Minnesota Microgrids:

Barriers, Opportunities, and Pathways Toward Energy Assurance

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Prepared by Microgrid Institute
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AUTHORS

Michael T. Burr (*primary author*), Burr Energy LLC / Microgrid Institute
Michael J. Zimmer, Thompson Hine LLP
Brian Meloy, Leonard, Street & Deinard
James Bertrand, Leonard, Street & Deinard
Walter Levesque, DNV KEMA
Guy Warner, Pareto Energy
John D. McDonald, IEEE

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DISCLAIMER

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GLOSSARY OF MICROGRID-RELATED TERMS*

Anti-islanding: Safety protocols intended to ensure that distributed energy resources can't feed power onto utility distribution lines during a system outage. IEEE 1547 includes anti-islanding standards to protect the safety of utility line workers. (*See also "islanding."*)

Balancing: Active efforts to match energy supply and demand to maintain stable system operations -- pertinent for large-scale and small-scale grids. Microgrids can help transmission operators keep large grids balanced, and microgrids internally perform balancing services to operate in island mode.

Combined heat and power (CHP) (a.k.a., "cogeneration"): Energy systems that supply both electricity and thermal energy. CHP systems could power microgrids at hospitals, institutional and corporate campuses, and some industrial sites.

Demand response (DR): Energy loads capable of being reduced or curtailed under certain conditions. If efficiency is the first step in designing a microgrid, then DR is the second.

Distributed generation (DG): A small power plant located near an end-use customer, often interconnected with the low-voltage utility distribution grid (versus the high-voltage transmission system). DG is the central asset in any microgrid.

Energy improvement district (EID): A vehicle used by local and state governments to promote planning, development, and funding activities supporting energy infrastructure improvements in a defined geographic area or community. Community leaders are considering microgrids as part of energy improvement district planning.

Energy management system (EMS): Software and hardware for balancing energy supply (including storage) and demand to maintain stable operations. Smart grid EMS software established the IT framework for operating microgrids.

Energy service company (ESCO): A non-utility entity that provides retail, commercial, or industrial energy services. A microgrid service provider is a type of ESCO, combined with a type of IPP.

IEEE 1547: A set of industry standards for interconnecting distributed energy resources to electric utility systems. IEEE 1547 is being amended to accommodate microgrids and higher penetrations of DERs.

IPP: Independent power producers are non-utility companies that generate and sell energy to one or more customers. Most IPPs sell their output in wholesale markets, whereas microgrids serve retail customers directly.

Islanding: Intentional islanding is the act of physically separating a defined group of electric circuits from a utility system, and operating those circuits independently. Islanding capabilities are fundamental to the function of a microgrid. (*See also "anti-islanding."*)

Microgrid: A small energy system capable of balancing captive supply and demand resources to maintain stable service within a defined boundary. There's no universally accepted minimum or maximum size for a microgrid. Defining characteristics involve function, not size. (*See further discussion in Appendix B: "Microgrid Definitions*)

MUSH: Military installations, universities, schools, and hospitals. Many of the first commercial microgrids are being installed for customers in MUSH applications.

Net-zero: The condition in which a building or campus is capable of generating energy equal to its aggregate annual consumption. Some net-zero energy buildings can be upgraded to function as islandable microgrids.

Photovoltaics (PV): Solar-electric energy cells in any of numerous forms and configurations. Rapid advances in PV technology create opportunities for remote and cost-effective green microgrids.

Plug-in electric vehicle (PEV): Transportation vehicle with an onboard electricity storage system and the ability to charge from an outside power source. Campuses with charging stations for fleet PEVs (and employee cars) will integrate V2G as storage and balancing assets in microgrid systems.

Smart city: A community that plans and develops infrastructure, buildings, and operations to intentionally optimize efficiency, economics, and quality of life. Some smart city plans call for microgrids as part of special development districts with enhanced infrastructure services.

Smart grid: A energy system characterized by two-way communications and distributed sensors, automation, and supervisory control systems. Smart grid systems allow utilities to dispatch microgrids for grid balancing and ancillary services.

Transactive energy: A market system in which retail energy consumption and supply decisions are driven by competitive market pricing, through a combination of long-term contracts and spot- and forward-market bids and tenders. Microgrids and their component nodes could be managed as part of a transactive energy system.

V2G: Vehicle-to-grid technology, integrating PEVs together for dispatchable electricity storage for grid support and ancillary services. EVs will provide storage capacity for microgrids through V2G technology.

Virtual power plant (VPP): Aggregated power generating capacity that's provided by multiple, real DG facilities operating in different locations. Some microgrid DG systems could run in VPP clusters.

* These definitions first appeared on the Microgrid Institute website, www.microgridinstitute.org. ©2013, Burr Energy LLC, used with permission.

EXECUTIVE SUMMARY

A. Microgrids and the Minnesota Energy Assurance Plan

1. Minnesota Department of Commerce White Paper Analysis

a. Objectives re: Energy Assurance, Policy Recommendations

The Minnesota Department of Commerce (Commerce), Division of Energy Resources, commissioned the Microgrid Institute Team, managed by Burr Energy LLC, to prepare a White Paper to identify regulatory barriers to and opportunities for microgrid development for energy assurance in the state of Minnesota, with recommendations to address barriers and identify pathways to facilitate microgrid development. This project was made possible by a grant from the U.S. Department of Energy and the Minnesota Department of Commerce through the American Recovery and Reinvestment Act of 2009 (ARRA).

b. Scope of Study

With direction from Commerce, Microgrid Institute pursued the following scope of study for this White Paper:

1) Regulation and 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.

2) Interconnection Standards and Practices: Identify Minnesota standards and practices involving interconnection, interoperability, and control of distributed resources. Compare and contrast these policies with the most current Federal and industry standards. Identify differences affecting microgrid development and optimization in utility systems.

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

4) Prospective Microgrid Capacity: Research and model potential electric load available to microgrids within the state of Minnesota. 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.

5) 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 Minnesota.

6) 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.

c. Microgrid Institute Methodology and Timeline

The Microgrid Institute Team pursued this scope of study with a multidisciplinary team of industry professionals, each addressing discrete subject areas under coordination and direction by Burr Energy

LLC, the primary contractor. Specifically: Michael T. Burr (Burr Energy LLC) studied of all areas of analysis, consulted with more than 25 subject matter experts and stakeholders, and led White Paper composition, integration, and editing; Brian Meloy and James Bertrand (Leonard Street & Deinard) addressed Minnesota law, regulation, and policy issues and barriers; Walter Levesque (DNV KEMA) led efforts to research and model potential microgrid capacity in the state; Michael Zimmer (Thompson Hine LLP) addressed financial and project development issues, as well as Federal and other policy issues; John D. McDonald (IEEE) assisted efforts to analyze interconnection standards and practices; and Guy Warner (Pareto Energy) examined regulatory, finance, and market issues, and provided models for interconnection agreements and project structuring.

Commerce authorized the Microgrid Institute Team to begin its work on Aug. 2, 2013. The Team performed study and analysis during the month of August 2013, and wrote and delivered to Commerce the first complete White Paper draft on Sept. 11, 2013. The Microgrid Institute Team performed additional study to address subsequent comments by Commerce staff and others, and completed the White Paper for final integration into the Minnesota Energy Assurance Plan on Sept. 30, 2013.

B. Microgrid Drivers and Enabling Factors

Numerous factors are driving increased interest in microgrid solutions – not only in Minnesota and the United States, but around the world. The key factors are:

- **Energy Assurance:** The need for stable and sustainable energy supply at sites deemed critical for public services and safety, especially during wide-scale outages and natural disasters;
- **Reliability:** The need for greater resilience and reliability at high-priority commercial, industrial, military, and other sites, where outages can cause serious disruption, risks, and financial costs;
- **Clean Energy Development:** Public policy goals for increasing utilization of renewable resources, improving system efficiencies, and reducing greenhouse gas (GHG) emissions and other environmental effects of energy services;
- **Economic Development:** Imperatives for encouraging and facilitating economic development, attracting new businesses, creating jobs, and advancing technology capabilities.
- **Disruptive Technologies and Forces:** Transformative industry trends that make distributed generation (DG), energy storage, and energy management technologies more useful and cost-effective for a wider range of applications, which increasingly could challenge the traditional utility business model; and
- **Local Self-Reliance:** Energy end-users' interest in alternative service models, especially those that enhance local self-reliance, environmental quality, and economic health.

Minnesota's Energy Assurance Plan process provides a strong context for this White Paper analysis, because microgrids represent one of many tools available to policy makers, community leaders, and the energy industry for improving the ability to maintain critical community services during emergencies. Microgrids that can operate in isolation from a utility grid can help communities' efforts to recover from natural disasters and restore normal operations – both in public infrastructure and economic activity. Specifically microgrids could provide energy assurance for critical sites, such as police and administrative facilities, hospitals, and public shelters, when disasters trigger cascading effects in interdependent systems and sectors.

Thus energy assurance goals provide a useful framework for studying and promoting microgrids. And other factors, including clean energy goals, technology transformation, and economic development opportunities, can be combined with energy assurance to establish a strong framework for the State of Minnesota to support microgrid development.

However, microgrids face serious impediments in Minnesota. Many of these involve policy barriers and uncertainties. But just as importantly, the microgrid platform remains a technical and economic work in progress. Although microgrids of some description have been operating for decades, the integrated, flexible, fully featured microgrid concepts that have sparked the keenest interest today are almost nonexistent outside of laboratories and limited demonstration projects. Very few operating examples today demonstrate the full scope of services and capabilities envisioned for advanced microgrids; examples described in this report include microgrids at the Santa Rita Jail in California, and the FDA White Oak Headquarters in Maryland.

Most microgrids, however, are substantially more modest in their design capabilities and operating attributes. For example, some islandable backup power systems might be described as microgrids, but they are incapable of any function besides maintaining some level of operations during an outage or a load-shedding call by the utility. Other microgrids operating today are actually off-grid systems, not connected to a local grid, and therefore incapable of doing anything except maintain limited service for specific dedicated loads.

This reality is belied by a substantial amount of hype in the popular and trade press, and fueled by the promise of new development opportunities. Applying the Gartner Group's well-known "hype cycle" model might show the current level of interest in microgrids near or just past its peak of inflated expectations, with the "trough of disillusionment" coming just around the corner.[1] As one utility executive consulted for this study stated it, "Microgrid is a rising shiny object that certainly is attracting attention around the nation."

The current state of over-hype, however, should not be interpreted to mean that microgrids are either a pipedream or a passing phenomenon. In addition to the few advanced microgrids operating in the United States today, dozens more are in development in this country, with hundreds more around the world. Moreover, tens of thousands of U.S. sites are available for potential microgrid development as technologies and business models mature.

Importantly, the microgrid concept itself is highly flexible and adaptable, accommodating an extremely wide range of possible applications and solutions. Almost all options for major component technologies and models considered for use in microgrids are advancing and improving – some of them at a very fast pace, and others more slowly. But microgrids don't rely on any one technology pathway for future success; if CHP hits a plateau, PV and batteries will continue improving, for example. And energy management software and smart grid control systems used in microgrids continue advancing separately for a wide range of utility, industrial, and military applications.

Moreover the microgrid topology can be applied in a countless different scenarios, scaling from the very small to the very large. Solar-powered, 150-kW community energy systems in developing countries apply simple microgrid systems to deliver minimal power to users who otherwise rely on burning kerosene for lighting. Large industrial CHP systems, up to 100 MW (or more) in generating capacity, could become more cost-effective and useful with the addition of microgrid systems. College and corporate campuses are being considered for microgrid deployment, with some already operating and others being designed and built today. (Minnesota universities provide noteworthy examples.)

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[1] Gartner Group, Interpreting Technology Hype website:
http://www.gartner.com/technology/research/methodologies/hype-cycle.jsp

Beyond the concept of a microgrid for a single facility or campus, a few utilities are considering designs that would create islandable loops within an existing distribution system, adding DG and energy management systems to create a microgrid within the architecture of the macro grid. Proposals for community microgrids envision the creation of energy improvement districts and cooperative associations, combining the diverse resources and requirements of clustered facilities and customers. And some future concepts for industry transformation suggest that microgrid topologies could scale up – and out – in nested and connected circles, providing layers and webs of integrated generation and energy management systems that could seamlessly exchange resources and support each other through system disturbances and imbalances.

All of these approaches represent forward pathways for microgrids, and development along any path will bring technology advances and best practices that support the others. For this reason, the microgrid concept almost certainly will prevail through Gartner's trough of disillusionment to eventually reach its "plateau of productivity." Indeed, it could be the foundation of a new industry, with economic development and competitive benefits far greater than its perceived niche status today might suggest.

C. Barriers and Opportunities for Microgrid Development

Most of the impediments to microgrid development in Minnesota involve four major factors:

■ Utility practices, requirements, and planning norms
■ Regulatory and policy barriers, gaps, and disincentives
■ Perceived risks, costs, and complexities for execution
■ Limited technical assistance and support

Specifically, utility practices in many cases actively or inadvertently deter microgrid development. Utility power systems engineers understandably view any customer-owned DG as technically questionable until proven otherwise. Utility interconnection tariffs are written almost exclusively to protect utility systems, with no consideration for microgrids' operational capabilities and economics. Utility interconnection policies have not been amended to accommodate revisions in prevailing industry standards and technology requirements. Most utility system planners do not consider microgrids as potential resources or assets capable of addressing system constraints – or deferring capital expense requirements. Many utility executives consider microgrids, as part of the broader class of distributed energy resources (DER), to be potentially competing and disruptive technologies.

Facing such inhospitality in the utility system, microgrid developers likely will rely on support from end-use customers, community leaders, and policy makers. But there too they face substantial impediments.

Minnesota's vertically integrated utility industry is regulated on the basis of traditional cost-of-service ratemaking. Retail utility rates are approved by the Minnesota Public Utilities Commission (PUC) to allow utilities to recover their costs of service, with allowed rates of return on equity (ROE). Generally these rates bundle the full scope of utility services together in the customer's bill. Volumetric pricing allows utilities to recover their fixed costs and earn a profit, and that billing approach creates a potent financial disincentive against the utility encouraging or financing initiatives that either reduce kilowatt-hour sales or provide opportunities for third-party resource development. Microgrids do both of these things – reduce sales and allow third-party development – which puts them squarely at odds with investor-owned utilities' financial interests under the State's utility ratemaking model.

Additionally, Minnesota law is virtually silent on microgrids, which leaves major uncertainties across many areas of regulation, policy, and incentive benefits and provisions that are available to other types of energy assets and resources.

Finally, microgrid developers face normal resistance to change among potential end-use customers and host facility owners. While microgrid technology has been isolating industry load for decades, today it is being offered mostly by companies with unfamiliar names, who promise to deliver a new scope of end-use services – at a perceived premium price. As such, the microgrid business case is a tough sell for the typical commercial or public-sector customer, who today in Minnesota likely receives reliable energy service, at prices that generally are below the national average, from an investment-grade rated utility company.

All of that resistance notwithstanding, substantial opportunities exist in Minnesota for developing microgrids that provide tangible and important benefits to the state. In addition to microgrids' direct benefits for energy delivery, efforts to develop them will foster economic growth, technology development, and educational advancements in Minnesota.

Near-term opportunities most likely involve a prospective State-supported microgrid pilot program. The State can play a pivotal role in initiating and assisting pilot project development, to help these projects overcome Minnesota's structural and market-entry barriers. Further, such a pilot program would help create the regulatory and contracting structures necessary to allow commercial development and third-party financing in Minnesota. Medium-term and long-term opportunities could then follow, allowing microgrids to deliver a range of energy assurance, clean tech advancement, and economic development benefits.

D. Policy Pathways for Minnesota Microgrids

Minnesota has a solid tradition of supporting DG, renewable energy, and efficiency alternatives. This White Paper analysis, commissioned by the Minnesota Department of Commerce, represents a promising step toward a future in which microgrids can serve Minnesota's policy goals. Next steps are described in Chapter V: Microgrid Roadmap.

Generally these policy steps involve:

- Setting and clarifying the role of microgrids in the State's policy vision and priorities, and integrating that role in regional planning
- Removing or reducing regulatory barriers and artificial, outdated institutional impediments to microgrids
- Establishing statutory frameworks and processes to support microgrid development as part of the State's utility planning and oversight roles
- Initiating and supporting a microgrid pilot program

The Minnesota Microgrid Pilot Program would provide a vital platform for developing and financing microgrids in the state. But its success hinges in part on efforts to advance the policy landscape so that it accommodates and supports microgrids, allows their development, and serves to attract available capital. We recommend that the State of Minnesota define "microgrid" for policy purposes, and reinforce the State's interest in enabling and encouraging microgrid development – consistent with its energy, environmental, and economic policy roles. Microgrids also should be considered as part of the State's broader strategic review of transformative forces in the utility industry, to ensure planning processes appropriately consider new technologies and business models.

With regard to regulation, we recommend, first and foremost, that State update interconnection standards and tariffs to address changing industry standards and market needs. At a minimum, the State's interconnection standards should conform to prevailing industry standards – specifically IEEE 1547 and the Federal Energy Regulatory Commission's Small Generator Interconnection Procedures and Agreements, including new amendments and changes.

Further, microgrids should be considered in utility system planning and resource planning processes, including periodic integrated resource plans (IRP) and regional transmission plans. We also recommend that the State reduce structural disincentives that hinder microgrids, and consider alternative utility rate mechanisms, cost-recovery approaches, and incentive programs that encourage and reward utility efforts to facilitate microgrid development.

Finally, we recommend statutory amendments and new legislation to allow microgrids to qualify for incentives afforded to other clean energy and reliability investments, such as funding through system benefit charges, PACE financing models, and bond financing. And we recommend that the State clarify regulatory and siting provisions that exempt microgrids from regulation as public utilities.

Taking these steps, the State of Minnesota can help ensure microgrids provide cost-effective and flexible solutions to address the State's policy goals, and become available as tools for efficiency, reliability, and economic development with 21st-century technologies. In particular, its commitment to establishing a Minnesota Microgrid Pilot Program would jump start these efforts in the state, and allow microgrids to move quickly toward the technology cycle's "slope of enlightenment," and onto the "plateau of productivity."

Chapter I:
MICROGRID DRIVERS AND OPPORTUNITIES IN MINNESOTA

A. Microgrids Old and New

Historically, many kinds of energy users in Minnesota have used onsite power systems. But while systems of the past provide instructive context and perhaps represent development opportunities, modern microgrids provide a much broader range of features and functionality, making them suitable to address a larger group of end-use applications.

1. Historic Context for Microgrids in Minnesota

Distributed energy resources (DER) have served Minnesota residents and communities since the earliest days of electricity-powered machines. Indeed, before the Rural Electrification Act of 1936 and electrification efforts in the 1930s and ’40s, such companies as Delco-Light sold gasoline-burning “electric plants” for homes and farms that hadn’t yet been connected to utility systems.[2] Many farms in Minnesota used “wind chargers” combined with lead-acid batteries and internal-combustion generators to provide power for lighting, pumping, welding, and other farm applications. The LeJay Manufacturing Company in Minneapolis distributed a popular farm equipment catalog in the 1930s and ’40s that featured parts and instructions for wind chargers and related electrical equipment.[3]

Such isolated power systems might be considered “quasi-microgrids”: not true microgrids in the strictest sense of the word. In most of the industrialized world, a microgrid is assumed to have a connection to a utility grid, except during times when it’s intentionally islanded – disconnected to operate in isolation, for instance during a storm outage.[4] (*See Appendix B: Microgrid Definitions.*)

Minnesota also has ample experience with two other forms of quasi-microgrids: cogeneration (or “CHP” for combined heat and power) plants, such as those at numerous paper mills and other industrial sites; and district energy systems, like those in downtown St. Paul and Duluth. These systems, however, are more limited in their functions than today’s sophisticated islandable microgrids. In the case of district energy plants, they generally provide thermal energy and not electricity service, and most CHP plants serve only dedicated loads, independent from utility service. Nevertheless, these systems provide familiar analogues for the microgrid concept – and in some cases they might also represent the building blocks for bona fide microgrids.

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[2] “Delco-Light Farm Electric Plant, 1916-1947,” *Doctor Delco* website: http://www.doctordelco.com/Dr._Delco/Welcome.html

[3] *Wind Charger Hall of Fame* website: http://www.windcharger.org/Wind_Charger/Hall_of_Fame.html

[4] The term “microgrid” (and “minigrid” in the parlance of the United Nations Foundation) also can describe entirely off-grid systems, in remote locations and on islands in the ocean. For the purposes of this paper, unless otherwise specified, “microgrid” means a utility-connected system that is capable of operating in isolation for some period of time. Our definition also will assume the microgrid has automatic energy management capabilities to balance critical loads against available energy supply. A recreational vehicle with a 110-volt power cable, a gas-powered generator, and a battery backup does not have a microgrid by our definition, because it has no capability to automatically balance load against supply.

2. Modern Microgrid Technologies and Emerging Features

New microgrid technologies and standards are emerging and promise to expand the functionality of microgrids and improve their cost-effectiveness – extending the potential range of end-user needs they can address.[5]

a. Design Technology and Fuels

Conceptually, a microgrid design can include several key functional components, each of which can be comprised of any number of different technologies and operational processes. (*See Figure 1-1*). These components include:

- Energy supply system (*e.g.,* distributed generation)
- Energy storage capacity (usually batteries and thermal storage)
- Demand response and efficiency measures
- Energy management systems
- Utility grid interconnection or non-synchronous connection

Virtually any distributed generation technology can serve in a microgrid configuration. The most important examples to date include CHP, microturbines, internal combustion engines, fuel cells, photovoltaic (PV) arrays, wind turbines, and small hydro power systems. In combustion systems, the full array of gas and liquid fuels can be used, including natural gas, gasoline, diesel, fuel oil, kerosene, naphtha, and biogas. Solid fuels, including biomass, coal, and petroleum coke, conceivably could be used in some CHP-based applications, but emissions concerns tend to limit the more polluting options. GHG standards recently proposed by the Environmental Protection Agency might make solid fossil fuels less likely for new generating units.[6] In the future, it's conceivable that small modular reactors could supply nuclear power for some microgrids, especially remote mission-critical installations such as military bases.[7]

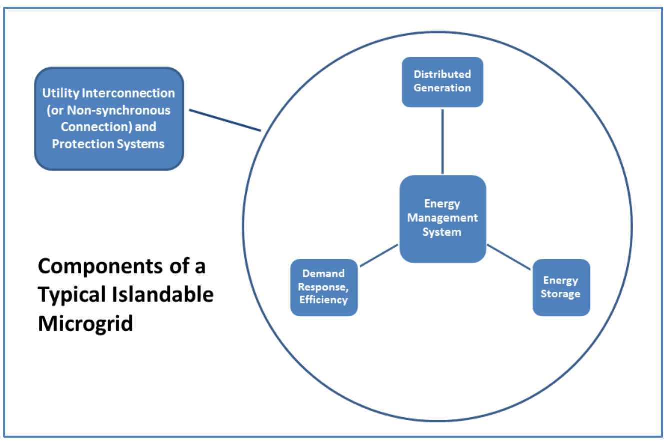

Figure 1-1: **Components of a Typical Islandable Microgrid**

Source: www.microgridinstitute.org, ©2013 Burr Energy LLC

b. Demand Response and Efficiency

Advanced microgrid designs today also include demand response (DR), conservation, and efficiency measures that aim to minimize overall energy use, and most importantly to reduce non-critical load during periods when the microgrid is operating in isolation from the utility grid. Demand-side management (DSM) measures can reduce total capacity (including storage) required to support the

[5] Schneider, Stephen: "March of the Microgrids: Technology is changing the game. Is your utility ready?" *Public Utilities Fortnightly,* January 2013.

[6] *Standards for Performance of Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 40 CFR Part 60,* Proposed Rule, Sept. 20, 2013.

[7] Such companies as NuScale Power, owned by Fluor Corp., are developing small modular reactors as small as 45 MW and promoting them for CHP and mission-critical microgrid applications. *See* www.nuscalepower.com/commercialapplications.aspx

microgrid's stable operation. Generation capacity generally is the most expensive component of a microgrid system, and as such, economically efficient use of DSM measures serve to optimize a microgrid's asset mix and reduce capital costs and operating costs. They also can help to maximize the exploitation (*i.e.,* capacity factor) of variable and non-dispatchable energy sources like wind and solar, reducing utility power purchases and fuel costs. (*See Chapter I-D-3. High-Penetration Wind and Solar.*)

A microgrid's load control capabilities also can allow it to provide DR capacity to support utility load shifting and load reduction requirements, and also might allow the microgrid operator to sell dispatchable DR capacity into wholesale markets, further supporting microgrid economics by generating sales revenue. The Midcontinent Independent System Operator (MISO) provides some opportunities for DR sales, and its Demand Response Working Group (DRWG) is working to address barriers and create mechanisms for DR to participate in the market.[8]

c. Energy Storage

Many microgrid designs also can include some form of energy storage. This usually takes the form of chemical battery systems – most commonly fixed lead-acid batteries, which today are the most economical – but sometimes more advanced systems, such as nickel-cadmium and lithium-ion batteries. Some campus microgrids also might include vehicle-to-grid (V2G) systems that can exploit capacity in electric vehicle (EV) batteries that are plugged into campus recharging stations.[9] Large campus microgrids might be among the first natural markets for V2G. Smart charging can allow EVs to participate in some DR markets.

Some microgrid designs today include standalone battery electric storage technologies, sometimes only to assist in the automatic transition from grid-connected to isolated operation, before captive generation sources are fully online and DR measures become most effective. Storage also supports voltage and frequency stability in an islanded microgrid, during periods when load and supply otherwise might fall out of balance. While battery costs and efficiency penalties have made them less cost-effective than other options for peak-shifting,[10] batteries can be used in some circumstances to reduce peak demand. Other, lower-cost energy storage technologies, however, might be more cost-effective for DSM, peak-shifting, and supply capacity-factor optimization. Such technologies include thermal storage – via pre-heating of water for CHP steam cycles, building and district heating, and absorption chiller systems. In other cases, pre-cooling and ice storage systems can cost-effectively shift air conditioning (AC) loads. Some microgrids also might incorporate mechanical storage in any of several configurations – via compressed air, pumped water, or even perhaps flywheel or other kinetic systems. Depending on how they're deployed, these storage technologies could address load management, voltage and frequency support requirements, or both.

d. Microgrid Controls and Energy Management Systems

Within the boundaries of a microgrid, all supply, storage, and demand-side resources can be combined and managed with electronic energy management systems (EMS) – which in some cases are purpose-built applications, and in other cases are simply scaled-down and adapted versions of distribution management systems (DMS) that technology vendors provide for distribution utilities.[11] Microgrid EMS

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[8] "2013 Entity Management Plan," MISO Demand Response Working Group, 2013.

[9] Simpson, Mike: "Microgrid V2G Charging Station Interconnection Testing," Electric Power Research Institute Infrastructure Working Council presentation, National Renewable Energy Laboratory, July 17, 2013.

[10] *Levelized Cost of Energy Analysis, Version 7.0,* Lazard, August 2013.

[11] Vendors currently offering microgrid energy management systems include ABB, General Electric, Honeywell, Lockheed Martin, Siemens, and many others, large and small, too numerous to list.

technologies are designed to maintain balanced and stable operations within a microgrid through numerous other systems and technologies, including remote sensors, switches, inverters, and load control devices. The effectiveness of a microgrid EMS at maintaining stable operations is determined largely by the sophistication of its process automation programming, as well as its degree of control over the full range of energy assets and processes within the microgrid.[12]

e. Seamless and Safe Connection and Islanding

Microgrids can be engineered to connect to utility systems with switchgear and protection systems that are meant to ensure safe and smooth operation through all modes – *i.e.,* fully grid-connected, islanded, and during transition, while an islanded system is preparing to re-connect to the grid. Some – but not all – microgrids are fully synchronized to the alternating current (AC) on the utility feeder line, matching the microgrid's power to the voltage, frequency, and phase angle of the utility's power. This provides for safe and seamless transitions from connected to islanded modes, and makes it possible for the microgrid to synchronize with the grid and feed power into the utility system. The synchronized configuration is more complex, but it can improve microgrid economics via power sales transactions, net-metering, and value-of-solar tariff (VOST) arrangements (*See A-1-d. Win-Win Microgrid Models*).

Interconnection equipment and practices are governed by technical standards and operating procedures, as well as interconnection tariffs and agreements between microgrid operators and connected utilities. (*See Chapter II-B. Interconnection Standards and Microgrid Integration*). Although some interconnection standards and agreements are well established, they also are in the midst of substantive changes that prospectively will resolve some uncertainties affecting microgrid interconnection, and in the future these standards are expected to provide greater opportunities for microgrids to serve as key assets in an integrated smart grid system.

3. Microgrids Today and Tomorrow

Few functioning microgrids today include all or most of the features that can be designed into a microgrid. This is especially true for islandable microgrids larger than 2 MW in capacity. Some are discussed below, but the most fully integrated microgrids are demonstration-scale systems. These projects are serving as technology test beds and examples of what larger commercial microgrids will be able to accomplish in the future.

B. Energy Assurance Imperatives

For policy makers, microgrids represent one of many tools for improving the ability to maintain critical community services during emergency situations that result from extended power outages. To what degree microgrids will serve this purpose in Minnesota depends on a variety of factors – some of which are unrelated to microgrid technology or regulatory issues.

Relative to other states, Minnesota's electrical grid provides a high degree of reliability for several reasons. First, Minnesota's transmission and distribution systems are newer than those of some other states, notably those in the Northeast. Second, the state has suffered fewer catastrophic "storms of the century," and none on the scale of Superstorm Sandy. Moreover, the interstate regional transmission grid hasn't experienced any disturbances on the order of the 2003 Northeast Blackout or the California energy crisis. Additionally, Minnesota's population density is lower than that of many states, which results in relatively fewer numbers of people affected by large storms and outages.

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[12] Piagi, Paolo, and Robert H. Lasseter, "Autonomous Control of Microgrids," IEEE PES Meeting, Montreal, June 2006.

Nevertheless, Minnesota does suffer significant outages, with noteworthy examples occurring recently. The state's grid faces major blizzards and ice storms, saturating rain storms and floods, high winds and tornadoes, and the failure of engineered transmission systems. At this writing, utility customers in Minnesota already had experienced two major storm-related outages during 2013. First, a series of winter storms in April destroyed thousands of power poles in southwestern Minnesota, and left large areas of without power for several days. Then, powerful wind storms in late June left nearly 200,000 residents in the dark for days on end.

So while Minnesota has been spared the sense of urgency that has spurred development in some states, concerns about reliability and resilience are contributing to growing interest in microgrids as tools for energy assurance and climate change adaptation in the state.

Moreover, as the technologies involved in microgrids become more effective and economical, microgrids seem likely to become an increasingly viable solution for a range of end-user requirements, including the need for energy supply assurance during outages and crisis situations.

1. Critical Community Assets and Microgrid Applications

The most logical applications of microgrids for community energy assurance purposes involve facilities in three categories: crisis response and management; public health, safety, and shelter; and basic needs and services. (*See Figure 1-2.*)

Asset Category	Examples	Priorities and Microgrid Factors
Crisis Response and Management	■ Utility and transportation crew dispatch, supply, and staging centers ■ Government command and control centers ■ Telecom infrastructure	■ Critical to facilitate repair and recovery, minimizing the damage from a crisis and avoiding cascading effects on interdependent systems. ■ Microgrids can be more effective when crisis management facilities are clustered together, allowing asset sharing and load diversity.
Public Health and Safety	■ Hospitals and other health care facilities ■ Police and fire departments ■ Public water systems	■ Vital to support first response, medical care, and law and order. ■ Many such facilities already have backup power systems that can be upgraded with microgrid technologies to increase their effectiveness.
Basic Needs and Services	■ Storm shelters and temporary housing ■ Grocery stores ■ Fuel infrastructure, including gas stations ■ Public transportation and transit systems	■ Vital products and services to support basic needs of residents, and provide shelter and vital mobility for displaced and at-risk populations. ■ Load-management systems and protocols can help conserve fuel and extend effectiveness of basic backup power supplies.

