City of Pittsfield Downtown Microgrid

MassCEC Feasibility Assessment

Task 6 Final Report

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in partnership with

S&C ELECTRIC COMPANY

Excellence Through Innovation

Contents

I. Chapter 1: Summary and Recommendations

1.0 CPDM Feasibility Assessment Process

The City of Pittsfield Downtown Microgrid (CPDM) Feasibility Assessment was initiated by the City of Pittsfield and executed by a Project Team comprised of staff representing Microgrid Institute, S&C Electric, and the City of Pittsfield, with subject-matter inputs from Skyview Ventures and UMass-Amherst. The assessment addressed all Tasks defined by the Massachusetts Clean Energy Center (MassCEC) for its Community Microgrids Feasibility Assessment program, specifically:

Task 1: Kickoff Meeting and Site Visits: Engaged numerous customers in the project area to learn about site energy loads, systems, priorities, and plans;
Task 2: Site Assessment and Description of Microgrid Characteristics: Analyzed energy load and cost data gathered from customers' utility bills and account records, as well as preliminary inputs from the electric utility serving Pittsfield (Eversource), to establish a preliminary design basis for the CPDM Project;
Task 3: Preliminary Technical Design and Configuration: Further engaged the utility to gather information about distribution system infrastructure and configuration options, and revised the proposed design to establish a technically feasible microgrid solution;
Task 4: Assessment of Microgrid's Commercial and Financial Feasibility: Identified and assessed proposed business model options for the Project; and
Task 5: Information for Cost-Benefit Analysis: Produced metrics to quantify its likely costs and benefits to various parties – most notably customers, third-party investors, and the utility.

For this Task 6 Final Report, the Project Team updated the information presented in earlier Task Reports, and developed the following summary of outcomes and recommendations. The Project Team closely collaborated throughout the Project process to identify and obtain the required inputs and to focus assessment efforts on factors affecting the feasibility of the CPDM Project for prospective development by Pittsfield stakeholders – most notably the City of Pittsfield and Berkshire Medical Center (BMC).

1.1 Findings, Observations, and Recommendations

• Discuss the observations and findings and recommendations, if any, from all Tasks, and avenues for further improvements, as appropriate.

The City of Pittsfield Downtown Microgrid (CPDM) Feasibility Assessment process yielded several key observations and findings that inform opportunities for future development of resilient renewable energy systems – and for consideration in Massachusetts policy and planning efforts. Key findings from each Task are discussed below, including the Project Team's recommendations where applicable.

1.1.1 Task 1 Findings

Task 1 efforts confirmed strong support for the proposed Project by key representatives of the City of Pittsfield, with varying levels of support among other key stakeholders including Berkshire Medical Systems and the Pittsfield Housing Authority. Site visits allowed the project team to observe site factors affecting system design and renewable resource potential, and confirmed that rooftop and parking-lot spaces could accommodate substantial new photovoltaic (PV) solar development.

1.1.2 Task 2 Findings

Task 2 efforts yielded a set of energy load and cost data for analysis, which allowed the Project Team to develop baseline models for the assessed facilities. A key factor affecting this analysis was the lack of granular interval data; in the Project area, site energy consumption and peak demand is measured on a monthly basis only, which necessitated simulation modeling using HOMER Pro to establish intra-day load profiles.

Recommendations: Advanced metering infrastructure (AMI) investments could produce substantial value for customers and the utility in Pittsfield. AMI would enable metering energy usage and demand on shorter intervals (*e.g.,* 15 minutes), providing actionable data that customers and the utility could use to optimize system efficiency. AMI also would enable more advanced load control capabilities, which could support a community microgrid designed to serve only critical loads in the microgrid area.

Until AMI can be installed in the project area, individual customers could take action to monitor their own building energy loads at the service panel. Doing so would allow those customers to identify opportunities for saving energy and costs, and to establish true demand peaks to be managed by building energy management systems (BEMS) and microgrid resources.

1.1.3 Task 3 Findings

The principal Task 3 findings are discussed in greater detail in Section 1.2. In sum, Task 3 revealed technical factors affecting the initial wide-area design that was contemplated for the CPDM Project. The utility distribution system in Pittsfield, like in many other places, has developed in ways that may be considered organic rather than driven by strategic distribution planning processes. As a consequence, some parts of the system are served by multiple different circuits, fed from different substations. This legacy architecture effectively precludes reconfiguration to serve changing local priorities – such as integrating substantial local renewable energy capacity or enabling microgrid islanding capabilities.

Recommendations: The utility's distribution planning processes can be improved through ongoing engagement with local community stakeholders. To the degree the community can identify and share its priorities for local energy resources and services, the utility will be better able to plan and prioritize distribution investments to support those priorities. The Commonwealth of Massachusetts can encourage proactive engagement among utilities and the communities they serve by establishing benchmarks and requirements for performance-based ratemaking incentives.

1.1.4 Task 4 Findings

Task 4 yielded several key findings for the project that are discussed in detail in Chapter 4. Most notably, the Project Team's efforts showed that each of two assessed microgrid zones could be independently developed using well-established structural and financing mechanisms. It also revealed a potential legal dilemma facing municipal energy users who wish to explore microgrid options. Specifically, the utility asserted the exclusive right to own and operate electricity infrastructure in a public right of way, which would require a municipality or other customer to rely on sole-source procurement from the utility for any assets needed to connect municipal loads and resources on alternate sides of a public street. However, because the public way has not been clearly established by Massachusetts law as the utility's franchise threshold, procurement requirements may compel municipalities to use competitive solicitation for microgrid assets.

Recommendation: For purposes of the assessment, the Project Team assumed the City will obtain permission from the Massachusetts Office of the Inspector General to apply sole-source procurement from the utility for any assets to be placed in a public way. This solution would allow the Project to proceed, but the regulatory uncertainty presents an ongoing barrier for other street-crossing energy projects sponsored by public agencies in Massachusetts. Lawmakers could resolve those uncertainties by clarifying the statutory boundaries of utility franchise rights and obligations, and it could establish alternative regulatory approaches that would allow municipalities and other critical community customers to aggregate energy loads at adjacent facilities for service by their own distributed energy resources (DER) and microgrid systems, even if those facilities are separated by public ways.

Task 4 assessments reinforced the Task 3 recommendation for utilities to engage more closely with local stakeholders on an ongoing basis to ensure utilities understand community priorities for investments in energy infrastructure and resources, and integrate those priorities into their planning processes.

