
New Hampshire Public Utilities Commission
Comments Pursuant to Case # IR 15-296
Submitted September 17, 2015

Comments Regarding Electric Grid Modernization in New Hampshire
***The Importance of Including Analysis of Microgrids as a Key Technology for Improving
Grid Resiliency, Reliability & Integration of Distributed Energy Resources***

Submitted By

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General Comments

The dramatic decrease in the cost of solar photovoltaics (PV), coupled with the steady increase of retail electricity rates and price volatility of fossil fuels, has led to a surge of solar development in states like Arizona, California, Colorado, New Jersey and North Carolina. Minnesota, despite its low solar potential during the state's long winters, is pushing forward with aggressive plans to increase solar generation over the next decade (Farrell, 2014). These trends indicate that stand-alone solar PV is reaching grid parity for many residential and commercial customers across the nation (Shah, 2014). Coupling solar PV with microturbines, battery storage and advanced power electronics in a microgrid configuration can help utilities integrate intermittent renewables while offering a variety of other benefits that should be analyzed in IR 15-296.

Microgrids can produce additional benefits beyond energy and fuel cost savings that must be accounted for in regulatory proceedings and utility resource planning. If the value of increased power quality and reliability (PQ&R), reduced emissions, deferred investment in traditional generating capacity, and fuel price hedging are included in cost-effectiveness calculations, then microgrids may represent a viable alternative to traditional services offered by utility distribution companies (UDC). Microgrids may well represent a desirable pathway for utilities operating in regulated markets to incorporate disruptive technologies as a new source of revenue, rather than a threat, which industry analysts expect to induce a major restructuring of the U.S. electricity sector over the coming decades (Farrell, 2015).

Historically, many utilities have opposed the deployment of distributed energy resources (DER), efficiency programs, and demand side management (DSM), which reduce electricity consumption and sales revenue for utilities operating in most regulated markets. As solar PV, battery storage, electric vehicles and microgrids continue to gain popularity and market share, utilities must consider innovative business solutions to incorporate these disruptive technologies in ways that maximizes cost savings for ratepayers without reducing long-term profitability, or shifting costs to customers receiving basic electricity services. I have conducted extensive research in the area of microgrid cost-benefit analysis and the application of traditional regulatory cost-effectiveness tests to evaluate microgrids against traditional generation and electric grid investments. The New Hampshire PUC should consider an in-depth analysis of microgrids as part of the IR 15-296 "Grid Modernization" including the following study areas:

- **Regulation & Policy**
- **Interconnection Standards**
- **Contracting Risk**
- **Prospective Microgrid Capacity**
- **Renewable Microgrid Prospects**
- **Development of a Microgrid Policy Roadmap**

These study areas are discussed in greater detail on the following page, and a summary of my own microgrid study results are included as an addendum.

New Hampshire Microgrid Feasibility Study Framework

The New Hampshire PUC should commission a study as part of the IR 15-296 “Grid Modernization” proceedings to identify regulatory barriers to and opportunities for microgrid development that can provide improved power quality and reliability, reduced emissions, integration of renewables, and increased customer control over energy consumption. The study should also provide recommendations to address barriers and identify pathways to facilitate microgrid development.

Regulation & Policy: Review applicable State, Federal, and regional laws, regulations, rules, incentives, siting and permitting requirements, and practices affecting microgrid development, ownership, and operation. Analyze policies and policy gaps, and discuss how they prohibit or discourage microgrids, or, conversely, how they support microgrids.

Interconnection Standards & Practices: Identify New Hampshire standards and practices involving interconnection, interoperability, and control of distributed energy resources. Compare and contrast these policies with the most current federal and industry standards. Identify differences affecting microgrid development and optimization in utility systems.

Contracting, Risk Assessment, and Financing: Discuss how traditional contracting, risk assessment, and financing practices apply to microgrids. Analyze New Hampshire policies that affect microgrid development, valuation, and access to third-party capital.

Prospective Microgrid Capacity: Research and model potential electric load available to microgrids within the state of New Hampshire. Segment potential load by user groups. Discuss assumptions and limiting factors affecting derived potential capacity, as well as such factors as fuel supply and access to infrastructure.

Renewable Microgrid Prospects: Identify renewable resources in Minnesota potentially available for use in microgrid applications. Discuss relevant trends in technologies and resource options, and examine economic and operational factors influencing prospects for renewable microgrids in New Hampshire.

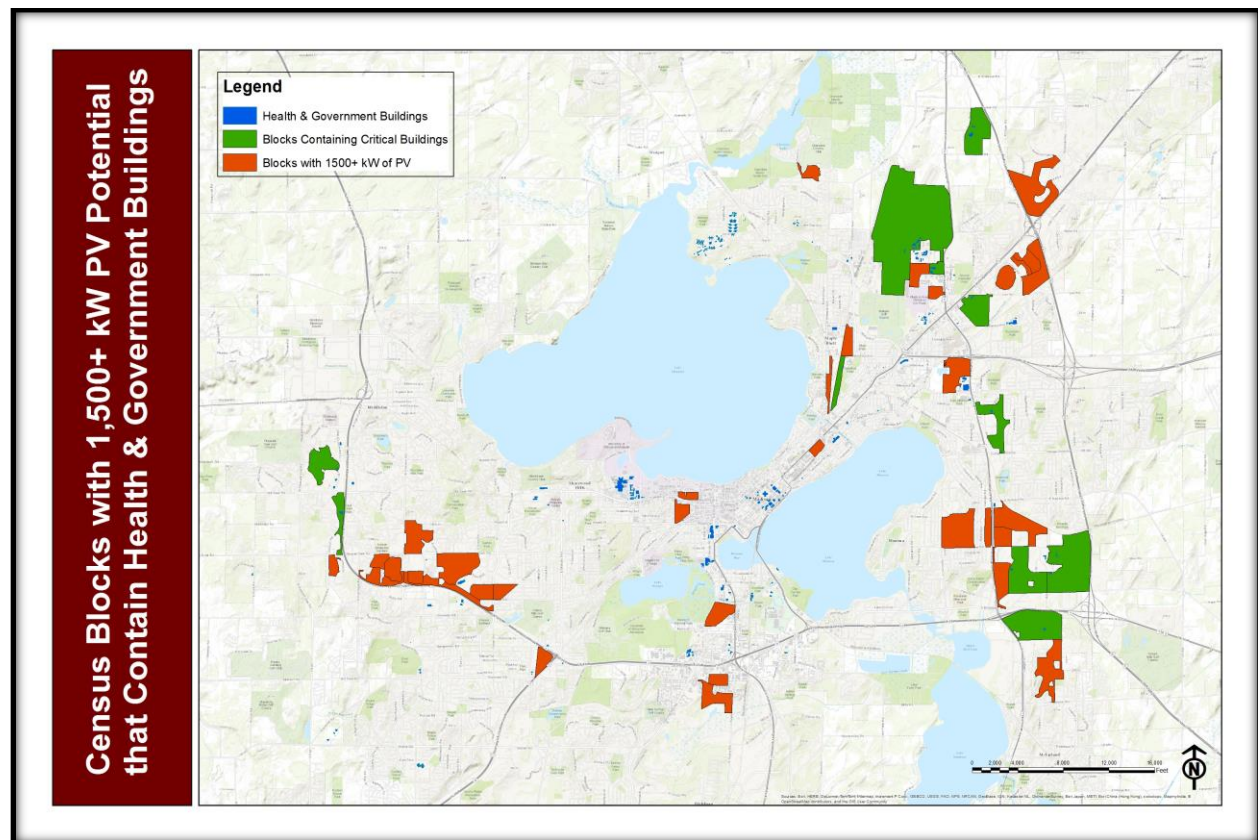
Microgrid Policy Roadmap: Recommend and explain policy steps that would help capture the benefits of microgrid development for Minnesota residents, and assist in their safe, cost-effective implementation and integration into the utility system.

This suggested framework is based on a study commissioned by the Minnesota Department of Commerce in 2013 ([link](#)). Completing a comprehensive study of microgrid opportunities, barriers, and economic conditions in New Hampshire will help the state keep pace with regional neighbors like Connecticut and New York who have already implemented microgrid development programs. The New Hampshire PUC can facilitate the microgrid study process by promoting collaboration between regulated utilities, ratepayer advocacy groups, and consulting firms selected through a competitive bidding process.