Figure 1-2: **Energy Assurance Priorities and Microgrid Applications**

2. Other Critical-Use Facilities Requiring Resilient Power Supply

Some of the largest and most sophisticated microgrids in use today are installed at critical-use facilities where outages can have serious consequences. These facilities don't necessarily fall into the main categories of critical community assets and services, but they merit robust backup power capabilities for other reasons.

One major example involves U.S. military bases across the country – and also forward operating bases elsewhere in the world. The U.S. Department of Defense identified microgrids as an important technology solution to assure energy supply security at military installations, and each branch has begun exploring microgrid options at various bases for that purpose.[13] Microgrids not only provide resilient supply with high security (including cybersecurity) to power critical military base functions during utility outages, they also allow isolated bases to increase the use of solar and wind resources, reducing the amount of fuel that must be delivered via costly and hazardous supply lines.

No microgrids are yet being developed at U.S. military bases in Minnesota, although some related efforts are underway that could serve as precursors. For example, the Minnesota National Guard training facility at Camp Ripley established net-zero energy goals, and recently completed a project to install geothermal space heating at the camp. Also the Army training facility in Arden Hills installed an uninterruptible power supply at a telecom data center.[14]

Other non-military government applications – for example, at the U.S. Food and Drug Administration's (FDA) White Oak Headquarters in Maryland, and the Santa Rita Jail in California – illustrate some of the most advanced microgrid deployments operating in the country today.

a. FDA White Oak Headquarters

A large campus with several buildings north of Washington, D.C., the FDA's White Oak Headquarters houses several laboratories that perform highly sensitive tests and experiments. Frequent outages in the Mid-Atlantic region – due to severe storms and aging utility infrastructure – led the FDA to install a microgrid with several generation sources. Currently the facility has 26 MW of generating capacity, including gas turbines and internal combustion generators, with additional phases expected to expand the system to more than 65 MW. Additionally, CHP infrastructure supports heating and evaporative cooling for what ultimately will be a campus exceeding 4 million square feet in size. A 2 million-gallon water tank provides thermal storage and backup water supplies in case of disruption in municipal water supplies. Reportedly the FDA White Oak microgrid has successfully islanded itself more than 70 times since the beginning of 2011, without disruption of critical loads in the campus.[15]

b. Santa Rita Jail

The Santa Rita Jail Microgrid integrates energy from multiple resources at the Alameda County (Calif.) complex – the fifth-largest prison in the United States, housing more than 4,000 inmates, near San

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[13] Van Broekhoven, S.B., *et al.*: *Microgrid Study: Energy Security for DoD Installations,* Technical Report 1164, prepared for the Office of the Secretary of Defense by the Lincoln Laboratory, Massachusetts Institute of Technology, June 18, 2012. See also for example, *Army Energy Security Implementation Strategy,* Army Senior Energy Council and the Office of the Deputy Assistant Secretary of the Army for Energy and Partnerships, Jan. 13, 2009.

[14] *2011 Annual Report and 2012 Objectives,* Camp Ripley Training Center and Arden Hills Army Training Site, Minnesota National Guard, updated Oct. 24, 2012.

[15] Note that "disruption" and "interruption" are related but separate terms. Users on an islandable system might experience brief interruptions during a utility outage while backup systems start up.

Francisco. The microgrid combines several existing generating resources, including PV arrays totaling about 1.5 MW, a 1-MW CHP-capable molten carbonate fuel cell, and backup diesel generators, along with a 2-MW, 4-MWh lithium-ion phosphate battery system. The overall system is electrically controlled by smart grid technology developed by the Consortium for Electric Reliability Technology Solutions (CERTS), as part of both the U.S. Department of Energy's Renewable and Distributed System Integration (RDSI) and California Energy Commission's Public Interest Energy Research (PIER) programs.[16] The goal of the RDSI program was to demonstrate 15 percent feeder peak load reduction by control of local distributed resources, while the PIER program is aimed at creating technology for sustainable communities. The project at Santa Rita Jail is expected to address integration challenges for new wind power, large-scale energy storage, demand response and solar thermal systems − along with the jail's pre-existing solar photovoltaics, fuel cell cogeneration system, and energy efficiency investments. Additionally the microgrid project aimed to address the facility's needs for energy independence, system reliability, high security, and energy management.[17]

Additionally the project serves as a test bed for the CERTS control technology and its ability to use fast-acting electronic power converters to balance loads and resources and maintain stable and high quality power through various system conditions. The jail's key reliability objective is ensure it never goes black following loss of grid power, or other local disturbance. The system can perform fast seamless disconnection, resynchronization, and reconnection. While islanding, the CERTS technology uses battery capacity for fast response and energy balance. These capabilities and the diverse nature of resources make Santa Rita one of the most advanced high power-quality microgrid demonstrations to date.

3. Roles of Microgrids in Community and State Energy Assurance Planning

Several U.S. states have asserted leadership in incorporating microgrid initiatives into their state planning efforts. At the forefront are Connecticut, New York, New Jersey, and California.

a. Connecticut DEEP Microgrid Initiative

The most comprehensive state-funded microgrid program in the United States today is proceeding in Connecticut. The processes and models being developed in Connecticut could serve as templates for other states seeking to encourage microgrid development for energy assurance purposes. (Note, however, that Connecticut's initiative is aimed solely at energy assurance, whereas other states also are targeting GHG reductions and renewable energy goals.)

Two major storms in 2011 – Hurricane Irene and an October Nor'easter – caused widespread and long-lasting outages in Connecticut, and prompted Gov. Dannel Malloy to form a task force to consider options for improving the resilience of the state's utility systems. The task force recommended, among other things, that the state consider ways to encourage development of microgrids to assure energy supply at critical community facilities. The State General Assembly subsequently enacted a bill (*CT Public Act 12-148*) that directed the Connecticut Department of Energy & Environmental Protection (DEEP) to "establish a microgrid grant and loan pilot program to support local distributed energy generation for

[16] Marnay, Chris, Nicholas DeForest, and Judy Lai: "A Green Prison: The Santa Rita Jail Campus Microgrid," presented at 2102 IEEE PES General Meeting, July 22, 2012.
[17] Abrams, Robert, and Benjamin Lawsky: *Moreland Commission on Utility Storm Preparation and Response, Final Report,* June 22, 2013.

critical facilities."[18] The State provided $18 million in 2012 for pilot projects, and DEEP issued a request for proposals (RFP) in April 2013, seeking projects for microgrids capable of operating in isolation continuously for at least four weeks. In July, DEEP selected nine community proposals to receive pilot project grants, from among 36 submitted proposals. (*See Figure 1-3*).

Proposals were subjected to feasibility analysis by the state, a technical consultant, and the state's two major utilities, Connecticut Light & Power and United Illuminating. Moreover, the two utilities are working closely with DEEP and the communities selected for project grants. In one case, CL&P's underground feeders and distribution facilities will comprise the bulk of the microgrid network, serving a cluster of buildings in Hartford's Parkville neighborhood.

The DEEP RFP specified that grant funds are to be used for microgrid design, engineering, and interconnection infrastructure; grant funds are not to be used to acquire generation resources, or for any work on non-critical facilities. The funding limit per award was capped at $3 million, and DEEP suggested that matching funds should be obtained to finance costs above that total.[19] Gov. Malloy recommended that the Assembly allocate an additional $30 million for projects in the next phase of the State's microgrid pilot program.

Host	Microgrid Project Details *Note: DEEP grants do not fund generation assets.*	Energy Sources	DEEP Grant
Bridgeport	■ City hall, police station, and senior center	■ Three 600 kW gas-fired microturbines	■ $2.97 million
Fairfield	■ Police station, emergency operations center, cell tower, fire HQ, and homeless shelter	■ 50 kW and 250 kW gas-fired engines, 47 kW PV array	■ $1.16 million
Groton	■ Naval submarine base	■ 5 MW turbine CHP, 1.5 MW diesel generator	■ $3 million
Hartford - Parkville Cluster	■ Parkville neighborhood, including school, senior center, library, supermarket, and gas station	■ 600 kW gas turbine	■ $2.06 million
University of Hartford	■ University campus and St. Francis Hospital	■ 250 kW and 150 kW diesel engines plus existing 1.9 MW diesel engine	■ $2.27 million
Middletown	■ Wesleyan University campus and athletic center/public shelter	■ 2.4 MW and 676 kW gas-fired CHP	■ $694,000
Storrs	■ University of Connecticut Depot campus	■ 400 kW fuel cell, 6.6 kW PV array	■ $2.14 million
Windham	■ Two schools for public shelter	■ Two 130 kW gas engines, 250 kW PV array, 200 kWh battery, and 2 kW diesel	■ $639,950
Woodbridge	■ Police station, fire station, Department of Public Works, town hall, and high school	■ 1.6 MW gas turbine, 400 kW fuel cell	■ $3 million

[18] CT Public Act 12-148 § 7, *Enhancing Emergency Preparedness and Response,* State of Connecticut, Approved June 15, 2012.
[19] "Request for Proposals: Microgrid Grant and Loan Pilot Program," Connecticut Department of Energy & Environmental Protection, April 9, 2013.

Figure 1-3: **Connecticut DEEP Microgrid Pilot Project Grants**

b. Microgrids and DG in New York City

Consolidated Edison, the primary distribution utility serving New York City, has for several years considered customer-owned DG to be valuable resources. In its 2010 long-range plan, for example, the company stated "some distributed generation technologies have become not only cost-effective options, but also offer an opportunity to increase system reliability by relocating load from the central station to the end-use location; and to reduce GHG emissions"[20] The company expects substantial growth in customer-owned DG, much of it from gas-fired CHP projects.[21]

As part of its 2010 rate case, Consolidated Edison collaborated with a group of stakeholders to consider methods of expanding customer-owned DG in its service territory. Participants included the City of New York Economic Development Commission, Westchester County, the New York Power Authority, and the New York/New Jersey Port Authority, among others. Their efforts included work to advance DG interconnection and control technologies that would address the utility's concerns about safety and adverse system effects, while also providing affordable and flexible options for operation of DG and microgrids.

Since their work in 2010, five so-called "storms of the century" have caused multi-day power outages in New York as well as several Northeastern states. In the wake of Superstorm Sandy, both the City and State of New York have called for distributed generation systems that can island to provide resilient power supplies. The New York State Energy Research and Development Authority (NYSERDA), which provides grants for distributed generation, mandates that projects applying for funding must demonstrate an ability to island. And most recently, in a June 2013 report, Mayor Michael Bloomberg's office endorsed the recommendations of the NYC Special Initiative for Rebuilding and Resiliency. Those recommendations, in part, called for addressing regulatory barriers to microgrid development in the state and the city, including re-evaluating tariff structures and interconnection standards for DG.[22]

Additionally the report commits the City to working with several groups, including NYSERDA, to explore the feasibility of microgrid pilots throughout the city, and to study the technical and economic effects of higher penetration of microgrids in New York City. Separately the City set a goal to increase DG in municipal buildings to 55 MW by 2017.

c. Microgrids in California Local Energy Assurance Planning (CaLEAP)

With funding from the U.S. Department of Energy, the California Energy Commission (CEC) launched the California Local Energy Assurance Program (CaLEAP) in September 2011. The program aims to help local governments become more energy resilient, through planning, tools, and efforts to improve energy assurance for critical community assets.[23] CEC and consulting firm ICF International are working with about 50 counties and cities, helping local leaders, utility executives, and others to develop strategic plans for energy assurance, and providing technical support. As part of that support, the program hosted three workshops for CaLEAP stakeholders focusing on microgrids. One such workshop involved a visit to the campus microgrid at University of California-San Diego (UCSD).

[20] *Consolidated Edison, Electric System Long Range Plan, 2010-2030,* Consolidated Edison, December 2010, p. 83.
[21] Jolly, Margarett, David Logsdon, and Christopher Raup: "Capturing Distributed Benefits: Factoring customer-owned generation into forecasting, planning, and operations," *Public Utilities Fortnightly,* August 2012.
[22] *A Stronger, More Resilient New York,* PlaNYC report, City of New York, June 11, 2013.
[23] CaLEAP website: http://www.caleap.org/

Additionally, consulting engineering firm EnerNex contributed to the CaLEAP effort by assisting some cities with specific project planning efforts. Such issues include concerns about microgrid and backup power interconnection and regulation, and also considerations that help cities think ahead about energy assurance planning. Building codes, for example, might be amended to contemplate more advanced energy management and power control technologies, and land-use plans might consider the prospect of clustering critical facilities together so they can be more effectively served with a microgrid.

Although CaLEAP isn't promoting microgrids as such, the program is encouraging communities to collaborate with utility companies. Several California utilities have become engaged in these efforts and now are exploring how to cooperate on developing projects for local energy assurance – and how to integrate local goals and projects into long-term system planning.

4. Complexities Facing Microgrids in Energy Assurance Planning

Efforts to include microgrids and related solutions in state and community energy assurance plans have encountered some noteworthy complexities and questions.

For example, stakeholders in Connecticut note that among the 36 proposals in the first round of DEEP's microgrid pilot program, virtually all of them were submitted by relatively affluent communities. Poorer cities and towns in Connecticut – which arguably have the greatest need for improvements in resilience and energy assurance – did not respond to the RFP. Causes for this merit further examination, but one possible explanation involves a lack of resources in those communities to perform the planning and development necessary to prepare a bid. Also DEEP grants cannot be used to finance generation systems, which typically are the most costly parts of a microgrid. Communities that lack existing DG might have chosen not to bid simply because they had no clear way to finance new generation investments.

Finally, many local decision makers have only limited experience with energy systems, markets, and regulation. A successful energy assurance planning approach requires a sophisticated understanding of system operations and requirements, as well as interdependencies with other infrastructure systems and markets. A diesel-fired generator, for example, can run only as long as fuel is available and can be replenished, which during a crisis can be difficult or impossible. Further, economic issues can lead facility managers to maintain only minimal supplies, limiting the time that a microgrid can operate during a system outage. Such factors might be well understood by crisis management professionals, but they introduce complexities that can deter local energy assurance planners from pursuing some onsite generation options.

C. Microgrids as Utility Reliability Assets

Because they represent large dispatchable loads, microgrids can in principle serve as DR resources. In markets where they can be compensated for this service, microgrids can earn revenue by islanding themselves or simply by applying their internal load-management capabilities to reduce their power consumption during peak demand periods. At this time DR resources in Minnesota have limited potential to participate in regional markets, but MISO reportedly is working to improve market access for DR capacity.

Beyond load reduction, microgrids can serve as valuable assets in an integrated smart grid. Multiple technology vendors are developing systems and approaches to serve this purpose, and experiences and tests so far demonstrate substantial potential. Achieving that potential, however, depends on more than technology innovation, and external factors likely will delay widespread use of microgrids as utility reliability assets – except for the simplest DR applications.

1. Microgrids as Part of an Integrated System Approach

a. Dakota Electric Dispatchable Microgrids

In the territory of Dakota Electric Association, several onsite power systems provide the utility cooperative with load-shedding services. These systems function similarly to traditional utility interruptible loads, but they can be described as microgrids[24] because they are capable of islanding and operating in isolation from Dakota Electric's system. Some of them serve multiple buildings via underground infrastructure. The systems – which range in size between 2 MW and 15 MW – rely on diesel-burning generators to provide backup power in case of outages. Dakota Electric offers discounted interruptible power rates to members who install these systems, which run, on average, for between 60 and 80 hours each year.

The first such systems on Dakota Electric's system were installed in the late 1990s. One example was installed in 2001 at the Treasure Island Resort & Casino. The current 8 MW system is capable of fully powering a complex of nine casinos, a resort, and other buildings on an island in the Mississippi River. It includes four 2 MW Caterpillar diesel generators, with automatic engine controllers that work to synchronize generator output with utility service during a three-minute "soft loading" transition process. In this way the system can be dispatched and the complex can be isolated from the utility system without any effect on electric service. Operators preemptively island the system when severe weather approaches, for example, without significant interruption. In event of a grid power outage, the system automatically starts up, islanding the ring bus that circles the complex and restoring power in less than 30 seconds.

Treasure Island leases the microgrid system from NRG Reliability Solutions, a subsidiary of Princeton, N.J.-based NRG Energy – the successor company to the former Xcel Energy subsidiary. NRG manages generation system operations and maintenance under its lease agreement with Treasure Island, in cooperation with the casino's onsite manager.

For Treasure Island, the microgrid ensures that it can continue regular operations during utility outages. An onsite 10,000-gallon diesel tank provides sufficient fuel for about three days. The generation system is oversized for the casino's load, which during summer peak periods equals about 60 percent of total onsite diesel capacity. Thus the casino has not installed DR systems, but it is pursuing conservation measures to reduce lighting load.

For Dakota Electric, systems like the one at Treasure Island allow the cooperative to work with its member-customers to ensure they can obtain highly reliable services. Dakota Electric installed and owns the ring bus and transformers at Treasure Island, as well as the radio-control system that allows the utility to dispatch the microgrid. It uses standardized, utility-specified breakers and switches that allow safe operation and maintenance.

d. DG Forecasting and Capital Planning at Consolidated Edison

Consolidated Edison's DG planning processes have explored the potential of customer-owned DG not only for peak-load management, but also as part of a long-term strategy for forecasting load and supply resources, and planning distribution investments.

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[24] For the purposes of this study, these installations do not meet the definition of fully featured microgrids because they lack the ability to balance internal loads against the available supply. Instead they simply operate sufficient backup generation to satisfy the systems' expected peak loads.

Starting in 2011, the company began modifying its DG planning practices in an effort to quantify the amount of reliably dispatchable DG capacity on its system, and to integrate that quantity into its 10-year and 20-year load forecasts. The company reports that this effort has allowed it to defer distribution system investments. "For example, 24 MW of summer peak-period baseload output of existing CHP capacity is defined as a load reduction in Con Edison's current area substation and sub-transmission plans – some of which, depending on location, has allowed Con Edison to defer traditional, costly utility infrastructure investments."[25]

Such an approach applied to microgrids – which could represent large blocks of curtailable load – might allow utilities to optimize their reliability investment plans, leading to more cost-effective deployment of capital and lower costs for customers.

b. Microgrids as Part of "Self-Healing" Architecture

A primary aspect of the smart grid concept for utilities involves its ability to improve reliability and resilience to issues that cause outages and power quality problems. In some sophisticated applications, intelligent systems can automatically isolate a line fault and re-route power around it to minimize the number of affected systems and users. Such a scenario is commonly referred to as "self-healing"[26] or "automatically reconfiguring" architecture, and technology researchers suggest that microgrid technologies could serve an important role in a self-healing smart grid.

By definition, an islandable microgrid is a reconfiguring system; when a utility system fault is detected, the microgrid is isolated – automatically or manually – to maintain service. However, most microgrids are contained within a specific facility or campus, and therefore they do not act as part of a utility self-healing architecture. They could, however, be applied to do just that.

For example, in the Parkville Cluster microgrid that CL&P expects to develop in Hartford, a microgrid will be created using existing utility infrastructure, with automated switches deployed so they can isolate the segments that serve several facilities in the Parkville neighborhood. When isolated, this closed loop will operate as a microgrid, with generation provided by captive DER within the neighborhood.

With additional technology steps, a microgrid's DG, storage, and load-management capabilities could be dispatched by substation automation systems to help the utility serve customers outside the traditional boundaries of the microgrid. Aspects of such an application are being demonstrated and studied in various forms, including the examples below.

c. Borrego Springs Neighborhood Microgrid

At Borrego Springs, San Diego Gas & Electric is developing a microgrid system to demonstrate how multiple technologies – including DER, feeder automation, outage management, and advanced controls and communications – can be used in a microgrid configuration to improve power grid reliability. The project aims to support the stability of the local distribution system by allowing SDG&E to manage feeder and substation capacity.

The system incorporates two 1.8 MW diesel generators, two transformers, a SCADA switch, and a microgrid control system, along with a 500 kW, 1,500 kWh battery at the Borrego substation, plus three

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[25] Jolly, p.34.

[26] Note: Power system engineers point out that the term "self healing" is deceptive, because the system does not actually repair the fault. It merely reconfigures itself to minimize that fault's effects on system operations. "Automatic reconfiguring" is a more precise term, but "self healing" generally is understood in the industry to mean the same thing and not to imply automatic fault repair.

community storage batteries (25 kW, 50 kWh each) and six home storage batteries (4 kW, 8 kWh).[27] SDG&E expects the project to demonstrate the potential value of using a system-integrated, multi-customer microgrid for price-driven load management and feeder optimization applications.

e. Cell Controller Project in Denmark

Energinet.dk, Denmark's state-owned gas and electricity transmission utility, initiated the Cell Controller Pilot Project in 2005 to develop and demonstrate using grid-connected DERs to support grid reliability and power-flow applications.[28] Over a seven-year period, the project sought to coordinate the control of local energy assets, including CHP plants, wind turbines, and DR resources, to provide grid-scale ancillary services. Additionally the project envisioned developing the capability to isolate local distribution networks (60 kV and below) during a system outage and to continue operating them on local DG supplies – *e.g.,* as part of a self-healing architecture.

The project involved evaluating a broad range of field assets and capabilities across the Danish utility system, and developing control strategies and systems. Spirae Inc. of Fort Collins, Colo., was Energinet.dk's primary contractor for developing, testing, and commissioning the Cell Controller system. Spirae and the project team tested the concept with modeling and simulation at Energinet.dk's InteGrid Laboratory, and ultimately began deploying Cell Controller pilot systems for live field tests in western Denmark starting in 2008 and expanding through 2011. The project team reported successful demonstration of all the major functions envisioned for the system.

Subsequently, the Cell Controller concept is being applied on the Danish island of Bornholm as part of a European Union's four-year EcoGrid EU smart grid project that began in March 2011.

2. Technology Challenges and Solutions

a. Nascent Standards for Integrating Microgrids and DERs into System Planning

To safely connect microgrids and DERs, utilities follow prevailing industry standards and regulations that govern technology functions and performance, as well as interconnection agreements and tariffs. (*See Chapter II-B-1. Standards for Microgrid Control and Safety*). IEEE 1547, the prevailing industry standard relating to interconnection of DG systems – including microgrids – is currently going through a process of amendments and updates that are expected to provide, among other things, specific guidance relating to specifications for intentional islanding of microgrids, and also utility system interoperability with smart inverters, including at high levels of penetration for small DG systems.

The amendments currently being considered, however, do not contemplate system interoperability issues for microgrids in particular. Such issues might be considered in future amendments, particularly if system planners in the United States begin pursuing integrated smart grid-and-microgrid architectures like those in Denmark's Cell Controller project. Until such standards are in place, however, utilities and microgrid operators who seek to develop integrated approaches likely will have to develop new models and agreements to accommodate the broader application of microgrids and DERs in system planning.

b. New and Unproven Technology Solutions

The difficulty of interconnecting large amounts of DG that can safely and affordably island to provide resilient power during utility grid outages explains much of the low penetration rate for microgrids and

[27] Bialek, Thomas: "SDG&E Borrego Springs Microgrid Demonstration Project," presentation, Sempra Utilities 2012 Smart Grid Program Peer Review Meeting, June 8, 2012.
[28] *Cell Controller Pilot Project: Smart Grid Technology Demonstration in Denmark for Electric Power Systems with High Penetration of Distributed Energy Resources,* EnergieNet.dk, 2011.

other islandable DERs in Minnesota and many other states. Utilities are understandably reluctant to connect their highly stable and reliable systems – using time-tested switchgear – to customer-owned digital switches and programmable logic controllers (PLC) that are outside the utility's specified equipment and perhaps have only recently entered the marketplace. Even systems that are UL listed and IEEE compliant raise concerns among power systems engineers who have learned to distrust new technologies until they are fully field tested and proven.

However, microgrid technology companies and developers in states affected by severe storms and frequent power outages are applying new interconnection technologies that enable automatic and cost-effective microgrid control and intentional islanding. These technologies have gained acceptance by utility companies in other states, and that acceptance can assist in their deployment in Minnesota. (*See Appendix C: Interconnection Technology Case Studies*).

Experience from other states also indicates a role for state policy makers, in facilitating working sessions where microgrid technology developers can interact with utility company engineers and DER users. To the degree concerns about engineering standards impede microgrids' safe and affordable access to the utility grid, communication among stakeholders can help to air and resolve those concerns.

3. Institutional challenges and solutions

a. Utility Planning Processes Favor Central System Approaches

For most of its history, the U.S. utility industry and its policy makers have been designing and building a system that's based on the central-station model of utility service. Minnesota's utility industry is no exception. In addition to inherent financial and regulatory disincentives against utilities developing distributed resources (*See Chapter II-A-1. Ratemaking, Cost-Recovery, and Disruptive Challenges*), Minnesota's utilities are staffed with professional engineers and planners whose educational and work experiences have centered on the traditional hub-and-spoke model of system design and operation. Moreover, as the world's most asset-intensive commercial business, with regulations for safety and reliability, electric utilities should be expected to remain focused on the operational models that have served customers effectively for more than a century.

At the same time, however, most utility managers today understand that the industry is exploring new approaches to resource planning, system design, and operational procedures, and they express a willingness to learn about them and consider their application. Some even express enthusiasm for these changes, and an apparent interest in seeing them succeed – but with the strong caveat that they cannot accept changes that either threaten the basic safety and reliability of the system, nor – as managers with fiduciary responsibility – that damage the financial health of the utility or its customers. Virtually without exception, all stakeholders prioritize the need to maintain the fundamental stability of Minnesota's electric utilities.

This appropriately cautious posture carries an inherent bias toward central system approaches. As a result, distributed energy resources that could serve safely and reliably – and moreover that could represent least-cost options – are unlikely to receive the same consideration as traditional designs in any regular utility planning process. This planning bias represents a substantial artificial barrier that will impede the natural development of DERs.

However, as microgrids and other DER technologies become more thoroughly tested, and as they are proven to be effective and economical as part of an integrated system, Minnesota utilities likely will give them more appropriate consideration – especially to the degree regulatory agencies encourage them to do so.

D. Microgrids as Renewable Energy Enablers

For renewable energy planning and development, microgrids offer the ability to exploit renewable resources – potentially at higher proportions than are typical on utility systems. As a result microgrids can help address policy and user objectives beyond their basic operational functions. However, integrating variable, non-dispatchable generation sources – most notably wind and solar power – requires microgrid designers to apply technologies and operational solutions to serve end users' energy needs.

1. Policy Drivers, Technology Trends, and End-User Optionality

Most microgrids operating in the United States today are powered almost exclusively by fossil fuels – mostly natural gas and diesel. Several well-known microgrid projects – including some discussed earlier, such as the FDA White Oak Headquarters – exploit very small amounts of solar and wind generation. The Santa Rita Jail is a notable exception, in that PV arrays comprise 1.5 MW of nameplate solar capacity, in combination with about 7 MW of fossil-fired generation and storage capacity.

Despite this fact, microgrids have gained attention for their potential to exploit renewable resources and provide environmental benefits. In part this attention relates to the rapid decline in costs for PV modules in recent years, and the rapid adoption of residential and commercial rooftop solar systems in some U.S. jurisdictions – especially California, Arizona, and Hawaii. The concept of a solar-powered microgrid seems to dominate the popular image of what microgrids represent. That image, however, belies the fact that almost all rooftop solar installations in the United States today are fully grid-tied, grid-actuated systems; without auxiliary actuating technologies, they cannot operate in a utility outage, specifically to prevent unintentional islanding and the safety issues that arise from it. (*See Chapter II-B-1. Standards for Microgrid Control and Safety*). Many larger commercial systems also are grid-tied.

In principle, microgrid technologies, with upstream safety systems and automatic islanding capabilities, could allow greater use of rooftop solar systems during utility outages. At this time, such technologies have not been scaled or priced for the small rooftop-PV system market. Moreover, such islanding solar systems would require storage capacity and perhaps incremental generation, if they were expected to operate at night or under heavy cloud cover – which substantially would increase their capital cost, as well as their emissions profile, assuming their backup generators would burn fossil fuels.

Thus, as attractive as the idea of small-scale solar microgrids might be, their practical application requires energy storage, at a current cost premium that limits the opportunity in the United States.

Nevertheless, larger scale microgrids can effectively integrate renewable energy resources, and doing so can add substantial benefits to the microgrid value proposition. First, exploiting renewable resources can allow microgrids to generate revenue, qualify for special tax treatment, and qualify for state planning benefits (*See Chapter II-A-6. Renewable Energy Incentives and Qualifications*). Second, microgrids can allow the owners of existing renewable generation systems to make greater use of those resources. And third, renewables can serve microgrid owners' need for energy resource options and price risk management benefits; wind and solar "fuel" is free, which means that these generation systems provide power at a predictable cost, compared to fossil fuels that fluctuate over time.

Moreover, to the degree microgrids exploit renewable resources, they can contribute toward Minnesota's efforts to achieve renewable energy and environmental goals.

2. Challenges and Solutions for Integrating Variable Generation

The primary challenge for integrating wind and solar energy into a microgrid involves the same general issue that these resources present to utility systems; namely, their variable and non-dispatchable nature. Technical and operational solutions that help system operators integrate variable resources into large-scale power grids also can be applied to microgrids.

In a large-scale regional grid, system operators apply forecasting technologies and techniques to estimate the amount of solar or wind resource that will be available at a given time in the future. This allows grid operators to schedule demand-response and alternative supply resources. A wind- or solar-powered microgrid can use the same technologies – albeit with a wider margin of error, commensurate with the system's smaller geographic footprint. As a general matter, the larger the area, the more accurate wind and solar forecasts can be – and vice versa.[29]

Additionally, in a large, integrated power grid, dynamic DR resources can be used to balance variable supplies. The same also is true for microgrids, and indeed dynamic load management represents one of the pillars of modern microgrid architecture. (*See Ch. 1-A-2, Modern Microgrid Technologies and Emerging Features.*) Greater reliance on variable resources can be accommodated by greater demand management, to the degree end-user loads are flexible.

Finally, large power systems call upon a portfolio of supply resources to serve the full range of dynamic energy loads. Likewise a microgrid operating in island mode can integrate supplies from various generation systems. When one source of variable supply serving a microgrid is generating less at a given time, the microgrid's energy management system can dispatch a different source of available supply to maintain stable and reliable service. Different types of variable supply also can be complementary within a microgrid system; wind resources might be greater at night, while solar PV generates during the daytime, for example.

Balancing different resources requires microgrid engineers to design systems and apply technologies sufficient to serve customers' needs. Some microgrids operating today demonstrate novel strategies for exploiting a large proportion of renewable supply (*see below*). Not all of these microgrids are designed to supply power with availability levels approximating utility grid power; for example, their users might be able to accommodate wide fluctuations in total supply – from generation far in excess of regular loads, to nearly zero at a given time – in the interests of maximizing capacity utilization of variable energy systems. Microgrids with less flexible demand requirements incorporate comparatively greater amounts of supply and storage resources. In each case, the microgrid's combination of supply (variable and otherwise), demand management, and storage resources are scaled to meet customers' particular needs.

A technical issue affecting microgrid design involves the need for reactive power to support required levels of voltage and frequency. On a large utility grid, with multiple conventional power plants, reactive power supplies generally are taken for granted. In a microgrid operating in island mode, nothing can be taken for granted; engineers designing a microgrid must anticipate the full range of system-load scenarios, and apply the technologies and resources necessary to address them.