1.1.4 Task 5 Findings

Through Task 5 assessments, the Project Team performed financial modeling to establish 25-year project costs and revenues, which for both Zones are derived entirely from net energy metering credits. Key Task 5 cost-benefit assessments include the following:

a. PV generation from the specified systems in Year 1 would reduce the site host's annual utility bill by about 15 percent ($397,066) in Zone 1, and by about 28.5 percent ($17,933) in Zone 2.
b. During a utility outage, the Zone 1 microgrid would support most or all loads during the daytime, when PV systems are productive, and would support minimal resiliency (15 to 40 minutes) at night or when solar energy is otherwise unavailable. The Zone 2 system would support full 24-hour resiliency against outages by relying on PV during the daytime and natural gas-fired standby generation at night. Neither zone would produce substantial additional savings of outage-related costs during the typical operating year, and as a result the benefits estimated for cost-benefit analysis exclude outage-related cost savings. However, in emergency situations that cause regional outages of extended duration, either zone, directly or indirectly, could produce substantial monetary and non-monetary benefits.
c. Assuming minimal grant support and federal tax incentives reduced to 2022 levels, net-present costs for Zone 1 exceed the 25-year net-present value of energy savings by $1.9 million or 33 percent. Net-present costs for Zone 2 exceed the net-present value of energy savings by $875,451 or 377 percent.
d. Costs for BESS, controls, and distribution system upgrades represent a substantial share of total Project capital costs. These microgrid assets are required to enable renewable-powered

resiliency, but in neither zone do they directly produce economic benefits.[1] The smaller size of the Zone 2 investment and the costs for proposed new gas-fired standby generation exacerbate this cost-benefit imbalance. Notably, if distribution infrastructure, storage, and standby generation costs were omitted for a PV-only project, the proposed PV investments alone would produce a positive 25-year net-present value in both zones – 42.7% ($1.75 million) in Zone 1 and 22% ($42,248) in Zone 2.[2]

e. Rather than producing direct financial returns, the investment rationale for community microgrid investments must be driven by the community's objectives for sustainable resiliency.

Recommendations: Results of cost-benefit analysis show that an investment in several PV arrays (rooftop and canopy-mounted) at Berkshire Medical Center (Zone 1) would substantially reduce the hospital's annual electricity costs. However, the capital costs incurred to integrate those systems into a microgrid would substantially exceed the costs saved over the Project's 25-year lifetime, and would produce only marginally greater resiliency than the hospital already has with fossil-fueled standby generation. In early assessment phases, the hospital's representative indicated that cost savings would be a threshold factor for considering any investments. Accordingly, the Project Team would recommend BMC consider installing behind-the-meter PV systems on its building rooftops and parking areas that are contiguous with BMC electric loads, but at this time the cost-benefit analysis does not support attempting to integrate such PV systems into a campus microgrid.

For Zone 2, although energy cost savings and emissions reductions were among the City of Pittsfield's objectives for the Project, the City's principal threshold was to produce sustainable energy resiliency for critical community facilities. The microgrid would provide the City of Pittsfield with resilient solar energy supplies to maintain service during daytime outages, and would include gas-fired standby generation to power the microgrid when PV generation is unavailable. The Zone 2 microgrid would substantially improve resiliency at the City of Pittsfield's most critical facilities, supporting the principal objective for the Project.

Notably, the relatively small size of the Zone 2 investment means even modest improvements in costs or benefits can yield a substantial effect on economic performance. For example, capturing 2020 tax credits[3] instead of the assumed 2022 credits would reduce total Zone 2 capital costs by more than 6%. Also, any additional grants or legislative allocation for the Project would substantially improve its net-present value for the City of Pittsfield; the cost-benefit assessment included $100,000 of State funding support, but the City would pursue other grants and aid for the Project as part of its work to strengthen community sustainability and resiliency.

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[1] Battery storage capacity was sized to support resiliency objectives only.

[2] In Zone 1, some proposed PV assets would require additional interconnection costs in any scenario. Accordingly, actual net-present value for a PV-only project would be somewhat lower than these estimates reflect.

[3] Solar and battery storage assets would be financed by a third party to capture investment tax credits and bonus depreciation benefits. The assets would transfer to the site owner following a five-year tax benefit payout period.

Accordingly, the Project Team recommends that the City of Pittsfield pursue opportunities to develop the Zone 2 microgrid at the earliest possible time, to secure maximum tax incentives, grant support, and sustainable resiliency benefits for critical community facilities.

1.2 Microgrid Design, Lessons Learned, and Implementation Scenarios

- *Discuss the Project results and lessons learned regarding configuration, capabilities and benefits of the Project; environmental and economic benefits, and implementation scenarios associated with such.*

In addition to the results and lessons learned discussed in the Task summaries above, the assessment produced key lessons regarding the initial proposed designs for Zones 1 and 2, as well as practical issues affecting potential benefits that those designs sought to achieve.

a. Valuing sustainable resiliency for critical community facilities

As noted above, costs for distribution system upgrades, control systems, and storage batteries proposed for each microgrid zone are greater than the quantifiable, direct economic benefits each zone would produce. This creates a substantial cost burden for a project whose primary purpose is to produce sustainable resiliency for critical community facilities, rather than financial returns. While PV systems directly produce economic value and may be financed on their own merits, assets required to integrate those PV systems in a resilient microgrid must be treated as infrastructure, and not subjected to the same economic expectations as generation systems.

Traditional approaches to utility system cost-benefit analysis have emphasized least-cost planning for all capital expenditures. State requirements such as integrated resource planning and renewable portfolio standards have enabled solar and other renewable energy resources to grow in Massachusetts, but with few exceptions those resources are incapable of supporting local resiliency – and indeed the way they have been integrated has emphasized least-cost approaches to maximize the owner's financial benefits rather than produce any operational benefits. As a result, utility system planning and cost-recovery processes have effectively prevented communities and other customers from using renewable energy to protect their critical facilities.

The Project assessment demonstrates an important lesson: To the degree the State values resilient sustainable energy for critical community assets, it should fund those assets in the same way it finances other types of assets intended to serve the public good rather than yield financial returns.

b. Enabling customer investments in behind-the-meter energy systems

The Project Team initially had considered customer investment and ownership of systems required to connect customer loads and resources on adjacent customer-owned properties. This approach would allow the Project host to benefit from market competition and innovation in procuring systems for behind-the-meter integration of DERs. Moreover, initial assessments suggested such an approach would not violate the utility's franchise rights, because each proposed system would serve the energy loads of a single customer with solar energy generated onsite or on the same customer's adjacent properties.

However, in each zone some PV sites are separated from some of the customer's loads by a single public street. The utility has asserted an exclusive right to own and operate any electric assets placed in a public way, irrespective of who owns the loads, DERs, or properties. This created economic and regulatory barriers in both zones.

In Zone 1, the utility's proposed approach would require directly interconnecting the new PV systems to the utility distribution feeder rather than interconnecting them behind the meter. As a result, much of the proposed PV capacity would not reduce the customer's metered monthly peak demand, and using the output to offset the customer's energy consumption would necessitate a more complex remote net-metered tariff structure.

In Zone 2, the utility's assertion of the public way as the franchise boundary creates a potential regulatory risk for the City of Pittsfield, which is required to competitively procure all services under Massachusetts law. Such services presumably would include all assets for Zone 2, which is designed to operate as a behind-the-meter microgrid due to the technical infeasibility of reconfiguring the local distribution system. Because Massachusetts law has not clearly established the public way as the utility's franchise threshold, sole-source procurement of assets from the utility could subject the municipality to legal challenges under Massachusetts public procurement law.

