesale price found in cell C16 of the 'Electricity Prices' tab. The net present value of these avoided losses are discounted using the user defined rate in cell B3 in cell O111.

Value of Distributed Generation as a Hedge Against Price Volatility

This value is calculated for years 0.5 through 19.5 (cells Q124:AJ124) by multiplying total renewable generation (solar, wind, biogas, battery storage) in cell F10 by a cost factor that the user can select from a drop down menu in cell E124. The cost factors range from $0.0055/kWh to $0.06/kWh based on a review of studies from NREL and the CEC. The net present value of fuel hedging is calculated in cell O124 but it is not included in any of our cost-benefit calculations.

Avoided Power Outage Costs

In addition to avoiding power purchases during expensive on-peak hours, microgrids offer increased reliability and power security from extreme weather and other causes of blackouts, power surges and other grid related problems. Microgrids can operate independently from the grid during outages and therefore prevent costs associated with damaged equipment or lost economic activity. These avoided costs can be significant for certain critical industries (i.e. healthcare, electronic financial trading and commercial businesses that rely on electronic credit card payments). To monetize the value of avoided power outages, MGE reported information about the annual risk and duration of power outages. MGE reported that customers experience a 30 minutes outage every two years. Information from an EPRI survey of medium sized commercial and industrial businesses is used to place value on the cost of each outage event. The value for the 30-minute outage (cell E117) can be set at either $4,750 or $15,709 and the 90-minute outage (cell E118) can be valued at either $11,549 or $36,099. The present value of avoided outages are discounted by the rate in cell B3 to calculate net present value in cells O117 and O118.

Salvage Value of Microgrid Equipment

The salvage or horizon value of the microgrid equipment (solar panels, wind turbines etc) is calculated in cell O110 using a 10% depreciation rate over the 20-year lifetime of the microgrid project. The 10% depreciation rate was taken from David Weimer's CBA textbook.

Federal Investment Tax Credit

Cell O113 calculates the one time federal investment tax credit (ITC) for qualifying renewable energy equipment. The one-time credit is equal to 30% of the cost of small wind turbines, solar PV and anaerobic digesters. There is no maximum limit for wind turbines installed after December 31, 2008. Microturbines can earn a 10% ITC with a limit of $200/kW calculated in cell O114.

Federal Production Tax Credit

Cell O115 contains the net present value of annual production tax credits (PTC) discounted over the microgrid's 20-year lifetime. The federal PTC pays 2.3 cents/kWh of generation produced by wind turbines, geothermal electric generators and closed-loop biomass systems. The PTC for electricity generated by anaerobic digesters is 1.1 cents/kWh. Both PTC levels can be reported for the first 10 years of a project's operational life. Cells Q115-Z115 calculate the annual PTC by multiplying the total generation (kWh) produced by wind and anaerobic digesters by the appropriate payment level. Soar electricity is not eligible for the federal PTC. Under Tier III analysis, the PTC is taken out of the benefit category and replaced with an METB calculated using a range of $0.20-0.30 per $1 of the tax rebate to reflect uncertainty and incomplete research into the appropriate METB rate.

Wisconsin Renewable Rebate Tax Credit

Wisconsin's statewide Focus on Energy program includes rebates for solar PV systems larger than 0.5kW equal to $600/kW with a maximum amount of $2,400. The program has been suspended for the remainder of 2013 because all funds have been disbursed, but we applied the $2,400 maximum amount to our urban case study (which uses 550kW of solar PV) in 2014 when the program will restart. The value of the rebate is discounted at the rate in cell B3 to calculate a net present value in cell O116.

Construction Costs

Cells C31-G31 in the 'MG Tool' tab calculate the construction cost for building the microgrid that are not included in the installed costs of the generation equipment. The construction costs encompass wiring and installation of the microgrid power electronics and system controls. We used a construction cost coefficient of $18/square foot included in the feasibility study for the GXM. We assumed the microgrid equipment would cover 180,000 square feet for a total cost of $180,000 above the baseline construction costs.