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[29] Burr, Michael T.: "Beyond Intermittency: Forecasting brings wind energy under control," *Public Utilities Fortnightly,* May 2010.

Designed and operated correctly, renewable energy microgrids can provide stable and high quality islanded service for end users. Microgrids that rely on wind and solar resources can use "smart" inverters and power converters to maintain stable frequency, voltage, and phase angle throughout the varying range of a wind or solar generator's output. Rotating generation systems, such as microturbines and reciprocating engines, can supply additional reactive power in a microgrid – and such systems can be fueled with renewable resources, including biofuels and other hydrocarbons produced by renewable energy processes. Likewise fuel cells can provide dispatchable, renewable-fueled energy. And electricity storage systems – *i.e.,* chemical batteries, flywheels, and pumped storage – can provide voltage and frequency support in a microgrid, while also maximizing use of renewable resources by storing excess generation.

Keeping a variety of energy sources in a microgrid synchronized within required tolerances – even as electricity loads are shifting in real time – requires fast-acting control systems. Numerous vendors are now offering such systems, and they are in use in various applications, including microgrids and similar systems requiring advanced energy management capabilities. The technologies required for managing the components of a mixed-resource microgrid continue improving, as equipment and software researchers design and test systems to provide greater capabilities. In fact, these efforts are happening in Minnesota at several laboratories and corporate centers, including:

■ Honeywell Automation and Control Solutions and Building Solutions units – microgrid controls and energy management systems development in Golden Valley.

■ Siemens Infrastructure & Cities Sector, Smart Grid Division – Microgrid strategy and development work in Minnetonka.

■ Open Systems International – Automation, EMS, distribution management, and SCADA systems development in Minneapolis.

■ University of Minnesota Technological Leadership Institute – "Smart Grid Sandbox" microgrid demonstration project at the U of M – Morris campus.

■ University of St. Thomas – Renewable Energy & Alternatives Laboratory microgrid R&D project and test bed, initially planned for Gainey Conference Center in Owatonna (*final site TBD*).

3. High-Penetration Wind and Solar

Numerous examples show how, in certain circumstances, microgrids can be applied to integrate renewable resources as a large percentage of overall energy consumption, up to 100 percent in some cases. These examples suggest models that might be applied or adapted for microgrids that can help Minnesota achieve its renewable energy goals.

a. Alaskan Village Wind-Diesel Hybrid Microgrids

Average electricity prices in Alaska are among the highest in the United States. But even more expensive is electricity generated in remote villages, many of which are not connected to an integrated utility system. Such villages rely entirely on diesel generators and CHP systems, burning fuel that must be delivered hundreds of miles through rugged terrain and often forbidding weather. That fuel is extremely expensive and has become more expensive in recent years.

Several Alaskan wind-diesel hybrid projects – at Anderson, Kodiak, Kotzebue, Noorvik, Pilot Point, and the remote island of St. Paul – demonstrate methods for offsetting diesel consumption. Such methods include energy storage systems that capture excess wind generation during off-peak times by pre-heating water for space heating and CHP systems. One project applies smart-grid technology to directly ramp non-critical loads up and down in real time in response to wind generation.

These projects are producing substantial savings in diesel fuel costs; Kodiak Island saved $3 million in diesel costs in 2009 alone, and subsequently doubled the size of its wind capacity to 9 MW. Wind power now supplies more than 18 percent of Kodiak's electricity.[30]

b. Hawaiian Water-Pumping Wind Microgrid

An agricultural company called Kohala Makani Wai LLC installed a 100 percent renewable-powered, commercial microgrid at its farm in Hawi, Hawaii.[31] The SkyGrid Energy system, developed by Gen-X Energy Development, uses a 100 kW Northern Power Systems wind turbine in an off-grid configuration to run a deep-well submersible pump to provide irrigation water.

A microgrid system was necessary because the wind turbine was designed to be grid-tied, and therefore it requires stable power conditions in order to operate. The microgrid includes a bidirectional inverter, supplied by Sustainable Power Systems LLC, that controls voltage and frequency, while an Alairnano Technologies lithium titanate battery charges or discharges to balance momentary fluctuations in the wind turbine's output against the pump's load. The system controller monitors and adjusts the pumping load to track the wind power output, and maintains the battery at its optimal state of charge. The controller also monitors turbine output and curtails it in high wind conditions to avoid overcharging. The system also includes a small PV array and separate lead-acid battery to power the system controller when the turbine is idle.

The system is designed to operate autonomously. Currently it provides water at between 70 and 250 gallons per minute, which is used for direct irrigation. In the next phase, a water storage system will be installed, allowing more optimal water production and wind utilization.

Although the configuration was purpose-designed for a remote water pumping application, the system developer anticipates similar approaches can serve in other situations with non-critical, variable loads, such as water treatment and desalination and ice making.

e. King Island Renewable Energy Integration Project (Tasmania)

Remote microgrids, on islands in the ocean and in places like Australia, Antarctica, and the Australian Outback, are at the forefront of integrating large percentages of renewable energy supply. Hydro Tasmania recently demonstrated stable operation on 100 percent wind and solar power – for a short period of time – at its King Island Renewable Energy Integration Project.[32]

The project includes wind turbines totaling 2.45 MW of capacity, along with PV arrays totaling about 200 kW, a group of diesel generators, a small amount of battery storage capacity, and a flywheel uninterruptible power system. Hydro Tasmania designed the microgrid's automated control systems and dynamic resistors to manage power quality. The company reported in July that the system had automatically shut down diesel power and transitioned to 100 percent renewable power for as long as 1.5 hours overnight during low-demand periods, and sometimes under high wind conditions during the day.

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[30] *Renewable Energy Atlas of Alaska,* Alaska Energy Authority, April 2013, p.16.
[31] Edgerton, Owen, and Steve Drouilhet, *A 100% Renewable Commercial-Scale Wind Powered Water Pumping System,* poster presentation, Asia Pacific Clean Energy Summit and Expo, Sept. 10, 2013.
[32] "KIREIP reaches renewable energy milestone," Hydro Tasmania press release, July 22, 2013.

Hydro Tasmania plans to install an additional 3 MW, 1.6 MWh ultrabattery storage system to increase the microgrid's total renewable penetration to more than 65 percent – and it expects to save money in the process by offsetting costly diesel fuel consumption.

4. Biogas-Fired Microgrids

Different renewable resources bring different characteristics and benefits to a microgrid. Although microgrids can, in principle, exploit almost any energy resource, biogas represents one of the more promising alternatives for three reasons.

First, in many cases biomass is a waste product[33] that if left to decay has a large environmental footprint; methane is believed to be a greenhouse gas with 20 times the effect of carbon dioxide, on a pound-for-pound basis.[34] Burning waste methane instead of allowing it to be emitted directly into the atmosphere reduces its climate effect by roughly 75 percent, and the net effect is reduced further if the combustion serves highly efficient energy production to offset fossil fuel combustion. Second, a sufficient supply of biogas allows a microgrid to use conventional combustion equipment or fuel cells, either of which can deliver controllable and dispatchable power and heat. And third, biogas generators can be co-located with other renewable resources. Landfill caps and reclamation zones can accommodate solar arrays and wind turbines, for example, along with landfill gas-fired generators, creating a synergistic combination of variable and dispatchable resources. As a result, biogas represents an attractive potential renewable energy resource for microgrids in Minnesota.

a. Agricultural Waste Biogas

Technologies for converting crop residue and animal waste into biogas offer potential for distributed energy applications. Examples being pursued in Minnesota demonstrate principles that could be adapted for use in microgrids.

■ Dairy farm quasi-microgrid: The AgSTAR Program, sponsored by the U.S. Environmental Protection Agency, Department of Agriculture, and DOE, assists dairy farmers to install anaerobic digesters to recover methane from animal manure and sometimes also food waste. One such application is located near Princeton, Minn., on the Haubenschild family's 1,100-head dairy farm. An anerobic digester was installed in 1999 to produce biogas, which fuels a 150 kW Caterpillar genset. The genset is equipped with a heat-recovery system that provides space heating for the dairy's parlor, holding area, and barns. About 45 percent of the electrical output is used on the farm, and the remainder provides power and voltage support for the East Central Energy cooperative. Subsequently the Haubenschild farm became the site of a four-year project to test emissions from a 5 kW fuel cell. The test showed that emissions from the biogas-fueled cell were virtually undetectable.

■ In Morris, the University of Minnesota operates a renewable energy incubation program through the U of M Morris (UMM) campus, and also the West Central Research and Outreach Center, affiliated with the U of M's St. Paul campus. At the UMM Renewable Energy Research and Demonstration Center, faculty and students develop systems for local energy production. One such system involves a biomass gasifier that the university installed in 2007 and 2008 to power the campus district heating and cooling system. Since it started operating in 2010, the system has been demonstrating the potential for gasifying corn cobs from local farms to displace natural gas and fuel oil and serve campus steam load – up to 100

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[33] Other forms of biomass combustion – including woody biomass – also present opportunities and benefits for microgrid and DER applications, but their environmental benefits are less clear than those for waste biogas.

[34] "Methane Emissions," U.S. EPA Overview of Greenhouse Gases website: epa.gov/climatechange/ghgemissions/gases/ch4.html

percent during much of the year.[35] Additionally, UMM installed a 325 kW backpressure turbine, which generates electricity from the pressure differential between the biogas-fueled boiler and the campus steam network.

Although the gasifier isn't part of the university's "Smart Grid Sandbox" microgrid demonstration project, the UMM gasification program has developed technologies for DG applications, including an integrated biomass gasification and 100 kW genset system housed within a 20-foot shipping container. The university designed the system in consortium with All Power Labs LLC, which hopes to commercialize the design and sell packaged gasifier CHP gensets with installed capital costs between $1.30 and $1.70 per watt.[36] All Power Labs currently sells pallet-mounted gasifier-gensets in 10 and 20 kW sizes, at prices under $2 per watt, and intends to add CHP and shaft power capabilities to those packaged systems.[37]

Finally, the West Central Research and Outreach Center operates a 2.65 MW wind turbine that produces anhydrous ammonia – which is sold to farmers as a fertilizer, but could be used to generate electricity through a fuel cell. Also the wind turbine drives a small electrolyzer that produces hydrogen for a 60 kW genset. Although not producing biogas, the system demonstrates technology for storing renewable energy, and doing so in coordination with local agriculture.

b. NEDO Demonstrations in Japan: Kyōtango and Hachinohe

In Japan, the New Energy and Industrial Technology Development Organization (NEDO) commissioned two microgrids that rely substantially on biogas, along with other renewable resources.

■ At Kyōtango City in Kyoto Prefecture, NEDO commissioned Amita Corp. to design and install a microgrid system with a biogas generator fueled by food waste. Byproducts from the biogas process were subsequently used as fertilizer for local rice fields. The 650 kW system included other resources, including PV, wind power, and a fuel cell, plus lead-acid batteries. Automated controls were installed to balance load against available supply to maintain stable service.

■ At Hachinohe, NEDO commissioned Mitsubishi to install a microgrid powered 100 percent by renewable energy to provide electricity and heat for seven buildings and a sewage treatment plant. The system used three 170 kW biogas-fueled engines, along with 130 kW of PV and 20 kW of wind turbine capacity, plus a 100 kW lead-acid battery, and wood- and biogas-fired boilers to serve additional heating load. The microgrid control system operated the system in island mode for one week in 2007.

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[35] Tallaksen, Joel, and Arne Kildegaard: *Biomass Gasification: A Comprehensive Demonstration of a Community-Scale Biomass Energy System,* University of Minnesota-Morris and West Central Research and Outreach Center, 2011.

[36] Voegele, Erin: "Demonstrating Portable Energy: A modular gasification technology produces on-demand, biomass-based syngas," *Biomass Magazine,* Aug. 29, 2012.

[37] http://www.gekgasifier.com/

Chapter II:
MINNESOTA UTILITY REGULATION AND MICROGRIDS

In general, microgrids occupy a regulatory void in Minnesota law. Minnesota statute does not provide a legal definition of "microgrid," nor does it provide clear policies on microgrid development, ownership, and operation. At the same time, however, many areas of Minnesota (and Federal) law and policy can apply to microgrids. Some of Minnesota's utility laws and regulations present challenges to microgrid development, and some encourage it. Microgrids include distributed generation capacity, some of which can be powered by renewable resources – which could qualify them for some state programs. Similar ambiguity applies to other features (and potential features) of microgrids. Some microgrids – but not all – apply efficiency, conservation, and DR measures. Some include energy storage capacity. In principle any grid-connected microgrid could serve as a utility reliability resource, but only some are used in that way, and to date utilities in Minnesota have not planned or designed them as part of their regular system planning processes.

Below we examine aspects of current laws that could apply to microgrids, how they create barriers or opportunities for microgrids, and uncertainties that merit further examination.

A. Utility Regulation

1. Ratemaking, Cost-Recovery, and Disruptive Challenges

The Minnesota PUC has ratemaking authority over public utilities and those unrelated utilities that have elected to be regulated by the PUC under Minn. Stat. §§ 216B.25 and .26 (*i.e.,* Dakota Electric). Under Minn. Stat. § 216B.03, the PUC is charged with ensuring that "[e]very rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05." Under Minn. Stat. § 216B.16, the PUC must approve any changes in rates by a public utility or rate-regulated municipal or cooperative utility.

In the context of these regulatory and ratemaking principles, microgrids encounter substantial objections and challenges from utilities[38] in Minnesota, as they do in other states. Some of these issues echo concerns involving DERs generally, but others apply specifically to microgrids. Utilities have expressed concerns about the following potential issues:

■ *Efficiency Disincentive:* For investor-owned utilities, the State's ratemaking framework – with bundled, volumetric pricing and rate-base capital cost recovery – rewards utilities for investing in capital assets and selling more energy (notwithstanding modest financial incentives related to meeting energy efficiency goals). Conversely it discourages utilities from investing in or pursuing solutions, that, like microgrids, defer asset investments and reduce customer energy purchases.

[38] In general "utilities" here refers only to companies subject to the Minnesota PUC's rate-setting authority. Similar issues affect municipal and cooperative utilities with respect to their differing obligations and operating models.

■ *Potential Cross-Subsidy:* Utilities' bundled prices might not recover adequate costs from DER/microgrid customers who rely on the utility system for reliable service, but who buy less energy from the utility than otherwise comparable customers do. Unbilled fixed charges then must be collected from non-DER/microgrid customers, resulting in an unintended cross-subsidy.

With specific reference to microgrids, this phenomenon also leads to questions about the utility's obligation to provide equivalent service. If microgrid customers obtain higher reliability levels, and they increasingly avoid paying their share of the utility's fixed costs for maintaining the utility system, then non-microgrid customers effectively are paying to support premium services for microgrid customers. Such concerns could implicate the non-discrimination provisions of Minn. Stat. § 216B.07, which provides that "[n]o public utility shall, as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage."

■ *Unfamiliar Systems:* DERs and microgrid systems might use control technologies that are unfamiliar to utility power system engineers, who are obliged by Minnesota's regulatory compact to ensure interconnected systems are safe and do not create reliability problems. Some utilities relate cases where customer-owned do-it-yourself systems have used non-standard and unsafe equipment and configurations. As a result, utilities take a cautious approach when evaluating new customer-owned systems for interconnection.

■ *Disruptive Technologies and Stranded Assets:* In terms of the levelized cost of energy, DG power output is more expensive than conventional generation, as well as utility-scale solar and wind.[39] However, system costs are steadily decreasing, and in some cases DG already has reached cost parity with retail utility rates. Consequently, DG systems are becoming cost-effective for increasing numbers of customers. Rapid penetration of rooftop solar and other behind-the-meter energy technologies will reduce the utilization rate of utility assets, perhaps ultimately leaving them stranded. The faster DG systems are deployed, the greater the need for utilities' regulatory and operating models to adapt to changing economics.[40] Microgrid technologies could accelerate this disruptive process by making a broader range of DERs cost-effective sooner, for a larger share of the energy market.

One critical question is implied in all of these issues. Namely, how should DERs and microgrids factor into Minnesota's regulatory strategies and energy policy goals? Establishing more clearly the role of DER and microgrids in Minnesota's desired energy future could help the State develop policies, regulations, and standards that support efforts to exploit these solutions to the benefit of businesses and residents – and avoid the unintended consequences of disruptive technology trends.

a. Options for Rationalizing Fixed-Cost Recovery

Policy makers and utilities in several states are addressing the question of how to fairly and appropriately recover fixed costs for serving customers who pursue microgrids and other DER alternatives.[41] Models under consideration range from traditional avoided-cost pricing under the Public

[39] *Ibid.,* Lazard, August 2013.

[40] The strategic implications of disruptive technologies, especially DG, have in the past year garnered a remarkable amount of attention in various utility forums, including the 2013 National Association of Utility Regulatory Commissioners Summer Meetings and the 2013 Edison Electric Institute (EEI) Annual Convention. Although the topics have been analyzed in utility policy circles for some time, a recent EEI report brought them into sharper focus. *See* Kind, Peter: *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business,* Edison Electric Institute, January 2013.

[41] See, for example, Zarumba, Ralph, Benjamin Grunfeld, and Koby Bailey: "Pricing Social Benefits: Calculating and allocating costs for non-traditional utility services," *Public Utilities Fortnightly,* August 2013.

Utility Regulatory Policies Act (PURPA), to fundamentally different frameworks, such as transactive energy (TE) markets. (*See Chapter IV-B-2. Transactive Energy Market Models*2. Transactive Energy Market). The State of Minnesota has engaged stakeholders in a series of workshops to address these issues as they apply specifically to DG, and especially in the context of net metering.[42] Solutions discussed in such proceedings tend to focus on two primary options: up-front fees and standby rates. While both concepts apply generally to all DERs, the specific characteristics of microgrids suggest specific approaches.

First, a utility could charge a microgrid owner or developer directly for any up-front costs associated with system impact studies, interconnection systems and switchgear, and protective equipment that must be installed on the grid. Experience in some states shows that uncertainties about the potential costs of system impact studies and remedial equipment might be discouraging developers from pursuing projects that otherwise might be beneficial.[43] Indeed, uncertainties about interconnection studies date back to the earliest days of the independent power industry, when early qualifying facilities (QF) under PURPA battled all the way to the Supreme Court to secure the access and interconnection rights that Congress provided under PURPA (*American Paper Inst. v. American Elec. Power, 461 U.S. 402 (Decided May 16, 1983)*).

Such uncertainties can be resolved if utilities establish fair and transparent policies on pricing system impact studies and remediation measures. (*See Ch. II, B-3, Evolving Industry Standards.*) Also, issues related to interconnection and system safety can be minimized if microgrid developers use well-proven equipment and work closely with utilities to identify potential conflicts early in the development process.

Second, utilities can charge standby rates for their power. Prevailing approaches to standby rates, including those already being used by utilities for some DG projects in Minnesota, present a dilemma, because the actual distribution network costs incurred to serve a microgrid will vary considerably at particular times and locations.[44] By not accurately valuing the net costs of serving a specific microgrid by time and location, standby charges might already be having a chilling effect on the adoption of cost-effective DG projects in Minnesota. In proceedings on the subject, several independent generators, equipment suppliers, and Minnesota utilities have acknowledged a need to review and improve the transparency of standby rates, and these proceedings continue. For example, at this writing the PUC was receiving comments on a proposal (*Dkt. No. E-999/R-13-729*) to implement statutory changes in the May 2013 Omnibus Energy Bill affecting CHP and small power producers, including a proposal to prohibit standby charges for facilities smaller than 100 kW. Additionally, the outcome of a current study project

[42] "Distributed Generation," Minnesota Department of Commerce, Division of Energy Resources website: http://mn.gov/commerce/energy/topics/clean-energy/distributed-generation/

[43] *CHP in NYC: A Viability Assessment,* Center for Energy, Marine Transportation and Public Policy, Columbia University, September 2007.

[44] See for example: *Interim Report on DG and Distribution Deferral,* Attachment B, Distribution Planning Work Group, Navigant Consulting Inc. report commissioned by MADRI/Massachusetts Technology Collaborative, Jan. 20, 2006. See also *Massachusetts DG Collaborative 2006 Report,* Attachment H – Report of Distribution Planning Work Group, June 30, 2006; Harrison, G. P., Piccolo, A., Siano, P., & Wallace, A. R.: "Exploring the Tradeoffs Between Incentives for Distributed Generation Developers and DNOs," *IEEE Transactions on Power Systems*, 821-828 (2007); and Costa, P. M., Matos, M. A., & Pecas Lopes, J., "Regulation of Microgeneration and Microgrids," *Energy Policy*, 3893-3904 (2008).

at the University of Illinois at Chicago is expected to provide greater clarity on the issue of how to appropriately value and recover standby costs for serving DG customers.[45]

More broadly, a utility's IRP processes could offer a logical context for quantifying the values and costs of microgrids, in part because utility companies have access to network planning data, software, and methodologies required to model the attributes of integrated microgrids, to reflect not only current conditions but also future conditions on the utility network. Expanding the scope of utility IRPs to substantively address microgrids would be consistent with the PUC's mandate to ensure that opportunities for DG are considered in utility resource planning under Minn. Stat. §§ 216B.2422 and 216.2426. As scholars in the U.K. stated in a 2007 IEEE presentation, "Given that one of the principal objectives of network pricing is to send signals to users of the network regarding the costs they impose on network development, it is necessary to first establish future network investment costs. Future network investments and the associated costs are driven by the network design (planning) process. There is therefore a close link between network pricing and network design (planning): network design, in a simplified form, is in fact a key input to network pricing."[46]

Efforts to develop transparent frameworks for valuing microgrids and pricing associated utility service will be most successful if they consider microgrids as integrated assets in the context of utility system planning. Some other states have made strides in this area, and their experiences can inform Minnesota's efforts to appropriately assess the costs and benefits of microgrids.[47]

b. Net-Present Value Analysis and "Real Options" Valuation

In considering the future benefits of microgrids and other DERs within utility IRP proceedings, using present discounted values could undervalue the actual benefits of microgrids. Within a net present value (NPV) framework, the decision rule is simple: if NPV > 0, the investment in DG has benefits and the microgrid users should receive a credit; if NPV < 0, the investment in DG has negative impacts and microgrid users should pay network charges.

The NPV framework by itself is inadequate, however, because it uses only mean values and disregards the potential for decision makers to create value by applying and operating microgrids in reaction to changing options and marginal price signals. In other words, the NPV framework is unable to quantify the value of more flexible microgrid technologies, relative to the changing set of available alternatives on the utility system at a given time. For example, a more insightful analytic framework would properly value microgrids and DERs generally for their greater modularity and granularity than central-plant alternatives. Such a framework also would assign value for DERs' much shorter time from conception to deployment.

Stewart C. Meyers of the Massachusetts Institute of Technology coined the term "real options" in 1984 to describe the valuation of non-financial assets using options theory as an alternative to simple NPV analysis. Further, in 1973 Myron Scholes, Robert Merton, and the late Fischer Black made a Nobel prize-winning breakthrough in how to price financial options. The Black-Scholes formula transformed financial options trading and helped create a global derivatives business. Using real options approaches can bring

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[45] Miller, Graeme H., Clifford P. Haefke, and John J. Cuttica: "Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota," Energy Resources Center, University of Illinois at Chicago, October 2013 [*forthcoming*].

[46] Pudjianto, Danny, Goran Strbac, and Joseph Mutale: "Access and pricing of distribution network with distributed generation," IEEE-Power-Engineering-Society General Meeting, 2007, pp. 1-3

[47] *Distributed Generation and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative,* Navigant Consulting Inc., Jan. 20, 2006.

the discipline of financial markets to bear on strategic investment decisions, and economists already have successfully applied real options valuation techniques to DG investments and found that the real options framework substantially clarifies the theory and practice of investment decision making.[48] However, because a real options valuation is more complicated than a simplistic NPV analysis, the approach has only recently been applied by project developers.

Irrespective of whether Minnesota policymakers and utilities consider real options pricing to be feasible in the near term, the principles of fair valuation apply to DER planning, and especially to microgrids, given their potential scope of features and functionality. Efforts toward transparent cost-recovery frameworks therefore should assign a premium to the more flexible, adaptable nature of microgrids, given that some projects would not be correctly valued using NPV analysis alone.

c. Decoupling and Unbundled Pricing

As noted, the bundled, volumetric pricing structures in place at Minnesota's regulated utilities create inherent disincentives against efficiency and DERs, including microgrids. Utilities and policy makers in Minnesota have considered and experimented with new rate structures that aim to remove or mitigate these disincentives. The most noteworthy examples involve pilot initiatives that unbundled natural gas utility rates, separating charges for different components of retail utility service, and separated utilities' allowed ROE from their energy sales revenues.[49] Such "decoupling" legislation is reflected in Minn. Stat. § 216B.2412, which notes that "[t]he purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." Minnesota's approaches, like those in other states, have been combined with performance criteria and incentive ratemaking to address concerns that decoupled rates weaken utilities' incentives for managing risks and cost factors affecting customers.

Decoupling and unbundling could simplify the process of integrating DERs and microgrids in utility planning processes and pricing structures. It would allow utilities to apportion fixed charges in a more transparent and accurate way, mitigating both cross-subsidies and discriminatory pricing. And it could provide a clearer pricing structure for allocating values and costs associated with the various attributes of integrated microgrids. Performance-based rate incentives could help ensure that utilities support microgrid development efforts, providing mitigation measures if they fall short of established goals.

As helpful as it might be for DERs and microgrids, however, decoupling also raises policy questions that thus far have impeded its wide-scale application in Minnesota. Short of full decoupling – or as an interim and complementary measure – the State could provide lost-revenue recovery mechanisms that help reduce the utility's disincentive against efficiency and DERs. Some states have used such policies in combination with decoupling options, with positive effects on microgrid development. Most notably, the State of Connecticut provides a regulatory process for utilities to recover revenues lost to customer-owned DG installations, and the State also provides decoupling mechanisms that some utilities have adopted, and others are considering. This framework allowed the state's two major utilities – CL&P and United Illuminating – to become actively engaged with the Connecticut Department of Energy and Environmental Protection in developing the State's microgrid program. The utilities remain engaged as

[48] Hand, Thomas J.: *Using Real Options for Policy Analysis,* National Energy Technology Laboratory, Office of Systems and Policy Support, Nov. 9, 2001.
[49] See *Report to the Legislature on Decoupling and Decoupling Pilot Programs Under Minnesota Statutes §216B.2412,* Submitted by the Minnesota Public Utilities Commission, April 2010; and also Shirley, Wayne, Jim Lazar, and Frederick Weston: *Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission,* Regulatory Assistance Project, June 30, 2008.

technical advisers and even project partners in the case of the Hartford Parkville Cluster microgrid project.

d. Win-Win Microgrid Models

Assuming least-cost planning and ratemaking can integrate microgrids as utility resources, and valuation methods capture their time- and area-specific costs and benefits to the utility system, then several possible approaches can produce mutually beneficial outcomes for utility shareholders, customers, and microgrid users. Some hypothetical examples follow:

■ The utility company unbundles its tariff to offer particular services to microgrids – such as interconnection, standby power, forecasting, balancing, dispatching, metering, and billing microgrid end users. The utility benefits by earning revenues from its core services and technology, while the microgrid owner benefits by obtaining industry-standard services at a lower cost than it could otherwise obtain them, either by developing in-house competency or by outsourcing.

■ Same as above, but to keep from complicating tariffs, the utility provides services through a long-term contract.

■ The utility and microgrid developer agree to share savings produced by the project, based on a real-options valuation model implemented by an independent third party.

■ The utility owns part or all of the microgrid, perhaps placing it in the regulated rate base, and negotiates time- and area-specific rates to sell power and DR from it.

■ The utility invests in the microgrid as a limited partner via a master limited partnership (MLP) project financing structure. (*See Chapter IV-B-1. Utility Models for Financing*)

■ The microgrid enters a "buy-all, sell-all" (BA/SA) arrangement with the utility. Using this model, all energy services produced by the microgrid are sold to the utility, and all energy consumption by the microgrid or its users are purchased from the utility.

■ The microgrid enters a contract with an interconnecting utility based on a modified value-of-solar tariff (VOST). Pursuant to legislative mandate in the May 2013 Omnibus Energy Bill (*85 HF 729, Article 9, §10*), Commerce is working to establish a VOST methodology. A modified VOST methodology could, in principle, be applied to other resources with multiple quantifiable attributes, including microgrids.

VOST is an alternative to net metering. Modified for use with an interconnected microgrid, a VOST-based methodology would include the value of a microgrid's energy supplied to the utility, as well as associated values for avoided costs of energy delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental benefits. To the degree a microgrid is designed and integrated to provide grid support services, those services also could be valued in the modified VOST methodology.

2. Service Territory and Franchise Laws

Minnesota's existing regulatory framework provides both opportunities and challenges to the development of microgrids in Minnesota. Minnesota does not currently have retail choice, and instead relies on incumbent utilities to serve retail customers. Under the compact established in Minnesota, utilities have both the right and obligation to serve retail customers. These rights and obligations are founded in Minnesota's exclusive service territory laws, which are generally set forth in Minnesota Statute Sections 216B.37 through 216B.43.

■ *Exclusive Service Territories:* Minn. Stat. § 216B.37 sets forth the state's policy with respect to exclusive service territories among electric utilities, providing:

> *It is hereby declared to be in the public interest that, in order to encourage the development of coordinated statewide electric service at retail, to eliminate or avoid unnecessary duplication of electric utility facilities, and to promote economical, efficient, and adequate electric service to the public, the state of Minnesota shall be divided into geographic service areas within which a specified electric utility shall provide electric service to customers on an exclusive basis.*

This law highlights the establishment of exclusive utility service territories and also the directive "to eliminate or avoid unnecessary duplication of electric utility facilities," both of which could impede the development of microgrids.

Specifically, Minn. Stat. § 216B.40 provides that "each electric utility shall have the exclusive right to provide electric service at retail to each and every present and future customer in its assigned service area and no electric utility shall render or extend electric service at retail within the assigned service area of another electric utility unless the electric utility consents thereto in writing…" The term "Electric utility" is defined in Minn. Stat. § 216B.38, Subd. 5 as "persons … operating, maintaining, or controlling in Minnesota equipment or facilities for providing electric service at retail and which fall within the definition of 'public utility' in section 216B.02, subdivision 4, and includes facilities owned by a municipality or by a cooperative electric association." This statute establishes a clear delineation between utilities' rights and obligations to serve retail customers.

■ *Exemption for Serving <25 Customers:* Importantly, Minn. Stat. § 216B.02, Subd. 4 provides that "[n]o person shall be deemed to be a public utility if it produces or furnishes service to less than 25 persons." Therefore, arguably an entity could furnish electric service to "less than 25 persons"[50] in an electric utility's exclusive service territory without running afoul of Minn. Stat. § 216B.40. This could assist in the development of a microgrid where service is provided to one or more retail customers by a third party.

■ *Transmission Access and Wheeling:* With the exception of limited wheeling rights for certain qualifying facilities under Minn. Stat. § 216B.164 and PURPA, there is no explicit requirement in Minnesota law that would require an electric utility to allow a microgrid to use its distribution facilities to wheel power, for instance. In contrast, delivery of power over utilities' transmission facilities is subject to open access under MISO Tariff and FERC requirements. As such, a microgrid developed without the utility's cooperation would need to avoid relying on existing distribution infrastructure, but could avail itself of the transmission system under MISO's tariff.