The Project Team identified three possible strategies for resolving this potential regulatory issue: 1) seek permission from the Commonwealth of Massachusetts to pursue sole-source procurement; 2) seek permission from the Massachusetts Department of Public Utilities or the utility for the City to cross the street with microgrid systems to serve its own loads; or 3) remove public-way designation from the affected streets to create a contiguous City-services campus. As noted, the Project Team assumed the first strategy for this assessment, because it is the simplest and most likely to garner utility support. That approach, however, disregards the potential value of competitive procurement. Until Massachusetts legislative or regulatory proceedings clarify the issue and provide workable alternatives, all three strategies remain viable for CPDM or other public agency-sponsored energy projects that would cross a public way.

c. Utility-community collaboration to support vulnerable populations

When the City of Pittsfield established its objectives for the CPDM Project, a key driver was the need for resilient renewable energy to protect Pittsfield's most vulnerable populations. In addition to several other critical community facilities – including medical services, first responders, and public shelters – the initial Zone 2 site assessment considered six (6) housing projects, most of which are operated by the Pittsfield Housing Authority, with 420 units serving elderly, disabled, and low-income residents. Resilient energy service using local renewable energy would minimize the effects of long-duration outages on such vulnerable residents by allowing them to shelter in place and avoid costly evacuation and relocation.

In designing a system to provide resilient sustainable energy for Pittsfield's public and subsidized housing facilities – which are distributed throughout the Pittsfield Downtown area – the Project Team asked the electric utility to consider potential for a wide-area microgrid that would serve a large part of

Pittsfield with energy supplied by existing and prospective new PV and BESS capacity, with support from local natural gas-fired power plants or standby generation if necessary. The utility considered this concept, and provided distribution-system information and guidance that indicated such a wide-area microgrid would be technically complex and costly to achieve within its existing Pittsfield distribution system. Further, the targeted facilities are too widely dispersed to reasonably consider creating new parallel underground infrastructure to serve them in a single islanding energy system.

Those determinations, which were reached during Task 3 assessments, led the Project Team to consider alternative design approaches including: serving parts of the original wide area with several smaller independent systems; or installing onsite solar+storage systems for individual facilities. Although the latter approach showed cost-savings potential for some customers, the Project Team rejected it because it would not support the CPDM vision of a community microgrid, sharing local renewable resources to serve community loads. These considerations led the Project Team to downsize the assessed design to serve only BMC and City of Pittsfield's critical first response, public safety, and emergency management offices.

Through this process, the Project Team's assessments established in early phases that the existing Pittsfield distribution system cannot feasibly be reconfigured to support one of the project's primary initial objectives – to provide resilient renewable energy for vulnerable populations. The assessment also showed, however, that a wide-area community microgrid approach could be feasible in a distribution system environment where the following conditions are met:

a. Multiple critical loads are served by common distribution infrastructure;
b. Non-critical loads can be curtailed or directly controlled, or generation capacity is sufficient to serve them all; and
c. The electric utility shares the community's goals for creating the wide-area microgrid.

The final condition may be necessary for the first two conditions to be met. Specifically, where community and utility engage and cooperate to develop a shared strategic vision for local electric distribution system planning, then the utility may be positioned to develop distribution systems and control methodologies to support that strategic vision.

II. Chapter 2: Site Assessment and Description of Microgrid Characteristics

2.0 Task 2 Assessment

2.0.1 Project Goals and Objectives

The CPDM Project was conceived as a wide-area utility distribution microgrid to serve the heart of Berkshire County's urban population center, a 1.3 square-mile area of Pittsfield's urban core (*see Figure 2.2*). Through the course of assessment, the Project Team engaged the utility in discussions to explore options and challenges affecting those options. As a result, the project scope discussed in the project

Task 2 Report evolved in subsequent tasks. This chapter presents the preliminary microgrid design, as well as information about how and why it subsequently changed.

The overarching goals of the CPDM are to support integrated planning and resource optimization, to help Pittsfield make the best use of its resource potential for sustainability and resilience, while also attracting and retaining living-wage jobs. The Project aims to achieve these goals by pursuing five discrete objectives:

1. Develop and deploy systems to provide resilient and sustainable energy service for vital community facilities in Downtown Pittsfield;
2. Modernize electricity infrastructure and systems to support job growth and retention;
3. Provide the City and residents with opportunities to reduce energy costs by investing in local renewable generation capacity;
4. Optimize use of local renewables to energize vital community electric loads (including during regional outages); and
5. Plan for and manage expanded energy storage capacity to support integration of local renewable energy.

These objectives remain relevant for the Project. However, the revised project scope can address Objective 3 only for the City of Pittsfield and Berkshire Medical Center, because photovoltaic (PV) generation capacity envisioned for the revised Zones 1 and 2 will displace utility energy consumption only for the site hosts.

2.0.2 Alignment of MassCEC Community Microgrids Program Goals

The goals of the CPDM are in close alignment with MassCEC's Community Microgrid Program goals. Section 2.2 details characteristics of the project that address Program goals, and considerations for assessment.

2.1 Site Assessment

2.1.1 Size and scope of the proposed microgrid

(Including inventory of the existing and planned buildings and assets included within the microgrid.)

The CPDM preliminary design envisioned a sustainable and resilient energy system capable of serving electric demands up to 4.5 MW and supplying approximately 23,000 MWh of electric power annually (*see Figure 2.4*). The preliminary design comprised three separately islanding zones:

- *Zone 1:* The Berkshire Medical Center campus, comprising several buildings on adjacent lots separated by two public streets. BMC already has an 800 kW natural gas-fired CHP system. New resources would include solar photovoltaics (PV), battery energy storage systems (BESS), and potentially thermal energy storage systems (TES) to support resilient microgrid service and economic benefits for additional hospital loads beyond those served by the existing CHP system.
- *Zone 2:* Several facilities owned by the City of Pittsfield, the Pittsfield Housing Authority, and Berkshire Health Systems, on separate lots spanning the Pittsfield Downtown area. These critical

facilities support first response, safety, emergency management, urgent care, emergency sheltering, and housing for vulnerable populations. New resources to serve critical facilities in Zone 2 are expected to include solar PV and BESS capacity, as well as distribution system reconfiguration and upgrades to support island-mode microgrid operations. In addition to the assessed critical facilities, Zone 2 encompasses numerous additional facilities that support CPDM goals and objectives – including public services, infrastructure, and additional housing for vulnerable populations, as well as Pittsfield's Upstreet Cultural District, with multiple arts, hospitality, and commercial venues that support the vitality of Pittsfield's vibrant urban core. If technical analysis shows the proposed system's viability would be strengthened by adding loads beyond those included in Task 2 critical load assessment, these facilities represent priority options for expanding microgrid benefits.

- *Zone 3:* An industrial park site comprising several adjacent lots separated by public streets. The brownfield redevelopment sites in Zone 3 are almost entirely unoccupied, with new construction proceeding at the Berkshire Innovation Center (BIC). Consequently, Task 2 assessments for Zone 3 have focused on reviews of facility plans and anticipated functional requirements. New resources in Zone 3 could include solar PV, BESS, and CHP capacity, depending on prospective tenants' energy requirements.