Loan Financing Costs

For both urban and rural case studies, we assumed that the microgrid developer would either pay for all capital costs upfront (no loan financing), or pay 20% down payment in year one followed by fixed loan payments over the next 20 years at an interest rate set by the user in cell B15. Total capital costs in cell L95 are multiplied by 20% to set the down payment amount in cell P97. The remaining balance is financed by the 20-year loan in cells Q98-AJ98 with the net present value of the annual payments calculated in cell O100. The annual payment amount is calculated using the follow formula:

(Principal in cell O98*interest rate in cell B16)/(1-(1+interest rate)^- loan term in cell B16

The value in O122 represents the financial net benefits (Tier I) without loan financing while the value in cell O123 represents the net present value of benefits with loan financing. Loan financing reduces net benefits by adding the cost of interest payments. Cell O126 represents net benefits to the utility (Tier II) with loan financing and cell O129 represents the net benefits to society (Tier III) with loan financing. Cells O125-O126 and O128-O129 do not subtract avoided electricity purchases from the Tier II net benefits calculation to show how net benefits can be dramatically increased under a policy framework that decouples utility revenue from electricity sales using a cost per customer approach.

Monte Carlo Analysis ('monte carlo' tab)

The results of Monte Carlo analysis for Tier I, II and III are contained on the 'Monte Carlo' tab of the Excel Tool. In this tab, the cost/benefit categories contained in the rows of the 'Test CBA' tab are transposed in columns to facilitate multiple tests using randomized variables. The randomized variables are included in cells D1-I10 (listed below):

CO_2 intensity of WI generation fleet (tons/kWh): Ranging from 0.0004-0.0018
Wind Capacity Factor (%): Ranging from 10% to 30%
Solar Capacity Factor (%): Ranging from 12% to 16%
Biogas Capacity Factor (%): Ranges from plus/minus 20% centered around 83%
Natural Gas Prices (% of current levels): Range from 50% to 200% of current levels
Demand Changes (% of current levels): Range from 80% to 120% of current levels
Marginal Excess Tax Burden: Range from $0.20 to $0.30
Social Cost of CO_2: Ranges from $1.90/ton to $100/ton

Fixed variables are included in cells J1-Q9 and are all pulled through from the 'Test CBA' page. Column BC calculates the net present value of the various Monte Carlo simulations. We decided to keep SO_2 and NO_x emissions intensity (tons/kWh) constant because of state and federal regulations that will prevent emissions from rising very far above current levels. If SO_2 and NO_x emissions decline, it would have only a marginal impact on the value of SO_2/NO_x allowances that utilities would avoid purchasing, but a larger effect on the avoided health and environmental impacts of avoided emissions. We also held the value of reducing SO_2 and NO_x emissions constant due to the wide range of values recorded in the scientific literature. We felt that using the values presented in Weimer's textbook reflect reasonable values that are echoed by EPA's technical support documents used during the development of its Cross-State Air Pollution Rule.

The user can look at the simulations for Tier I, Tier II and Tier III cost-benefit categories by using the drown down menu in cell B68 in the "MG Tool" tab. The Monte Carlo results are displayed in cells BC1053-1055. Row 1053 includes values designed to match the values calculated in the 'Test CBA' tab (pull through in row 1054) to make sure the calculations match. For the urban excel tool, all values match those from the 'Test CBA' tab EXCEPT Tier III because of rounding errors in the calculation/discounting of avoided CO_2. Cell BC1064 shows the difference between the Monte Carlo calculations and the "Test CBA" calculations (these are zero for Tier I and Tier II and less than 1% error for Tier III). Rows 1057-1060 display the average, minimum and maximum values from all of the Monte Carlo simulations.