Summary of Wisconsin Microgrid Research

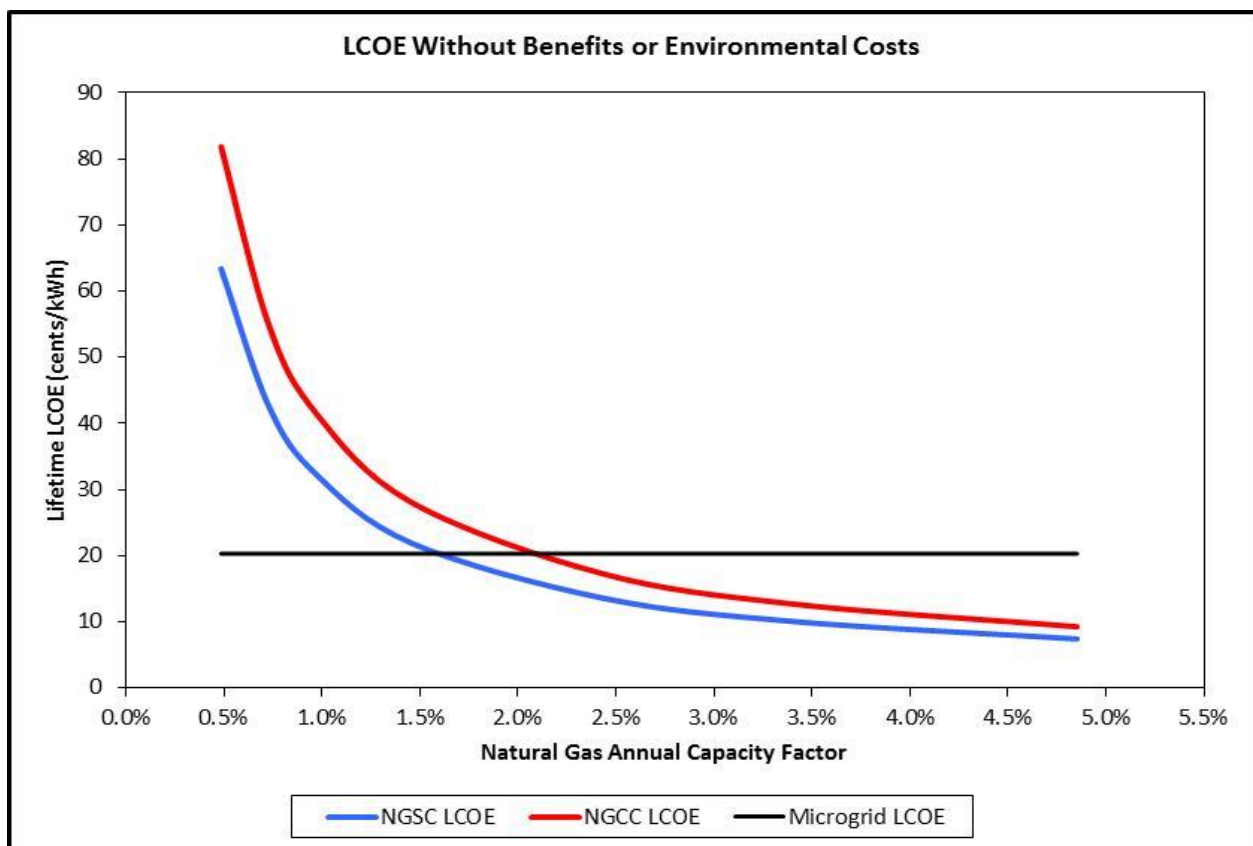
Research completed at UW-Madison with support from the Wisconsin Distributed Resources Collaborative (WIDRC), and the Wisconsin Energy Institute (WEI) shows that microgrids can deliver positive net benefits to electricity customers, the host electric utility, and society at large, under certain scenarios.

The study quantifies the costs and benefits associated with using microgrids as the main technology to promote distributed renewable electricity generation in Madison. A multi-stakeholder analytical process was employed to evaluate cost-effectiveness from the perspective of electric ratepayers served by microgrids, the local electric utility, ratepayers not served by microgrids, and electric utility regulators. The cost-effectiveness methodology combines the use of existing geographic information systems (GIS) software, and the Model for Distributed Energy Resource Networks (MoDERN), which was developed specifically for analyzing utility distribution microgrids. GIS analysis determined that there were 45 locations in Madison capable of supporting at least 1,500kW of rooftop solar PV capacity, while 11 of those locations also contain critical facilities (health and government buildings) that would benefit from improved power quality and reliability offered by microgrids. The map below shows the location of these potential microgrid development sites (green areas are sites that contain health and government buildings).

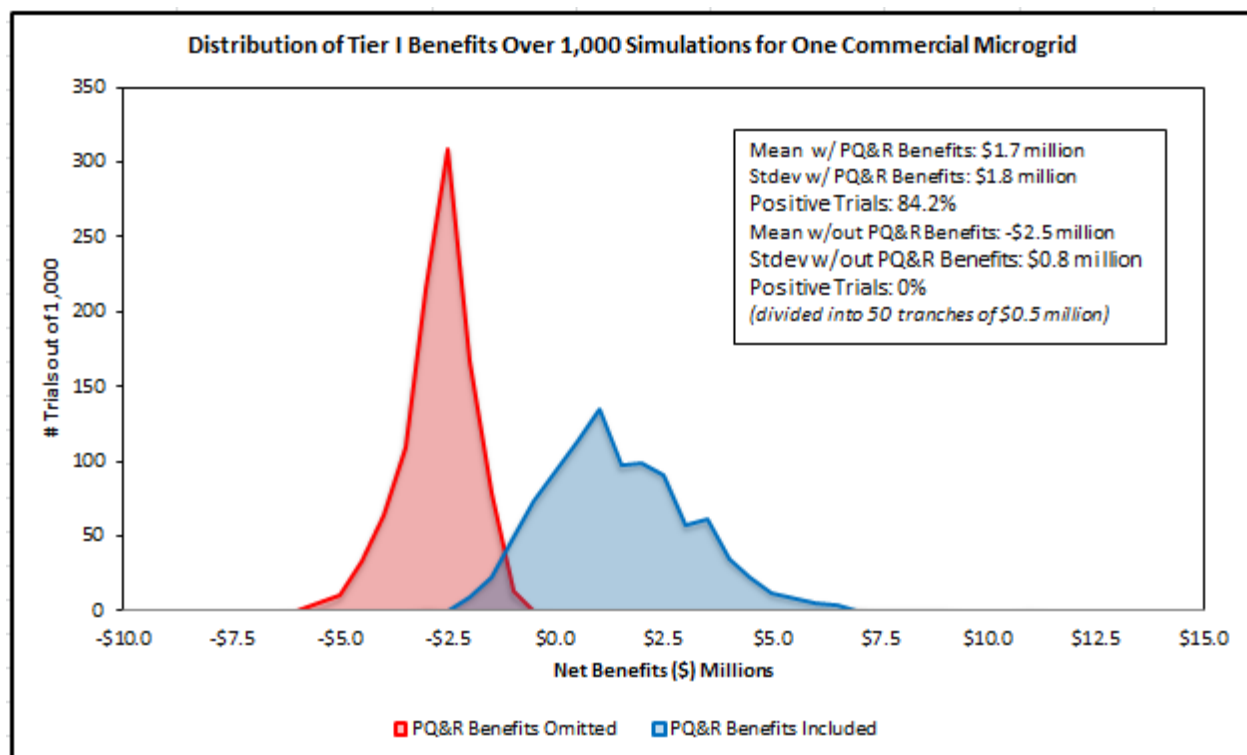


The study evaluated six microgrid deployment scenarios using widely accepted cost-effectiveness metrics developed by the California Public Utilities Commission (CPUC). The six deployment scenarios are; 1.5% and 3% of annual electricity demand in the residential, commercial and industrial sectors based on 2012 data obtained from the U.S. Energy Information Administration (EIA). Using a standard microgrid configuration consisting of 750kW of rooftop solar PV and one 1,000kW natural gas microturbine, it was determined that the 45 potential microgrid sites with at least 1,500kW of solar PV potential could support each of the microgrid deployment scenarios. Each microgrid system was estimated to cost \$8.5 million with annual operations and maintenance costs of \$250,000-\$350,000.

Over a 25-year analysis period, the levelized cost of electricity (LCOE) for one hypothetical microgrid system was found to be 17-19 cents/kWh, compared to 30-40 cents/kWh for a natural gas-fired peaking unit operating at an annual average capacity factor of 1% (based on a comparison with a 25MW unit that operates roughly 50 hours each year to meet extreme peak demand). This comparison does not account for the added benefit of increased power quality and reliability delivered to microgrid customers, which would decrease the microgrid's lifetime LCOE. This analysis shows that microgrids represent a lower cost, and less emissions intensive, alternative to building traditional power plants. However, baseload power plants that operate at much higher capacity factors are still cheaper than microgrid systems, with LCOE's ranging from 4-8 cents/kWh (Utah University, [link](#)).