■ *Duplication of Services:* As noted above, microgrid development could be viewed as the duplication of utility facilities where a customer or group of customers already receives electric service from a utility. Arguments could arise that microgrid development is redundant to existing infrastructure. In addition, if a customer or group of customers leaves a utility system, the embedded cost of the existing utility infrastructure would be allocated among the remaining utility customers, potentially increasing their rates and raising concerns at the Minnesota PUC, which has a mandate to ensure that utility rates are just and reasonable.[51]

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[50] The Statute defines a "person" broadly to include groups of individuals with a shared interest in the utility service, such as a household or a corporation. *See* Minn. Stat. § 216B.02, Subd. 3.
[51] *See e.g.,* Minn. Stat. § 216B.03 (providing that "[e]very rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably

■ *Deferral Rates:* Existing law provides a variety of mechanisms designed to keep large customers from leaving an incumbent utility system. For example, the PUC has statutory authority to approve a "competitive rate" to prevent a large customer from exiting a utility system. In particular, Minn. Stat. § 216B.1621 permits a public utility to enter into an electric service agreement with a retail customer in its service territory when that customer proposes to acquire power from or construct a new electric power generation facility in the utility's assigned service territory. Such an agreement (which must be approved by the PUC) is used to defer construction of the proposed facility and provide an economic disincentive to dropping off the system.

■ *Municipal Franchise Laws:* Another potential impediment to the development of microgrids based on utility service territory laws is municipal franchise law. Municipalities often sign "franchise agreements" with utilities, which not only provides the utility with the right to provide electric service within the municipality, but also provides access to municipal rights-of-way to locate distribution and transmission facilities.[52] Microgrids might not have the same access to utility rights of way within municipalities.

■ *Community Microgrids and Utility Responses:* Research has not revealed any examples of multiple microgrid users organizing themselves under Minnesota's exemption for less than 25 persons, for example creating an energy improvement district under Minnesota laws on special districts.[53] Whether a municipal entity or other governing body has concurrent rights to generate and distribute power with a local microgrid to supplement utility grid power within a utility franchise is not a settled question. How franchise-holding utilities might react to such an initiative – or any effort by a microgrid to serve multiple customers – remains unknown, but utilities in some other states have responded defensively.

When the Connecticut General Assembly enacted a law explicitly enabling the distribution of power from a distributed generator across public roadways to multiple users, Northeast Utilities adopted the legal position that "any attempt by the owner of the microgrid installation to buy backup power and resell it to its Customer who is not part of the QF under FERC's regulations would constitute a sale for resale. That would likely invoke FERC jurisdiction under the Federal Power Act." Subjecting a microgrid to Federal regulatory jurisdiction – rather than State jurisdiction – could complicate the State's efforts to accommodate and support microgrids in planning and ratemaking processes.

■ *Sole-Source Contracts and Service Agreements:* Many municipal utilities and electric cooperatives buy their wholesale power supplies through long-term, sole-source contracts. Municipal utilities and cooperatives might seek to prevent customers from obtaining alternative supply sources to avoid violating those long-term agreements. Minnesota Statute (216B.164) provides the option for such non-generating utilities to treat purchases from qualifying facilities as a pass-through to their sole-source suppliers, as being made on their behalf and therefore subject to reimbursement. A given municipal utility or cooperative might or might not elect that option, and the Statute limits the option to PURPA qualifying facilities.

However, as evidenced by the City of Minneapolis in its ongoing negotiations with Xcel, municipalities might have opportunities to support microgrid development by negotiating favorable provisions with

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preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers…").

[52] *See e.g.,* the City of Minneapolis' Franchise Agreement with Northern States Power Company (Xcel) at http://library.municode.com/HTML/11490/level1/APXDNOSTPOCOCHUSST.html

[53] For example, Minn. Stat. § 471.655 defining the power of municipalities, school districts, and other special purpose districts to create an economic opportunity program.

incumbent utilities to secure support for innovative projects. Such concessions also could arise in the context of a municipal option to purchase public utility facilities within the municipal borders.

Under Minn. Stat. § 216B.45, "[a]ny public utility operating in a municipality under a license, permit, right, or franchise shall be deemed to have consented to the purchase by the municipality, for just compensation, of its property operated in the municipality under such license, permit, right, or franchise." This municipal right could be used to promote microgrids directly or indirectly during negotiations with an incumbent utility provider.

Thus while Minnesota's traditional vertically integrated utility structure presents structural impediments to microgrid development, the legislature also has enacted laws to support microgrids, albeit indirectly.

3. Laws Supporting Distributed Generation

Notwithstanding the potential impediments to microgrid development, there are existing laws designed to support distributed generation and by extension microgrids. For instance, under Minn. Stat. § 216B.2426, the PUC is directed to ensure that opportunities for distributed generation are considered in (1) utility resource planning under Minn. Stat. § 216B.2422; (2) the state transmission plan under Minn. Stat. § 216B.2425; and (3) Certificates of Need for Large Energy Facilities under Minn. Stat. § 216B.243. It should be noted, however, that such consideration has not resulted in a wide deployment of distributed generation in lieu of traditional transmission and generation development. Nevertheless, these laws can be used to promote and support microgrid by Minnesota policy makers.

Other laws also are designed to support the development of DG resources. Minn. Stat. § 216B.2411, for example, further provides that Minnesota utilities may spend 5 percent of approved energy conservation spending requirement on DG and may request permission for up to 10 percent for qualifying solar energy projects (<100 kW). As discussed below, the state's renewable energy mandates also could support the deployment of microgrids.

Finally, through Minn. Stat. § 216B.1611, the legislature directed the PUC to establish generic standards for utility tariffs for interconnection and operation of DG facilities up to 10 MW in capacity. In September 2004, the PUC issued an order establishing standards for interconnection and operation of DG facilities.[54] (*See Chapter II-B. Interconnection Standards and Microgrid Integration*). The Commission directed retail electric public utilities to file tariffs consistent with the new standards. The standard tariff provides for the interconnection of resources totaling up to 10 MW of power for use onsite by the customer, with any unused electricity sold to the utility.[55]

These policies supporting DG resources demonstrate the state's support for DERs in general, and they can be used as building blocks for the deployment of some microgrids. Importantly, however, these policies don't consider microgrids specifically, and therefore don't value the full range of microgrids'

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[54] "Order Establishing Standards," Dkt. No. E-999/CI-01-1023, *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212,* Minnesota Public Utilities Commission, Sept. 28, 2004.

[55] For instance, Otter Tail Power Company has a Distributed Generation Service Rider which requires that "[t] he distributed generation system must be fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than 10 MW of interconnected Capacity at a point of common coupling to Company's Distribution system. The distributed generation facility must be an operable, permanently installed or mobile generation facility serving the Customer receiving retail electric service at the same site." *See* *https://www.otpco.com/RatesPricing/Documents/PDF/MN/MN_12.04.pdf*

prospective functional potential – including DR, storage, and generation. Even more importantly, the capacity limits imposed on DR are inappropriate for microgrids. Although some microgrids will represent less than 10 MW of generating capacity, many microgrids will generate substantially more energy – and indeed some key examples of microgrids deployed for energy assurance purposes provide much more than 10 MW of capacity. (*See Chapter I-B-1. Critical Community Assets and Microgrid Applications*).

4. Net Metering Laws

Minnesota's net metering law is set forth in Minn. Stat. § 216B.164 and applies to all investor-owned utilities, municipal utilities, and electric cooperatives. Before recent legislative changes all "qualifying facilities" less than 40 kW in capacity were eligible to participate in net metering. In general, the statute provides that each utility must compensate customers for their net excess generation at the "average retail utility energy rate," which is defined as "the retail energy rates, exclusive of special rates based on income, age, or energy conservation, according to the applicable rate schedule of the utility for sales to that class of customer."

Legislative changes enacted in 2013 Minn. Sess. Law Serv. Ch. 85 (H.F. 729), 2013 Minn. Sess. Law Serv. Ch. 125 (S.F. 827), and 2013 Minn. Sess. Law Serv. Ch. 132 (H.F. 854), collectively referred to as the "Omnibus Energy Bill," included, among other revisions, the following changes to Minn. Stat. § 216B.164 related to DG for investor-owned utilities: (1) expanded net metering eligibility to systems less than 1,000 kW; (2) added a provision that a customer with a net metered facility between 40 kW and less than 1,000 kW capacity may elect to be compensated for any net input into the system in the form of a kWh credit carried forward and applied to subsequent energy bills; (3) removed mandatory standby charges for systems up to 100 kW; and (4) added meter aggregation (however, the meter must be owned or leased by the customer requesting aggregation, and must be located on contiguous property owned by the same customer).

On Aug. 22, 2013, the PUC requested comments in Docket No. E-999/R-13-729 on amendment to rules governing Cogeneration and Small Power Production to incorporate these recent statutory changes.

5. Tax Policies

In general, electric facilities (distribution, transmission, and generation) are subject to a personal property tax in Minnesota.[56] Personal property used to generate power is exempt if the power is used to manufacture or create goods, products, or services, other than electric power, by the owner of the electric generation plant. The exemption does not apply to property used to produce electric power for sale to others.[57] Therefore, generation used to support microgrid development would be subject to personal property taxes if it is sold to a third party (*i.e.,* if not all output were consumed by the owner).

Over the past two decades, however, the legislature has granted property tax exemptions for the attached machinery and other personal property at newly constructed generation facilities. For example, most independent power producers have received exemptions from personal property taxes,

[56] *See generally,* Minn. Stat. § 272.01, Subd. 1 providing that "[a]ll real and personal property in this state, and all personal property of persons residing therein, including the property of corporations, banks, banking companies, and bankers, is taxable, except Indian lands and such other property as is by law exempt from taxation."

[57] Minn. Stat. § 272.027 provides that "[p]ersonal property used to generate electric power is exempt from property taxation if the electric power is used to manufacture or produce goods, products, or services, other than electric power, by the owner of the electric generation plant. Except as provided in subdivisions 2 and 3, the exemption does not apply to property used to produce electric power for sale to others and does not apply to real property."

but have made payments in lieu of taxes to local jurisdictions.[58] In this respect, legislative exemptions could be sought to support the development of microgrids. Other tax policies could also support the development of microgrids that produce environmental or renewable energy benefits.

Pursuant to Minn. Stat. § 297A.67, Subd. 29, solar energy systems are exempt from the state's sales tax.[59] Similarly, "wind-energy conversion systems" used as electric power sources ("and the materials used to manufacture, install, construct, repair, or replace them") are exempt from Minnesota's sales tax under Minn. Stat. § 297A.68, Subd. 12.[60]

Personal property exemption provisions could be clarified or expanded to include microgrids, but such actions might require State legislative review.[61]

6. Renewable Energy Incentives and Qualifications

Minnesota has an aggressive renewable portfolio standard (RPS) for electric utilities. The state's largest electric utility, Xcel Energy, is subject to one standard, and a separate RPS applies other electric utilities. In 2013, further legislation (H.F. 729) was enacted to create a 1.5 percent solar standard for public utilities, a distributed generation carve-out, and a solar goal for the state.[62]

In total, the RPS for Xcel Energy requires that eligible renewable electricity account for 31.5 percent of total retail electricity sales in Minnesota by 2020.[63] Of the 31.5 percent renewables required of Xcel Energy in 2020, 1.5 percent must be met with solar PV (10 percent of which must be met with systems of 20 kW or less), at least 25 percent must be generated by wind or solar energy systems, with solar limited to no more than 1 percent of the requirement.

The standard for other public utilities requires that eligible renewable electricity account for 26.5 percent of retail electricity sales to retail customers in Minnesota by 2025. Of this electricity, 1.5 percent

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58 *See e.g.,* Minn. Stat. § 272.02, Subdivisions 68 and 92 providing exemptions for specific generation facilities, without naming them.

59 Under Minn. Stat. § 216C.06, Subd. 17 "Solar energy system means a set of devices whose primary purpose is to collect solar energy and convert and store it for useful purposes including heating and cooling buildings or other energy-using processes, or to produce generated power by means of any combination of collecting, transferring, or converting solar-generated energy."

60 Under Minn. Stat. § 216C.06, Subd. 19, "Wind energy conversion system" (WECS) means any device, such as a wind charger, windmill, or wind turbine, which converts wind energy to a form of usable energy."

61 *Primer on Minnesota's Property Taxation of Electric Utilities,* Updated to include laws enacted in the 2006 legislative session, Minnesota House of Representatives, October 2006.

62 H.F. 729 can be found at https://www.revisor.mn.gov/laws/?id=85&year=2013&type=0. The new law requires all investor-owned utilities in the state to provide at least 1.5 percent of their retail sales from solar power by 2020. This requirement is expected to raise Minnesota's current solar output from 13 MW to approximately 450 MW. Excluded from retail sales subject to this requirement are sales to iron mining extraction and processing facilities, paper mills, wood products manufacturers, and certain related facilities.

63 Minn. Stat. § 216B.1691, Subd. 1 defines "eligible energy technology" as "an energy technology that generates electricity from the following renewable energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this paragraph; or (5) biomass, which includes, without limitation, landfill gas; an anaerobic digester system; the predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of wastewater sludge to produce electricity; and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel."

must be solar PV by 2020, and 10 percent of the solar standard must be met with systems of 20 kW or less.[64]

While the state's RPS specifically, and renewable energy goals specifically, may not directly relate to microgrid development, the objectives provide an opportunity to promote state goals related to distributed generation and renewable energy in a microgrid context. Moreover, a microgrid's unique ability to maximize the utilization of variable supply in some applications could allow projects to improve the cost-effective exploitation of renewable resources toward the State's goals. (*See Chapter 1-D-3. High-Penetration Wind and Solar*).

7. MISO Considerations

Under a microgrid concept, certain loads will be served and effectively carved out from incumbent utility service. This raises the question of whether microgrids might be subject to provisions of the Midcontinent Independent System Operator (MISO) tariff. The answer might depend on defining which entity is responsible for serving load and thus meeting MISO's reserve requirements.

In the MISO context, a load serving entity (LSE) is defined as "[a]ny entity that has undertaken an obligation to serve Load for end-use customers by statute, franchise, regulatory requirement or contract with Load located within or attached to the Transmission System, including but not limited to purchase-selling entities and retail power marketers with the obligation to serve Load." This broad definition would appear to capture an aggregator developing a microgrid. However, because large-scale deployment of DERs is largely still in its infancy in the MISO footprint, treatment of DG and microgrids within MISO likely will evolve over time.

LSEs have certain obligations within MISO, including the obligations to meet the resource adequacy requirements of Module E of the MISO tariff – including a demonstration that they have sufficient generation capacity to meet their share of MISO's capacity requirements plus reserves. While MISO is in the nascent stages of determining where microgrids fit into transmission planning and generation development, whether and how the system operator will consider such issues is unknown. Specifically, will MISO and transmission owners integrate microgrids and other NTAs into their planning processes? Will MISO consider load-management resources, including microgrids, as part of resource adequacy and system planning? What processes will accommodate microgrids in planning and cost allocation processes? None of these issues have yet received substantive public policy development or yielded opportunities for stakeholder input.

8. Siting and Permitting

The Minnesota PUC has siting authority over large electric power generating plants and high voltage transmission lines. Depending upon the size of the generation source and transmission infrastructure, the Commission's siting jurisdiction could be implicated by microgrid development.

[64] In sum, 10 percent of the solar mandate must be met by energy generated by facilities with a nameplate capacity of 20 kW or less. The solar garden program is limited to facilities with a nameplate capacity of nor more than one megawatt, and that generate no more than 120 percent of the subscribers annual energy consumption. The solar energy incentive program only applies to facilities of no more than a total nameplate capacity of 20 kW. There are also several net metering limits: (1) IOUs may limit individual systems over 40 kW that participate in net-metering to 120 percent of the customer's on-site electric energy consumption; (2) IOUs may request that the PUC limit cumulative generation of net metered facilities if such generation reaches 4 percent of the IOU's annual retail electric sales, and (3) qualifying net metered facilities must be less than 1 MW capacity. This last requirement appears to apply to the value of solar tariff, but the bill is not perfectly clear on this point.

Under the Power Plant Siting Act, Minnesota Statute Chapter 216E, a site permit from the Commission is required to site a large electric power generating plant, which is generally defined in Minn. Stat. § 216E.01 as power plant and associated facilities capable of operating at a capacity of 50 MW or more. (The siting of large wind energy facilities is set forth in an entirely different Chapter, Minnesota Statute Chapter 216F.)

New power plants under 50 MW but over 25 MW do not require a Commission site permit, but do require an Environmental Assessment Worksheet (EAW) under the Minnesota Environmental Policy Act (*Minnesota Statute Chapter 116D*). The Environmental Quality Board oversees the preparation of EAWs. New power plants under 5 MW are exempt from any state environmental review, and plants between 5 and 25 MW are subject to discretionary review.

A route permit from the Commission is required to construct and operate a high voltage transmission line (HVTL) – though local review is available for some smaller HVLTs under Minn. Stat. § 216E.05. A HVTL is defined in Minn. Stat. § 216E.01 as "a conductor of electric energy and associated facilities designed for and capable of operation at a nominal voltage of 100 kilovolts or more and … greater than 1,500 feet in length." The siting and routing processes can be completed in as little as six months, but can take over one year to complete for more complicated or controversial projects.

In addition to site and route permits, the Commission has a role in determining whether there is a need for certain large electric power generating plants and HVTLs through its certificate of need requirements set forth in Minn. Stat. §§ 216B.243 and .2421. Specifically, Minn. Stat. § 216B.243 Subd. 8 (1), states that a certificate of need is not required for a cogeneration or small power production facility having a combined capacity at a single site of less than 80 MW or a high-voltage transmission line proposed primarily to distribute electricity to serve the demand of a single customer at a single location. Both of these exemptions could be implicated in microgrid development.

Of note, Minn. Stat. 216B.243, Subd. 3 (6) requires the Commission to evaluate "possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation." Under Minn. Stat. 216B.243, Subd. 5, the Commission has one year to approve or deny an application for a certificate of need.

Finally, energy facilities that fall outside of the Commission's jurisdiction generally are sited through local zoning processes. Accordingly, while the PUC's siting authority could cover microgrid development, that authority is largely neutral with respect to microgrids vis-à-vis other infrastructure.

9. Public Records Laws and Municipal Utilities

As quasi-government entities, municipal utilities and other public power agencies are subject to laws involving public records and open meetings that do not apply to privately owned utilities. In some circumstances, these laws could affect a municipal utility's involvement in microgrid projects.

Minn. Statute § 13.685 provides that data on customers of municipal electric utilities are private and non-public, but may be released to (1) a law enforcement agency that requests it in connection with an investigation; (2) a school for purposes of compiling pupil census data; (3) the Metropolitan Council for use in studies or analyses required by law; (4) a public child support authority for purposes of establishing or enforcing child support; or (5) a person where use of the data directly advances the general welfare, health, or safety of the public.

Additionally, Minn. Statute § 13D specifies that, in general, any "meeting" (including via electronic means) that includes a quorum of the governmental body must be convened openly, with proper public notice, and with relevant materials made available to the public.[65]

These two sets of obligations have presented issues for Minnesota municipal utilities engaging in smart grid programs, especially those involving smart metering and time-of-use rates. For example, if a municipal utility customer installs an interval meter at a customer's property, the utility will then be able to collect highly granular data about the customer's electricity usage patterns. The municipal utility is obliged to protect the privacy of that data, but also may release it under the conditions set forth in the Statute. Further, when the municipal utility conducts meetings and discussions that address the smart grid program, if those meetings include a quorum of the utility's governors, then that meeting must be conducted openly, and the information discussed must be available to the public.

These two requirements are not actually in conflict, but they do impose procedural obligations on municipal utilities handling customer data in open meetings; such data must be presented in aggregate form, for example, or rendered anonymous. If the number of customers in a program is small, however, private information might be discovered by inference. A microgrid presents precisely such a scenario; so far every microgrid in Minnesota considered in this study is a single-customer microgrid, and very few microgrids have been developed to date, leaving customer identity readily discernible.

In fact one such example is located at the Shakopee High School, a customer of the Shakopee Public Utilities Commission. The municipal utility, working with the Minnesota Municipal Utilities Association (MMUA) and the school, installed a small islandable microgrid at the site of the school's Environmental Learning Center. The microgrid is an educational demonstration project, comprised of solar arrays totaling 12 kW, a 2.5 kW wind turbine, and 10 kW of battery storage, all controlled by a microgrid energy management system. The microgrid is connected to the Shakopee utility's distribution grid, but can be islanded to serve a dedicated circuit at the Environmental Learning Center.

This project, as well as others that MMUA members have pursued, raised legal questions that required careful consideration. For another project at Shakopee, MMUA worked with Shakopee Public Utilities and the University of Minnesota Clean Energy Resource Team to develop a customer agreement that addressed issues involving the privacy of customer records and the utility's obligations.[66]

Similar issues also have been addressed by the American Public Power Association, which commissioned a model customer privacy policy from the Vermont School of Law.[67] The APPA model and MMUA's work on the issue can help Minnesota municipal utilities engaging in microgrid projects and other initiatives that might expose customer data.

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[65] The manner in which public utilities protect and use customer data is subject to investigation by the PUC at this time. See *Commission Inquiry into the Privacy Policies of Rate-Regulated Energy Utilities,* Docket No. E,G-999/CI-12-1344. One of the focuses of inquiry is on the advent of smart grid and other programs where allowing greater access to customer energy usage data could be warranted.

[66] "Smart Grid/Smart Home Research Study Participation Agreement," Shakopee Public Utilities, Minnesota Municipal Utilities Association and the University of Minnesota, October 2012.

[67] Hagan, Colin, and Katie Thomas: "A Model Privacy Policy for Smart Grid Data," Institute for Energy and the Environment, Vermont Law School, Nov. 4, 2011.

B. Interconnection Standards and Microgrid Integration

1. Standards for Microgrid Control and Safety

Several important industry standards – promulgated by IEEE, UL, IEC, and FERC, for example – exist to address utility companies' concerns about interconnecting DG systems. These concerns include:

■ **Anti-islanding:** Without anti-islanding features, grid-connected DG could unintentionally cause current to flow onto a circuit that otherwise should not be energized – *i.e.,* during a utility outage – creating an electrified "island" of live wire in a sea of de-energized circuits. This is the oft-cited scenario where a line worker touches a conductor that was supposed to be safe, and gets electrocuted because a customer's DG was not properly installed to prevent it.

■ **Fault current contributions:** Some distribution systems do not have the protective equipment necessary to safely prevent short circuits from distributed generators running in synchronous, parallel interconnection to the utility grid.

■ **Voltage instabilities**: Even where protective equipment can be installed, voltage instabilities can result from synchronized generators that fluctuate to follow microgrid loads or from variable energy resources that have sudden changes in generation output due to weather variability. The resultant voltage sags and surges on the grid side can require utilities to install expensive capacitor banks and voltage regulators to maintain stable voltage levels and avoid cascading nuisance trips of their circuit breakers by their protective devices.

■ **DG control limitations:** Generally, customer-owned distributed generators have very little telemetry visible to utility control rooms. This lack of coordinated supervision and control often results in sub-optimal operations for the DG customer and the utility.

New interconnection technologies and approaches to microgrid control have gained acceptance among utility companies and public policy makers in other states to affordably solve these DG interconnection problems (*See Appendix C: Interconnection Technology Case Studies*). However, even new technologies that are compliant with industry standards can encounter resistance from utility power system engineers, whose experiences have taught them to distrust new systems until they are proven through exhaustive field testing to be safe and effective. Their concerns are well founded, given the potential consequences for failure. Vendors and integrators bear the burden of proof to demonstrate the reliability of new technologies – as well as their cost-effectiveness.

Today, technology changes more rapidly than ever. Testing methodologies and simulation tools reduce the time to prove the value and safety of new technology. An active utility program to test and implement new technology (*e.g.,* microgrid pilots, conservation voltage reduction (CVR) and others), supported by cost recovery, can benefit consumers.

a. "Islanding" vs. "Anti-Islanding"

The similarity of the terms "islanding" and "anti-islanding" cause some confusion that bears addressing.

The anti-islanding provisions of IEEE 1547 are intended to prevent unintentional islanding of grid-connected generation. Separate provisions also provide standards for intentional islanding, and pending changes are expected to clarify how the two effects differ and how they interrelate.

Anti-islanding is a vital safety feature of protective systems, and it will remain in the amended 1547 standard. Standards-compliant, grid-tied DG systems generally are grid-activated, which means they automatically shut down in case of an outage, to prevent unintentional islanding.

Amendments to IEEE 1547 provide some key provisions to assist intentional islanding, in which a microgrid or other islandable generation source is designed to operate both when connected to the grid, and when disconnected from it. One key example involves ride-through standards. The original 1547 standards had very sensitive trip-off settings, so that even a minor fault could cause the DG to deactivate. Such a hair-trigger anti-islanding feature is problematic at high levels of DG penetration, and also is a nuisance for systems designed to isolate themselves and start backup generators upon a system fault. Proposed 1547 amendments will allow for a wider ride-through tolerance, so DG and microgrids can be configured to continue generating despite minor fluctuations in grid frequency.

The key difference between anti-islanding and intentional islanding is this: once a system is intentionally islanded, anti-islanding requirements no longer apply. The isolated (islanded) system is disconnected from the grid, and therefore it no longer presents a safety concern. Recommended practices for intentional islanding are contained in IEEE 1547.4, and the forthcoming 1547.8 standard addresses further functionality of small generators that are designed to intentionally island themselves – *e.g.,* microgrids.

So, despite the nominal contradiction in terms, islanding and anti-islanding features are meant to work together in the IEEE 1547 standard. Moreover, systems that are compliant with the new version of IEEE 1547 will allow more seamless and stable interconnection of islandable microgrids, while also preserving the vital safety provided by anti-islanding features.

2. Islanding and Interconnection costs

Most states – including Minnesota – enact regulations for interconnection based on IEEE 1547, as well as FERC interconnection standards for small generators adopted in May 2005 under FERC Order 2006.

Several states with concerns about the potential for faults and unintentional islanding require the utility to conduct system-impact studies. Depending on how the process is handled, such studies can impose high costs on microgrid developers, and also can cause many months or even years of delay. Then, once a study is completed, the developer might be required to fund the installation of additional protective measures on the utility grid, at an additional cost of thousands of dollars per kilowatt of capacity.

In one example, a large CHP system serving New York University in Greenwich Village faced this dilemma and decided to spend the funds and time needed to enable islanding, at a cost to the University of thousands of dollars per kilowatt. NYU's microgrid turned out to be one of the few systems in Manhattan to island and provide uninterrupted power during Superstorm Sandy, suggesting the investment was worthwhile. But extraordinary interconnection charges easily can undermine a project's financial feasibility.

Notably in this regard, the NYU microgrid project differs from many that might emerge in Minnesota. First, utility customers in New York City pay more than twice the retail electricity rates that average Minnesota customers pay. Also, the university needed large amounts of reliable power to support critical research facilities, creating a must-have resilience requirement that helped it justify the high cost of interconnection. Finally, NYU faced substantial deferred maintenance for boilers and chillers that were past their useful lives, which resulted in more than $4 million in annual financial savings for NYU, compared with the alternative of grid power, backup diesels, and replacement boilers and chillers.

Absent such drivers, and in a state like Minnesota with lower electric rates, microgrid developers and their customers might be unable to afford the cost burdens of system impact studies and protective equipment to allow synchronous interconnection.

3. Evolving Industry Standards

As mentioned above, standards are changing to meet new industry needs.[68] The most important industry standard for purposes of microgrid development in Minnesota is IEEE 1547.

IEEE 1547 (*Standard for Interconnecting Distributed Resources with Electric Power Systems*) is meant to provide a uniform set of criteria and requirements for interconnecting DG resources with the power grid. It provides requirements regarding performance, testing, operation, maintenance, and safety of a DG interconnection. IEEE 1547 is applied mainly in North America, but it also serves as a template for other countries that are drafting their own interconnection standards.

The standard dates back to early 1999, when IEEE approved P1547 (the "P" designating its status as a draft standard). After numerous amendments, it was approved by the IEEE Standards Board in 2003. Eight complementary standards expand upon or clarify the initial standard. The two standards that are most important for microgrids are IEEE 1547.4 and IEEE 1547.8, and they are subject to a current process of amendments.

Specifically, the IEEE P1547a - Amendment 1 focuses on establishing updates to voltage regulation and response to abnormal conditions of voltage and frequency on a utility grid. The IEEE 1547a amendment was introduced to fast-track the highest priority changes needed for 1547. At this writing, a balloting process had been completed among voting IEEE members, but the outcome was not yet known. Assuming the amendments are approved, they are expected to take effect early in 2014. Subsequently, the fast-track amendment process is expected to be followed by a full revision of 1547 to address a wider range of issues than were identified for P1547a - Amendment 1.

Among the issues addressed in the amendment, two key changes affect microgrids.

1) Allowing voltage regulation: Previously, DG was not allowed to actively regulate the voltage at the point of common coupling. With the amendments, DG systems will be allowed to actively participate in voltage regulation through changes in real and reactive power supplies. This will allow utilities to more easily integrate DG as resources capable of providing grid support. Where utilities do not practice conservation voltage reduction, these standards will permit the microgrid user to regulate voltage and save energy.

2) Ride-through provisions: As discussed above, IEEE 1547 defines recommended practices for a DG system's behavior in response to abnormal frequency conditions – *i.e.,* defining when it must stay connected and when it must disconnect. The amendments were fast-tracked in part because rapidly increasing numbers of rooftop PV systems in some areas of the country exposed utilities to the prospect of dozens or hundreds of DG systems simultaneously disconnecting at the same time, because of a dip in frequency. If that underfrequency situation were caused by an unscheduled outage at a major power plant, for example, then the sudden loss of DG supply could make a bad problem much worse.

Both of these amendments will enable microgrids to perform at higher levels of efficiency and encourage more DER and microgrids. The first one allows a potential microgrid to be integrated into

[68] Fox, Kevin, et al.: *Updating Small Generator Interconnection Procedures for New Market Conditions,* Technical Report, National Renewable Energy Laboratory, December 2012.

distribution control systems and actively serve grid-support functions. The second allows a microgrid to remain connected, avoiding unnecessary startup of backup generation. And if an interconnected microgrid is feeding power onto the utility system, then the ride-through amendments will help avoid the bad-to-worse scenario above.

More comprehensive revisions next year might address further functional capabilities of microgrids. In early stages of development, for example, are standard information models for microgrid control point functionality, and the future vision of a distribution system comprised of multiple interacting microgrids that can support reliability on both distribution and transmission grids. These standards are relatively nascent because the technologies and applications are still developing, but examples like Denmark's Cell Controller architecture and prospects for virtual power plants illustrate the need for uniform standards to allow such sophisticated smart grid applications.

a. Federal and State Best Practices

In some states, utility interconnection requirements – and the uncertainty surrounding the time and costs required to fulfill them – have acted to deter DG and microgrid development. As a result, some State governments and FERC have acted to streamline processes and improve transparency to minimize delays and unnecessary costs.

In California, the CPUC overhauled its Rule 21 interconnection process to accommodate market changes and technology advances.[69] Among other things, California expanded fast-track screening; specified time limits for analysis in interconnection studies; gave generators options for requesting a pre-application report; and created new dispute-resolution mechanisms. The state also established that interconnected DG on a distribution line segment can equal 100 percent of that segment's minimum load – as opposed to the previous practice limit of 15 percent of that segment's peak load. The 15 percent-of-peak standard remains in place in California, with the 100 percent-of-minimum-load threshold applied in a secondary evaluation for generator applicants that fail the first, 15 percent screen.

Updates in California were driven by cases of high-penetration DG in some areas, but the drivers are analogous and important for microgrids in Minnesota. On a single distribution segment, a large microgrid might provide generation equivalent to dozens of solar rooftops. Thus standards developed to accommodate the capability for DG systems using smart inverters to provide voltage support also apply in larger scale to a microgrid acting as a DG source, a controllable load, or both. Further, the best-practice standards developed in California and at FERC indicate the direction of policies to improve transparency and certainty in interconnection study processes.