Fig. 2.1: CPDM Modeled Facilities

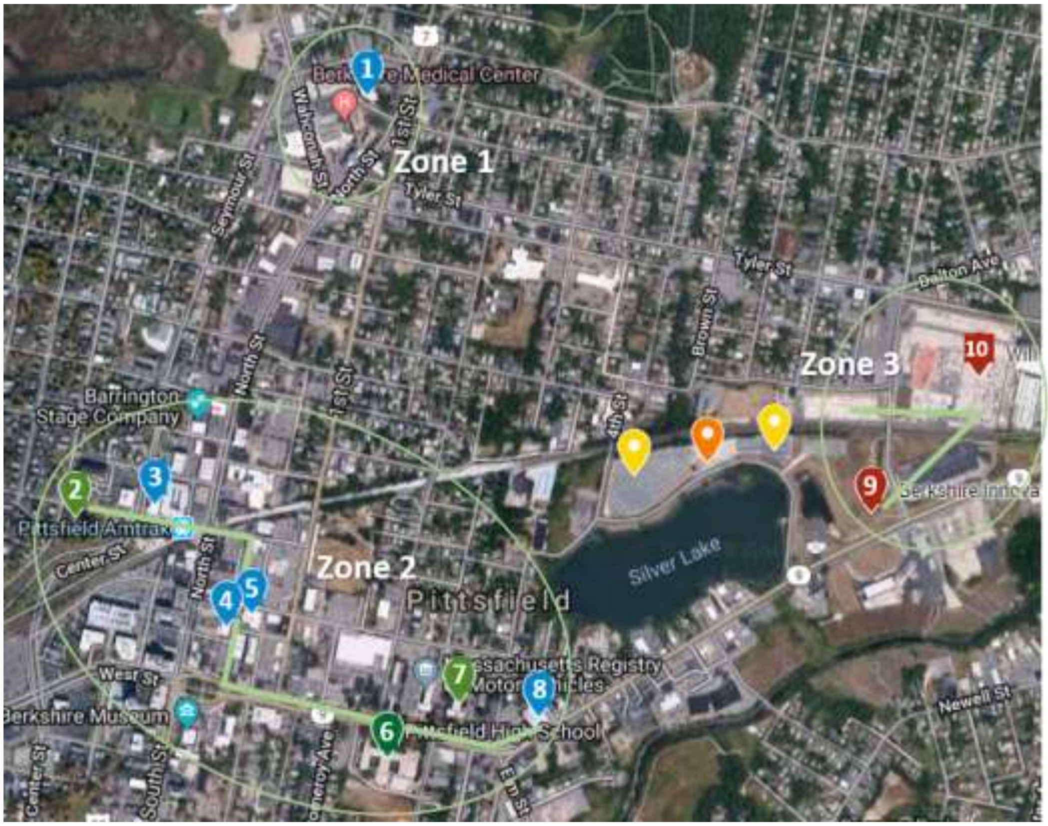
Facilities in bold-italic included in revised Project scope.

#	Facility	Address	Zone	Owner	Critical Function(s)
1	***Berkshire Medical Center***	***725 North St***	***1***	***Berkshire Health***	***Medical services***
2	PHA Columbia Arms Apartments	65 Columbus Av	2	Pittsfield Housing Authority	Housing for vulnerable populations
3	Pittsfield Fire Department HQ	74 Columbus Av	2	City of Pittsfield	Fire protection, first response, EoC
4	***Pittsfield Police Department***	***39 Allen St***	***2***	***City of Pittsfield***	***First response, law enforcement, public safety***
5	***Pittsfield City Hall***	***70 Allen St***	***2***	***City of Pittsfield***	***Public shelter, city admin***
5a	***100 North St****	***100 North St***	***2***	***Scarafoni Associates***	***Public health and building inspection services***
6	Pittsfield High School	300 East St	2	City of Pittsfield	Public shelter
7	PHA Providence Court Apartments	379 East St	2	Pittsfield Housing Authority	Housing for vulnerable populations
8	Berkshire Health Urgent Care	505 East St	2	Berkshire Health	Medical services
9	Berkshire Innovation Center	Woodlawn Av	3	City of Pittsfield	Employment
10	William Stanley Business Park	81 Kellogg St	3	City of Pittsfield	Employment

**100 North St., a privately owned building adjacent to the Pittsfield City Hall, was not included in Task 2 assessments, but was added in Task 3. The Project would serve City of Pittsfield loads located at 100*

North St., including 8,890 square feet of offices on the mezzanine level that are occupied by Pittsfield Health Department and Building Inspection staff.

Fig. 2.2: CPDM Preliminary Design - Area Map



Note: *Yellow and orange pins indicate location of Silver Lake solar arrays and substation.*

During Task 3, further engagements with Eversource showed that the preliminary design faced technical viability challenges. The Project Team considered multiple iterations and determined that the most technically viable Zone 2 design would serve only City of Pittsfield loads at three buildings – as noted, City Hall, Police Department, and 100 North Street. This revised Zone 2 design is described and assessed in subsequent chapters of this final report.

Zone 2 Additional Vital Facilities: As noted above, in addition to the facilities described in Figure 2.1, the Project Team in Task 2 also reviewed numerous other facilities in the preliminary Zone 2 area that support CPDM goals (*see Figure 2.3*). The Project Team considered how these facilities could be served by the prospective microgrid on an optional or opt-in basis. They were excluded from Task 2 load assessment, but considered for potential future development if adding them to the microgrid loads would improve its cost-benefit performance.

Fig. 2.3: CPDM Additional Vital Facilities (For potential future development)

Facility	Address	Vital Community Purpose
Berkshire Athenaeum	1 Wendell Av	Public shelter and Internet access
Verizon Downtown Pittsfield	24 Federal St	Telecom infrastructure
WMECO (Eversource) HQ	33 West St	Utility service center
CVS Pharmacy	107 West St	Pharmacy and essentials
Sunoco Gas Station	51 Center St	Auto fuel
Joseph Scelsi Intermodal Transportation Center	1 Columbus Av	Public transit station
Berkshire Bank	99 North St	Public banking and private offices
Crown Plaza – Pittsfield Berkshires	1 West St	Private lodging
Hotel on North	297 North St	Private lodging
Beacon Cinema	57 North St	Community cultural asset
Barrington Stage	30 Union St	
Colonial Theatre	111 South St	
Berkshire Museum	39 South St	
USPS	212 Fenn St	US mail service
Intertek Plastics Material Lab	50 Pearl St	Light industrial employer
Morningside School	100 Burbank St	Public shelter
Reid Middle School	950 North St	
Berkshiretown O'Connell Senior Living	176 Columbus Av	Housing for vulnerable population
Rice Silk Mill	55 Spring St	
Capitol Square Apartments	369 North St	
Central Annex Apartments	99 Second St	
New Amsterdam Apartments	140 Bradford St	
YMCA	292 North St	

Finally, because the prospective commercial and industrial loads in Zone 3 did not exist during Task 2 load-assessment phases, Zone 3 was omitted from subsequent assessments. Like the Zone 2 additional vital facilities noted above, Zone 3 is considered an option for potential future assessment and development if and when the technical and economic potential supports it.

2.1.2 Assessment of Loads, Resources, Infrastructure, and Programs:

a. Electric and heating/cooling loads

The Project Team's Task 2 site assessments focused on the following information and metrics for electric and thermal loads at the microgrid facilities:

- Electricity consumption (kWh) and peak demand (kW) requirements to serve metered circuits defined by facility customers as critical.
- Heating, cooling, and thermal process opportunities for energy savings, load modulation, or service with combined heat and power (CHP).

Facilities management staff provided the Project Team with access to data for Task 2 analysis, including billing and energy consumption summary data, and questionnaire inputs for facility surveys. Quantitative analysis focused on electric consumption and demand data to produce baseline critical resiliency requirements.