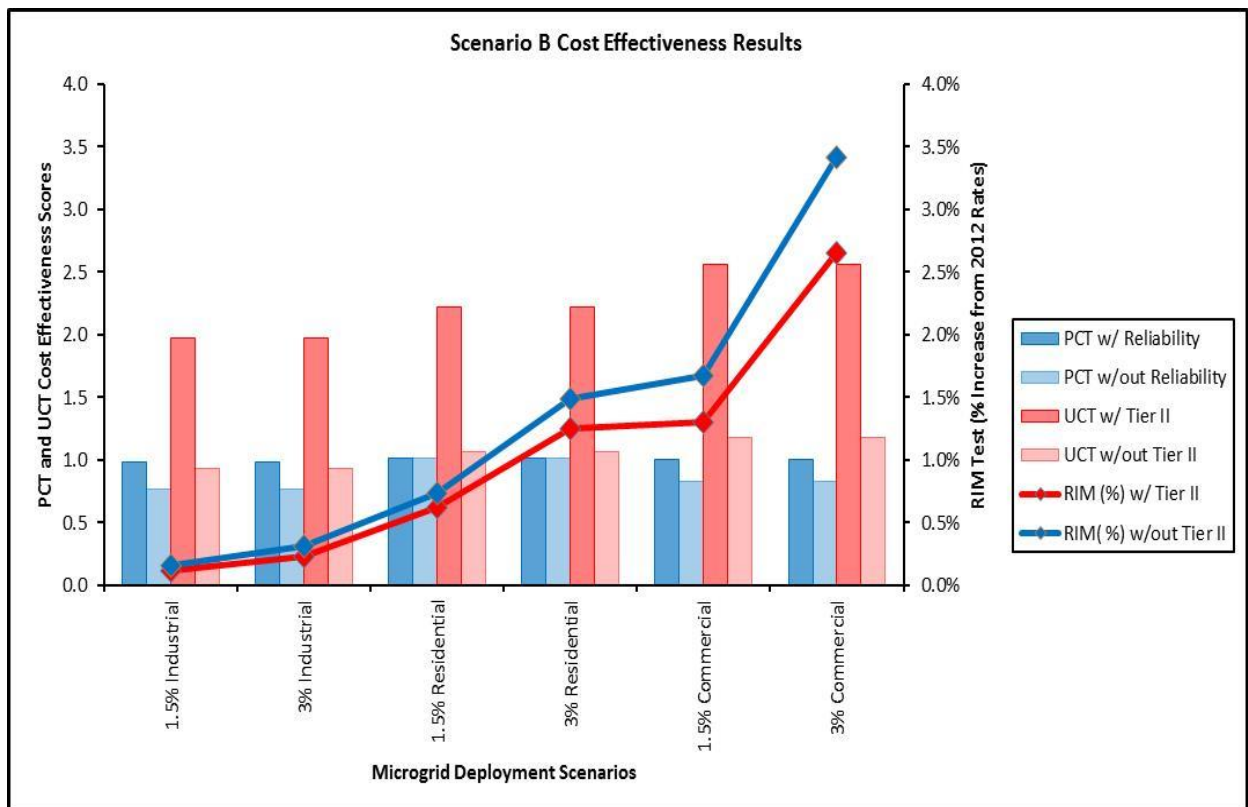
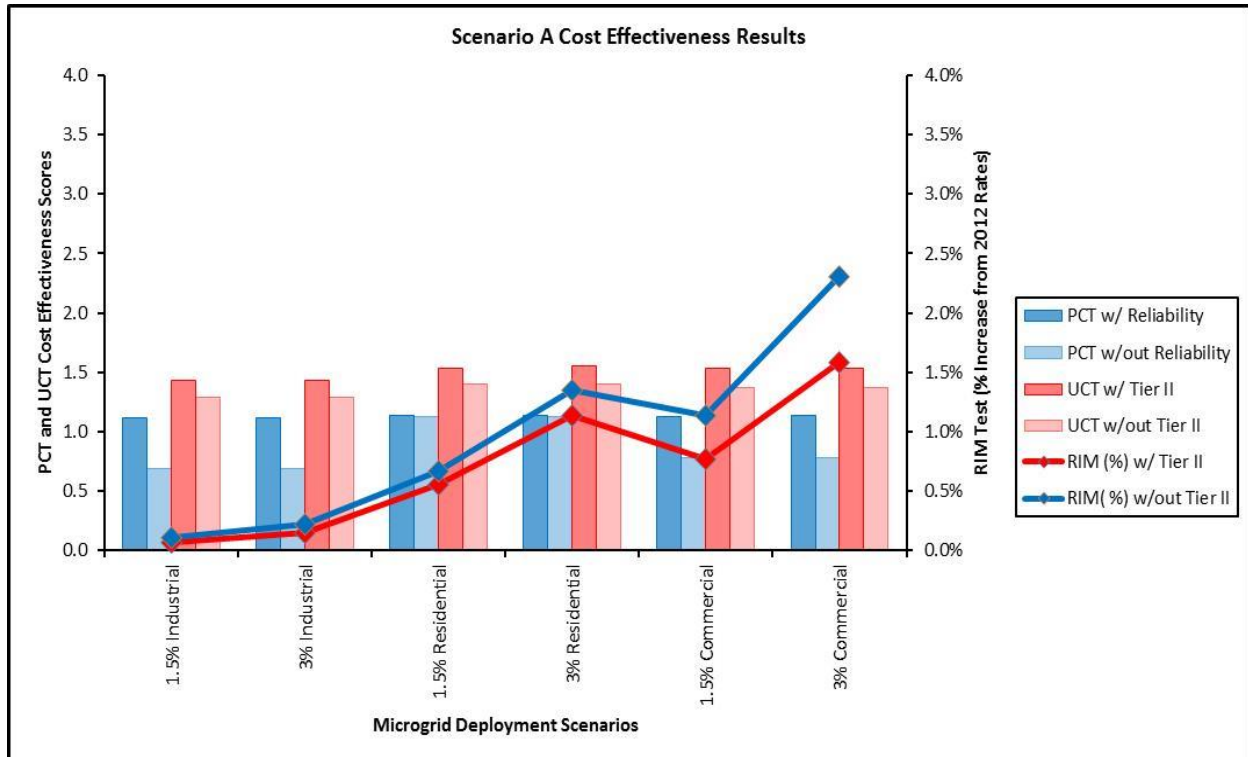


The results of the cost-effectiveness analysis found that solar PV-based microgrids capable of meeting 1.5% of annual electricity demand in each customer segment pass all three cost-effectiveness tests when built, owned and financed by the local electric utility (termed Scenario A in the study). Microgrids built and operated by a third party developer (termed Scenario B in the study) were not cost-effective under test case assumptions, but may provide positive benefits to customers who place a high value on power quality and reliability. The graph below shows the distribution of 1,000 Monte Carlo simulations that compares the lifetime net benefits received by commercial microgrid customers when the value of power quality and reliability is included, or excluded, in their lifetime net benefit calculations. Clearly, a customer who does not place a high value on power quality and reliability would not be interested in paying higher electricity rates for microgrid services, but the value of increased reliability can be significant and should not be ignored by the utility or industry regulators.



Analysis of microgrid deployment at the city-level found that 12 of the 24 scenarios tested under Scenario A passed all three cost-effectiveness tests, while none of the 24 scenarios tested under Scenario B passed all three tests (Scenarios must have a PCT and UCT (participant and utility cost test) score of at least 1.1 and a RIM (ratepayer impact measure) score lower than 1.5% to be considered cost-effective). These results show that microgrid deployment in Madison can be cost-effective for all major stakeholders at low penetration levels. Third party microgrids are only cost-effective in niche markets serving customers who place high values on power quality and reliability. However, as the cost of solar PV and microgrid power electronics continues to decline, third party microgrids may be able to offer services that are cost competitive with traditional grid services.

Cost Effectiveness Test Results under Scenario A & B



In the figures on the previous page, the blue and red bars display the PCT and UCT scores for each microgrid deployment scenario using the numerical scale on the left vertical axis. The red and blue line graphs display the RIM test results for each microgrid deployment scenario using the percentage scale on the right vertical axis. The results clearly show that microgrid deployment under Scenario A produces higher lifetime net benefits for microgrid customers with lower rate increases on non-microgrid customers. The following tables provide a complete summary of the cost-effectiveness results under Scenario A and Scenario B. Green cells show the microgrid deployment scenarios that passed all three cost-effectiveness tests, while red cells highlight the failed cost-effectiveness tests for each microgrid deployment scenario.