FERC's Small Generator Interconnection Procedures (SGIP) govern how DG units up to 20 MW in size interconnect with interstate transmission systems – as differentiated from local distribution grids. The FERC standards are especially important for Minnesota microgrids seeking to sell wholesale power into the MISO market, and also for potential application of microgrids as NTAs for transmission system planning. Just as importantly, however, they serve as a model for state standards and tariffs, because they establish the Federal government's best practices for interconnecting small generators.

[69] *Decision Adopting Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations – Electric Tariff Rule 21 and Granting Motions to Adopt the Utilities' Rule 21 Transition Plans,* Rulemaking 11-09-011, California Public Utilities Commission, filed Sept. 22, 2012.

In January 2013 FERC issued a Notice of Proposed Rulemaking that would amend its SGIP and Small Generator Interconnection Agreement (SGIA) policies under Order 2006. Among other things, the proposed rule change would:

■ Provide a process for the generator to request from the transmission provider a pre-application report on existing conditions at a possible point of interconnection;
■ Either eliminate the 2 MW threshold under which generators can participate in a fast-track process for interconnection, or increase it to 10 MW;
■ Allow a generator to opt for supplemental review following failure of a fast-track screening process;
■ Revise FERC's pro-forma SGIP Facility Studies Agreement to provide a process for generators to make written comments to the transmission provider on required upgrades for interconnection.

FERC intends these and other changes in its notice of proposed rulemaking (NOPR) to "ensure the time and cost to process small generator interconnect requests will be just and reasonable and not unduly discriminatory." These changes are good news for microgrids and other DG owners that have faced costly and onerous interconnection study and equipment burdens. They are particularly important for those generators interconnecting to high-voltage transmission systems, but they provide useful guidance for policy makers and utilities generally regarding best practices for accommodating growth in distributed resources and microgrids.

b. Updating Minnesota Standards

Minnesota's interconnection requirements are contained in Docket No. E-999/CI-01-1023, issued on Sept. 28, 2004. Electric utilities in Minnesota have adopted these requirements generally, with a subset of interconnection requirements generally used for small grid-tied DG (either 40 kW or 100 kW, depending on the utility).

Assuming IEEE accepts the 1547a amendment, Minnesota will need to review and perhaps update its interconnection standards and tariffs in order to remain compliant. Because 1547 is set for additional revisions, more changes likely will be necessary in coming years. Also, FERC is updating its SGIP and SGIA policies, establishing the Federal baseline for small generator interconnection practices, which can inform the State's efforts to ensure its processes follow best practices.

Although Minnesota's utilities have not formally taken steps to adopt the newest standards and practices, they have processes and staff in place to review the changes and accommodate them. Some utilities have staff members serving on the IEEE Standards Committee, and so utilities are aware of the forthcoming changes. Some utilities have established distribution technology teams and committees charged with reviewing and updating technical specifications and practices. Additionally, Commerce's series of workshops in 2012, combined with other proceedings on DG-related issues, have set the stage for the State to take affirmative steps toward updating the state's interconnection processes, concurrently with changes happening in the IEEE and FERC standards. The State will encourage a more rapid deployment of microgrid technology if it continues its regular standards review and rapid adoption of the new standards as they are approved.

Additionally, as part of interconnection standards and tariffs, Minnesota and its utilities have established thresholds and size limits affecting DG and microgrids. In addition to the aforementioned 40 kW or 100 kW thresholds, the State has set a system capacity limit of 10 MW – which is half the size of FERC's 20

MW limit for small generator treatment, and lower than those of most other states. Several states have no limits at all.[70]

Minnesota's restrictive definition of DG for interconnection purposes poses challenges for microgrids exceeding 10 MW in size. Larger units will be required to negotiate one-off agreements with the utility, incurring greater costs and uncertainties than distributed generators generally face.

Updating Minnesota's standards and practices to conform with industry best practices will help ensure that microgrids can safely and cost-effectively interconnect – and ultimately enable them to provide more advanced grid support services. Although IEEE hasn't yet proposed draft standards addressing microgrid control point functionality and multiple connected systems, those needs are coming and bear consideration in standards-setting processes – especially if the State wishes to continue clearing pathways for microgrid development and integration into Minnesota's utility grids.

[70] *Freeing the Grid,* National Renewable Energy Laboratory, at: http://freeingthegrid.org/

Chapter III:
MINNESOTA'S MICROGRID POTENTIAL

Minnesota electricity customers on average pay prices that are lower than the national average.[71] Recent and pending rate cases affect customers' bills, but nevertheless the prevailing retail power prices affect the near-term potential for microgrid development in the state. Microgrid developers will seek to leverage existing DG capacity, to apply a range of new technology solutions to extend the value of onsite generation, and thereby produce new economic benefits for customers from existing infrastructure. Other microgrids will exploit opportunities to meet a range of customer needs – beyond pure price economics. Examples include the demand for ultra-reliable and resilient service, and the opportunity to integrate renewable energy sources.

A. Existing DG Capacity in Minnesota

1. CHP Capacity and Opportunities for Microgrid Enhancements

Combined heat and power represents a natural application for microgrid technology. CHP provides highly efficient onsite power and useful thermal energy. Microgrid controls and energy management technologies can bring further efficiencies by making greater use of available output – managing distribution of electricity to nearby loads, for example, when electric output exceeds dedicated loads. Contrariwise, microgrids can serve to maximize the utilization of additional energy sources – such as incremental renewable energy – by pre-heating CHP makeup water or pre-cooling common areas when electric loads are lower than available supply.

Further, as existing CHP units in Minnesota near the end of their useful lives, they present opportunities for repowering or redevelopment around a microgrid model. Replacing diesel-fired CHP with natural gas and more efficient equipment will reduce emissions. A new CHP plant, upsized to serve a larger portion of the customer's overall energy requirements (or to serve additional, adjacent customers), can bring substantial economic advantages compared to simply swapping old capacity for the same amount of new capacity.

In recent years, advances in technologies and manufacturing have improved the economics of CHP facilities, especially for medium and smaller units. However, the larger a CHP installation, and the greater its capacity factor, the more economical it is. For this reason, microgrid approaches that diversify loads and supply resources can optimize a CHP unit's investment and operations.

ICF International maintains an online database of CHP sites for the U.S. Department of Energy.[72] According to that database, Minnesota has at least 55 sites with CHP plants, comprising about 918.5 MW. Fully half of those sites (27) are boiler units, and of those, 18 are more than 25 years old (several being much older). And most of those burn coal, which suggests a looming need for replacement. (*See below, 3. Boiler MACT Regulations and Replacement Outlook.*)

[71] Minnesota's average 2013 retail electricity price in 2013 was 10.12 cents/kWh, compared to the national average of 10.92 cents. See *Electric Power Monthly,* U.S. Energy Information Administration, Aug. 22, 2013. http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a

[72] http://www.eea-inc.com/chpdata/

2. Other DG History and Trends

Historically DG applications in Minnesota have been very modest, both in scale and numbers.

For example, Minnesota's largest utility, Xcel Energy, serves more than 1.2 million customers in the state. In 2012, the company had 347 applications for new DG interconnections, totaling 38.3 MW. The vast majority of this capacity – 32 MW – was comprised of projects using "other" fuels, mostly natural gas and diesel backup systems. Most applications are very small, with one 20 MW gas-fired application in 2012 dwarfing the rest. Almost all of Xcel's DG interconnection applications are for projects smaller than 1 MW in size, mostly much smaller.[73]

The numbers for small solar DG interconnections are increasing at a substantial pace – in some cases exceeding utilities' budget limits for DG programs. A similar situation in Massachusetts resulted in a backlog of DG interconnection applications.[74] Adopting a standard statewide procedure helped to eliminate the backlog and also reduced costs.

Xcel Energy's Solar Rewards program, for example, offers a $1.50 per-watt incentive for customers installing grid-connected PV systems between 500 Watts and 40 kW in size. By September 2013, the company had allocated 100 percent of the budgeted $4.6 million in incentives under this program. Xcel received 282 applications for interconnection under its Solar Rewards program in 2012, fully 69 percent more than the number of applications in 2010 (166), and more than double the number in 2011 (140).

As noted, the 2013 Omnibus Energy Bill created new targets for small solar installations. Solar DG interconnection applications likely will increase substantially in Minnesota during the law's term through 2020.

Special incentives to offset the higher cost to island might help Minnesota to achieve its solar energy goals. The inability to use grid-tied DG during an outage reduces its perceived value, and creates bad press for expensive technology that sits idle just when their customers most wish they could use it.[75] In effort to overcome this problem for rooftop PV, NYSERDA has linked isolation from the grid to the incentives it pays for DG.

3. Boiler MACT Regulations and Replacement Outlook

The U.S. Environmental Protection Agency (EPA) promulgated new clean air standards and other emissions standards affecting industrial and utility combustion units. Among the most noteworthy are EPA's Maximum Achievable Control Technology (MACT) standards (*EPA Dkts. OAR-2002-0058 and -0790*), which set hazardous air pollution standards for industrial, commercial, and institutional boilers.

These new standards likely will force the shutdown and possible replacement of numerous coal- and oil-fired boilers in Minnesota. The U.S. Department of Energy's Midwest Clean Energy Application Center at the University of Illinois-Chicago has initiated a technical assistance program that is providing site-specific information to about 480 boilers in the Midwest. The program offers help with compliance strategies, including assistance on implementing natural gas-fired CHP, and identifying funding

[73] Lehman, Paul J.: "RE: Distributed Generation Interconnections – Annual Report," Letter to Burl W. Haar, Minnesota Public Utilities Commission, March 1, 2013.

[74] *Massachusetts Distributed Generation Interconnection Report,* prepared by KEMA for Massachusetts Department of Energy Resources and Massachusetts Clean Energy Center, July 25, 2011.

[75] Solar Companies Seek Ways to Build an Oasis of Electricity, Diane Cardwell, November 19, 2012, New York Times. http://www.nytimes.com/2012/11/20/business/energy-environment/solar-power-as-solution-for-storm-darkened-homes.html?_r=1&

opportunities. This program so far has identified 15 facilities in Minnesota that will be affected by EPA's Boiler MACT regulations, most of which are located at industrial, mining, and agricultural processing facilities throughout the state.

Some of these boilers might present potential candidates for repowering with microgrid technologies to bring greater efficiencies and cost-effective utilization of upgraded generation capacity.

B. Assessing Microgrid Potential Capacity

Microgrids could be developed to serve a wide variety of customers in Minnesota. The task of estimating that potential over the medium- and long-term future is complicated by several factors, such as: technology and market trends; regulatory developments; and external forces driving customer needs and interests.

An empirical study of potential microgrid capacity can help to inform the analysis of prospects and barriers to microgrid development. To assess market potential, Microgrid Institute engaged DNV KEMA to develop an analytic model and to apply it to available data on prospective microgrid customers. As the following section explains, the data sets included this study provided an empirical basis for estimating microgrid-addressable capacity for 12 categories of electricity customers, namely: hospitals, nursing homes, prisons, universities, schools (elementary, middle, and high schools), public buildings, computer/data centers, other commercial buildings, dormitories, and multi-family buildings. For that subset of the potential universe of prospective microgrid customers, DNV KEMA's model estimated 489 MW of electric capacity could be served by microgrids during summer peaks, and 703 MW during winter peaks.

Modeling potential microgrid capacity for other important categories of prospective customers – including industrial sites, hotels and resorts, and energy improvement districts, for example – would require further data collection and study.

1. DNV KEMA[76] Analysis of Potential Electric Load Addressable by Microgrids Within the State of Minnesota

a. Objective

Our objective was to determine the potential electric load within the state of Minnesota that might be isolated from the larger distribution grid by becoming supported by alternative sources of generation in the form of a microgrid. Note: This potential assessment excludes the following prospective categories of microgrids discussed elsewhere in this report: industrial factories and plants; community or cluster microgrids that combine multiple separate facilities and customers within a distribution system segment; military bases; hotels, motels, resorts, and entertainment complexes; and small commercial facilities.

b. Microgrid Potential Capacity Explained

The peak electric requirement for each facility represents the upper bound of microgrid potential. However, factors such as the economics and the capacity to place alternative sources of generation within the facility affect the desirability of a business to install DG to support a microgrid. We adopted a methodology (applicability factor) to evaluate the potential microgrid capacity within the upper bound. The applicability factor determines the microgrid potential capacity of what might be feasible within

[76] DNV and GL merged on Sept. 12, 2013, to form DNV GL.

each category of electric load, based on the known and expected environment affecting the implementation of microgrids.

c. Methodology

Prior experience: DNV KEMA has conducted two national studies to estimate the potential revenue for CHP systems and microgrids for the benefit of equipment providers. These successful studies were based on a “bottom up” approach using the number of buildings and facilities within geographic regions as the data foundation for the analysis. These counts of buildings and facilities were categorized by appropriate standard industrial classification (SIC) codes to provide a market view of the industries and types of facilities of importance to the equipment providers.

DNV KEMA completed a similar third project to identify the potential for DERs within a state. This project included a projection of the effect that incentives might have to encourage growth of DER. The methodology for the project included the apportionment of electric load by function: heating, ventilation, air conditioning, lighting, and others. This apportionment of load was to size the thermal requirements for facilities to exploit a dual use of the fuel used by the CHP equipment. The optimal application of a CHP unit requires proper sizing, based on the thermal and electrical requirements, so as to maximize the overall efficiency (fuel input vs. heat and electricity output). CHP, by generating electricity while following the thermal requirements of the facility, reduces the carbon output per unit of heat and electric output.

Categorization of electric load: The DNV KEMA project team identified 17 target categories relevant to microgrids for which to gather and analyze data. The subsequent analysis resulted in 12 meaningful categories for inclusion in the analysis of microgrid potential. Categories were eliminated because of the lack of quality data available or a determination that the category itself would not yield a meaningful amount of microgrid potential capacity. Industrial facilities specifically were excluded because they have a wide variance in electric load requirements and there were no broad averages, similar to those in the B3 and CPECS databases, to apply. Industrial facility opportunities are discussed generally elsewhere in this report.

The 12 categories included in the analysis are: public buildings, hospitals, nursing homes, universities, elementary schools, middle schools, high schools, computer/data centers, other commercial buildings, dormitories and multi-family buildings. These facilities in the 12 categories are candidates for DG and a microgrid capability, for the purposes of this assessment.

Data sources: The State of Minnesota B3 benchmarking database (B3 Data) provided data for state owned facilities. The Minnesota Hospital Association was a source for data on hospitals. This category has requirements to provide back-up generation. When back-up power is in use, the hospital is isolated from the larger grid and becomes a microgrid providing electricity to critical electrical loads within the facility. Additional resources – including the Minnesota Department of Employment and Economic Development (DEED); the Commercial Buildings Energy Consumption Survey (CBECS) prepared by the U.S. Energy Information Administration (EIA); U.S. Census Bureau Data; and DNV KEMA’s proprietary material developed to apportion loads by function – were used to determine the number of facilities and energy intensity, and to formulate the applicability factor for each category of electric load. The sources used are further identified in Appendix E: Modeling Minnesota Microgrid Potential.

Applicability factor: The applicability factor consists of eight criteria. The DNV KEMA research team assessed the applicability of each criterion in each buildings and facilities category. This approach adjusts the upper bound of microgrid potential capacity based on those factors that will influence deployment of a microgrid. The criteria in the applicability factor are: regulatory mandate for back-up power, feasibility of incorporating renewable energy on sites, size of the facility, access to alternative fuels, reliability requirements, access to tax incentives, dual-fuel use of CHP, and economic return and access to capital for implementation of a microgrid. Each criterion was evaluated and awarded an applicability index score on a scale of 0 to 3. The maximum total criteria score is 24.

DNV KEMA, based on previous experience, understands that the total criteria score is not sufficient as an applicability factor. There is some threshold requirement below which a site will not adopt a new technology or convert to a new process. As an example, a total criteria score yielding a 10 percent applicability factor does not mean that 10 percent of the sites will make a change. The 10 percent applicability factor may be so low within the category that few sites will make a change, perhaps only sites with specific goals. Judgment is required establishing the threshold for change. DNV KEMA chose to set a threshold point factor of 2 by reducing the total criteria score by two to account for the effect of the threshold in decision making.

While subjectivity is involved, the ratings are not arbitrary. The assignment of a rating is based on experience, analysis and logic. Size of facility is an example of a criterion built into the applicability factor. Certain buildings and facilities are not large enough to accommodate renewable energy such a PV array and battery storage. A school is an example of such a facility. A school might install DER and a microgrid. However, the smaller average square footage and thermal requirements in an elementary school make it a less likely candidate to install a microgrid than a high school with its larger size and higher thermal requirements. Therefore, an elementary school will have a lower index score for size than will a high school. Table 3.1 below contains the index rating for each criterion.

Regulatory Mandate	Feasibility of Renewables	Influence of Facility Size	Access to Alternative Fuels	Reliability Requirement	Incentives	CHP	Economics Access to Capital	Total Factors - Threshold of 2	at 6% per point
3	1	3	3	3	-	1	2	14	84%
3	1	2	2	3	-	1	1	11	66%
-	2	2	1	2	-	3	-	8	48%
1	3	3	3	2	-	-	2	12	72%
-	1	1	1	1	-	-	-	2	12%
-	2	1	1	1	-	-	-	3	18%
-	2	2	2	1		-	1	6	36%
-	1	1	1	1	-	-	-	2	12%
-	-	-	1	1	1	-	1	2	12%
-	1	2	-	3	-	-	1	5	30%
1	2	2	2	2	-	2	1	10	60%
-	1	1	1	1	1	1	1	5	30%
Applicability Factor: 0 = none, 1 = Low, 2 = Medium, 3 = High									

Table 3.1: **Applicability Factor Criteria**

The result of applying the applicability factor is further detailed in Appendix E: Modeling Minnesota Microgrid Potential.

Summary of methodology: The DNV KEMA project team developed a count of the buildings and facilities within the defined categories of potential microgrid users. The State of Minnesota B3 benchmarking database for state-owned facilities was used to develop estimates of size (square footage) and energy intensity (annual energy per square footage) and provide a minimum count for overall statewide facilities. Counts of non-state owned facilities were derived from regional data from DEED, EIA, and other sources. The B3 database provided the average square feet for each category of facility. The team used these averages as a proxy for the square footage of the non-state owned facilities.

CBECS data and DNV KEMA load models were applied to square footage and usage data to determine the percentage of end use by type of load for each facility type as well as to derive the peak load (summer and winter), determined by the average ratio of annual usage to seasonal peaks, based on summer afternoon and winter mornings. The peak load represents the microgrid potential capacity for each facility based on the average kWh per site and the average square footage for the facilities in each category. The count of facilities within each category was then adjusted by the applicability factor. This revised count was then used to determine the microgrid potential capacity contained in this report.

The total microgrid potential capacity concept seems to be original with this project and we were not able to identify a meaningful comparison against which to assess our result.

1. Load Segmented by Building and Facilities Category

The electric load was segmented by standard industrial classification (SIC) code. This segmentation provides relative consistency in the amount of electricity per square foot and the type of use among facilities of a given type – i.e., either weather-sensitive (heating, air conditioning) or other loads, such as lighting, computers, etc. As observed in many studies, the proportion of use by type of load is relatively consistent when grouped in this manner.

2. Assumptions and Limiting Factors Affecting Derived Potential Microgrid Capacity

Several key assumptions were used to derive the microgrid potential.

■ The microgrid potential is as of a point in time, derived from B3 Data for 2011 and 2012; changes in energy requirements were not considered.

■ Northern and Midwest regional data, with appropriate modification of quantities of energy use reflecting specific Minnesota weather, is a reasonable proxy where Minnesota specific data is unavailable.

■ The B3 Data are representative across the state and accurate enough for the purpose of estimating the microgrid potential.

■ The size (square footage) and energy intensity (electric load per square foot) of a non-state owned facility will be approximately the same as that within the B3 database for state-owned facilities.

■ Access to alternative generation and to the fuels required for CHP or other electric generation equipment is relative uniform throughout the state with respect to the location of the population of facilities in each category.

3. Results and Observations.

Results: The total aggregate microgrid potential calculated for 11 categories of facility types in Minnesota, based on the assumptions above, is estimated at 503 MW during summer peaks and 714 MW during winter peaks. Additional potential exists at facility types not considered in this assessment – most notably universities and energy improvement districts.

Building and Facilities Category	Applicability Factor	Applicable Minnesota Count	Total Applicable Sq Ft	Total Applicable MWh	Summer Peak MW	Winter Peak MW
Hospitals	80%	120	16,373,176	304,308	51	57
Nursing Homes	70%	279	23,716,655	669,732	102	144
Prisons	50%	11	1,177,254	18,107	2	4
Universities/ Colleges	70%	140	15,363,324	248,052	33	51
Elementary Schools	5%	52	3,926,091	21,642	3	8
Middle Schools	5%	15	2,243,358	14,897	2	5
High Schools	30%	210	42,257,628	328,556	44	121
Public Bldg	10%	12	2,376,070	38,341	7	8
Other Commercial	10%	344	26,770,768	447,340	81	98
Computer Centers	30%	102	5,178,034	150,808	22	27
Dormitory	60%	60	13,397,066	165,652	22	34
Multi-Family Units	20%	1,839	88,694,941	834,540	120	147
Totals		**3,183**	**241,474,365**	**3,241,974**	**489**	**703**

Table 3.2: **Microgrid Potential Capacity**

Observations: The microgrid potential calculated represents a total based on an adjusted count of the number of facilities. This is a reasonable approach because not every facility has the capability to economically deploy the DG that will support a microgrid. Federal and state tax incentives as well as mandates for renewable energy renewable and efficiency will influence deployment of alternative sources of generation. The requirements for isolation from the grid are key elements that also will affect the microgrid potential within the state.

C. Prospects for Renewable-Energy Microgrids in Minnesota

1. Renewable resources for Minnesota microgrids

Minnesota is a leader among U.S. states in renewable energy. Minnesota's RPS requirement – 25 percent by 2025 – is one of the most aggressive in the country, and the state ranks 4th in the nation in net wind-generated electricity.[77] (*See Chapter II-A-6. Renewable Energy Incentives and Qualifications.*) Wind, however, is not likely to be the most useful renewable option for microgrid projects in Minnesota, because the state's best wind resources are concentrated in the southwestern corner of the state – on the eastern downslope of the Buffalo Ridge geologic formation. Some locations in the northwestern, central, and southern parts of the state offer moderate to good wind resources at the 30- and 80-meter

[77] "Minnesota State Profile and Energy Estimates," U.S. Energy Information Administration, July 2012.

elevations best suited for distributed and community wind systems.[78] Unfortunately wind resources are poorer in the most densely populated part of the state – the Minneapolis-St. Paul metropolitan area.

As a consequence, wind likely offers a relatively minor contribution to energy supply at microgrids in Minnesota. More important resources in the state are biomass and, increasingly, solar generation. (*See Chapter I-D. Microgrids as Renewable Energy Enablers).*

Despite the predominance of wind for electricity generation, biomass is Minnesota's largest renewable energy resource. In fact, according to EIA data, biomass contributes a greater share of Minnesota's energy supplies (electric and thermal) than all other renewables combined, and it contributes more energy than nuclear power and nearly as much as fuel oil in the state. Corn-based ethanol production for transportation fuel represents Minnesota's biggest source of biomass energy – with 21 ethanol plants in the state – but biomass power is a major source with considerable growth potential.

2. Trends in Technologies and Resource Options

Microgrids could use biomass as a fuel source in four general technology categories: anaerobic digestion; gasification; landfill gas; and solid fuel combustion (either solely biomass or blended with coal). Of these, anaerobic digestion might offer the greatest near-term potential for DG applications, because it involves relatively low-tech processes and can generate fuels from a range of waste fuels that tend to be located in proximity with substantial energy loads (animal waste, food waste, and municipal wastewater slurry). (*See Chapter I-D-4. Biogas-Fired Microgrids*). Biomass gas from these waste streams and also landfill emissions brings the added benefit of substantial greenhouse gas reductions, by capturing and burning methane that otherwise would escape into the atmosphere.

Environmental attributes of biomass gasification and woody biomass combustion are more ambiguous; where fuels would naturally degrade, burning them can reduce GHG emissions, but it also leaches nutrients and fibrous content from the soils where biomass is harvested. And the process of harvesting and preparing solid biomass for either gasification or combustion consumes energy that likely produces additional emissions. Finally, gasification and solid fuel combustion both involve inherently baseload generation systems, which cannot easily follow loads. By contrast, gas-fired systems – predominately using internal combustion engines or gas turbines – can more readily ramp up and down without severe efficiency or maintenance penalties. Biogas also can be successfully used in fuel cells, but the economics of fuel cells depend on high operating utilization, making them less suitable for load-following applications.

In contrast to biomass and wind, solar resources contribute a tiny portion of Minnesota's electricity supply – less than 14 MW of capacity. That portion, however, is growing quickly, and its future growth is driven by two major factors: the 2013 Omnibus Energy Bill (*see Chapter 2-A-6. Renewable Energy Incentives and Qualifications*), and the technology development path for PV modules and systems.

By some calculations, the levelized cost of electricity from PV technologies has declined by at least 50 percent in the past four years, and utility-scale PV has reached unsubsidized cost-parity with marginal peaking generation sources in many parts of the world.[79] The rate of improvement in PV's levelized life cycle costs has proceeded at an exponential pace for at least a decade, as has the rate of growth in total

[78] http://mn.gov/commerce/energy/images/80MeterCFWindMap.pdf
[79] *Ibid.*, Lazard, August 2013.

installed PV capacity.[80] If PV's exponential advancement is sustained, it can be expected to reach retail cost parity in Minnesota sometime in the next decade.

3. Economic and Operational Factors Influencing Prospects for Renewable Microgrids in Minnesota

As a general matter, Minnesota's solar energy resource does not rank among the best in the United States. The state's northern latitude, cloud cover trends, and snowfall rates weigh against solar expanding rapidly in the state in the short term. Additionally, Minnesota's winter peak coincides with the state's lowest solar intensity and its fewest hours of daylight.

Finally, because the state's average retail rates are comparatively lower than states where PV is expanding the quickest, microgrids in Minnesota will be more likely to pursue other resource options before they seek large contributions from PV. In some sites with strong wind resources, microgrids might be developed to capture wind energy. But the most plentiful and cost-effective renewable resource in Minnesota likely will continue to be biomass. Biomass provides greater flexibility as a generally dispatchable and stable combustion fuel, which can be blended with fossil fuels in various DG configurations to strengthen both operational and economic attributes. Moreover, the state's historic emphasis on biomass has established a strong technological and economic foundation for Minnesota microgrids to develop options using biomass fuels.

[80] *BP Statistical Review of World Energy,* 2012.

CHAPTER IV:
MICROGRID DEVELOPMENT MODELS

A. Contracting, Risk Assessment, and Financing

1. Microgrid Financing Factors and Complexities

a. Project Structure and Financing

A microgrid presents a challenging package to finance. The primary difficulty arises from the fact that a microgrid is not just one type of asset, but rather is a combination of assets that present different technology risks, capital cost factors, and value streams. A microgrid includes generation, a distribution system, consumption, and often storage. The system is integrated and managed with advanced monitoring, control and automation systems. Many microgrids will have almost 20 to 25 percent of their on-site generation from renewable technologies integrated with thermal energy storage and electric battery storage if price competitive.[81] Government incentives for energy efficiency, renewable power generation, and electric infrastructure all may qualify for investment stimulus for advanced energy infrastructure.[82]

The implementation of a microgrid rarely occurs as one project and a common investment. Instead, the value proposition of microgrid evolves over multiple phases, centered on demand and consumption reduction, on-site generation and storage, advanced control systems, and automatic grid independence. Each phase isn't completely distinct from the others, nor must each phase be implemented in a rigid sequence. Often areas of development can overlap, and newer technologies might be considered later in the life cycle of the project.[83]

Not all phases or asset components will qualify for incentives or grants, and the overall capital investment will be substantial. The simple payback calculation might exceed 15 years, but economic considerations are not the sole factors for investors or end users. Some are mostly interested in resilient, reliable, and secure power; physical and cyber security; planned transformation and growth; regional and sector benefits; technology advancement and demonstration; environmental strategies; emission reductions; or some combination of value drivers, along with purely financial considerations.

All such investments, however, will be driven by the need to deliver value for end users.

Starting from that premise, securing affordable financing for a microgrid project depends first on clearly defining value drivers and seeking opportunities to improve the cost-benefit attributes of microgrid solutions and architecture, along project schedules that satisfy customers' requirements. The strongest business propositions likely will depend on the cost-effective deployment of energy management systems, efficiency measures, and DR technologies to minimize capital costs and operating expenses. Efforts to reduce consumption of fuel, electricity, water, and other resources offer quicker ROIs, and can be compounded with simple DR programs to improve ROI.

A variety of applications offer potential for microgrid development, and each can offer different options for project structuring and financing.

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[81] Dohn, Robert Liam, *The Business Case for Microgrids: The new face of energy modernization,* White Paper, Siemens AG, 2011, at p.3.
[82] *Ibid.,* at p.4.
[83] *Ibid.,* at p.6.

For example, some of the best opportunities for fully developed microgrids reflecting the four phases of development likely will be found in the MUSH markets (military, universities, schools, and hospitals) with certain scale propositions. These customers – and others with similar attributes, including facilities considered critical for community services (*See Chapter I-B-1. Critical Community Assets and Microgrid Applications*) – have special needs for reliability and security, with patience to accept longer paybacks over an extended period. They also might be interested in pursuing a package of values and benefits, rather than requiring only a bare financial calculus. Finally, they might improve microgrid financing options by affording access to funding sources and structures inaccessible to strictly commercial projects.

Commercial and industrial customers in Minnesota also offer interesting possibilities for microgrid development – especially in cases where requirements for high resilience carry a high value premium. The Treasure Island Resort & Casino, for example, discussed earlier in this report, places a high premium on resilience because its primary source of revenue – gambling – is entirely dependent on stable and reliable electricity. Such a customer also values the worry-free, turnkey nature of a third-party managed microgrid, and thus is well prepared to engage in a long-term contract arrangement for its full scope of utility services.

A third possible arrangement, though perhaps more complicated, offers interesting prospects for microgrid development in Minnesota: the cluster or community microgrid, developed through a special economic development or energy improvement district (EID) structure, perhaps in cooperation with a municipality. Such a cluster approach can combine a range of synergistic values and benefits, and maximize the utilization of generation resources by diversifying load profiles and criticality attributes. In some cases it might be developed around a core asset – a CHP plant, for example, installed to replace an aging boiler that must be shut down to meet Clean Air Act regulations. A project of this type could deliver an attractive energy cost proposition while also capturing tangible incremental benefits, such as tax-advantaged municipal bond financing, renewable energy incentives, and technology and economic development grants and loan guarantees.

Minnesota has some experience with such approaches. In one recent example, District Energy St. Paul, a public-private partnership that serves 100 buildings in downtown St. Paul with district heating and cooling services, commissioned a study to explore potential for combining resources and needs for energy planning in the Green Line light rail corridor.[84] The study included development of a pre-feasibility methodology intended in part to help other system planners assess options and pursue opportunities for EID projects.

b. DBOOT Project Finance Approaches

Multiple financing options can be used or adapted to design, build, own, operate, and transfer (DBOOT) microgrids in exchange for agreements to purchase energy products and services.

A financing framework for microgrid projects will focus on the following issues initially:

■ What is the best way to fund the early-stage microgrid designs and structuring to secure project financing and attract third-party capital?