Comparing Microgrid Scenarios Against the Base Case

In the 'Base Case Compare' tab, the base case scenario is shown in rows 14-62. It includes the NPV of sales from all three customer segments as well as fuel costs (row 59, based on the MISO wholesale price), environmental compliance (total kWh multiplied by the SO_2/NO_x factor and associated allowance prices), and a category of "all other costs" which make up the difference between retail sales and the other costs in order to earn a 10.3% ROI that is allowed by the Wisconsin PSC. The MG deployment case is shown below in rows 64-115 and also includes the same cost categories in rows 110—115 (with additional rows for microgrid O&M and financing).

Row 117 shows the net reduction in sales from the base case scenario to the microgrid deployment scenario. Row 118 shows MGE's gained benefits under the microgrid scenario (no costs). Row 119 shows MGE's total microgrid development costs (which are $0 under Scenario B because the third party developer is responsible for all microgrid development costs). Row 120 (MGE Net Benefits) shows the NPV of benefits gained from the deployment of microgrids against the costs of microgrid investment (so ROI is 100% in Scenario B because MGE reaps benefits without paying for any microgrid investment). Row 121 shows the NPV of MGE's sales under the microgrid deployment scenario and subtracts all costs (i.e. fuel cost, environmental compliance, MG O&M/financing etc) to display the financial health of the utility, NOT JUST the benefits associated with microgrid deployment.

Row 122 thus calculates MGE's ROI based solely on the benefits gained from microgrid deployment versus the costs of microgrid deployment and ignores the costs associated with providing electricity services not fulfilled by the microgrds (i.e. off-peak generation). Row 123 calculates MGE's ROI based on the NPV of benefits for their entire business operation (benefits based on the value in row 121 versus all costs). Cell B122 allows the user to select whether MGE counts the lost sales revenue as a cost in the ROI calculations. Excluding them returns a positive ROI while including them returns a typically large negative ROI because the lost sales are in the $1-$3 billion range over the 25-year evaluation period. I believe that excluding the lost sales is appropriate because it amounts to double counting costs that are intrinsically included in the calculation of retail sales using the user selected off-peak rate. The total in C80 reflects the lost sales due to microgrid deployment so subtracting the lost sales again as a separate cost amounts to double counting.

The microgrid deployment scenario represents a mutually exclusive situation whose benefits and ROI should be compared against the base case. The lost sales from the base case are simply a comparison of revenue under different business models and should not be counted as a cost against the microgrid deployment scenario being compared. Essentially, the sales, costs and fixed ROI (10.3% for the base case) should be COMPARED to the values for the microgrid deployment scenario and the differences between these values do not constitute costs on either scenario, merely a comparison. Counting lost retail sales from the base case versus the microgrid deployment case imposes an unfair comparison between two separate business models and simulated results.

Figure L.7: Screenshot of Results in 'Base Case Compare' Tab

	A	B	C	D	E
120					
121	MGE Sales Gap from Base Case	-$278,008	-$11,974,621	-	
122	MGE Gained Benefits	$2,988,196	$14,996,822	-	
123	MGE's Total MG Development Costs		-$14,396,948	-	
124	MGE Net Benefits (MG only)		$599,874	-	
125	MGE Total Costs		-$11,728,861,846	-$11,770,548,222	
126	MGE NPV Sales+Benefits-All Costs		-$442,054,668	-$481,853,955	
127	MGE ROI (MG Only)	Exclude Lost Sales	4.17%	-	
128	MGE ROI (Total Sales & All Costs)		-3.77%	-4.09%	
129	Ratepayer Net Benefits	$331,382	$107,334	-$11,974,621	
130	Third Party NPV Benefits		-	-	
131	Third Party ROI		-	-	
132	LCOE for all Customers ($/kWh)		$0.1110	$0.1111	
133					
134					
135	Generation Technology	Capacity (MW)	ieneration (kWh/yr	Capital Cost	Annual O&M
136	Solar PV	2.25	2,852,154	-$6,750,000	-$45,000
137	NG Microturbines	0.60	945,560	-$1,446,000	-$143,972
138	Wind	0.00	0	$0	$0
139	Biogas	0.00	0	$0	$0
140					

The combined results of each simulation (residential, commercial and industrial) are copied into a companion file that aggregates all of the results into a final summary.

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