Cost Effectiveness Results under Scenario A

| Tier II & Reliability | PCT | UCT | RIM (%) |
|----------------------------|-------|-------|---------|
| 1.5% Residential | 1.135 | 1.531 | 0.56% |
| 3% Residential | 1.135 | 1.558 | 1.13% |
| 1.5% Commercial | 1.122 | 1.531 | 0.78% |
| 3% Commercial | 1.133 | 1.531 | 1.58% |
| 1.5% Industrial | 1.12 | 1.436 | 0.07% |
| 3% Industrial | 1.12 | 1.436 | 0.15% |
| Tier II, No Reliability | | | |
| 1.5% Residential | 1.124 | 1.531 | 0.56% |
| 3% Residential | 1.124 | 1.558 | 1.13% |
| 1.5% Commercial | 0.776 | 1.531 | 0.78% |
| 3% Commercial | 0.776 | 1.531 | 1.58% |
| 1.5% Industrial | 0.688 | 1.436 | 0.07% |
| 3% Industrial | 0.688 | 1.436 | 0.15% |
| No Tier II & Reliability | | | |
| 1.5% Residential | 1.135 | 1.401 | 0.67% |
| 3% Residential | 1.135 | 1.401 | 1.36% |
| 1.5% Commercial | 1.122 | 1.366 | 1.13% |
| 3% Commercial | 1.122 | 1.366 | 2.31% |
| 1.5% Industrial | 1.12 | 1.289 | 0.11% |
| 3% Industrial | 1.12 | 1.289 | 0.23% |
| No Tier II, No Reliability | | | |
| 1.5% Residential | 1.124 | 1.401 | 0.67% |
| 3% Residential | 1.124 | 1.401 | 1.36% |
| 1.5% Commercial | 0.776 | 1.366 | 1.13% |
| 3% Commercial | 0.776 | 1.366 | 2.31% |
| 1.5% Industrial | 0.688 | 1.289 | 0.11% |
| 3% Industrial | 0.688 | 1.289 | 0.23% |

Cost Effectiveness Results under Scenario B

| Tier II & Reliability | PCT | UCT | RIM (%) |
|----------------------------|-------|-------|---------|
| 1.5% Residential | 1.017 | 2.221 | 0.62% |
| 3% Residential | 1.017 | 2.221 | 1.25% |
| 1.5% Commercial | 1.005 | 2.557 | 1.30% |
| 3% Commercial | 1.005 | 2.557 | 2.65% |
| 1.5% Industrial | 0.988 | 1.977 | 0.11% |
| 3% Industrial | 0.988 | 1.977 | 0.23% |
| Tier II, No Reliability | | | |
| 1.5% Residential | 1.011 | 2.221 | 0.62% |
| 3% Residential | 1.011 | 2.221 | 1.25% |
| 1.5% Commercial | 0.833 | 2.557 | 1.30% |
| 3% Commercial | 0.833 | 2.557 | 2.65% |
| 1.5% Industrial | 0.769 | 1.977 | 0.11% |
| 3% Industrial | 0.769 | 1.977 | 0.23% |
| No Tier II & Reliability | | | |
| 1.5% Residential | 1.017 | 1.064 | 0.74% |
| 3% Residential | 1.017 | 1.064 | 1.49% |
| 1.5% Commercial | 1.005 | 1.185 | 1.68% |
| 3% Commercial | 1.005 | 1.185 | 3.42% |
| 1.5% Industrial | 0.988 | 0.929 | 0.16% |
| 3% Industrial | 0.988 | 0.929 | 0.31% |
| No Tier II, No Reliability | | | |
| 1.5% Residential | 1.011 | 1.064 | 0.74% |
| 3% Residential | 1.011 | 1.064 | 1.49% |
| 1.5% Commercial | 0.833 | 1.185 | 1.68% |
| 3% Commercial | 0.833 | 1.185 | 3.42% |
| 1.5% Industrial | 0.769 | 0.929 | 0.16% |
| 3% Industrial | 0.769 | 0.929 | 0.31% |

The study results show that the local UDC can develop microgrids more cost-effectively for microgrid customers than a third party developer. However, if the utility is unwilling to pursue microgrid development, there are a few scenarios where microgrids could be cost-effective for all stakeholders when built and operated by a third party developer. Third party microgrids would have to serve commercial or industrial customers who place a high value on increased power quality and reliability in order to pass the 1.1 PCT cost-effectiveness threshold. Third party microgrid deployment in the industrial sector could pass all three cost-effectiveness tests if the industrial customers served by the microgrid place a high value on power quality and reliability. The 1.5% commercial/industrial and 3% industrial deployment scenarios passed the UCT and RIM tests, while a higher value for power quality and reliability benefits would result in a PCT score of 1.1 or higher. Table 28 on the following page illustrates the values for increased power quality and reliability that would be necessary for commercial and industrial customers to see lifetime net benefits and a 25-year ROI greater than 10% (reflecting a PCT score of 1.1 or higher) under Scenario B.

An overview of the MoDERN Tool is included in the following section

MoDERNToolkit Functionality and Summary of Features

Hourly Energy & Cost Simulations

Annual Energy & Cost Simulations

Lifetime Net Benefits from Four Perspectives

- Microgrid Project Developer
- Electric Ratepayers Served by the Microgrid
- Host Electric Utility
- Environment & Societal Benefits

Risk Analysis Based on 1,000 Simulations

Cash Flow Analysis

Project Payback Period

Internal Rate of Return (IRR)

| Technology Types | Included in MoDERN |
|---------------------------------------|--------------------|
| Solar PV | ✓ |
| Wind Turbines | ✓ |
| Biogas Digesters | ✓ |
| NG Microturbines w/ CHP | ✓ |
| Diesel Gensets | ✓ |
| Battery Storage | ✓ |
| Demand Response | ✓ |
| Analytical Features | |
| Hourly Energy Demand & Costs | ✓ |
| Lifetime Net Benefits | ✓ |
| Cash Flow/Payback Period/ROI/IRR | ✓ |
| Regulatory Cost Effectiveness Tests | ✓ |
| Risk Analysis Using 1,000 Simulations | ✓ |
| Host Utility Financial Analysis | ✓ |

MoDERN Input Screens

Easy-to-Use User Interface

Financial Inputs

| | |
|---|---------------|
| New Microgrid on Existing Customer? | New Microgrid |
| Is the project financed with a loan? | Yes |
| Loan Downpayment (% of total costs) | 20% |
| Amount Financed | \$215,266,000 |
| Loan Term (years) | 20 |
| Loan Interest Rate Variable | 5.00% |
| Price of BECs (\$/MWh) | \$18.00 |
| Inflation Adjusted Rate (%) | 2.54% |
| Annual Loan Payment | \$14,658,082 |
| Include Deferred Tax & Benefits? | No |
| External Funding (\$) | \$0.00 |
| Net Cost of Carbon (\$/ton) | \$15.00 |
| Carbon Price Growth Rate (%/year) | 2.10% |
| Hold CO2 Price Constant? | Yes |
| PV Installed Cost (\$/kW) | \$2,000 |
| Momentary Power Outage Cost (\$/year) | \$5,000 |
| Extended Power Outage Cost (\$/year) | \$50,000 |
| Utility Incur CO2 Cost? | Yes |
| Demand Charge Applied During | Peak Hours |
| Net Microgrid Sell Back Rate (\$/MWh) | \$0.0500 |
| Use Original Rates | \$0.0850 |
| On-Peak Rate for Non-MG Power | \$0.0500 |
| On-Peak Rate for Non-MG Power | \$0.0555 |
| Utility Rate Escalator | 2.00% |
| Utility WGS for MG Only | 61.21% |
| Utility WGS w/ Microgrid | 19.16% |
| Utility WGS w/ Non-MG Rate Increases | 19.30% |
| 25-Year Ratepayer Benefit After Rate Increase | \$18,143,452 |
| MG Utility Benefits After Rate Increase | \$22,712,017 |
| Customer WfY of Tier 1 & Tier 2 Benefits | \$365,455,424 |
| Additional Costs for Non-MG Customers | \$122,251,992 |
| Total Net Benefits Across All Stakeholders | \$687,709,382 |
| 25-Year Benefits of Reduced Emissions | \$23,615,244 |

Financial Structure for Costs & Benefits

| | |
|----------------------------|---------------------|
| MG Construction Revenue To | 2nd Party Developer |
| MG Sales Revenue To | 2nd Party Developer |
| MG Sales Revenue To | 2nd Party Developer |
| Tax Credits Revenue To | 2nd Party Developer |
| Loan Payments By | 2nd Party Developer |
| Downpayment Paid By | MG Customer |
| Annual O&M Costs Paid By | 2nd Party Developer |
| Annual Fuel Costs | Utility |
| Substation Upgrades | Utility |
| Transmission Lines | Utility |
| Distribution Lines | Utility |
| Relay Value | Utility |
| # of MG Events per Year | 0 |
| # of Outages per Year | 1 |