■ Can lessons from public-private partnerships, bond financing, and infrastructure banks apply to strategies for microgrid funding?

[84] *Energy Island Integration Study, Completed for the Central Corridor/Green Line Study Area,* prepared by Ever-Green Energy for District Energy St. Paul, April 2013.

■ Can solutions for end-user customers to make commitments for purchasing power from a microgrid be recorded off balance sheet? Do state or municipal governments have a role in entering or supporting long-term microgrid service contracts?

■ Might an investor-owned utility acquire microgrids or their components as a regulated rate-base assets or unregulated investments? Might cooperative or public power utilities support microgrid projects or contribute infrastructure or services on behalf of their members/customers?

■ What role might PACE 2.0 financing play in funding microgrid investments?

■ What project structures will facilitate access to capital and credit enhancement?

■ What roles will be played by various kinds of developers, engineering and construction firms, and vendors of equipment and services?

For purposes of this analysis, the hypothetical Microgrid Project Finance Company ("Company") will be a limited partnership (LP) or limited liability company (LLC) established by a developer to secure debt and equity financing needed to design and own the microgrid. Energy development companies likely will contribute the equity investment necessary to complete the design of microgrids and act as the general partner of a limited partnership or company. Under this approach, microgrid end users – if other than the equity partner(s) – would pay little or no capital costs toward the development of the microgrid. The experience of the developer and its partners will be pivotal to attract third-party capital.

A significant benefit of a DBOOT approach is that the limited partnership or company can earn significant tax benefits not available to entities such as municipalities, special districts, and non-profit or government bodies that are non-tax paying entities. Businesses within the community can be offered an option and assume a role as investment partners in the limited partnership or company and thereby earn Federal tax incentives to lower their investment costs.

Under the DBOOT approach, energy users served by a microgrid would enter into an Energy Services Agreement (ESA) with the Company to pay charges for electric, heating, and cooling services, and to manage efficiency and DR measures. The ESA can have a term of up to 20 years and allows the limited partnership or company that financed the microgrid to recover capital costs and expenditures for construction of the microgrid. After payback to the Company, sole ownership of the microgrid asset could transfer and vest to the end users in its entirety.

The Company might guarantee that the ESA service charges would be no higher than the same rates that the energy users would have paid without the microgrid. Such charges could include costs to obtain qualitative benefits from the microgrid beyond bare costs for energy supply. This would guarantee that energy users in the microgrid never pay more than utility rates and other costs they would incur for the same set of benefits, but in the ESA, it does not limit the possibility that they would pay less. A true-up could be used annually, and any savings from actual costs would be shared among the Company and the microgrid's energy users. In this manner, a user or group of users can choose to emphasize cash flow savings or secure a faster transfer of ownership of the microgrid for earlier control of the assets and costs in the future.

B. Market and Financial Models

1. Utility Models for Financing

Utility grid models have been evolving since enactment of PURPA in 1978, and its implementation by the FERC and the states by 1982. Technology advances have slowly affected the utility system, increasing opportunities for development and operation by non-utility stakeholders, except for most transmission and smart grid applications, and distribution.

Safe interconnection can occur using standardized and proven systems and procedures, fostering a new technology revolution with microgrids. Ultimately, a change in distribution company business models could be fostered by these developments integrated with technology (*See Chapter II-A-1. Ratemaking, Cost-Recovery, and Disruptive Challenges*). These evolutionary trends resemble the changes and transformation that happened when decentralized telecommunications, information processing technologies, and cloud computing merged. Just as telecom industry transformation led to the emergence of new service models and a wave of investment in infrastructure, so too will the industry's evolution toward a more distributed model bring new investment and business opportunities.

Effects on legacy central utility models might lead to utility stranded asset compensation claims. Theories of stranded cost recovery could appear at the State level for distribution assets, which could impose a chilling effect on development of microgrids and DERs generally if they prompt Minnesota policy makers to reduce existing support for DG, or even to erect additional regulatory barriers and limits.

Additionally, however, utility companies will have new opportunities to earn returns – regulated or unregulated – on distribution assets serving independently managed microgrids. This precedent exists where utilities earn a regulated rate of return on transmission assets already in the utility's rate base, but independently managed by RTO/ISOs. In other cases utilities' unregulated affiliates earn revenues on non-utility assets, including IPP and merchant transmission systems.

In some cases, regulated utilities might initiate or participate in microgrid development. As in CL&P's participation in the Hartford Parkville Cluster microgrid, SDG&E's Borrego Springs demonstration project, and initiatives at Duke Energy to develop neighborhood-level microgrid architectures,[85] utilities might continue earning regulated rates of return on existing distribution assets used in a microgrid project, and incremental revenue streams – regulated and unregulated – on additional related investments.

In some cases, environmental compliance obligations will necessitate replacing aging boilers, creating opportunities for utilities to participate and contribute toward optimizing new plant or repowering investments with integrated microgrid solutions. In other cases, load pockets requiring new transmission service might be better served with localized resources, of which microgrids or microgrid-type load-management and DG models might prove to be more effective.

For such projects, the utility could partner and operate or manage microgrid control systems. The utility's role could be important in a campus microgrid, where microgrid wires or pipes serving a single campus cross a public right of way or other demarcation line in the utility franchise. The utility's participation also would help reduce barriers to previously unaffiliated customers voluntarily joining the microgrid for service by contract.

[85] Burr, Michael T.: "Economy of Small," *Public Utilities Fortnightly,* May 2013.

Joint ownership or cooperative structures could collectively own and operate a microgrid, and they could grow to add other customers. In each case, utilities could play a key role in making microgrids more cost-effective by ensuring they are planned and developed as part of the integrated distribution system (*See Chapter I-C-1. Microgrids as Part of an Integrated System Approach*). Moreover, utilities with investment-grade credit ratings and deep balance sheets would bring easier access to low-cost financing, making them logical partners in microgrid projects.

Other physical microgrid models or structures might emerge, as they have already in some locations.[86] Eventually, microgrids might be structured to also connect with each other and with other distributed resources (*See below, 2. Transactive Energy Market Models)*. In such scenarios, a common pooled resource would emerge – *i.e.,* a virtual power plant (VPP). At this stage, no single party would own the network business or control the market's growth and direction; an Internet-style model would emerge that would be Federally regulated if regional, or state regulated within the boundaries of a single distribution company. But energy sale and purchase transactions could occur outside of the rate-regulated utility framework.

The ownership role of incumbent utility companies in such a scenario still bears scrutiny and remains to be determined. In the short- and medium-term future, utilities occupy a strong position as effectively sole providers of retail electric and gas services. But creeping disintermediation by third parties and new technology options will erode that position over time. Whatever the market structure and regulatory model, utilities increasingly will be forced to compete with other types of service providers and intermediaries, including companies in IT, cable TV, telecommunications, financial, independent power, energy technology, and related industries that offer more innovative solutions and that demonstrate better ability to assume entrepreneurial risk than the incumbent utility industry has shown.

To the degree electric utilities choose to focus on preserving and protecting a rate-regulated commodity business with approved pass-through provisions, while other companies are offering enhanced customer service with new technology options, utility customers and shareholders could face the prospect of a shrinking role in the market, and therefore eroding value proposition. Ultimately this could lead to higher capital costs as investors shift resources toward companies with more future-proof business models.[87] Contrariwise, utilities that pursue win-win approaches to exploit emerging technologies and resource opportunities, including microgrids, will be better positioned to benefit from those changes rather than be marginalized by them.

2. Transactive Energy Market Models

Alongside more sophisticated approaches to energy asset valuation and cost recovery, new operational and market models are emerging in the electricity industry, with advances in information processing technology, communications networks, and automated power systems. Collectively these can be referred to as smart grid technology, "big data" analytics, and transactive energy[88] (TE).

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[86] Hyams, Michael A., *et al.*: *Microgrids: An Assessment of the Value, Opportunities, and Barriers to Deployment in New York State, Final Report,* prepared for the New York State Energy Research and Development Authority (NYSERDA), Sept. 2010, pp. 7-9.
[87] Kind, p.8.
[88] Definition from the Transactive Energy Association (www.tea-web.org): "Transactive energy engages customers and suppliers as participants in decentralized markets for energy transactions that strive towards the three goals of economic efficiency, reliability, and environmental enhancement." See also Cazalet, Edward G.: "Automated Transactive Energy (TeMIX)," Grid-Interop Forum 2011.

Utilities in some jurisdictions are applying smart grid and big data analytics technologies to optimize real-time system performance as well as to guide system planning and investment decisions. These technologies and practices lead toward a future in which system resources can be managed on a more granular, dynamic basis. While those capabilities serve traditional utility operational structures, they also could enable a new market model to emerge, in which retail energy consumption and supply decisions are driven by competitive market pricing, through a combination of long-term contracts and spot- and forward-market bids and tenders.[89]

Such a transactive energy model could introduce market efficiencies and price transparency into an energy industry heretofore characterized by central dispatch methodologies and postage-stamp rate structures. Although those structures historically brought reliable service at affordable prices, their ability to continue doing so is eroding in a market characterized by flat load growth, increasing costs, and rising competitive pressures. TE architects suggest that the transactive market model might be the natural next step in the utility industry's evolution[90] – and arguably it would be better suited to allocating the fixed and variable costs of service in an increasingly distributed operating structure.

Transactive energy could factor into microgrid planning in two ways. First, microgrids could demonstrate TE models in microcosm, providing the opportunity to test automation and data processing systems and competitive energy market models in real time, and to gauge their ability to manage energy sale and purchase transactions while maintaining reliable service. Second, microgrids and their asset components could operate as part of a larger TE market, maximizing their cost-effective operation in a larger, deeper pool of resources that also are being traded in real time.

Moreover, the TE vision proposes a new electricity market structure that exploits new technology capabilities to enable the cost-effective, market-based deployment of distributed resources, while resolving the disincentives, cross-subsidy concerns, and unintended consequences of disruptive forces.

Specifically, the basic principle of a TE market is for customers and suppliers to enter into long-term contracts or subscriptions for fixed quantities of electricity services (energy, distribution, and transmission) for fixed payments. Then automated agents and devices acting for customers would buy and sell electricity services as market prices and customer needs change.

The TE idea ultimately is simple, with familiar analogues in wholesale commodities markets, where participants enter long-term contracts to secure commodity supply and transport capacity – natural gas, for example – and then engage in spot-market and forward trades to manage fluctuating needs and price exposure. The TE model is foreign to the utility industry, because historically the industry has been designed and operated under a strict central dispatch model, with regulated cost-of-service rates.

Market pricing within a central dispatch model has been less than satisfactory, especially in competitive retail markets, largely because end users can only make energy purchase decisions. They cannot sell their energy or capacity – or that ability is severely constrained – leaving market power in the hands of the central dispatcher. Participation in such central-dispatch markets is complex even for the largest customers.

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[89] Burr, Michael T.: "Big Data, Big Change: Analytics chart a path for industry transformation," and also "Rise of the Machines: Who's afraid of the transactive grid?" *Public Utilities Fortnightly,* August 2013.

[90] De Martini, Paul: "Transactive Energy," *Proceedings, First International Transactive Energy Conference and Workshop,* GridWise Architecture Council, May 23, 2013.

Also, the TE market model has been impeded in part because storing electricity is expensive, and a key feature of most commodities markets has been the ability to store supply resources. However, the need for storage becomes less important in a system where market resources can be dispatched or curtailed very quickly, virtually in real time; where resources are increasingly modular and distributed; and where information processing power is sufficient to manage the real-time dispatch of localized resources through competitively priced transactions.

TE concepts and standards are being discussed and developed through such organizations as the GridWise Architecture Council, Harvard Electricity Policy Group, OpenADR Alliance, Organization for the Advancement of Structured Information Standards (OASIS), and the Smart Grid Interoperability Panel (SGIP). As such development continues and TE concepts are demonstrated and deployed in operating energy markets, they might support or complement the emergence of microgrids as efficient systems for deploying and managing resources. And ultimately they could offer visionary approaches for transforming Minnesota's regulatory and operational models to exploit the capabilities of new DER technologies.

3. Microgrid Organizational Models

Generally, three types of organization entities are preferable to finance and govern the microgrid.[91] Other organizational structures likely will follow with supportive federal or state legislation.

a. Energy Improvement Districts

Energy or Special Improvement Districts are organizations with one or more energy users enabled by state and local laws to self-generate and distribute power, for both heating and cooling services. The initial customer for a microgrid could choose to be the sole participant in the EID or to add other neighboring participants in order to optimize microgrid efficiency and capacity utilization. The EID is formed to enable:

■ The initial customer and other participants (if any) to capitalize the microgrid with the same cash flows already allocated for traditional gas and electric service. The initial customer and each EID participant would sign an ESA to purchase a specific quantity of electric, heating, cooling, and energy management services from a microgrid Company. This operates much like a performance contract. If structured as an operating lease, the ESA could avoid a liability on the balance sheet.

■ Legal access to electric power from both the new microgrid and existing grid sources.

■ Low-cost regulation as a municipal or cooperative utility.

b. Private Equity DBOOT

In a private equity DBOOT structure, the Company uses private equity funding to design, build, own, operate, and transfer the microgrid. The DBOOT structure enables the users and other improvement district participants to monetize Federal tax credits, reduce community and energy user exposure to project risk, avoid any liabilities on their books, and add a valuable asset to the community infrastructure once the Company achieves payback. Especially when combined with PACE financing, this model offers substantial potential.

c. Microgrid Operating Company

[91] The transactions among the three microgrid organization entities have been illustrated within in greater detail for reference (www.paretoenergy.com/the-financing.tml).

A Microgrid Operating Company is commissioned by the Company to design, build, and operate the microgrid for the end users or community, effectively as a concession or operating agreement. Mechanisms and contracts used in cases 1) and 2) also could apply in a commissioned microgrid.

4. Microgrid Revenues and Expenses

The value stream from microgrids is critical to generate revenues to retire debt service. Two sources of value arise from: (1) the benefits provided by the specific DER applications that are used within a given microgrid, and (2) the additional benefits created by the unique attributes and geographic location of the microgrid.[92]

Several potential sources of revenue can be developed to support adequate cash flow. These revenues, and their integration in firm ESAs, will provide the critical framework for accessing third-party capital in microgrid project financing structures.

Planning and building a microgrid will require capital investments, start-up spending, and ongoing expenses. These need to be accurately reflected in modeling. Figure 4-1 (*next page*) outlines several examples of potential microgrid revenue streams and categories of expenses:

[92] Hyams, p.69.

Revenue Sources	Capital and Development Costs	Operating Expenses
A microgrid services fee can be assessed to all participants in the system for its management, operation, and maintenance.	Capital cost for procurement and installation of onsite CHP systems, solar PV arrays, storage capacity, and thermal energy conduits, etc., and their associated rights of way and permits.	Costs of fuel for generation systems, with associated hedging arrangements.
Payments for power and thermal energy sales (especially for CHP systems) can consist of fixed or variable rates per kilowatt hour, shared savings payments, or some combination of the two.	Capital costs and licenses for microgrid energy management and control systems and software.	Operational costs, such as salaries of management and operational employees of the system, expenses of physical premises of company (rent), and fees for professional advisors to the operator (accountants, attorneys, etc.).
If a customer desires ultra-reliable power, it can be provided under a special "ultra-reliability" tariff as a premium service.	Fees of professional consultants in the development phase, such as engineers, financial advisers, attorneys, permitting specialists, and financial placement firms.	Fees of consultants and subcontractors employed to support operation and maintenance of the system.
Payments from building owners for the installation of energy efficiency measures, such as upgrades of HVAC systems and lighting and installation retrofits, can consist of fixed payments for services and shared savings incentives. Grants from State and Federal agencies also might be available.	Capital costs of protective relaying needed for interconnection, costs for interconnection and transmission studies for connecting microgrid systems to the utility grid, and for possible upgrades to utility substations for standby power and fault protection.	A management fee for the managing general partner or operating manager.
Payments from third-party customers for thermal energy for heating and cooling if they wish to be connected to a district energy system.	Capital cost of equipment needed to implement energy efficiency measures, such as new boilers, chillers, lighting, and insulation, and fees of service providers.	Standby service rates to be paid to the central grid for providing backup power.
Incentive payments from government agencies and private foundations.	A financing fee payable to the managing general partner or operating manager in connection with a successful raising of capital.	Insurance premiums, including for a new insurance product coupled with ultra-reliable power covering business losses in the event of power loss (which is much less likely with reliable onsite generators).
Selling of renewable energy credits, emissions allowances, or emissions reductions credits where applicable.		

Fig. 4-1, **Microgrid Revenues, Costs, and Expenses**

C. Capital Access and Win-Win Models

1. Attracting Third-Party Capital

A microgrid could qualify for Federal or state tax incentives for certain, discrete phases of the project. These include policy provisions and incentives for renewables, energy efficiency, energy storage, demand side management, and CHP. (*See for example Chapter II-A-6. Renewable Energy Incentives and Qualifications*).

A commercial focus to the microgrid opportunity in Minnesota will be appealing to third-party developers, because it will provide more effective access to private capital markets for microgrid hosts or government entities. Absent such a business orientation, effective microgrid development will depend on direct funding by microgrid hosts – universities, public agencies, etc. – as well as utilities. The host-funding approach will delay implementation and introduce uncertainties that will constrain microgrid applications. Critical support among a handful of other states also will foster better market penetration with access to capital. Minnesota has tools to show leadership for microgrid development.

Critical to financing success will be an understanding of both the costs and sources of economic value that microgrids can provide. Historic projects offered emergency services and little more. They were not integrated or interconnected with the grid, and generally have served only a single facility. A more modern, integrated microgrid will provide secure sources of power, with high levels of quality and reliability, through a combination of onsite generation, storage, distribution, and energy management technologies. Microgrids that make the most of each of these values, and exploit the full range of revenue streams and incentive opportunities, will be in a better position to attract third-party financing, especially if they consolidate them in easily understood financial analysis (*See Appendix D: Financial Model for a CHP Microgrid*).

Moreover, the best financing opportunities might be obtained by combining multiple microgrid projects together into a portfolio. While an individual microgrid project might be too small to attract interest from private equity and institutional investors, for example, a group of microgrids could achieve the scale needed to raise cost-effective financing – most likely through a secondary-market transaction, after most or all of the assets are operating. Such a microgrid portfolio "YieldCo" even could provide opportunities to raise equity or debt financing in public markets.

a. Federal Incentives

Existing financing strategies are being adapted and implemented to accelerate access to funding under clean energy finance requirements for federal, state, and local financing.[93] Several tools are emerging that can benefit microgrids, especially as the clean energy sector seeks alternatives to traditional tax-equity funding. Historical reliance on tax equity-driven structures has yielded one-off deals with high transaction costs, and has subjected the renewable energy industry to feast-and-famine cycles that have hindered rational long-term success.

Treating microgrids as infrastructure investments will allow developers to begin accessing broader and deeper pools of funds, including bond financing. Numerous possible structures can be explored and

[93] Sanders, Robert G., Lewis Milford, and Toby Rittner: *Reduce Risk, Increase Clean Energy: How States and Cities are Using Old Finance Tools to Scale Up a New Industry,* Clean Energy and Bond Finance Initiative, August 2013, at p.3.

exploited for specific projects, including: public benefit funds such as Xcel Energy's Renewable Development Fund; Property Assessed Clean Energy (PACE) loans and loan-loss funds; tax-equity pooling matched with bonds for debt; establishing new asset classes for infrastructure, especially to attract investment by pension funds; credit enhancement with bond financing; regional bond banks; special bonding for microgrids; statewide pools; and project or contract aggregation. Credit enhancement will be key to reduce the risk of development. This will increase the credit rating of a project, which reduces the cost of debt capital for financing.[94]

Congress is also considering legislation (the Master Limited Partnerships Parity Act) to extend master limited partnerships (MLP) to renewable energy assets. MLPs help project developers and investors to avoid double taxation and thereby attract capital at lower costs. MLPs generally are publicly traded entities that operate like a corporation, but do not pay corporate income taxes. After raising capital in the public markets, MLPs distribute the income to shareholders, who pay taxes at their personal income tax rate.

Whether microgrids could qualify for MLP treatment will depend on the legislative outcome, as well as development approaches that structure projects specifically to qualify. The opportunity for microgrids might be substantial, as it would create opportunities to access new investment pools.

b. Minnesota Incentives

Minnesota has tools to offer upon review that could provide support or credit enhancement value to microgrids. Minnesota has enacted a system benefits charge,[95] and legislation to facilitate PACE bonding (*H.F. 2695 and H.F. 3729*). Minnesota is one of 15 states plus D.C. and Puerto Rico that has public benefits funds for renewables – projected to offer in the aggregate nationwide $7.7 billion by 2017. Minnesota raised $19.5 million in 2012 – and offered in the aggregate $339 million from 1999 through 2017. The Minnesota fund does not have a current expiration date.[96] One microgrid project, advocated by the University of St. Thomas, was conditionally selected for funding under the latest Xcel Energy Renewable Development Fund solicitation process. Clearer guidance on how future funding will be allocated by the State could help microgrids access these resources. Future additions to the funds could be allocated to microgrid projects, and other funds could be sourced from financial penalties assessed by the Minnesota PUC for utility noncompliance under Minnesota RPS policies – if and when Minnesota utilities fall short of RPS goals.

PACE financing allows property owners to borrow money from new established municipal financing districts to finance efficiency and renewable energy measures in retrofit projects. The loan is repaid through an annual special tax, usually assessed on property owners' real estate tax bills. Minnesota enacted legislation (H.F. 2695) in 2010 that allowed cities, counties, and towns to offer PACE financing programs. These provide loans for energy conservation improvements, including renewables, HVAC, or electrical upgrades. On-demand bond-financing structures are provided for smaller projects, and pooled or interim financing structures are being developed. Subsequently in H.F. 3729, Minnesota allowed a local government to designate another authority – as an implementing entity – to implement a PACE program.

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[94] *Ibid.,* at p.8.
[95] The Xcel Energy Renewable Development Fund was established in 1999 legislation authorizing Xcel's onsite storage of spent nuclear fuel.
[96] *DSIRE: Database of State Incentives for Renewables & Efficiency,* U.S. Department of Energy, April 29, 2013.

Clarification for microgrids is starting to appear, while implementation issues are ironed out. PACE tools are critical for microgrids in Minnesota as they offer very low or zero risk of loss. Property tax liens are senior to mortgage debt, with 97 percent of property taxes current, and losses on PACE loans currently total less than 1 percent. PACE financing is beneficial to the community as it promotes local job retention and creation, while providing no credit or general obligations risk.[97]

The St. Paul (Minn.) Port Authority recently approved the issuance of almost $10 million of revenue bonds for PACE financing. The authority will issue the bonds to finance loans to cities throughout the state for projects to boost efficiency or install renewable energy systems. This financing builds from the Trillion Btu program in which Xcel Energy and a local non-profit have teamed to fund energy retrofits in commercial buildings for heating and lighting. These bonds have a repayment term of 20 years, and their issuance represents one of the first PACE financing transactions in Minnesota since 2010.

Working with local governments in establishing energy improvement districts would be a logical step for microgrid development. The inclusion of district heating and cooling systems along with microgrids as eligible community-based clean energy systems would be an important next step. This would allow for equipment that is not permanently fixed to the property to qualify for PACE financing. A broader definition of eligible property or improvements would also recognize that microgrids favor no specific technologies, but focus on performance and results. They should not be penalized for access to financing as a community-based energy system that links multiple clean energy resources to multiple properties (building or owners).

2. Win-Win Scenarios in Minnesota

In states where microgrid developers are pursuing project opportunities, the lack of win-win business models for microgrid users, other utility customers, and utility company shareholders often prevents projects from moving forward. Utility disincentives create a powerful barrier, and utilities wield potent tools for preventing or delaying microgrid development – such as uncertain and excessive interconnection study requirements. However, developers in a few states are finding microgrid use cases that clearly demonstrate safe, affordable islanding while providing net benefits to utility customers and shareholders. This is particularly true where existing DG systems that cannot island to provide uninterrupted power during utility outages can be retrofitted with new interconnection technology, and reconfigured as microgrids.

Several Minnesota utility companies have expressed interest in exploring win-win models. One example is the buy-all, sell-all proposal discussed in Chapter II. Such models offer promise – assuming the valuation models are successfully developed to implement such an approach. Quantifying win-win benefits will depend upon utility companies contributing data about the marginal cost of grid power at particular times and places.

However, such win-win models are meaningless without projects to implement them. Microgrids and other DERs are novel and disruptive technologies, and mainstream demand is not likely to emerge organically – especially in the face of arrayed challenges – without pilot projects by first adopters. As with other disruptive technologies – such as peer-to-peer computing and even the Internet itself – some

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[97] "FAQs about PACE," Frequently Asked Questions Website, Minnesota Department of Commerce, Division of Energy Resources, 2012. http://mn.gov/commerce/energy/topics/financial/Energy-Savings-Programs/Commercial-and-Industrial/PACE.jsp

states are finding that universities and the U.S. Department of Defense make ideal first adopters for microgrids. Other states, such as Connecticut and California, are assisting local communities in energy assurance efforts that involve microgrid development. In each case, pilot projects require supportive organizations and governments to help resolve complexities and craft win-win models.

Finally, as projects emerge, market penetration will improve with a microgrid governance structure that enables multiple users to manage shared energy investments as an infrastructural commons. Like many other states, Minnesota already has begun activities within EID structures. A cooperative approach involving EIDs, local community leaders, utilities, and the State seems likely to result in a win-win framework that serves utilities, ratepayers, and microgrids alike.

Chapter V:

MICROGRID ROADMAP

Minnesota's policy landscape provides several paths forward for microgrid development. But the pace of that development is severely hindered by several important factors.

■ Franchised electric utilities in the state currently view microgrids primarily as technically problematic and competitively challenging, rather than as potentially efficient and flexible solutions for the benefit of customers and shareholders.
■ Under current regulatory regimes, DER expansion generally conflicts with the utility's financial interests. Decoupling and unbundling can help in the short term, but uncertainties remain about utility economics in the long term.
■ Interconnection standards and tariffs are too restrictive, and they don't adequately provide for the scale or flexibility of microgrids. Also utility distribution policies, driven by expressed concerns for safety and ratepayer equity, seem to discourage pursuing innovative approaches that can reduce microgrid interconnection costs safely and effectively.
■ State policies are silent on microgrids, and policies addressing related areas are only partially applicable or are ambiguous. Programs and incentives generally do not assign value to the synergistic benefits that microgrids can deliver.
■ Structural challenges hinder access to affordable financing. Qualification factors for special low-interest and tax-benefit financing exclude some microgrid assets and revenue streams. Higher-cost, venture capital financing increases lifecycle costs and challenges microgrid business models.
■ Customers in Minnesota are unfamiliar with the concept of microgrids. As such they may be reluctant to become involved with innovative technologies and business approaches that some might perceive as untested or risky, especially if local utilities avoid involvement, withhold support, or even actively oppose them.

In the face of these challenges, the fact that microgrids are still being considered indicates a strong set of motivating factors and potential benefits. In order to help capture these benefits for Minnesota businesses and residents, and assist in their safe and cost-effective implementation, policy makers can pursue several important paths toward bringing microgrids to the state. These paths involve energy policy priorities, specific regulatory options, and potential legislative changes.

A. Minnesota Policy Options

Policy Action Steps:

> Define "microgrid" for State policy purposes, including energy assurance and renewables objectives
> Actively support and encourage community leaders pursuing microgrids
> Ensure microgrids are properly valued and considered in energy resource and policy initiatives
> Consider modernization and transformation trends in State policy and planning

1. Define "Microgrid" for State Policy Purposes

A key problem hindering microgrids in Minnesota involves the fact that they haven't been clearly defined, either as a general industry term or, more importantly, as a class of business assets for regulatory purposes. Defining microgrids for State purposes could occur through multiple venues, legislative and administrative.

The State's definition of "microgrid" should be based on commonly accepted definitions, such as those described in this White Paper. Most notably, a microgrid must be capable of islanding to serve critical loads for some period of time. To be most effective and consistently applicable, the definition would be established as part of the State's effort to develop and renew its energy strategy and policy priorities. Moreover, the potential roles of microgrids will be most appropriately considered in the context of an overall assessment of future energy technologies, as well as service models, market structures, and regulatory frameworks. To the degree disruptive trends are changing the likely trajectory of the energy industry, those trends also should factor into State energy planning and regulatory development.

2. Support Microgrids as Energy Assurance Solutions

State policies and initiatives can directly support microgrids' potential role in State and local energy assurance planning. Moreover, ongoing efforts to assist community leaders with energy assurance planning and emergency preparedness can include a subset of efforts to help communities evaluate, plan, and implement microgrids as part of the full set of appropriate and effective DER tools. Microgrids frequently present an array of complexities, in terms of engineering, operations, and business execution. Communities – many of which lack adequate planning resources and wherewithal – will benefit from the State's active assistance in navigating those complexities.

State assistance also can help ensure that community DER development efforts occur in the context of an integrated approach that optimizes microgrid capital investments and resource utilization. State guidance can improve the likelihood that community planning efforts incorporate a broad scope of perspectives, experience, and expertise. The State's active participation can help local leaders to consider microgrids in their proper context as part of an integrated utility system.

Finally, the State also can ensure that the most robust energy assurance tools are not reserved only for the wealthiest and most populous communities. Microgrid assets have substantial capital costs, and their engineering and planning complexities can represent barriers for communities with limited budgets and planning staff resources. Even when grants are made available to encourage microgrid development, grant application requirements and processes alone can strain community resources. Any microgrid pilot projects or support grants should be based on empirically supported performance criteria. Nevertheless, a full scope of State technical assistance, from outreach and education through project engineering and financing, can help ensure microgrids can serve the communities that need them most, rather than only those with the most money to spend.

3. Support Microgrids' Role in Achieving Renewable Energy, Efficiency (Including CHP), and Environmental Objectives

The State has a long tradition of promoting and providing incentives for renewable energy development, energy efficiency, and environmental protection. These same State policies and initiatives can support the potential for microgrids to effectively integrate renewable resources, increase energy efficiency, and reduce environmental impacts. Microgrids can maximize renewable resource penetration and utilization factors by diversifying generation and technology types, incorporating energy storage, and improving system efficiencies with load management technologies and measures. State policy guidance and attention can help to ensure that microgrid sponsors can use state renewable and efficiency incentives and provisions to deliver cleaner, more efficient, renewable energy for microgrid customers.

Microgrids also can serve as dispatchable loads and generation sources, assisting in an integrated utility strategy for balancing variable renewable resources. By defining and supporting microgrids' potential role, the State can help ensure that utilities apply the best available technologies and resources to maintain a reliable and balanced energy system, with greater contributions from renewable energy than they could without microgrids.

Finally, microgrids can serve as a key technology platform for optimizing CHP assets. By ensuring that CHP policies consider and support the role of microgrids to further increase the overall system efficiency and cost-effectiveness of CHP applications, the State can encourage development of CHP for a wider range of potential customers than might otherwise benefit from CHP's superior efficiency.

4. Support Microgrids for Local Economic Development and Energy Self-reliance

Microgrids represent a green technology solution that can support Minnesota's economic development in substantive ways. First, energy improvement districts can create direct employment through microgrid construction and support jobs, and also can improve local communities' ability to attract business development by demonstrating commitment to providing state-of-the-art infrastructure systems and services. Second, microgrids represent an advanced technology solution that already is supported by world-class academic and corporate research institutions in Minnesota. Advancing microgrid deployment in the state will encourage continued and growing commitment to development of clean and resilient energy technologies in Minnesota. In addition, microgrids can support greater reliance on local energy supplies. Such supplies can include clean and renewable resources whose exploitation directly and indirectly serves to improve local economies, by capturing payments and locally re-deploying funds that otherwise are diverted to more distant suppliers.