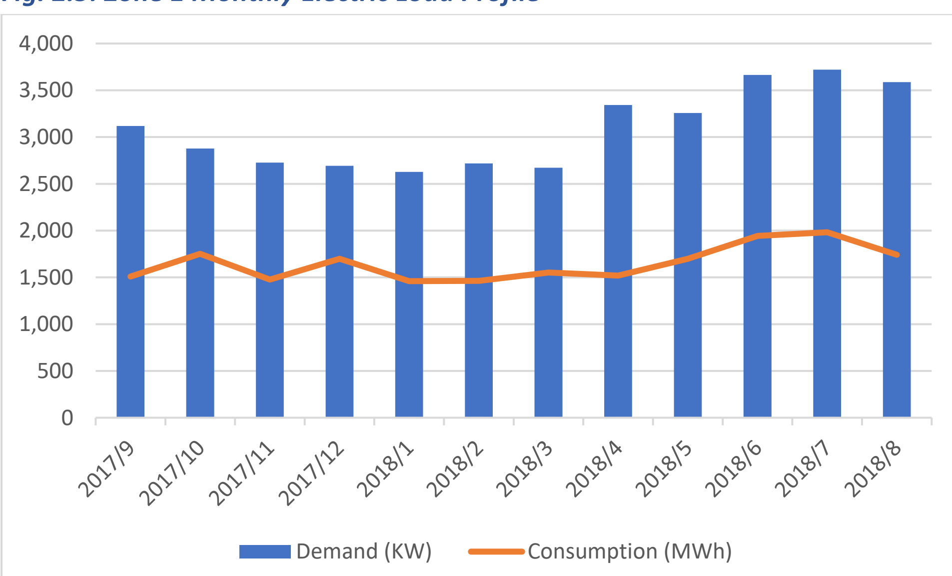
Electric loads were grouped into three discrete zones for assessment (*see Figure 2.4*). Zone 1, comprised of the Berkshire Medical Center campus, represents the zone with the greatest energy consumption, and it hosts an existing 800 kW natural gas-fired CHP system serving electric and thermal loads for hospital in-patient critical facilities. The Zone 2 preliminary design included seven downtown facilities – police station, fire department HQ, and EOC, as well as an urgent care facility, emergency public shelter, and two public housing facilities. For Zone 3, no energy load history was available for assessment, and so it was omitted from quantitative assessment.

Fig. 2.4: CPDM Preliminary Design - Zone Electric Load Summary

Zone	Energy (kWh)	Demand* (KW)
1	19,796,434	3,719
2	3,251,452	778
3	NA	NA
Total	23,047,886	4,497

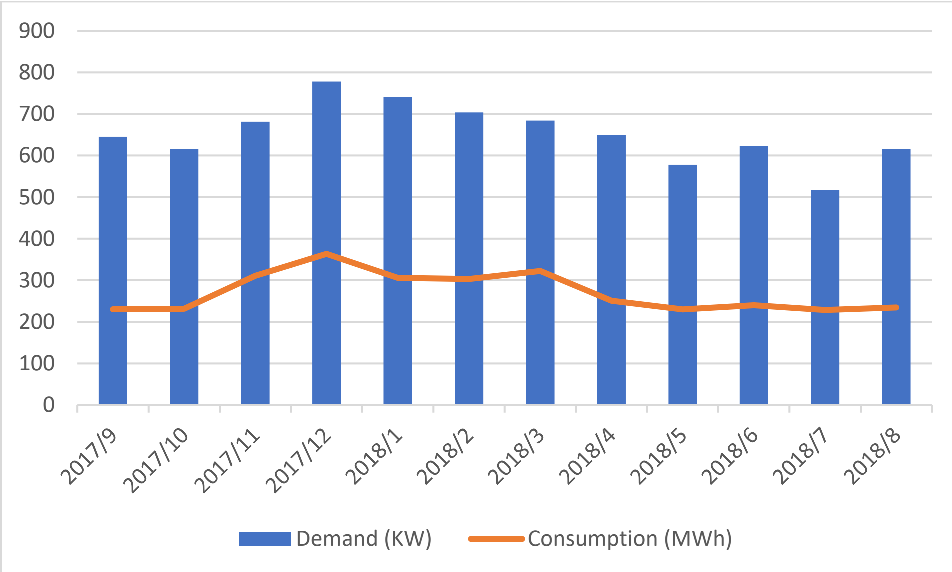
**Combined system monthly peak demand for all facilities in zone.*
Zone 1 peak demand occurs in July, Zone 2 in December.

Fig. 2.5: Zone 1 Monthly Electric Load Profile[4]



[4] Electric load analysis period: 1 Sept. 2017 through 31 Aug. 2018

Fig. 2.6: Zone 2 Monthly Electric Load Profile



b. *Generation resources or other relevant technologies*

The City of Pittsfield's goals for the project support increased reliance on cost-effective renewable energy resources to the greatest practical extent, and aim to reduce if not entirely eliminate reliance on fossil-fueled generation as a primary resource for microgrid loads. In the Pittsfield area, solar energy represents the primary available renewable resource.

Existing CHP capacity would support Zone 1 islanding capabilities, with additional PV, BESS, and gas-fired generation as required in Zone 1 to enable resilient service for the entire BMC campus. Existing fossil-fueled backup generation systems in all three zones would continue providing backup capacity for facility loads via existing transfer schemes, but in most cases would not be used to energize the microgrid.

Existing and Planned Solar Systems: To date, relatively little solar generation has been developed in the Project area. Notwithstanding some privately owned rooftop solar systems, two major ground-mounted solar systems are operating in Pittsfield, with at least three more in construction or in advanced development (*see Fig. 2.7*). Of these projects, however, only one (Silver Lake Solar) is located inside the Project area.

Fig. 2.7: Pittsfield Solar PV Projects

Project	Capacity (MW ACp)	Owner/Lessee	Location	Status
Silver Lake Solar	1.8	Eversource	Silver Lake Blvd	Operating since 2010
Pittsfield Landfill Solar	2.9	Ameresco	Downing Industrial Pkwy	Operating since 2016
Pittsfield Airport Solar	6.8	OakLeaf Energy	Tamarack Rd	In construction
BVD East Street Solar	1.9	BVD Solar	East St	In development
Pontoosuc Solar	6.5	Nexamp	Hancock Rd & Ridge Ave	In development

The Project Team considered the viability of using generation outputs from Silver Lake or other PV systems to support microgrid loads. Initial assessments indicated that integrating these systems into the preliminary Zone 2 design would require interconnection reconfiguration, which may be technically and economically challenging. Notably, the Silver Lake system is nine years into its operating lifespan, which impairs the cost-benefit attributes of reconfiguring its interconnection systems, if required to serve microgrid loads. Zone 2 was downsized during Task 3 assessments in ways that further impair the technical ability to integrate output from any PV systems outside the revised Zone 2 area. Accordingly, options for energizing the microgrid with existing PV systems in the Pittsfield area were deemed technically infeasible and omitted from further assessment.

Onsite PV and BESS Potential: The CPDM design envisions installing new PV and BESS capacity to serve microgrid loads. The new solar capacity would involve a combination of ground-mounted, covered-parking, and rooftop solar arrays in locations that can supply microgrid loads, either behind facility meters or through Eversource distribution infrastructure. Several of the buildings in all three zones have rooftop capacity for new PV systems. Onsite BESS capacity would be required for reactive power and generation shifting to enable grid-forming, balancing, and transitions into and out of safe-island operating modes.