Environmental Benefit Values

| | |
|--|----------|
| Grid CO2 (\$/MWh) | 856 |
| Grid SO2 (\$/MWh) | 1.50 |
| Grid NOx (\$/MWh) | 2.50 |
| SO2 Allowances (\$/ton) | \$0 |
| SO2 Health Benefits (\$/ton) | \$2,754 |
| NOx Allowances (\$/ton) | \$0 |
| NOx Health Benefits (\$/ton) | \$1,622 |
| Uncertain Tier 2 Benefit Values (\$/MWh) | |
| Auxiliary Services | \$0.0050 |
| T&D Deferrals | \$0.0100 |
| Capacity Deferrals | \$0.0550 |
| Fuel Price Hedging | \$0.0055 |

Microgrid Variable Inputs

| | | |
|--|--------------------|------------|
| Number of MGs Built / Customer Group | 1 | Commercial |
| Electric Utility / Customers Served by Each MG | Microgrid Electric | 10 |
| Actual Utility Demand Met by MG Construction | | 100.00% |
| Use Predicted Hourly Load | Hourly Inputs | |
| Discount Rate | 5.00% | Constant |
| Electricity Rate Increases (%/yr) | 2.00% | 4.00% |
| Inflation Rate (%/yr) | 2.00% | 4.00% |
| Peak Hourly Load (MW) & Reliability Margin | 83.4 | 11.21% |
| Average Hourly Load (MW) & Reliability Margin | 42.8 | 10.0% |
| Annual Demand (MWh & reliability) | 375,000 | 23,680 |
| Demand Response Price (% Load Reduction) | \$100.00 | 0% |
| Electric Consumption Variance (% of baseline) | 80% | 100% |
| Hold Capital Costs Constant in Sensitivity Analysis? | No | 10% |
| Netgas Price Increase (% of current price) | 20% | 200% |
| Utility Electric Service Charge (Original/MG) | \$0.0000 | \$0.0000 |

Microgrid Components

| | Unit Size | Number |
|--|--------------------------|---------------|
| Solar PV (MW) | 50,000 | 1 |
| Small Wind (kW) | 50 | 1 |
| Storage (MWh) (MW) | 0 | 1 |
| Fuel Cell | | |
| Lead Acid Battery | 50 | 1 |
| Capacity (MW) (MW) | 7,200 | 1 |
| Smart Grids | 1 | 1 |
| Other Microgrid Power Electronics | 1 | 1 |
| Microgrid Construction & Engineering Costs (\$/kW) | \$10.00 | 1,000,000 |
| Microgrid Support Structure | All Hours Load Following | Maximum CF % |
| Maximum Microgrid CF (%) | 50% | 50% |
| Assumed Electricity Purchases | MWh/year | \$/year |
| On-Peak (Microgrid Costs include fuel & O&M) | 153,212,560 | \$ 2,820,000 |
| Off-Peak (Microgrid Costs include fuel & O&M) | 218,812,120 | \$ 24,000,000 |
| Total | 372,024,680 | \$ 26,820,000 |
| Net Revenue (Total) | 15,943,600 | \$ 207,182 |
| Grid Purchases (\$) | 17,015,384 | \$ 1,100,100 |

Transmission & Distribution (T&D) Variables

| | |
|----------------------------------|--------------|
| Transmission MGs Line | 20.0 |
| Transmission MGs Line | 20.0 |
| Feeder MGs Line | 8.20 |
| Feeder MGs Line | 8.20 |
| Peak MW/SV Substation Ratio | 1.00 |
| 138V Feeder Line (MW/line) | 1.00 |
| New 330/138V Substation Cost | \$11,000,000 |
| New 115/138V Substation Cost | \$11,000,000 |
| New 69/138V Substation Cost | \$11,000,000 |
| 115/138V Substation Upgrade | \$11,000,000 |
| 115/138V Substation Upgrade | \$11,000,000 |
| 69/138V Substation Upgrade | \$11,000,000 |
| Substation Cost Low | 100% |
| Substation Cost High | 100% |
| 230kV Line Cost/Mile | \$1,000,000 |
| 69kV Line Cost/Mile | \$1,000,000 |
| Line Cost High | 100% |
| Line Cost Low | 100% |
| 138V Line Cost | \$400,000 |
| 120V Line Cost | \$200,000 |
| Requires new Transmission Asset? | No |
| Requires new Distribution Asset? | No |
| Requires new Substation? | No |

Model Author: Ben Kaldunski

Version: 2.0

Version Date: 6/5/2015

Version Notes:

MoDERN

MoDERN Input Screens

Rate Structures & Load Curves

Hourly Electricity & Heating Load Profiles

Hourly Defined Hourly Load (Paste Hourly Data in Y1-E179W Columns)

| Date | Hour | 2002/2003 Load | 2002/2003 Load Factor | Residential Electricity Load | Residential Electricity Load Factor | Commercial Electricity Load | Commercial Electricity Load Factor | Industrial Electricity Load | Industrial Electricity Load Factor | Residential Heating Load | Residential Electricity Load Factor |
|----------|------|----------------|-----------------------|------------------------------|-------------------------------------|-----------------------------|------------------------------------|-----------------------------|------------------------------------|--------------------------|-------------------------------------|
| 1/1/2010 | 1 | 303.0 | 41.4% | 303.0 | 35.4% | 0.0 | 42.4% | 0.0 | 76.6% | 4.760 | 49.8% |
| 1/1/2010 | 2 | 280.9 | 38.3% | 433.2 | 38.4% | 26.7 | 42.2% | 35.8 | 49.3% | 4.890 | 49.2% |
| 1/1/2010 | 3 | 279.5 | 38.4% | 404.1 | 34.4% | 26.0 | 42.4% | 35.4 | 48.4% | 5.052 | 48.2% |
| 1/1/2010 | 4 | 267.1 | 36.4% | 367.7 | 28.4% | 26.7 | 42.2% | 35.3 | 48.2% | 5.218 | 76.9% |
| 1/1/2010 | 5 | 267.1 | 36.4% | 367.3 | 28.3% | 26.0 | 42.2% | 35.3 | 48.2% | 5.385 | 75.8% |
| 1/1/2010 | 6 | 286.9 | 38.3% | 427.3 | 38.3% | 26.7 | 42.2% | 35.4 | 49.3% | 5.555 | 75.8% |
| 1/1/2010 | 7 | 327.4 | 44.4% | 349.8 | 29.2% | 26.3 | 42.4% | 36.8 | 72.2% | 6.037 | 81.6% |
| 1/1/2010 | 8 | 376.1 | 51.4% | 734.2 | 52.4% | 24.2 | 36.4% | 38.1 | 75.4% | 6.370 | 82.4% |
| 1/1/2010 | 9 | 367.3 | 51.4% | 708.8 | 50.4% | 24.2 | 36.4% | 38.3 | 76.4% | 6.538 | 73.4% |
| 1/1/2010 | 10 | 367.3 | 51.4% | 638.2 | 43.4% | 23.9 | 36.2% | 38.3 | 76.4% | 6.700 | 68.9% |
| 1/1/2010 | 11 | 360.9 | 51.2% | 638.3 | 43.4% | 23.8 | 36.2% | 38.4 | 76.9% | 6.867 | 68.7% |
| 1/1/2010 | 12 | 360.9 | 51.2% | 633.3 | 44.4% | 23.3 | 34.4% | 38.4 | 76.8% | 6.986 | 57.7% |
| 1/1/2010 | 13 | 384.2 | 52.2% | 607.8 | 42.4% | 23.4 | 34.4% | 38.2 | 76.2% | 7.090 | 42.8% |
| 1/1/2010 | 14 | 367.3 | 51.4% | 580.8 | 42.3% | 23.3 | 34.2% | 38.3 | 76.4% | 7.263 | 58.9% |
| 1/1/2010 | 15 | 367.3 | 51.4% | 588.4 | 42.4% | 23.0 | 34.4% | 38.3 | 76.4% | 7.446 | 44.2% |
| 1/1/2010 | 16 | 360.9 | 51.2% | 626.7 | 44.7% | 23.0 | 35.4% | 38.4 | 76.9% | 7.642 | 51.4% |
| 1/1/2010 | 17 | 380.9 | 53.4% | 776.3 | 54.9% | 25.8 | 37.4% | 38.4 | 76.4% | 8.249 | 57.4% |
| 1/1/2010 | 18 | 417.0 | 56.4% | 1001.1 | 75.2% | 28.2 | 41.2% | 26.0 | 76.4% | 8.820 | 65.2% |
| 1/1/2010 | 19 | 430.8 | 58.2% | 1233.6 | 87.2% | 26.3 | 40.9% | 26.4 | 76.2% | 9.360 | 59.6% |
| 1/1/2010 | 20 | 426.4 | 57.2% | 1109.4 | 85.4% | 26.9 | 42.4% | 26.1 | 76.6% | 9.280 | 57.4% |
| 1/1/2010 | 21 | 408.4 | 57.2% | 1108.2 | 79.2% | 26.0 | 40.4% | 26.1 | 76.6% | 9.436 | 58.6% |
| 1/1/2010 | 22 | 402.2 | 54.9% | 1025.1 | 75.1% | 26.8 | 42.2% | 26.7 | 77.5% | 9.438 | 60.2% |
| 1/1/2010 | 23 | 360.9 | 51.2% | 849.1 | 60.4% | 26.8 | 40.9% | 26.4 | 76.9% | 9.614 | 41.2% |
| 1/1/2010 | 24 | 349.8 | 47.2% | 675.8 | 48.2% | 26.8 | 42.4% | 27.4 | 73.9% | 9.577 | 41.9% |