In addition to supporting the development of microgrid projects generally, the State can help local communities pursue the economic benefits of microgrids by providing a range of consultation and direct funding assistance.

5. Support Grid Modernization and Industry Evolution

State policy and planning efforts should consider long-term industry trends, and actively support evolutionary steps that lead toward better solutions for Minnesota businesses and residents. Rapid advances in energy technology, combined with new and radically more powerful communications platforms and computing capabilities, have reshaped the current utility industry landscape – and they portend even more fundamental changes to come. These changes inevitably will affect the options available for serving Minnesota utility customers, enabling the emergence of more cost-effective energy service models and market structures. Accordingly, State policy processes should seek to aid the utility industry's transition toward a future in which it can more easily and effectively integrate new and more efficient technologies – including DERs and microgrids.

By evolving to fully consider the capabilities and implications of grid modernization, the State's policy goals and strategies can support the industry's transformation for the ultimate benefit of energy consumers. Minnesota customers cannot accept an abrupt and chaotic transition that allows service and reliability to degrade, and causes economic dislocations and imbalances. Nor can they accept an unmanaged transition that permits continued, business-as-usual expenditures on assets that foreseeably and avoidably might become stranded, while marginalizing beneficial alternative technologies and business arrangements.

The State's active effort to prioritize and facilitate utilities' timely transition to a modernized power grid will help ensure fair outcomes and sustainable, affordable, reliable energy service for Minnesota customers.

B. Regulatory Pathways

Regulatory Action Steps:

> Update interconnection policies to address changing industry standards and market needs
> Include microgrids among options utilities must consider in resource- and system-planning processes
> Define special frameworks and regulatory treatment for energy improvement districts
> Initiate and support microgrid pilot projects
> Examine and address structural disincentives and cross-subsidies

Minnesota's regulatory agencies have focused considerable attention on studying and accommodating the development of DG projects, and further efforts continue through work to implement the 2013 Omnibus Energy Bill. Including consideration of microgrids, in terms of how they are organized, planned, built, interconnected, owned, and operated, will allow the State to address barriers and uncertainties facing microgrids in Minnesota.

1. Update Minnesota's Interconnection Standards and Tariffs

Minnesota's interconnection standards are based on outdated assumptions about the scale and requirements of DG facilities, and they do not contemplate the prospect of integrated microgrids with generation, storage, and load-management capabilities. The State's efforts to review interconnection standards and utility interconnection tariffs will help to facilitate the integration of new DER technologies and projects – including microgrids – by incorporating current and expected changes in prevailing industry standards, including those involving IEEE 1547 and FERC Standard Interconnection Agreements and Procedures for Small Generators.

Moreover, the approaches of other states and jurisdictions that are accelerating their standards development processes can serve as examples to help Minnesota to plan for technology changes that are outpacing IEEE balloting and FERC rulemaking processes. Examples include California, where the CPUC overhauled its Rule 21 interconnection process to accommodate the rapidly changing needs of both utilities and DG owners. Other states, including New York and New Jersey, similarly updated their interconnection rules and standards in recent years. Although each state's unique situation might dictate specific requirements, as a general matter Minnesota's standards and tariffs will be most effective if they reflect prevalent industry standards and practices, and also provide a forward path for accommodating evolution in those standards.

2. Encourage Consideration of Microgrids in Utility Planning

The Minnesota PUC already has a mandate to ensure that DG alternatives are considered in utility resource planning processes and regional reliability plans. Including microgrids as a defined class of DG would encourage utilities to expand the scope of their planning efforts to consider the benefits that microgrids can offer for peak shifting, grid support, capital expense deferrals, and non-transmission alternatives. Microgrids and related solutions – including virtual power plants – should receive fair cost-benefit analysis in system planning. The most accurate and effective approaches to modeling and valuing microgrids will consider the full range of costs and benefits of microgrids, including time- and location-sensitivity factors.

a. Rigorous and Transparent Analysis and Valuation

IRP and system planning processes should include prospects for both utility-sponsored and third-party developed microgrids to address system constraints and growth requirements. Moreover, least-cost planning and ratemaking for transmission and distribution investments in Minnesota and the MISO regional market will be most effective if utilities are required to demonstrate rigorous consideration of alternative approaches, including microgrids. Requiring objective analysis and validation by third-party experts will help ensure utilities consider microgrids and other DERs in a way that is impartial and thorough, to provide the greatest value for ratepayers.

To the degree utility network planning models and analysis influence valuation factors, such information should be made available for microgrid real-options valuation analysis, with utility trade-secrets protection where appropriate.

b. Grid Modernization Planning

When microgrids are developed in a utility's service territory, the utility's costs associated with integrating those microgrids should be considered in their proper context of overall grid modernization and resource planning by that utility – rather than as isolated endpoints connected to the existing grid. Moreover, investments and policies regarding interconnection and control systems should be planned as part of an integrated, modern utility operating model. The State can facilitate the industry's transition to a modernized grid by encouraging utilities to update and apply DER interconnection policies as part of their long-term grid planning and development efforts.

c. Minnesota and MISO Planning Processes

As MISO and its transmission owners consider investment needs for reliability and market enhancements, non-transmission alternatives (NTA) can offer solutions that cost less, intrude less on landowners and the environment, and raise fewer siting conflicts. Microgrids and other DERs can serve as NTAs if they are designed and planned to address transmission system and market constraints.

FERC Order 1000 established NTAs as a category of asset that merits consideration in regional planning. So far, MISO has not provided guidance regarding processes for proposing, evaluating, or developing NTAs to address regional system requirements. Whether and when it might do so could depend on stakeholder pressure on MISO to drive efforts forward. Through its participation in the Organization of MISO States, and through direct engagement with MISO and FERC, the State of Minnesota can actively encourage MISO to provide transparent and constructive processes for considering microgrids and other potential least-cost NTAs in regional planning.

3. Define Organizational Frameworks (*i.e.,* "Energy Improvement Districts") for Community Microgrid Development

Minnesota's laws on special districts provides broad latitude for organizations to form in support of local and regional development initiatives. State agencies, local governments, and public-private partnerships working together can create model frameworks and administrative treatment for energy improvement districts, intended to facilitate upgrades of local utility infrastructure in support of an energy improvement district's defined goals. Such goals could include reliability and resilience improvements; technology advancement; smart city and smart building concepts; development of renewable resources; community economic renewal, development, and job creation; and local self-reliance and energy sustainability.

A regulatory review of agreements and structures regarding rights-of-way, franchise concessions, asset transfers, permitting and siting, and tax and finance benefits can reduce legal and administrative cost burdens for community microgrid development. It could address uncertainties about legal status, boundary rights, and organizational governance, and could provide for exemptions and guidance regarding open-meeting laws and customer privacy issues.

4. Initiate the Minnesota Microgrid Pilot Program

Microgrid Institute recommends that the State of Minnesota establish a program to facilitate and support microgrid pilots projects in the state – the "Minnesota Microgrid Pilot Program."

The importance of State-supported projects with active utility involvement cannot be overstated. Because modern, integrated microgrids represent complex packages of technologies, processes, and arrangements, the first commercial-scale projects will face serious challenges securing the long-term customer commitments necessary to support development and financing. The State of Minnesota can play a pivotal role in opening future opportunities for commercial microgrids.

a. State and Local Government Microgrid Opportunities

The Minnesota Microgrid Pilot Program could make rapid progress by first considering sites owned and operated by units of State and local government. Excellent opportunities exist in Minnesota to develop microgrids at such facilities, including law-enforcement and administrative buildings, community centers, and schools and universities. The CHP facility at the University of Minnesota and the renewable energy facilities at U of M Morris provide obvious opportunities for microgrid development. Other examples include State-affiliated prisons, as well as housing authorities, hospitals, and other facilities with populations that are particularly vulnerable during outages.

b. "Pilots" vs. "Demonstration" Projects

The Minnesota Microgrid Pilot Program will be most effective if it facilitates development of commercial microgrids, rather than focusing on technology demonstration for its own sake. Demonstration projects around the country and in Minnesota already have established technology capabilities. While the technology will continue advancing, microgrid applications are ready for commercial application in Minnesota – hence an ongoing "pilot" program to advance commercial applications will be more effective and appropriate than "demonstration" projects.

c. Minnesota Funding Avenues

Projects could be partially supported with existing clean energy funding sources, such as the Xcel Energy Renewable Development Fund. Other potential avenues for state support include utility rate-base treatment and funding pre-approvals for microgrid-related investments; state implementation planning (SIP) processes to comply with Federal Clean Air Act requirements; and provisions under State bonding authority related to special projects, such as the Mayo Clinic-Rochester development plan, and the Minnesota Vikings football stadium project.

Further, some phases of the Minnesota Microgrid Pilot Program likely will require direct funding from the State of Minnesota, most notably with appropriations from the Legislature for direct loans and grants, loan guarantees, and agency support. The regulatory and administrative processes described above require substantial commitments of time and expertise. To the degree microgrids can serve the State's policy goals, the State's efforts to clarify related policies and facilitate project development merit appropriate budget allocations.

d. Planning, Management, and Benchmarking

The Minnesota Microgrid Pilot Program will be most successful and create the greatest value for Minnesota businesses and residents if it is developed and executed as part of a long-range effort. It should include carefully developed criteria that consider the full range of interrelated public and commercial interests that microgrids can address, such as energy assurance and emergency preparedness, clean energy development, and business development to attract private funding.

Transparent planning, management, and benchmarking, with regular and rigorous performance assessments, will ensure the best possible outcomes for the State. The Minnesota Microgrid Pilot Program will produce the greatest value if it is conceived and developed as a long-range initiative with multi-phase planning. In this way, best practices can be refined and applied from one phase to the next, and overall experiences will be captured in subsequent expanded projects. Moreover, a multi-phase program will focus first on achievable short-term objectives for microgrid development, with subsequent phases addressing broader objectives and higher goals for technology advancement and public benefit.

5. Provide Rate Structures and Models that Support Microgrids

To the degree existing rate structures and regulatory models discourage utilities from supporting the development of microgrids that can deliver net benefits and serve the State's policy goals, then the State can improve prospects for microgrids by reforming the regulatory framework. The most effective approaches will aim for win-win arrangements that equitably compensate stakeholders in a microgrid project, and that avoid or address potential structural disincentives. At the same time, however, alternative rate structures and structural methodologies will be most successful and economical if they are based on transparent and rigorous analysis, and if they are designed to prevent "pancaking" of policy benefits – *i.e.,* layering of special incentives on top of preferential rate treatment, for example.

a. Alternative Rate Structures

Minnesota has dedicated substantial effort toward exploring and implementing alternative cost-recovery and ratemaking approaches, including decoupling, rate unbundling, and performance-based ratemaking. The State's support for alternative rate treatment approaches can help DERs, including microgrids, to overcome structural and regulatory hurdles that deter their development. The State has a unique role in ensuring that lessons learned from previous alternative cost-recovery programs are applied to future proposals and rate cases.

The State's efforts to analyze utility rates and adjustment requests to determine how these rate structures affect the financial interests of utilities and other stakeholders will support microgrid and DER solutions that defer or reduce rate-base capital expenditures.

The potential for DER integration to shift fixed utility costs onto other customers, and especially the degree to which such cost shifts could create unintended cross-subsidies between customer classes, merits thorough and objective examination. The State can lead efforts to clarify these issues and recommend policy measures to address them, if necessary. Likewise, the State can help clarify factors regarding utilities' requirements for non-discrimination and service equivalency, as well as potential liability concerns that create disincentives for regulated utilities.

b. Win-Win Business Models and Regulatory Structures

The State can help encourage utilities to support microgrid development by providing appropriate incentives for them to participate in microgrids, either through cooperation or active support and even investment. Existing incentives that utilities may earn for investing in efficiency and conservation, such as the DSM Financial Incentive, might either apply to microgrid-related investments, or might be adapted to provide direct incentives for microgrid efforts.

Win-win business models, such as the proposed "buy-all, sell-all" approach, might be adapted for application to microgrids. The State can ensure such models appropriately value microgrid contributions by requiring that they accurately reflect time- and location-specific factors. Also, value-of-solar tariff structures could be expanded to include other resources and asset types, including microgrids. Real-options valuation techniques can improve methodologies for pricing alternative assets and resources.

State regulations and structures that directly limit or hinder microgrid development bear review and reform. For example, utility requests for deferral rates discourage customers from adopting efficient CHP and microgrid technologies. Similarly, exclusive supply arrangement among municipalities, cooperatives, and wholesale power generators can impose barriers to new DG and microgrid development. Finally, existing standby rates and interconnection policies in Minnesota can deter microgrid development. The State's effort to update these policies and ensure they accommodate current industry standards and customer needs will help reduce costs and improve utilities' ability to treat microgrids as system assets rather than liabilities.

C. Legislative Pathways

Action Steps:
> Define "microgrid" for statutory and policy purposes, in ways that support flexible approaches to development, ownership, and financing
> Allow microgrids to qualify for incentives afforded to other clean energy and reliability investments
> Clarify regulatory provisions that exempt microgrids from regulation as public utilities

Some statutory provisions codify limitations that directly affect microgrid development. Legislators should enact amendments and new legislation to remove unintended barriers to microgrids, and clarify the status of microgrids for the purposes of existing and future energy policy legislation.

1. Codify the Definition of "Microgrid"

Because they occupy a legal void in Minnesota, microgrids face uncertainties and barriers that do not affect competing solutions that provide fewer benefits. Describing the legal definition of "microgrid" in Minnesota statute – in addition to policy processes described above – will help to remove development barriers and clarify policy direction. Minnesota's definition of "microgrid" should:

a. Allow Ownership, Operation, and Energy Sales by Microgrid Hosts, Independent Developers, and/or Utilities

Microgrids will be more likely to deliver a full range of benefits if they can be developed and owned under any model that serves to improve services for customers, increase access to affordable financing, and support Minnesota's energy policy objectives. In Minnesota policies and statutory language, broad latitude regarding organizational structure, ownership, and commercial arrangements will support innovation and efficiency in technology applications and business models.

b. Eschew Limits on Microgrid Size

Microgrids are defined by function, not by size. The beneficial attributes of microgrid architecture do not cease when the system reaches a certain arbitrary scale. In fact larger microgrids likely will be more cost-effective by virtue of more efficient capacity utilization, and more operationally robust by virtue of resource and load diversity. Therefore the statutory definition of "microgrid" should be entirely indifferent to size, either in terms of total capacity, load, production, customers served, or any other quantitative criterion.

c. Establish that Microgrids Are Not Duplicative of Utility Facilities

Amendments to Minn. Stat. § 216B.37 could clarify that microgrids developed to support customer needs or State policy goals in Minnesota are not considered "unnecessary duplication of electric utility facilities." Microgrids by definition cannot be unnecessary if they serve the defined needs of microgrid customers, and likewise they should be considered necessary by definition if they are designed and developed to address objectives established by the State of Minnesota.

2. Allow Microgrids to Access Programs for Renewable Energy, DG, DR, CHP, Efficiency, Conservation, etc.

Microgrid assets that can contribute toward achieving State policy goals might not currently be included in the scope of eligible property and activity under applicable programs and incentives. Amending policies to explicitly allow microgrids to access benefits appropriately will encourage optimal use of technologies. Also, when multiple programs might apply to a given microgrid project, then consolidated and aggregated treatment can improve the project's ability to capture benefits and deliver value. Such consolidated treatment, however, should disallow double-counting of assets to capture multiple benefits, unless doing so is explicitly defined for purposes of meeting State policy objectives.

3. Clarify Exemptions for <25-Customer Microgrids

Minn. Stat. § 216B.02, Subd. 4 defines "public utility" to include only those entities serving 25 or more persons. This definition leaves some ambiguity that might lead to legal conflicts and disincentives for microgrid development by third-party organizations, including private developers, public-private partnerships, and EIDs. Amending or clarifying this and other statutes will ensure that a third-party developer of a microgrid serving less than 25 end-use customers would not be subject to regulation as a public utility or run afoul of existing service territory and franchise laws.

Additionally, the exemption for <25-customer microgrids could be interpreted in ways that discourage equity investment and formation of special purpose organizations to finance and own microgrids. Amending the statute could ensure that, for example, a minority limited partner in a microgrid will not be defined as a "public utility" as the result of investing in multiple microgrids that, in total, serve more than 24 customers in the state. Likewise it could allow cooperative organizations, such as condominium associations and community EID groups, to form community microgrids without concern that they will be subjected to regulation as public utilities merely because they might serve more than 24 customers. Language regarding aggregated metering in the 2013 Omnibus Energy Bill also could be clarified to ensure that its provisions can apply to microgrids serving multiple customers.

4. Exempt Microgrid Infrastructure from Limits on DR Projects and Total DR Capacity in Utility Systems

Although microgrids include DG, in principle they can provide a broader range of energy supply, storage, and management services. The size of a microgrid should not be limited by statutory definitions intended to control burdens on utilities that are compelled to connect and provide rebates and other incentives for certain kinds of DG systems. Microgrids will be more cost effective and will contribute greater benefits toward State policy goals if they are not arbitrarily constrained to a certain size.

Amending statutes regarding DG, renewables, and other resources could ensure that if individual assets within a microgrid allow it to qualify for special treatment under such statutes, then only those assets will be counted in calculating applicable limits. Other microgrid infrastructure, including complementary generation or storage capacity, for example, should not affect the way the microgrid's qualifying assets are quantified.

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Appendix A
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Appendix B:
"MICROGRID" DEFINITIONS

Numerous people and organizations have attempted to formally define the term "microgrid," and still today no single definition suits every possible meaning for the term as users might apply it.

The simplest and most inclusive definition of microgrid is largely self-referential: a microgrid is a very small energy network. Exactly how small or large it can be is a matter for great disagreement among those who work with microgrids. Some people use the term "nanogrid" to describe the smallest systems, such as a single-home microgrid, but the difference between such a system and the small-scale remote microgrids discussed in this paper are largely qualitative. At the other end of the scale, the largest and most complex microgrid systems envisioned so far, such as the FDA's White Oak Headquarters, are in the range of 65 MW. But some industrial CHP microgrid applications and community microgrid concepts easily could exceed that. At the same time, many municipal utility systems have peak loads considerably below 65 MW, and they've proved themselves capable of operating on backup power in island configuration.[98] Few people would call such a system a microgrid, even though it fits comfortably within the capacity range typically discussed. Thus setting size limits helps little in attempts to define "microgrid."

The one aspect of the definition that almost everyone acknowledges is that a microgrid must be capable of providing stable electricity service within its defined perimeter for some period of time. This is, ultimately, the key defining characteristic of a microgrid. Even with this characteristic, however, the term is still too inclusive. Under this definition, both the aforementioned municipal power system could be a microgrid, and a home-computer uninterruptible power supply (UPS) or a recreational vehicle with an onboard generator and battery backup also could be a microgrid.

Furthermore, these examples also would fit within the definition if we add a third factor – the ability to operate in utility-connected mode. Yet that narrower definition would exclude some other systems that their designers and users call microgrids. Microgrids today are being developed on islands in the ocean, in remote Alaskan villages, and in communities in the developing world that are not connected to any utility service. Indeed, microgrids are being viewed in India and Africa as "leapfrog" technologies, akin to bringing cell phone service to locations that never had landline telephones.

The definition of "microgrid" cannot exclude these systems, as they represent perhaps the fastest-growing market for the fundamental technologies that make microgrids work, namely: distributed generation (DG), energy storage, demand response, and energy management systems.

Not all microgrids contain all of those technologies, and in some sense that fact helps to define the term. So: *A microgrid is a small energy system, capable of providing stable electricity service within its defined perimeter for some period of time, using any of several distributed energy resource technologies in a design configuration that suits the requirements of energy end-users.*

[98] During an April 2013 storm that caused a widespread outage in southwestern Minnesota, Worthington Public Utilities islanded its system and maintained a rolling blackout using backup diesel generation. *See* Burr, Michael T.: "Old-School Microgrid: Resilience depends more on determination than technology," *Public Utilities Fortnightly,* May 2013.

This general definition is useful, but understanding is further illuminated by considering other prevailing definitions in use today (*as edited below*).

U.S. Department of Energy:
A group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid [and can] connect and disconnect from the grid to enable it to operate in both grid connected or island mode.

DNV KEMA:
An integrated energy system of multiple distributed energy resources and electrical loads capable of operating parallel to AND as an autonomous grid - 'islanded' - from the existing utility power grid. DNV KEMA includes load management systems – including demand Response, building management systems, and energy efficiency – in its list of energy resources.

Galvin Electricity Initiative
Microgrids are modern, small-scale versions of the centralized electricity system. They achieve specific local goals, such as reliability, carbon emission reduction, diversification of energy sources, and cost reduction, established by the community being served. Like the bulk power grid, smart microgrids generate, distribute, and regulate the flow of electricity to consumers, but do so locally.

Lawrence Berkeley National Laboratory
A microgrid is a localized grouping of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and function autonomously as physical and/or economic conditions dictate.

Microgrid Institute
A microgrid is a small energy system capable of balancing captive supply and demand resources to maintain stable service within a defined boundary.

Microgrids are defined by their function, not their size. Microgrids combine various distributed energy resources (DER) to form a whole system that's greater than its parts. Most microgrids can be further described within three categories:

- *Isolated microgrids, islands, and other remote sites, not connected to a local utility grid.*
- *Islandable microgrids that are fully interconnected and capable of both consuming and supplying grid power, but can also maintain some level of service during a utility outage.*
- *Asynchronous microgrids connected to utility power supplies, but not interconnected or synchronized to the grid. Such non-synchronized microgrids are capable of consuming power from the grid, but they aren't capable of supplying it.*

Microgrids combine local energy assets, resources, and technologies into a system that's designed to satisfy the host's requirements – which can include factors as basic as electrification, and as complex as integrating variable DERs in a balanced net-zero system.

DERs and technologies available to make microgrids work include Gas or diesel cogeneration; Fuel cells and microturbines; Photovoltaic (PV) modules; Wind, biomass, small hydro; Storage capacity; and Energy management and automation systems.

Fully grid-tied systems that can't operate in island mode or actively balance supply and demand aren't microgrids, but instead are defined as grid-tied distributed generation (DG).

Pareto Energy
i. Diversity: microgrids can serve a variety of loads by optimally combining utility grid resources and a diversity of on-site distributed energy resources (DER). Microgrids can optimally dispatch power by minimizing the marginal cost of each DER at a particular time and place. DERs include supply side distributed generation (DG) and demand-side energy savings measures (ESMs) and demand-side curtailment that is often called demand response (DR).

ii. Efficiency: microgrids can make the maximum use of waste usable heat so that that optimally dispatched combination of DERs and utility grid resources achieves a much higher fuel-use efficiency than dispatching utility grid resources alone (i.e., microgrids make the maximum use of combined heat and power).

iii. Affordability: microgrids are less expensive than what the cost of grid power, backup power, heating, and cooling would be without a microgrid, unless microgrid users are willing to also pay a premium for lower air emissions or carbon footprints

iv. Grid Access: microgrids can provide safe and affordable access to the existing utility network. Microgrids can island to provide uninterrupted power during a grid power outage.

v. Win-Win-Win Business Models: microgrids result in win-win-win benefits for microgrid users, other rate payers and utility company shareholders.

vi. Governance: microgrids are organized as an infrastructural commons whereby multiple users can pool their economic and management resources to govern a microgrid; self-determination of the microgrid users is recognized by higher-level authorities.

Siemens:
A discrete energy system consisting of distributed energy sources (e.g., renewables, conventional, storage) and loads capable of operating in parallel with, or independently from, the main grid. The primary purpose is to ensure reliable, affordable energy security for commercial, industrial, and federal government consumers. The core of a microgrid will be one or more small (under 50 MW) conventional generation assets (e.g., engines or turbines) fueled by natural gas, biomass, or landfill methane. When connected to the main grid, microgrids will rely on a mix of power generation sources depending on the metric to be optimized (cost, GHG, reliability). Specialized hardware and software systems control the integration.

Appendix C:
INTERCONNECTION TECHNOLOGY CASE STUDIES
Finding New Technologies to Overcome Fault Current Contributions and Enable Islanding

Case Study 1:
Commutating Current Limiter: An Innovative Synchronous Interconnection Solution for New York Presbyterian Hospital

The commutating current limiter (CCL) approach was developed as part of a pilot project run by the New York State Energy Research Development Authority (NYSERDA). NYSERDA co-funded pilot projects aimed at producing alternatives to upgrading utility substations and improving the economics of customer-owned combined heat and power (CHP) projects in Manhattan. The end result was an innovative solution that successfully utilized a CCL in order to protect the utility grid from potential faults created by a 7.5 MW CHP system serving New York Presbyterian Hospital (NYPH).[99]

Overview

Energy users considering implementing synchronous parallel cogeneration in the Consolidated Edison service territory were faced with the prospect of paying for significant substation upgrades. These costs can run into the millions of dollars. As an alternative, NYSERDA co-funded pilot projects that could provide an alternative to substation upgrades and improve the economics of cogeneration (CHP) projects in Manhattan.

The NYPH demonstration project involved using a commutating current limiter to protect the Consolidated Edison distribution network from potential faults created by the cogeneration project. The use of the CCL resulted in significantly lower costs to the project than the current alternative and sought to help more cogeneration projects move forward.

The NYPH cogeneration project used a G&W "CLiP" as its protection alternative, and Consolidated Edison approved its use for the CCL. In addition, the device was triggered shortly after start-up of the cogeneration project by a fault on the utility side of the service. The CCL provided the protection anticipated and no equipment failure resulted from the fault.

Upgrading the substation was estimated to cost anywhere from $380 to $1,000 per kW. However, because the substation upgrade costs are not related to the size of the cogeneration, with a larger number of breakers in the vault, the cost could be much greater. For this 7.5 MW project, the CCL cost approximately $220,000 to implement, or $29 per kW. As a result of this demonstration project, facilities considering synchronous parallel cogeneration now have a viable alternative to substation upgrades.[100]

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[99] Negron, R.M.: *New York Presbyterian Hospital Combined Heat and Power Project Commutating Current Limiter Electric Power Transmission and Distribution (EPTD) Program,* New York Energy Research and Development Authority, February 2010.

[100] *Ibid.*, p.3.

CCL applications

Commutating current limiters (CCL), also known as Triggered Current Limiters (TCL), are devices that have been used in transmission and distribution systems to protect utility grids for many years. Their primary application has been to provide over-current protection in the high continuous current range (up to 5,000 Amps) of medium voltage (1 to 38 kV) equipment where traditional, melting element current-limiting fuses reach their practical limit and generally do not exist.[7]

Traditional applications of CCL include the following:

1) Reactor Bypass: CCLs have been used to bypass reactors in utility and industrial applications. The operating current flows through the CCL until a fault occurs. The CCL trips and "commutates" the current through the reactor. This allows the reactor to provide fault protection without a power interruption. This system results in lower operating costs and better voltage control during normal operation.

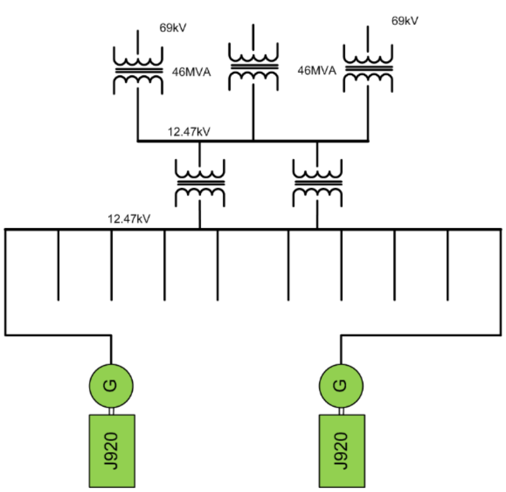
2) Service Entrance and Substation Equipment: CCLs have been used to extend the maximum capacity of service entrance equipment and substations without the need for expensive upgrades to breakers, transformers and other gear.

3) Protection against Catastrophic Failure: CCLs have been used to mitigate faults before they reach critical equipment such as oil filled transformers.

4) Bus Tie Closure: In cases where closing a bus tie will allow a distribution system to meet load requirements, the CCL has been used to protect against high fault currents within the systems.

5) Installation of DG: CCL have been used to protect against fault currents from large power plants without the need to replace switchgear or install reactors.

CCLs are currently manufactured by G&W (the CLiP), ABB (Is Limiter) and S&C (Fault Fiter). The NYSERDA demonstration project used the G&W CLiP. According to the manufacturer, this will be the first time the device is used to protect the grid from a DG client in Manhattan.



The image at the left shows a standard, Consolidated Edison approved synchronous interconnection similar to the one used at New York Presbyterian Hospital. In this scenario, the site will actually integrate two generation sources as opposed to the single Solar turbine installed at NYPH.

At this site, Consolidated Edison required the customer to install a third feeder and an isolation bus. The CCL components were installed between the ring bus and the generation sources. The customer was required to absorb the costs for installing this protective equipment. As with the control scheme at NYPH, however, this project was capable of safely islanding to provide power during grid outages. Most importantly, this site was one of only a few in the five boroughs area to successfully provide power during Hurricane Sandy.

Conclusion

Projects considering synchronous parallel interconnection of their cogeneration plants with Consolidated Edison's distribution system must meet strict standards for protecting the utility's equipment from potential fault currents created by their cogeneration plants. Options include upgrading the utility's substation or installing protective equipment on the client's side of the service entrance. Upgrading the utility substation requires that all of the breakers within the substation serving the client be upgraded with higher amperage breakers. This could cost millions of dollars and will likely make projects uneconomical. Alternatives to this include installing reactors, current limiting fuses, breakers or commutating current limiters.

CCL technology has very high nominal operating currents and will clear a fault very quickly – in ¼ to ½ cycles. The clearance methodology limits the actual current through the conductor and the operating time should easily satisfy the utility's requirements, protect the system and avoid damage to any downstream equipment.

This project demonstrated that the CCL technology can be acceptable to the local utility as an alternative to substation upgrades for fault mitigation. In addition, using the technology could be a very cost effective way to implement synchronous parallel cogeneration. The cost impact of the CCL for this project is estimated at around $29 per kW whereas a substation upgrade would have cost anywhere from $400 to $1,000 per kW as shown in the table below.

Solar Turbine Capacity	7,500	kW
Technology	**Estimated Cost**	**Cost/kW**
Substation Upgrade (low)	$2,800,000	$373
Substation Upgrade (high)	$7,200,000	$960
CCL	$220,000	$29

In addition to gaining interconnection approval, the technology proved effective when it mitigated an incoming fault early in the operation of the cogeneration plant. Although the fault current was large enough to trip utility side-substation breakers, the CCL protected the Solar Turbine cogeneration plant, the control panel, and other ancillary equipment within the hospital.

As stated in an e-mail message by a representative of Consolidated Edison to a member of the project team after the successful installation of the CCL for the project:

"… ConEd has agreed that the current-limiting fuse proposal from NYPH, the G&W CLiP, will satisfy our concern about fault current contribution by eliminating the generator contribution within ½ cycle. The G&W CLiP was also approved for use on another generator connected in the LIC network and we anticipate that the application would be appropriate for other such DG installations, as long as they are properly specified, tested, and installed."[101]

[101] *Ibid.*, p.16.

Case Study 2:

GridLink: A Non-Synchronous Alternative for Co-Mingling the Utility Grid and Distributed Generation

GridLink is a non-synchronous interconnection alternative for co-mingling grid power and distributed generation (DG) safely and affordably. GridLink was invented and patented by Pareto Energy's Vice President of Engineering Alan McDonnell[102] and was first developed as a solution for a project at the Stamford (Ct.) Government Center.