In addition to solar resources, the Project Team reviewed other renewable resource potential in the Project area (including wind, hydro, geothermal, and biomass/biogas options) and found no substantial renewable electric resources for consideration. Onsite solar-thermal and ground-source heat pumping may be viable options for site-specific energy performance improvements, but such systems are unlikely to contribute to microgrid viability.

During Task 2 assessments, the Team reviewed thermal energy systems, functions, and fuels at the microgrid facilities, and produced the following conclusions regarding thermal requirements and opportunities:

i. *CHP Potential:* Berkshire Medical Center operates an 800 kW (725 kWe, 75 kWt) natural-gas fired CHP system to serve the hospital's critical thermal loads, with electric islanding capabilities in development. Among the other facilities assessed, none currently have thermal loads of the magnitude or consistency to support CHP viability – *e.g.,* substantial thermal demands at least 8,000 hours/year. CHP could, however, be considered in the future in Zone 3, as an efficient alternative to separate thermal and electric systems to serve prospective industrial loads that may have substantial thermal requirements.

ii. *Existing Energy-Savings Programs:* Many of the proposed microgrid facilities have, within five years, performed energy audits and implemented substantial thermal energy-saving measures, as part of ongoing programs administered by the City of Pittsfield and Berkshire Health Systems. Most facilities have building energy management systems (BEMS) in place, but some performance opportunities may remain to be exploited, especially regarding advanced demand-response potential. Chapter 3 addresses load management among potential solutions to support microgrid requirements.

TES Potential: Thermal energy storage systems can reduce demand charges and shift peak loads to off-peak periods. In the Project area, TES was considered as a potential option for load management and system energy conservation for large building thermal loads that could accommodate pre-cooling retrofits or replacements. In the revised Project design, however, the only buildings with large enough thermal loads to justify consideration of TES are already being served by CHP resources at the hospital. Therefore, TES was omitted from further assessment. It could be reconsidered in future phases, especially to support prospective Zone 3 industrial thermal loads.

c. Distribution system infrastructure

Eversource operating company Western Massachusetts Electric Co. (WMECo) owns and operates the local electric distribution system in the Project area. Most of the microgrid facilities are served by 13 kV overhead secondary distribution lines, energized from the Silver Lake substation (42.45, -73.24), Pearl Street substation (42.45, -73.25), and Francis Ave substation (42.45, -73.26).

The Project Team's assessments indicated that serving the preliminary set of Zone 2 facilities in a safely islanding microgrid would require reconfiguring circuits, reclosers, and control facilities in the Project area. Some system upgrades also may be needed. In particular, initial assessments indicated capacity constraints including single-phase distribution lines in some parts of the Project area, which likely would affect potential for interconnecting new PV generating systems on affected segments.

Chapter 3 addresses system design based on detailed distribution system architecture models.

d. Utility assets including metering and interconnection

Electricity services for facilities included in the microgrid are metered primarily with traditional electromechanical and simple electronic metering systems. This fact leads to two primary consequences for the Project, particularly for Zone 2, which includes multiple geographically separated facilities:

i. *No Interval Data:* Assessed electric load data includes monthly total energy consumption (kWh) and monthly peak demand (kW); the lack of advanced metering infrastructure (AMI) means granular interval data was unavailable for the studied facilities. As a result, facility electric load profiles were based on annual month-by-month trends in consumption and demand. Simulated intra-week and intra-day load profiles were produced in Task 3, based on similar facility load profiles, to help estimate time-of-day usage and likely system coincident peak demand.

ii. *No Remote Disconnect:* Most AMI devices include remote connect/disconnect functionality, but traditional meters do not. The lack of AMI in the Project area limited options for energizing only critical loads in the preliminary Zone 2 area. However, because Zone 2 was downsized to serving only three buildings, those limitations became irrelevant for subsequent Project assessments.

e. Existing energy efficiency programs

The City of Pittsfield, Pittsfield Housing Authority, and Berkshire Medical Center all have implemented ongoing energy efficiency and conservation programs for their facilities. Task 2 assessments indicated energy efficiency audits and upgrades have been performed at substantially all facilities within the last 5 years. Upgrades included new HVAC systems and lighting replacements with high-efficiency LED systems. Chapter 3 includes assessments of how additional BEMS or other active load-control technologies would support microgrid objectives.

2.2 Minimum Required & Preferable Microgrid Characteristics

2.2.1 Characteristics and capabilities that are required of the microgrid

Fig. 2.8: Assessment of Program and Project Objectives

MassCEC Program Goal/Objective	CPDM Goal/Objective
Explore benefits microgrids can offer to Massachusetts energy customers.	The Project is focused on assessing multiple types of benefits for various kinds of customers (government, commercial, industrial, and housing for vulnerable populations).
Catalyze the development of community microgrids that can:	
Reduce customer energy costs.	Reduce customer energy costs through energy conservation measures and locally owned renewable energy investments.
Reduce GHG emissions.	Reduce GHG emissions through energy conservation measures and by displacing fossil-generated power with clean renewable energy generation.
Increase resiliency of critical facilities and infrastructure.	Improve the resiliency of several critical facilities in Pittsfield by providing local energy resources and safe-islanding systems to assure continued electric service during regional power disruptions.
Serve at least one, but preferably more, physically separated critical facilities located on one or more properties.	CPDM includes multiple physically separated critical facilities on multiple properties.
Include clean or renewable energy; diesel fuel may NOT be primary resource.	Exclude diesel fuel as a primary generation resource and reduce diesel consumption by preventing outages that cause dispatch of diesel backup generation.

Include energy efficiency upgrades to minimize new microgrid generation requirements.	Primary opportunities include some remaining LED lighting conversions and upgrades to BEMS technologies. TES may be considered in the future for Zone 3 facilities with large thermal loads.
Provide power to critical facilities, for a diverse group of customer and load types.	CPDM includes multiple critical facilities with differing customer and load types, including municipal first response, EOC, public shelter, housing for vulnerable populations, inpatient and outpatient medical care, and commercial and light industrial facilities.
Resilient to forces of nature that are typical and pose highest risk.	Improve resiliency against regional outages caused by the most prevalent natural threats, including major hurricanes and winter storms affecting the long-distance transmission system. Zone 1 solutions also would protect the BMC campus from disruptions to local distribution service.
Provide one or more distribution system services, such as: Grid capacity support, black-start capability, facilitating renewables integration, etc. Services must be meaningful to the utility.	Support multiple distribution system services, including improvements in grid capacity, reliability, and ability to integrate renewable energy into local energy supplies. The Project Team has engaged the utility to identify local grid issues that could meaningfully be supported by microgrid upgrades.

2.2.2 Characteristics and capabilities that are preferable but not required

a. Advanced technologies and designs

During Task 2 assessment the Project Team identified potential to apply distributed automation and AMI technologies in the Project area to enable load management for microgrid resiliency purposes. The non-contiguous nature of the facilities in the preliminary Zone 2 area called for an innovative approach to microgrid design, to manage electricity supplies for critical facilities on circuits that serve both critical and non-critical loads. In both the preliminary and revised Zone 2 systems, BEMS upgrades and microgrid signaling would support demand-response and load management for support resiliency requirements, and also could be operated for additional cost savings. Current rate options, however, offer only limited opportunity to capture economic value from load shifting.

b. Integration of energy storage technologies

The Project requirements include BESS capacity to support grid forming and modal transitions, as well as system balancing in islanded operating modes. Project design scope considered a combination of facility-scale and community-scale BESS systems. The Project Team also contemplated TES systems – namely ice energy storage for cooling load shifting – to support load-management and system energy conservation for large building thermal loads. Future industrial loads in Zone 3 might incorporate CHP or district energy into their designs, or accommodate it with pre-cooling retrofits or replacements, but no loads in the revised Project area were found likely to support TES investments.