Electricity Rates, Natural Gas Prices & Load Profiles (enter rates here to be used in the Hourly Simulator)

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|-------|-------------------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|
| Hour | Residential Hourly Load Rates | | | | | | | | | | | |
| 1 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 2 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 3 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 4 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 5 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 6 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 7 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 8 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 9 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 10 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2394 | \$0.2394 | \$0.2394 |
| 11 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2394 | \$0.2394 | \$0.2394 |
| 12 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2394 | \$0.2394 | \$0.2394 |
| 13 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2394 | \$0.2394 | \$0.2394 |
| 14 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2394 | \$0.2394 | \$0.2394 |
| 15 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2394 | \$0.2394 | \$0.2394 |
| 16 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2394 | \$0.2394 | \$0.2394 |
| 17 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2911 | \$0.2394 | \$0.2394 | \$0.2394 |
| 18 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2394 | \$0.2394 | \$0.2394 |
| 19 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2394 | \$0.2394 | \$0.2394 |
| 20 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2394 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2679 | \$0.2394 | \$0.2394 | \$0.2394 |
| 21 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 22 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |
| 23 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 | \$0.0729 |

Hourly, Monthly, Annual Energy Consumption & Cost Analysis

Comparison of Monthly Energy & Demand Costs

| Month | Base Case Demand \$ | Microgrid Demand \$ |
|--------------|---------------------|---------------------|
| January | \$884,240 | \$713,742 |
| February | \$897,238 | \$775,238 |
| March | \$897,238 | \$750,547 |
| April | \$925,777 | \$729,951 |
| May | \$898,272 | \$782,200 |
| June | \$1,088,000 | \$717,831 |
| July | \$1,373,000 | \$717,580 |
| August | \$1,088,000 | \$677,838 |
| September | \$1,022,118 | \$704,247 |
| October | \$953,621 | \$776,367 |
| November | \$898,307 | \$714,417 |
| December | \$898,307 | \$717,831 |
| Total | \$11,448,000 | \$8,706,577 |

| Month | Base Case Demand \$ | Microgrid Demand \$ |
|--------------|---------------------|---------------------|
| January | \$1,300,412 | \$473,445 |
| February | \$1,300,412 | \$411,000 |
| March | \$1,310,092 | \$400,411 |
| April | \$1,293,618 | \$348,348 |
| May | \$1,318,888 | \$717,687 |
| June | \$1,748,342 | \$708,015 |
| July | \$1,875,825 | \$716,780 |
| August | \$1,310,000 | \$688,548 |
| September | \$1,815,300 | \$684,400 |
| October | \$1,373,849 | \$470,947 |
| November | \$1,310,450 | \$443,388 |
| December | \$1,363,888 | \$476,078 |
| Total | \$17,388,800 | \$6,616,513 |

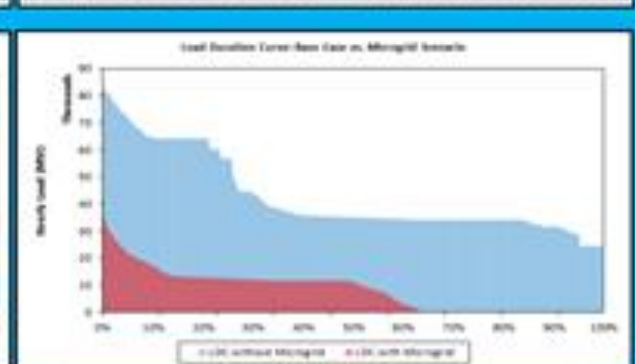
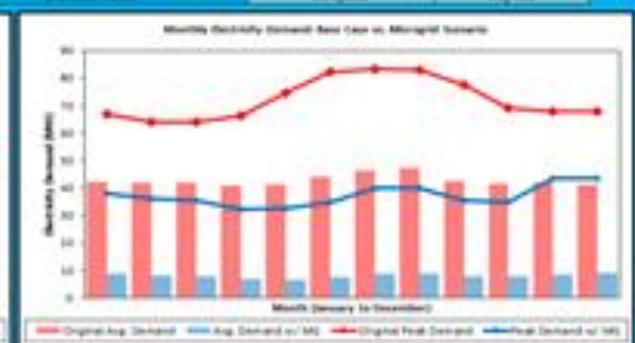
| | | |
|----------------------------|---------------------|--------------------|
| Energy & Demand | \$18,636,800 | \$8,318,090 |
|----------------------------|---------------------|--------------------|

Monthly Peak Demand (MW)

| Month | Base Case Demand | Microgrid Demand |
|----------------------------|------------------|------------------|
| January | 67.8 | 38.0 |
| February | 68.2 | 36.1 |
| March | 68.0 | 35.7 |
| April | 68.3 | 32.4 |
| May | 78.7 | 32.3 |
| June | 80.3 | 34.9 |
| July | 80.4 | 40.1 |
| August | 80.0 | 39.9 |
| September | 77.4 | 35.3 |
| October | 68.1 | 35.0 |
| November | 67.9 | 43.3 |
| December | 67.8 | 40.9 |
| Average Peak Demand | 73.3 | 37.3 |

| Month | Base Case Demand | Microgrid Demand |
|------------------------|------------------|------------------|
| January | 21,430 | 0.000 |
| February | 19,247 | 0.000 |
| March | 21,071 | 0.000 |
| April | 19,380 | 0.000 |
| May | 20,714 | 0.000 |
| June | 21,818 | 0.000 |
| July | 24,114 | 0.000 |
| August | 25,250 | 0.000 |
| September | 27,544 | 0.000 |
| October | 25,399 | 0.000 |
| November | 25,113 | 0.000 |
| December | 25,783 | 0.000 |
| Monthly Average | 24,000.3 | 0.000.0 |

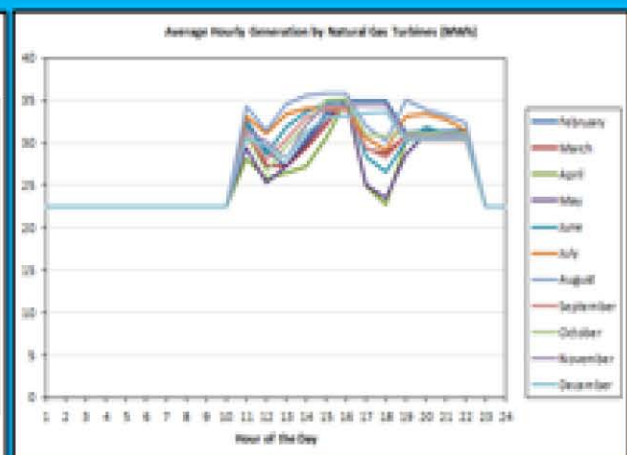
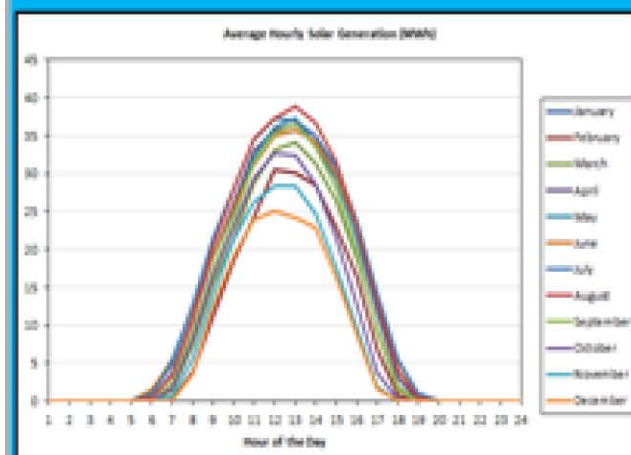
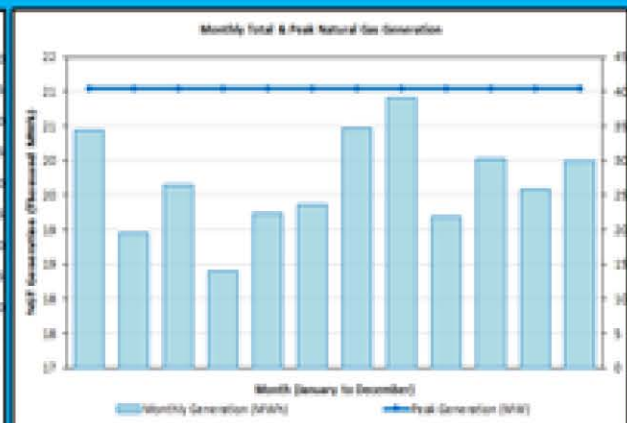
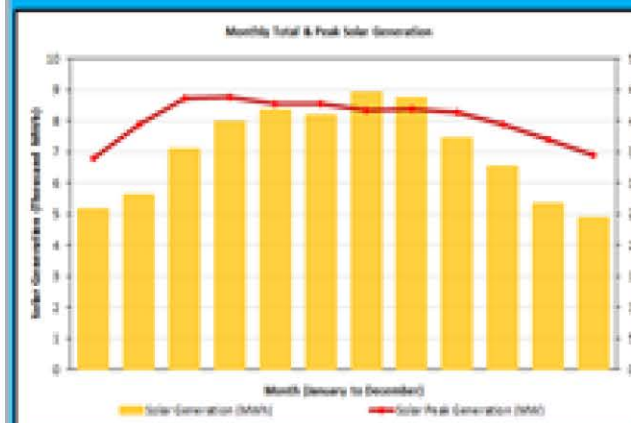
| | | |
|---------------------|----------------|---------------|
| Annual Total | 276,000 | 73,462 |
|---------------------|----------------|---------------|