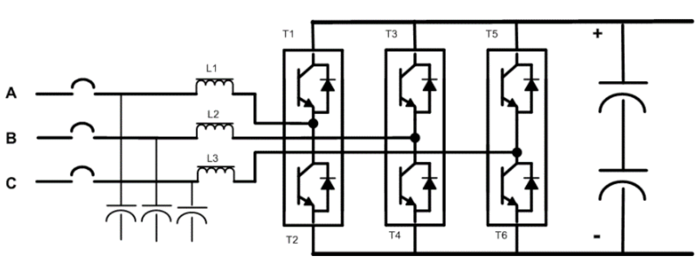
The most basic difference between GridLink and other control schemes is that at no point is the DG ever required to synchronize to the utility grid. Currently, GridLink has been accepted as a safe control topology by Northeast Utilities, Potomac Electric Power Co. and Consolidated Edison.

Overview

GridLink is a new power distribution architecture that utilizes DC power conversion to enable the integration of power generation sources in ways that are otherwise not permitted. It uses new power converter technology to achieve levels of control over amounts of power that were not possible a few years ago. GridLink has been accepted as a new configuration of existing, off-the-shelf components currently used in a variety of power distribution applications. In each of their rulings, the utility companies have determined that no additional safety equipment is required to be installed and that the new generators will have no impact on the utility system. Additionally, each utility has expressly stated that the generators do not operate in parallel with the utility grid and, therefore, operate in an always-islanded mode.

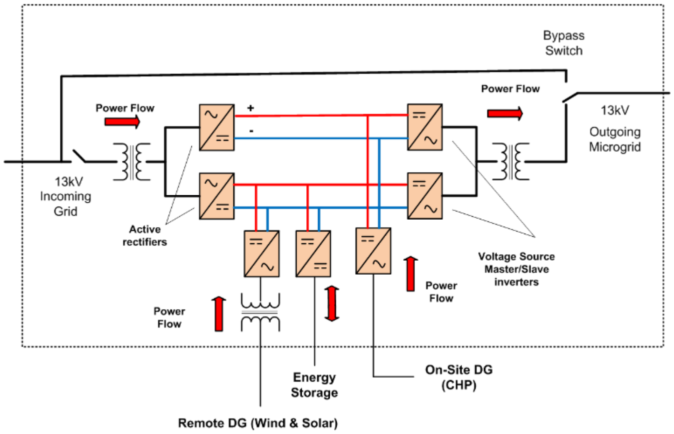
GridLink application

GridLink utilizes a series of back-to-back AC to DC to AC power converters in order to totally separate the voltages, phase angles, and frequencies of the utility grid power from that of the on-site generators. As a result, all incoming power sources are treated in the same manner: they are converted from their original AC source to DC and then immediately back to AC. The result is a smoothed-out AC curve for all power sources. The AC to DC to AC conversion does create some efficiency losses (generally in the 2 to 3 percent range). However, since the on-site generation is not required to synchronize to the grid, each individual generator can run at variable speeds, increasing fuel-use efficiencies that more than negate any conversion losses.



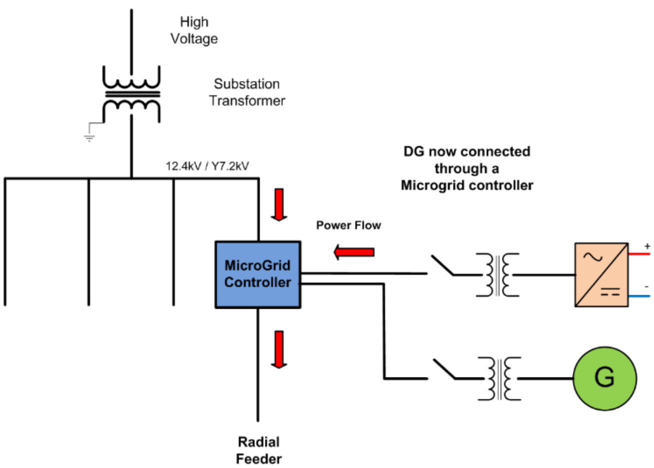
The image on the left illustrates the back-to-back AC to DC to AC converters. Although all incoming power is AC, in any given small window of time (a few mSecs), the voltage at any incoming phase can be treated as a DC value with respect to any other phase, and thus a switch can be made to draw current from one to another through the DC Bus. This process goes on and off very quickly, and changes with each pulse. As a result, the inverter can control the current flow in each phase, and it can do it in such a way that the amplitude, wave shape and phase angle can be controlled separately. In most cases, the current will be a sine wave in phase with the voltage.

[102] Pareto Energy President Guy Warner co-authored the White Paper in which this case study appears.



The image on the left depicts a GridLink setup with a 13 kV utility feed and multiple on-site generators. This approach provides flexibility to arrange these "blocks" as necessary on a common DC bus in order to achieve the amount of input and output power required.

Utilizing the DC as the collector bus also allows for many smaller, perhaps different, energy sources to be combined into a larger AC output. Additionally, as a redundancy strategy, isolated DC busses can be used to limit the size of potential failures. Finally, note the red arrows show the direction of power flow: the key to the "active rectifier" mode of control that allows for the unlimited penetration of these microgrids.



Each of the packages shown in the previous image can be shown as a single "blue box" in a system layout such as in the image on the left. Each microgrid can be custom designed for the generators, load, and incoming utility as required. In this control scheme, the substation now simply sees a reduced load, not the connected generators.

Since the voltages, phase angles and frequencies of the on-site generation are completely isolated from the grid, utility companies have determined that a microgrid utilizing GridLink may install unlimited GridLink units and generation without requiring upgrades to the utility grid. Moreover, the customer would not be required to apply for the additional interconnection permits mentioned earlier. As a result, systems could be modularly built to accommodate only the existing loads of a site instead of building out a system to cover any future load growth.

Appendix D:
FINANCIAL MODEL FOR A CHP MICROGRID

1. Combined Heat and Power Engineering and Economics

In many cases, a microgrid developer will want to use the maximum amount of combined heat and power (CHP) that it can, given that CHP fuel use efficiency can be two to three times greater than the fuel use efficiency of central generation on the utility grid. Therefore, many projects will design for an amount of DG that makes the optimal use of heating and cooling and use some other combination of grid power and other DERs for meeting total peak electrical demand.

During peak use of heating and cooling, CHP generators can produce more electricity than a single DG customer can use. Conversely, during peak use of electric power, CHP generators can produce more heating and cooling than a single DG customer can use. This is why distributing energy in a microgrid to multiple users with complementary load profiles, or non-coincident peaks for power and thermal load can result in projects that are more efficient than DG customers acting alone.

A software architecture developed at Lawrence Berkeley National Laboratory, called DER-CAM (Distributed Energy Resources Customer Adoption Model), has capabilities for suggesting the optimal installation and dispatching of CHP. The engineering parameters involved in a typical CHP project include the following:[103]

■ A distributed generator will produce waste heat that is either high-grade thermal output or low-grade thermal output, depending on its temperature. In either case, the waste heat available will be measured in millions of BTUs or MMBtu for short.
■ Low-grade thermal output can be used for domestic hot water, and high grade heat can be used for space heating via a district energy system, using steam or hot water. Given the relative difficulty of installing larger steam conduits, it will be assumed in the discounted cash flow analysis below that a district hot water system is used.
■ As noted in the March 2003 LBNL report footnoted above: "a compressor-driven cooling system running on electricity could be replaced by an absorption chiller that provides cooling by using rejected heat from power generation or from a natural-gas-fired burner." A chiller would require higher temperatures so the amount of cooling in a CHP project could be limited by the availability of high-grade thermal output. On the other hand, the Minnesota climate might limit opportunities to use all the available cooling capacity of a microgrid. For purposes of the discounted cash flow analysis below, we assume that a larger amount of non-weather related cooling is needed because of heat from equipment operating at data centers.

2. How DER-CAM Develops Optimal Microgrid Efficiencies

The inventors of DER-CAM describe the software as follows:

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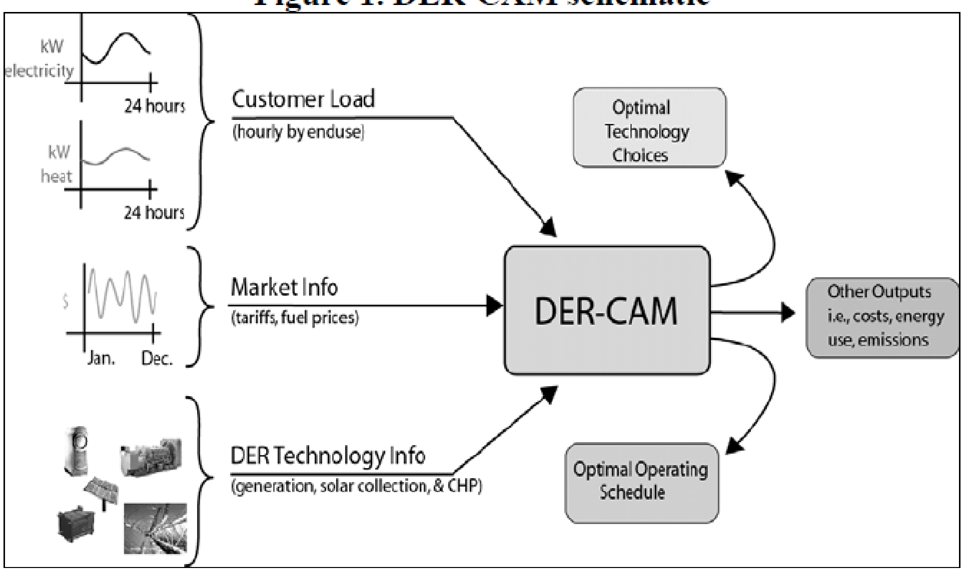
[103] For a more detailed review on CHP engineering that also provides information on how CHP is optimized in DER-CAM, see: Firestone, R., Chris Marnay, and Maribu, K.: "The Value of Distributed Generation under Different Tariff Structures," *2006 ACEEE Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, 2006.

"Developed at Lawrence Berkeley National Laboratory, DER-CAM is software designed to factor many variables into determining the DG investment decision that minimizes the annual costs, including capital costs, for a given site with a maximum payback constraint. The DER-CAM solution provides both the optimal generating equipment and the optimal operating schedule. The optimal operating schedule gives a basis to estimate energy costs, utility electricity consumption, and carbon emissions. Input to DER-CAM includes the hourly end-use energy demand, electricity and natural gas supply costs, and DG technology options. DG generation technology options include solar photovoltaic systems, natural gas fueled internal combustion engines, micro-turbines, gas turbines, and fuel cells. By matching thermal and fuel cell generation to heat exchangers and absorption chillers, heat recovered from natural gas driven generators can be used to offset heating and cooling loads. Figure 1 shows a high-level schematic of DER-CAM."[104]

Figure 1. DER-CAM schematic



The discounted cash flow analysis below assumes that DER-CAM suggests meeting 2 MW of current peak demand with a combination of energy savings measures and curtailment via demand response. Another 3 MW of non-critical demand will be met by grid power only, leaving 5 MW of critical demand to be met by distributed generation.

In terms of electricity, 5 MW of on-site CHP capacity will be installed. In terms of cooling, the model assumes a large amount of non-seasonal cooling because the project serves a microgrid with some data centers. In terms of heating and hot water, the low-grade and high-grade thermal output from the CHP will meet all needs for domestic hot water and district heating.

The resulting system's size and engineering data would emerge from DER-CAM as follows:

[104] *Ibid.,* pp. 7-8.

Project Size & Performance	Unit	Input Value
Installed CHP Electric Capacity	kW	4,680
CHP High-Grade Thermal Output (specify exhaust-only or Ex+JW)	MMBtu	9.15
CHP Low-Grade Thermal Output (Oil + Intercooler) - DHW only	MMBtu	7.11
CHP Electric Efficiency	%	43.38%
CHP Cooling Capacity (Specify Single Effect Ex+JW or double-effect)	Tons	572
Microgrid / eHouse System Size	MVA	12,000
eHouse Efficiency Derate	%	4%
Absorption Chiller COP	COP	0.75
Annual Customer Electric Consumption	kWh	43,800,000
CHP Annual Capacity Factor	%	90.19%
Annual Electric Output	kWh	36,973,989
% of Electricity Produced Onsite	%	100.0%
Grid Purchases	kWh	6,826,011
CHP Annual Thermal Utilization - Heating	%	45%
CHP Annual Thermal Utilization - Cooling	%	30%
CHP Annual Thermal Utilization – Domestic Hot Water	%	20%
Annual Heating Delivered Energy (Hot Water)	MMBtu	32,530
Annual Domestic Hot Water Delivered Energy	MMBtu	11,234
Annual Cooling Delivered	ton-hrs	1,355,417

3. Achieving Affordability

a. Cost of and Financing of Construction

The discounted cash flow analysis assumes that the capital cost of the optimal system suggested by DER-CAM would be as follows:

Capital Costs	Unit	Input Value
CHP System - Construction Costs per Unit of CHP Capacity	$/kW	$3,000
Total Distribution System Costs (Electric + Pipes)	$	$4,000,000
Construction Costs	$	$19,000,000

To complete the next step of the discounted cash flow analysis, the developer assumes he or she will secure 20-year purchased energy contracts from the potential microgrid customers to sell them microgrid power, heating, and cooling services. The developer should be able use these contracts to arrange permanent financing once construction is complete. In these circumstances, the developer would first negotiate with a bank to determine the terms of a construction line of credit, prospectively secured with purchased energy contracts, and also the terms of permanent project financing.

Project construction loans are usually variable-rate loans priced at a spread to the prime rate or some other index. They also include a commitment fee on the loan balance not yet drawn down. Finally, the bank will normally allow the loan amount to include a contingency over the estimated construction costs to account for the possibility of engineering change orders and also for higher-than-expected interest rates. Therefore, the DCF analysis will assume the following terms for the construction line:

- 24 month availability
- Total loan amount of $19 million plus 20 percent contingency = 22.8 million
- 5 percent interest rate on funds drawn
- 0.5 percent commitment fee on the balance not yet drawn

The drawdown and costs of the construction loan are shown on the next page and indicate that one the permanent project financing uses will be to pay the $19.61 million balance at the end of the construction period.

Total Project Cost and Construction Loan Drawdown Schedule (Millions of Dollars)

Total Direct Costs	**$19.00**	**million**	**Commitment Fees**	**0.50%**	**per annum**
Commitment Amount	**$22.80**	**million**	**Interest Rate**	**5.00%**	**per annum**
Construction Period - Months	**18**				

End of the Month	% Construction	Construction Drawdown	Commitment Fees	Interest	Total Financing Cost	Total Construction and Financing	Cumulative Funds Used	Unused Balance of Commitment
0		--	--	--	--	--	--	$22.800
1	1.00%	$0.190	$0.010	--	$0.010	$0.200	$0.200	$22.601
2	1.00%	$0.190	$0.009	$0.001	$0.010	$0.200	$0.400	$22.400
3	2.00%	$0.380	$0.009	$0.002	$0.011	$0.391	$0.791	$22.009
4	2.00%	$0.380	$0.009	$0.003	$0.012	$0.392	$1.183	$21.617
5	2.00%	$0.380	$0.009	$0.005	$0.014	$0.394	$1.577	$21.223
6	4.00%	$0.760	$0.009	$0.007	$0.015	$0.775	$2.353	$20.447
7	4.00%	$0.760	$0.009	$0.010	$0.018	$0.778	$3.131	$19.669
8	4.00%	$0.760	$0.008	$0.013	$0.021	$0.781	$3.912	$18.888
9	6.00%	$1.140	$0.008	$0.016	$0.024	$1.164	$5.076	$17.724
10	6.00%	$1.140	$0.007	$0.021	$0.029	$1.169	$6.245	$16.555
11	8.00%	$1.520	$0.007	$0.026	$0.033	$1.553	$7.798	$15.002
12	8.00%	$1.520	$0.006	$0.032	$0.039	$1.559	$9.356	$13.444
13	10.00%	$1.900	$0.006	$0.039	$0.045	$1.945	$11.301	$11.499
14	10.00%	$1.900	$0.005	$0.047	$0.052	$1.952	$13.253	$9.547
15	10.00%	$1.900	$0.004	$0.055	$0.059	$1.959	$15.212	$7.588
16	8.00%	$1.520	$0.003	$0.063	$0.067	$1.587	$16.799	$6.001
17	8.00%	$1.520	$0.003	$0.070	$0.072	$1.592	$18.391	$4.409
18	6.00%	$1.140	$0.002	$0.077	$0.078	$1.218	$19.610	$3.190
	100.00%	$19.000	$0.122	$0.487	$0.610	$19.610		

b. Federal and State Incentives

In addition to designing the optimal mix of DERs and boosting fuel use efficiency, microgrids will have a number of government incentives that can cover up to half or more of the capital cost, depending on the state where the microgrid is installed. Unfortunately, most incentives expire at some date with no guarantee they will be renewed. Here are some examples of the types of incentives available for financing the CHP project:

■ **Federal Investment Tax Credits:** 10 percent of generator costs for CHP using pipeline natural gas. The credit increases to 30 percent for variable energy resources and CHP using certain types of waste-to-energy or biomass fuels.
■ **Federal Accelerated Depreciation:** The ability to deduct most microgrid costs over 5 years for taxes will cover about 12 percent of the project costs.
■ **Federal New Markets Tax Credit:** In certain low-income parts of a town or city, there will be a credit that amounts to about 22 to 30 percent of total microgrid costs. The University of California San Diego used a new markets tax credit to fund part of the generation at its 27 MW microgrid.
■ **State and Federal Production Tax Credits:** These can amount to 1 to 3 cents per kWh of generation from a microgrid with certain kinds of VERs.
■ **State Net Metering:** Excess power that cannot be used at certain times within the microgrid can be sold back to the grid at premiums over wholesale prices.
■ **State and Corporate R&D Incentives:** Many states will pay a capital incentive from their energy R&D budgets. This is particularly relevant when states receive Federal funds after a natural disaster for developing more resilient electric power systems.

c. Project Financing Structure[105]

Developers will normally structure a special purpose entity for permanent project financing to isolate the risks of the project from the assets of any equity investors that they recruit to co-own project. For purposes of the DCF analysis, it will be assumed that permanent project financing is through a master limited partnership. The project developer contributes the costs of project design as an equity investment, recruits limited partners to provide additional equity, and arranges a bank loan for the remainder.

As shown in the illustration on the next page, it will be assumed that the limited partners enter in a so-called tax equity flip transaction (i.e., they will have the type and amount of income and associated tax liabilities to use the tax credits optimally).[106]

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[105] Many structures can be used for project financing. For reviews of the options with case studies and DCF illustrations, see: Karmer, A. S., and Peter C. Fusaro: *Energy and Environmental Project Finance Law and Taxation: New Investment Techniques,* Oxford University Press, 2010; and Dipa, Sharif, Amy Grace, and Michael Di Capua: "The return – and returns – of tax equity for US renewable projects," *Bloomberg New Energy Finance* and Reznick Group, 2011.

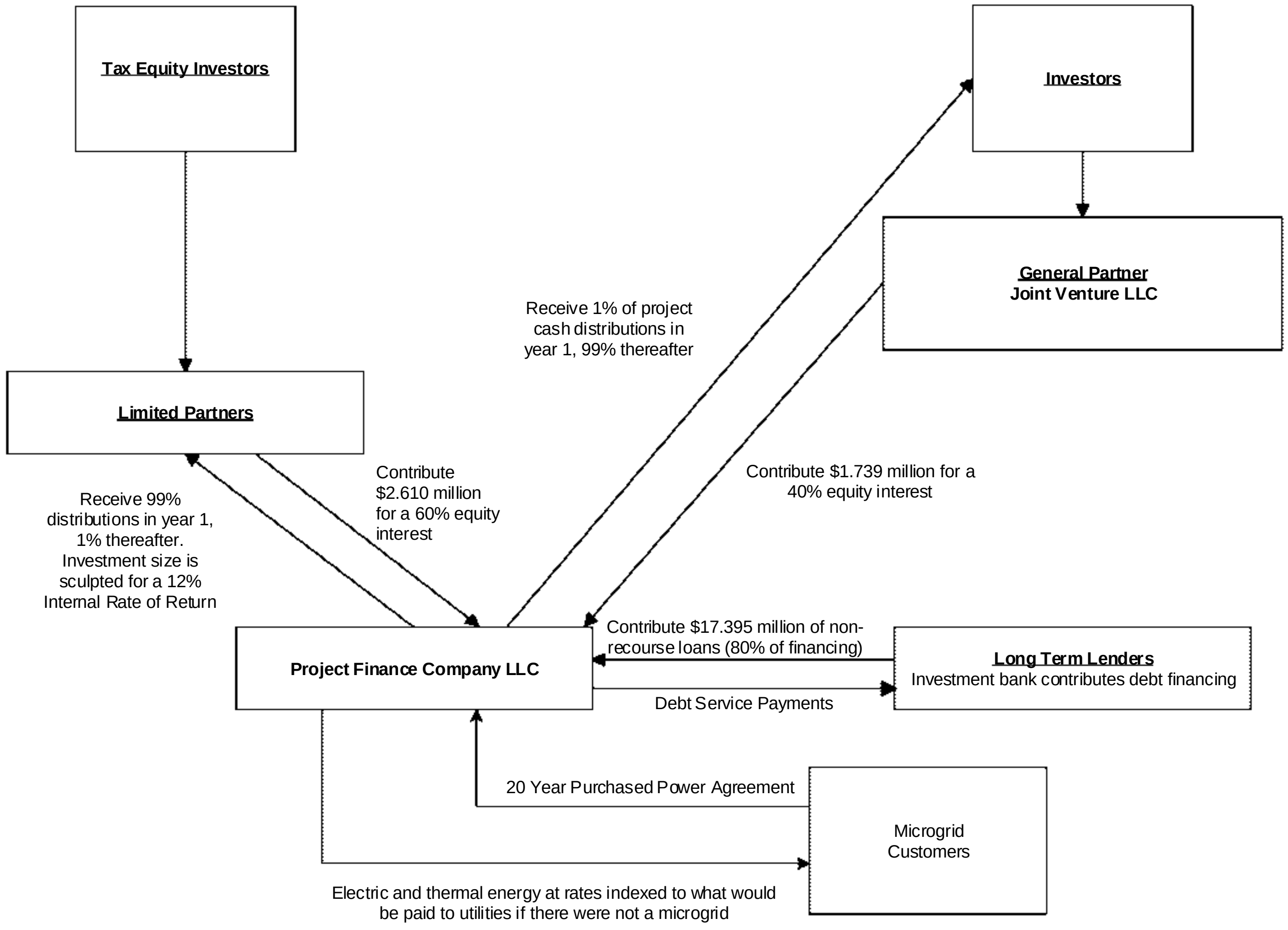
[106] The information contained in this publication is for general purposes and is not intended and should not be construed as legal, accounting or tax advice or opinion provided by the authors to the reader. This material might or might not be suitable or applicable for the reader's specific circumstances or needs. Therefore, the information should not be used as a substitute for consultation with professional legal, accounting, tax, or other competent advisors.

The following assumptions were made in developing the structure for project financing:

Standard Leveraged Project Finance	Unit	Input Value
Bank Loan Facility Fee (as percentage of total debt)	%	1%
Costs to Recruit Project Equity	$	$750,000
Project Leverage	%	80%
Commercial Debt Interest Rate	%	4.0%
Loan Tenor	yrs	20
Expected Returns (Hurdle Rate) Tax Equity Participant	%	12%
Partnership Flip Scenario - Tax Equity % Before Reversion	%	80%
Partnership Flip Scenario - Tax Equity % After Reversion	%	10%
Percent of Project Costs Eligible for Federal ITC	%	80%
Federal ITC Percentage	%	10%
Project Costs % Eligible for 5-yr MACRS Tax Depreciation	%	74%
Project Costs % Eligible for 15-yr SL Tax Depreciation	%	12%
Project Costs % Eligible for 20-yr SL Tax Depreciation	%	9%
Project Costs % Non-Depreciable for Taxes	%	5%
Combined Federal + State Tax Rate	%	40%
Percent of Shared Savings Paid to Customers	$	30%

Microgrid Project Finance Structure

(Assumes a 5 MW, $21.744 Million Project)



d. Operations and Maintenance

The discounted cash flow model makes the following assumptions for project operations and maintenance. It is assumed that the microgrid users will sign 20-year purchased energy contracts at market rates based on what they would have paid for grid power, heating, hot water, cooling, and backup diesel power for critical operations. 30 percent of savings below these rates, if any, are paid to the customer at the end of each year of microgrid operation.

Operations & Maintenance	Unit	Input Value
O&M Costs - Total for all Energy Systems	$/kWh	$0.020
O&M Escalation Rate	%	3%
Utility Electricity Rate	$/kWh	$0.07
Demand Charge portion of Electricity Rate	$/kWh	$0.00
Utility Gas Rate	$/MMBtu	$6.00
Estimated Gas Rate for DG Purchases	$/MMBtu	$5.10
Electricity Escalation Rate	%	3.5%
Gas Escalation Rate	%	5.0%
Price of Delivered Unit of Heating / Hot Water	$/MMBtu	$18.00
Price of Delivered Unit of Cooling	$/ton-hr	$0.09

e. Results of the DCF Model

The following pages provide the results of the discounted cash flow analysis. Paying market rates typical of those in Minnesota, the microgrid users can expect to earn substantial shared savings once the equity investors earn their hurdle rate of return of 12 percent. So before the complexities of negotiating with utilities to support the project in terms of affordable access to their grid and not invoking regulatory impediments, it appears the project might be financeable.

There are no surveys available regarding the extent to which a developer would risk the $1.7 million in design fees before obtaining a long-term purchased power agreement that enable construction loans and permanent financing. A developer might be able to obtain matching funds in other states that would not be available in Minnesota, such that they might prefer developing projects there instead. Also, where utility rates for power are much higher in some other states, a developer might concentrate design monies there on the promise of charging microgrid user more. However, these risks would be manageable, compared to the institutional, regulatory, and market barriers discussed in this White Paper.

Sources and Uses of Funds		
Sources		
Long Term Debt	Amount	Percent
Tax-Exempt Bonds	$-	0.0%
Subsidized debt	$-	0.0%
Commercial Debt	$17.395	80.0%
Total Debt	$17.395	80.0%
General Partner		
Developer Contribution of Pre-Construction Costs	$1.739	8.0%
Total General Partner Equity	$1.739	8.0%
Limited Partners		
Tax Equity Investors	$2.610	12.0%
Total Limited Partner Equity	$2.610	12.0%
Total sources	$21.744	
Uses		
	Amount	Percent
Pre-Construction Costs for Deign & Permits	$1.739	8.0%
Loan Facility Fee	$0.194	0.9%
Cost to Arrange Permanent Financing	$0.200	0.9%
Construction Period Costs	$19.610	90.2%
Total Uses	$21.744	100.0%

Annual Interest and Debt Service Coverage Ratios							
	Principal Amount			$17.395	million		
	Term			20	years		
	Interest Rate			10.2%	per annum		
Year	**EBIT**	**EBITDA**	**Interest**	**Principal**	**Tax-Adjusted Principal**	**Interest Coverage Ratio**	**Debt Service Coverage Ratio**
1	$2.797	$3.812	$1.781	$0.296	$0.477	2.14	1.69
2	$2.370	$3.961	$1.751	$0.326	$0.525	2.26	1.74
3	$3.137	$4.114	$1.718	$0.359	$0.579	2.40	1.79
4	$3.664	$4.273	$1.681	$0.396	$0.639	2.54	1.84
5	$3.829	$4.437	$1.640	$0.436	$0.704	2.71	1.89
6	$4.275	$4.607	$1.596	$0.481	$0.776	2.89	1.94
7	$4.727	$4.783	$1.546	$0.530	$0.856	3.09	1.99
8	$4.909	$4.965	$1.492	$0.585	$0.943	3.33	2.04
9	$5.097	$5.153	$1.432	$0.645	$1.040	3.60	2.08
10	$5.291	$5.348	$1.366	$0.711	$1.146	3.91	2.13
11	$5.493	$5.549	$1.293	$0.783	$1.264	4.29	2.17
12	$5.701	$5.757	$1.213	$0.864	$1.393	4.75	2.21
13	$5.916	$5.973	$1.125	$0.952	$1.536	5.31	2.25
14	$6.139	$6.195	$1.027	$1.050	$1.693	6.03	2.28
15	$6.369	$6.425	$0.920	$1.157	$1.866	6.99	2.31

Note: The DCF analysis assumes that a 1.25 debt coverage ratio will be sufficient to arrange bank loans for 80 percent of the project financing.

Projected Operating Cash Flows ($Millions)								
	Revenues		**Cash Expenses**			**Income from Operations**		
Year	Electricity	Themal Sales	Natural Gas	Operating & Other	Accelerated Depreciation	Pre-Tax	After-Tax	Pre-tax Cash Flow from Operations
1	$6.40	$4.32	$4.20	$3.15	$1.02	$2.36	$1.47	$3.38
2	$6.60	$4.41	$4.28	$3.24	$1.59	$1.89	$1.17	$3.48
3	$6.79	$4.50	$4.37	$3.34	$0.98	$2.61	$1.62	$3.58
4	$7.00	$4.59	$4.46	$3.44	$0.61	$3.08	$1.91	$3.69
5	$7.21	$4.68	$4.54	$3.55	$0.61	$3.19	$1.98	$3.80
6	$7.42	$4.77	$4.64	$3.65	$0.33	$3.58	$2.22	$3.91
7	$7.65	$4.87	$4.73	$3.76	$0.06	$3.97	$2.46	$4.03
8	$7.88	$4.97	$4.82	$3.87	$0.06	$4.09	$2.54	$4.15
9	$8.11	$5.07	$4.92	$3.99	$0.06	$4.21	$2.61	$4.27
10	$8.36	$5.17	$5.02	$4.11	$0.06	$4.34	$2.69	$4.40
11	$8.61	$5.27	$5.12	$4.23	$0.06	$4.47	$2.77	$4.53
12	$8.87	$5.38	$5.22	$4.36	$0.06	$4.60	$2.85	$4.66
13	$9.13	$5.48	$5.32	$4.49	$0.06	$4.74	$2.94	$4.80
14	$9.41	$5.59	$5.43	$4.63	$0.06	$4.88	$3.03	$4.94
15	$9.69	$5.70	$5.54	$4.76	$0.06	$5.03	$3.12	$5.09
16	$9.98	$5.82	$5.65	$4.91	$0.00	$5.24	$3.25	$5.24
17	$10.28	$5.93	$5.76	$5.06	$0.00	$5.39	$3.34	$5.39
18	$10.59	$6.05	$5.88	$5.21	$0.00	$5.55	$3.44	$5.55
19	$10.90	$6.17	$6.00	$5.36	$0.00	$5.72	$3.55	$5.72
20	$11.23	$6.30	$6.12	$5.52	$0.00	$5.89	$3.65	$5.89
							Project IRR	**29%**

Note: the discounted cash flow analysis assumes that the hurdle rate for financial project feasibility is a 20 percent internal rate of return. Therefore, the DCF analysis suggests a financially feasible project.

3. DER-CAM and DCF for Minnesota microgrids

A successful CHP microgrid development likely will depend on sophisticated use of DCF modeling. This approach can help developers establish a financeable business case, and also might help utilities quantify the value of microgrids to customers, understanding the values of both kWh and Btu outputs. Minnesota's universities have some of the world's best financial and optimization modeling professionals, presenting the State with opportunities to work with one or more universities and their students to establish modeling competencies for potential microgrid developers and customers.

Appendix E:
MODELING MINNESOTA MICROGRID POTENTIAL

[*Please see separate XLS Workbook*]