Chapter 3 includes assessments of potential for using BESS capacity to produce economic benefits, including monetizable ancillary services. In general, the Project Team's analysis showed that on a life-cycle cost basis, the best economic cases included minimal BESS capacity, to support grid forming and balancing only.

c. Integrates relevant technologies designed and/or manufactured in Massachusetts

Technology products for all key Project elements could be procured from any of multiple sources. For software modeling purposes using HOMER Pro, the simulation library's generic values are applied to the degree possible for key technology components in the project – PV systems, BESS, inverters, and fossil-fueled generators. In post-processing cost-assessments, the Project Team estimated pricing information in part on S&C Electric switchgear and Taylor gas-fired standby gensets, both of which are sourced outside of Massachusetts. Procurement processes could include Massachusetts content preferences, to the degree such preferences are consistent with Project objectives and procurement requirements and practices.

d. Leveraging significant third-party investment, including private capital. Project characteristics should be informed by the Project Team's Expression of Interest and viability assessment;

For the preliminary Project design, the Project Team anticipated that implementation would require a combination of private third-party investments in new electric generation (primarily solar PV) and BESS capacity, as well as utility investment in distribution system upgrades and reconfiguration. This expectation was consistent with the Project Team's Expression of Interest in response to MassCEC's Community Microgrids program solicitation, which envisioned partnering with Eversource to develop a hybrid utility microgrid. Under the proposed model, third parties and the microgrid customers would finance and own generation and storage assets, while the utility would maintain ownership of distribution system assets.

When Zone 2 was downsized to only three facilities, the Project Team first considered options to create an islanding system within or in parallel with the utility distribution system to serve only City loads at those three buildings. Subsequent chapters include assessments of opportunities and challenges for both options, including potential to leverage third-party or municipal investments.

Financial structuring is assessed in Chapter 5; in sum, the Project PV and BESS assets would be financed on a build-operate-transfer basis. A third-party investor would fund initial deployment to capture the value of tax benefits. Following a 5-year paydown period, each site host – Berkshire Medical Center or City of Pittsfield, respectively – would take ownership by paying the assets' remaining book value. For financial modeling purposes, the Project Team assumed these buyouts would be funded with 10-year corporate or municipal bonds, respectively.

e. Additional required and/or preferable characteristics

Like any community setting, the City of Pittsfield is a dynamic environment, with changes occurring in facilities and services within the CPDM area. To support quantitative modeling and analysis, the Project

Team's assessment focused on currently known energy requirements. At the same time, however, meeting the proposed microgrid's goals for supporting economic development and employment required consideration of future-phase development. This was a primary motivating factor for including Zone 3 in Project assessment, despite the lack of energy load information.

Zone 3 is envisioned as a future-phase deployment to serve prospective industrial loads at properties owned by the City of Pittsfield through the Pittsfield Economic Development Agency (PEDA). Specifically, the William Stanley Business Park is a cluster of eight lots that formerly housed a General Electric manufacturing facility. The 30+ acre industrial park development includes several existing buildings, foundations, large parking areas fit for solar carports, and construction-ready sites for mixed-use commercial and industrial development. At the industrial park in early 2020 PEDA opened the Berkshire Innovation Center (BIC), a 22,000 ft2 research and development facility that will house multiple testing and workforce training facilities. PEDA is actively engaging prospective tenants and users of the William Stanley Business Park properties.

For purposes of this assessment, Zone 3 is described as a potential project for future consideration. It likely would require new ground-mounted and rooftop PV systems, as well as BESS and potentially CHP capacity to supply electricity for BIC and other occupied commercial and industrial facilities at the William Stanley Business Park.