Hourly, Monthly, Annual Generation Dispatch & Cost Analysis

| Monthly Peak (MW) & Total (MWh) Solar Generation | | |
|--|-------------|-----------|
| Month | Monthly MWh | Peak (MW) |
| January | 5,155 | 30.9 |
| February | 5,825 | 39.4 |
| March | 7,187 | 43.7 |
| April | 7,678 | 43.7 |
| May | 8,371 | 42.8 |
| June | 8,168 | 42.7 |
| July | 8,906 | 43.7 |
| August | 8,753 | 43.9 |
| September | 7,440 | 43.3 |
| October | 6,537 | 39.4 |
| November | 5,340 | 36.9 |
| December | 4,890 | 34.6 |
| Monthly Average | 7,028 | 40.2 |
| Annual Totals | 84,249 | |

| Monthly Peak (MW) & Total (MWh) Natural Gas Generation | | |
|--|-------------|-----------|
| Month | Monthly MWh | Peak (MW) |
| January | 20,435 | 40.5 |
| February | 18,848 | 40.5 |
| March | 19,646 | 40.5 |
| April | 18,399 | 40.5 |
| May | 19,242 | 40.5 |
| June | 19,362 | 40.5 |
| July | 20,476 | 40.5 |
| August | 20,908 | 40.5 |
| September | 19,796 | 40.5 |
| October | 20,828 | 40.5 |
| November | 19,594 | 40.5 |
| December | 19,999 | 40.5 |
| Monthly Average | 19,686 | 40.5 |
| Annual Totals | 236,232 | |



Comprehensive Financial Analysis

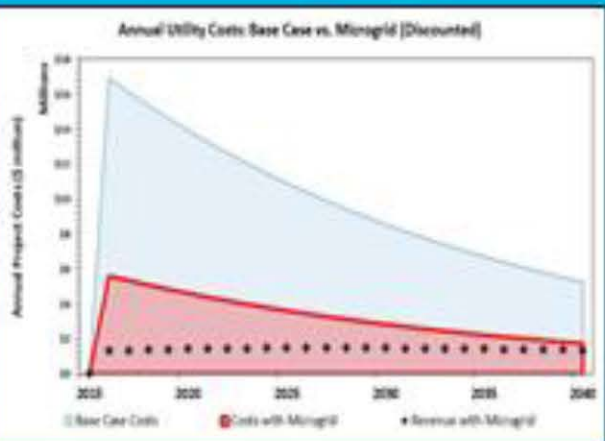
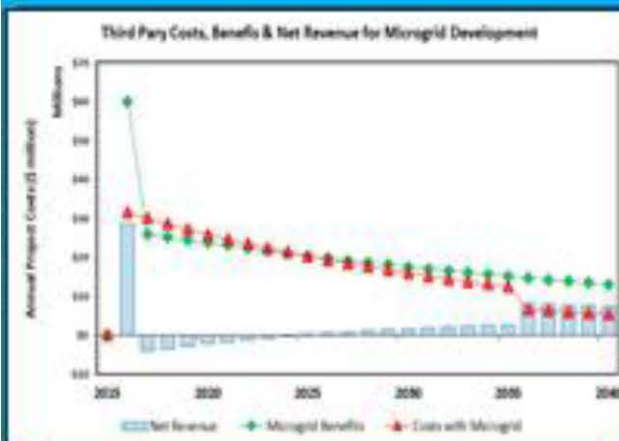
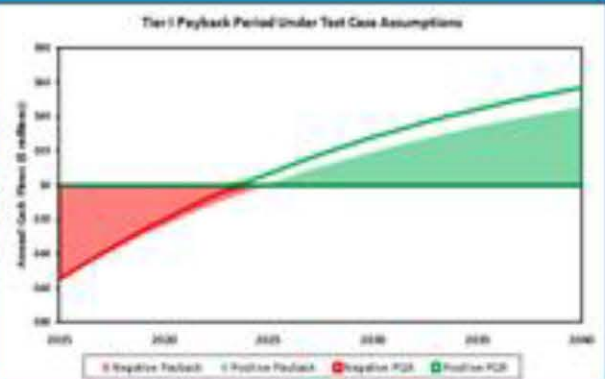
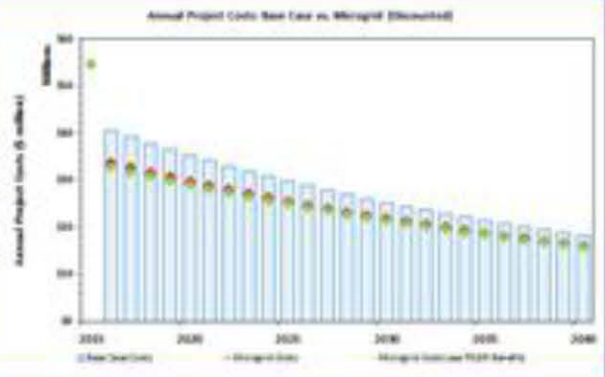
Cash Flow, Payback Period, IRR, ROI

Cash Flow Analysis: Microgrid Cashflows (Tier 1)

| Year | Original Energy Costs | Costs w/ MG | MG Payback |
|------|-----------------------|-------------|------------|
| 2015 | \$0.0 | \$0.0 | \$0.0 |
| 2016 | \$40.3 | \$33.9 | \$66.3 |
| 2017 | \$39.2 | \$30.9 | \$89.9 |
| 2018 | \$27.8 | \$25.9 | \$113.9 |
| 2019 | \$38.6 | \$20.9 | \$136.3 |
| 2020 | \$26.2 | \$19.7 | \$159.3 |
| 2021 | \$24.2 | \$26.9 | \$183.3 |
| 2022 | \$33.8 | \$27.9 | \$206.9 |
| 2023 | \$34.8 | \$27.9 | \$230.9 |
| 2024 | \$30.9 | \$26.2 | \$254.3 |
| 2025 | \$28.9 | \$25.3 | \$277.9 |
| 2026 | \$28.9 | \$24.7 | \$301.9 |
| 2027 | \$27.8 | \$23.9 | \$325.9 |
| 2028 | \$27.8 | \$23.2 | \$349.9 |
| 2029 | \$28.1 | \$22.8 | \$373.9 |
| 2030 | \$24.2 | \$21.9 | \$397.9 |
| 2031 | \$24.4 | \$21.7 | \$421.9 |
| 2032 | \$22.6 | \$20.3 | \$445.9 |
| 2033 | \$22.6 | \$19.9 | \$469.9 |
| 2034 | \$22.5 | \$19.2 | \$493.9 |
| 2035 | \$23.4 | \$18.7 | \$517.9 |
| 2036 | \$20.7 | \$18.2 | \$541.9 |
| 2037 | \$20.2 | \$17.9 | \$565.9 |
| 2038 | \$18.4 | \$17.3 | \$589.9 |
| 2039 | \$18.6 | \$16.6 | \$613.9 |
| 2040 | \$18.2 | \$16.3 | \$637.9 |

25 Year Totals \$695.7 \$595.3 \$100.3

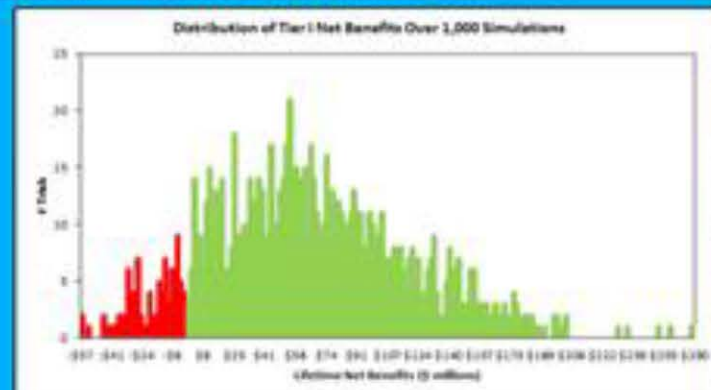
| Year | 2038 | 2039 | 2040 |
|-----------------------------------|---------------|---------------|---------------|
| Original Energy Costs | \$25,343,466 | \$25,249,545 | \$24,356,740 |
| Energy Costs w/ Microgrid | \$20,625,548 | \$22,326,047 | \$20,458,219 |
| Microgrid Development Costs | \$0 | \$0 | \$0 |
| Financial Benefits | -\$20,625,548 | -\$22,326,047 | -\$20,458,219 |
| Benefits w/ PQ/Reliability | -\$20,625,548 | -\$22,326,047 | -\$20,458,219 |
| Financial Cash Flow | -\$20,625,548 | -\$22,326,047 | -\$20,458,219 |
| Cash Flow w/ PQ/Reliability | -\$20,625,548 | -\$22,326,047 | -\$20,458,219 |
| Financial Payback Tracker | \$26,393,382 | \$45,730,443 | \$65,071,877 |
| Payback Tracker w/ PQ/Reliability | \$26,393,382 | \$45,730,443 | \$65,071,877 |



Monte Carlo Risk Analysis Module

Analyze Variables Over 1,000 Trials

Monte Carlo Analysis: Tier 1 Results



Monte Carlo Results: Percentage Distribution

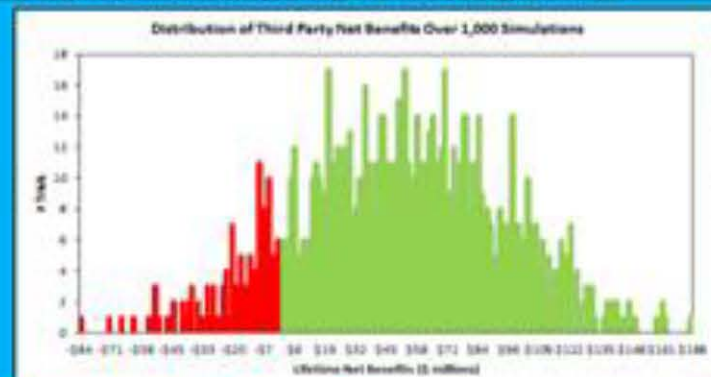
| | |
|------------------------------|---------------|
| Monte Carlo Average | \$45,932,281 |
| Monte Carlo Median | \$42,145,131 |
| Monte Carlo Minimum | \$10,726,081 |
| Monte Carlo Maximum | \$273,413,434 |
| % with Positive Net Benefits | 89.91% |
| 10th Percentile | \$24,928,287 |
| 20th Percentile | \$36,185,751 |
| 30th Percentile | \$47,334,491 |
| 40th Percentile | \$576,635,824 |
| 50th Percentile | \$134,930,487 |

| Input Definition Variables | Min | Max |
|---------------------------------|----------|-----------|
| CO2 Intensity (tons/kWh) | 8.0000% | 8.0000% |
| Solar Capacity Factor (%) | 12.00% | 16.00% |
| Wind Capacity Factor (%) | 30.00% | 30.00% |
| Single Capacity Factor (%) | 41.64% | 50.94% |
| 100 Annual Price Change | 75.00% | 200.00% |
| Social Cost of Carbon | \$1.00 | \$100.00 |
| WACC Tax Rate | \$0.30 | \$0.30 |
| Demand Growth/Decline | 80% | 120% |
| Avg Rate Growth Factor | 1.00 | 1.0400 |
| Annual Power Quality Events | 0 | 2 |
| Annual Extended Outages | 0 | 2 |
| Cost of PQ Events | \$1,100 | \$10,000 |
| Cost of Extended Outages | \$12,500 | \$100,000 |
| Auxiliary Services | \$0.0013 | \$0.0020 |
| Fuel Hedging Value | \$0.0000 | \$0.0061 |
| 1&D Deferred Costs | \$0.0000 | \$0.0270 |
| Capacity Deferred Costs | \$0.0000 | \$0.0613 |
| Battery O&M Costs | 85% | 115% |
| Discount Rate (%) | 7% | 10% |
| Inflation Rate (%) | 1% | 8% |
| Loan Interest Rate (%) | 4% | 6% |
| Salvage Value (% of Total Cost) | 0% | 100% |
| Total Capital Cost | 85% | 115% |
| REC Prices (\$/MWh) | \$1.00 | \$90.00 |
| SO2 Intensity (tons/kWh) | 7,298.97 | 1,218.06 |
| NOx Intensity (tons/kWh) | 4,898.97 | 8,008.97 |
| SO2 Allowance Price (\$/ton) | \$1.00 | \$2.00 |
| NOx Allowance Price (\$/ton) | \$0.00 | \$100.00 |
| SO2 Health Cost (\$/ton) | \$100 | \$4,000 |
| NOx Health Cost (\$/ton) | \$100 | \$4,000 |
| Integration/Admission Cost | \$0.0000 | \$0.0000 |

Distribution of Variables

Normal

Monte Carlo Sensitivity Analysis: Third Party Developer



Monte Carlo Results: Percentage Distribution

| | |
|------------------------------|---------------|
| Monte Carlo Average | \$58,995,954 |
| Monte Carlo Median | \$53,213,494 |
| Monte Carlo Minimum | \$42,850,132 |
| Monte Carlo Maximum | \$176,172,176 |
| % with Positive Net Benefits | 89.91% |
| 10th Percentile | \$39,876,912 |
| 20th Percentile | \$48,743,144 |
| 30th Percentile | \$57,328,444 |
| 40th Percentile | \$109,215,104 |
| 50th Percentile | \$118,411,080 |

| Input Definition Variables | Min | Max |
|---------------------------------|----------|-----------|
| CO2 Intensity (tons/kWh) | 8.0000% | 8.0000% |
| Solar Capacity Factor (%) | 12.00% | 16.00% |
| Wind Capacity Factor (%) | 30.00% | 30.00% |
| Single Capacity Factor (%) | 41.64% | 50.94% |
| 100 Annual Price Change | 75.00% | 200.00% |
| Social Cost of Carbon | \$1.00 | \$100.00 |
| WACC Tax Rate | \$0.30 | \$0.30 |
| Demand Growth/Decline | 80% | 120% |
| Avg Rate Growth Factor | 1.00 | 1.0400 |
| Annual Power Quality Events | 0 | 2 |
| Annual Extended Outages | 0 | 2 |
| Cost of PQ Events | \$1,100 | \$10,000 |
| Cost of Extended Outages | \$12,500 | \$100,000 |
| Auxiliary Services | \$0.0013 | \$0.0020 |
| Fuel Hedging Value | \$0.0000 | \$0.0061 |
| 1&D Deferred Costs | \$0.0000 | \$0.0270 |
| Capacity Deferred Costs | \$0.0000 | \$0.0613 |
| Battery O&M Costs | 85% | 115% |
| Discount Rate (%) | 7% | 10% |
| Inflation Rate (%) | 1% | 8% |
| Loan Interest Rate (%) | 4% | 6% |
| Salvage Value (% of Total Cost) | 0% | 100% |
| Total Capital Cost | 85% | 115% |
| REC Prices (\$/MWh) | \$1.00 | \$90.00 |
| SO2 Intensity (tons/kWh) | 7,298.97 | 1,218.06 |
| NOx Intensity (tons/kWh) | 4,898.97 | 8,008.97 |
| SO2 Allowance Price (\$/ton) | \$1.00 | \$2.00 |
| NOx Allowance Price (\$/ton) | \$0.00 | \$100.00 |
| SO2 Health Cost (\$/ton) | \$100 | \$4,000 |
| NOx Health Cost (\$/ton) | \$100 | \$4,000 |
| Integration/Admission Cost | \$0.0000 | \$0.0000 |

Distribution of Variables

Normal

Analyze Impact on Utility Revenue Electricity Rates & Lifetime Benefits