III. Chapter 3: Preliminary Technical Design and Configuration

3.1 Proposed Microgrid Infrastructure and Operations

3.1.1 Simplified Microgrid Diagrams

Fig. 3.1: Zone 1 (Berkshire Medical Center) Simplified Single-Line Diagram

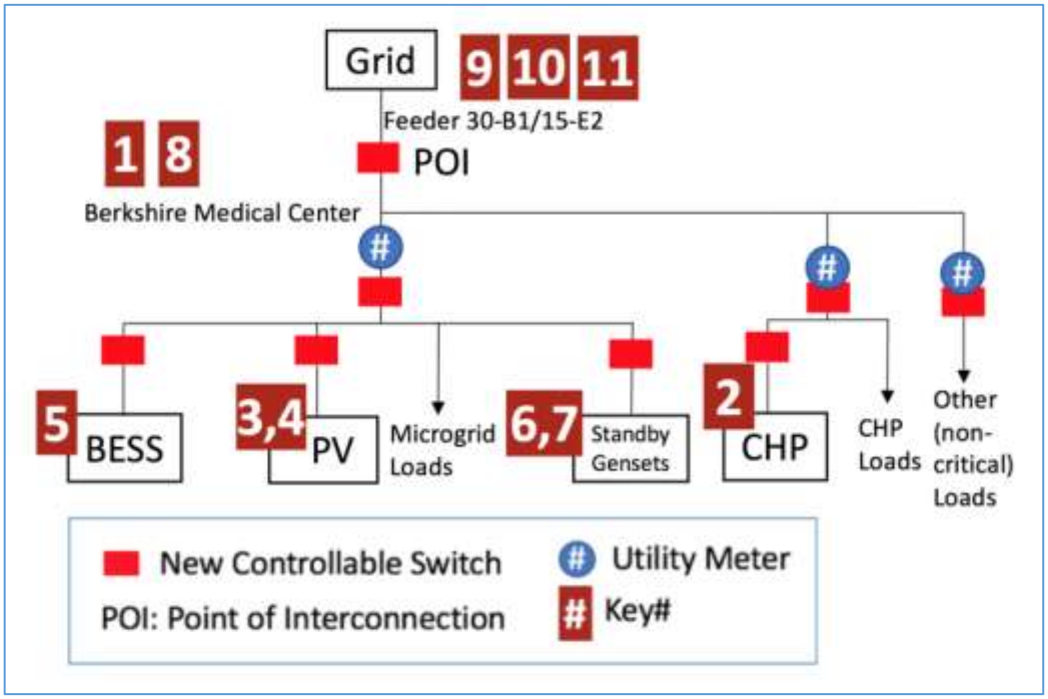


Fig. 3.2: Zone 1 Geospatial Overview

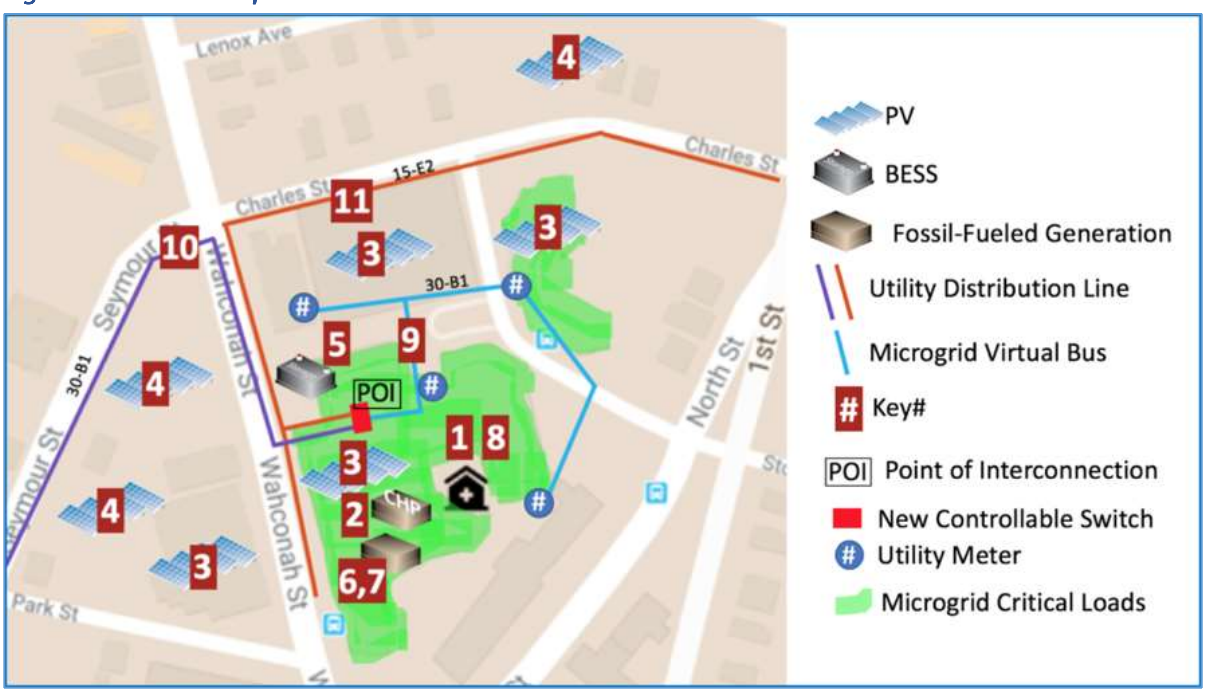


Fig. 3.3: Zone 1 Key to Loads, Resources, and Infrastructure

Key #	Facility or Component	Description	Existing or Proposed
1	Berkshire Medical Center	~1,410 kW average demand, 19,058 MWh annual consumption, commercial profile	Existing
2	CHP System	725 kWe	Existing
3	Rooftop PV	894 kW, 1,074 MWh/yr	Proposed
4	Covered Parking PV	1,265 kW, 1,520 MWh/yr	Proposed
5	BESS	4,000 kW/1,000 kWh	Proposed
6	Standby Generator	2,000 kW natural gas	Existing
7	Standby Generator	700 kW #2 fuel oil	Existing
8	Controls	Microgrid master and BEMS controls	
9	Microgrid Bus	Virtual microgrid bus isolated on 30-B1	
10	Feeder 30-B1	Eversource 23 kV feeder	Existing
11	Feeder 15-E2	Eversource 23 kV feeder	Existing

Fig. 3.4: Zone 2 (Revised) - Simplified Single-Line Diagram

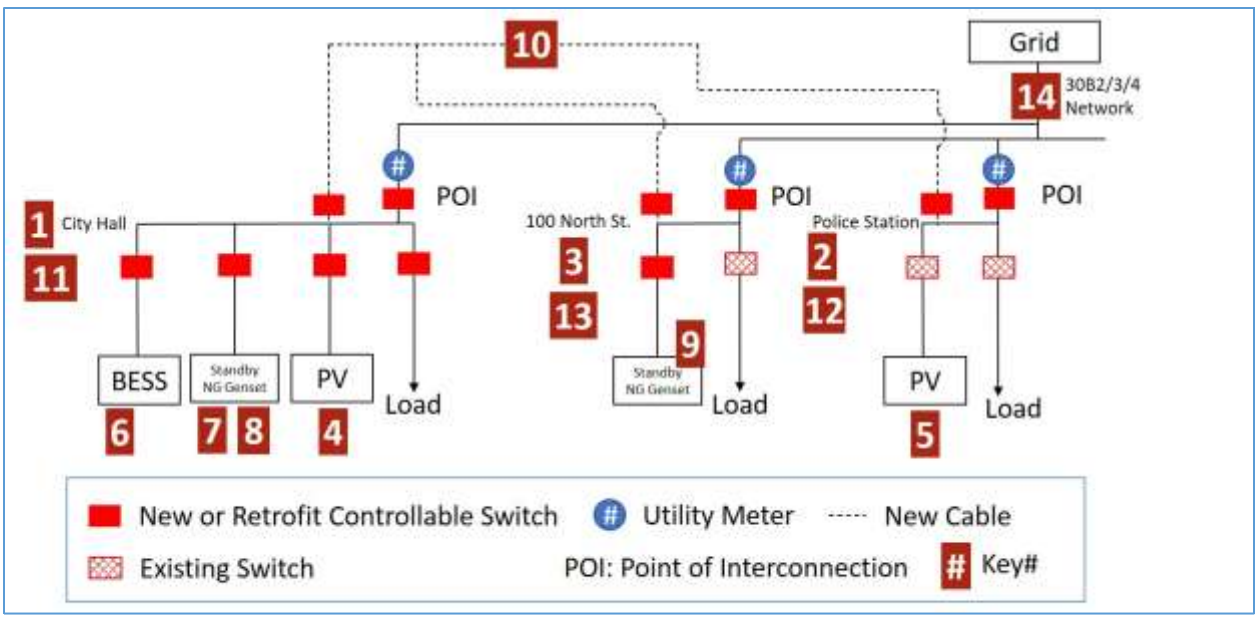


Fig. 3.5: CPDM Zone 2 – Geospatial Overview

Fig. 3.6: CPDM Zone 2 – Key to Loads, Resources, and Infrastructure

Key #	Facility or Component	Description	Existing or Proposed
1	City Hall	~36 kW average demand, 245,382 kWh annual consumption, commercial profile	Existing
2	Police Station	~55 kW average demand, 233,440 kWh annual consumption, commercial profile	Existing
3	100 North St.	~11 kW average demand, 106,131 kWh annual consumption (City loads only), commercial profile	Existing
4	Rooftop PV	67 kW, 80,514 kWh annual production	Proposed
5	Rooftop PV	54 kW, 64,892 kWh annual production	Proposed
6	BESS	200 kW/50 kWh	Proposed
7	Standby Genset	150 kW natural gas	Proposed
8	Standby Genset	20 kW	Existing
9	Standby Genset	125 kW diesel	Existing
10	Microgrid bus	450 ft underground conduit, conductors, and communications cable (fiber optics)	Proposed
11	Controls	Microgrid master and BEMS controls	Proposed
12	Controls	Integrated BEMS	Proposed
13	Controls	Integrated BEMS	Proposed
14	Feeder 30B2/3/4 Network	Eversource 23 kV mesh network	Existing

3.1.2 Normal and Emergency Operations

The City of Pittsfield Downtown Microgrid is comprised of two separately islanding systems. Defined as "zones" for purposes of this feasibility assessment, these systems comprise:

- Zone 1: The Berkshire Medical Center Pittsfield Campus

- Zone 2: City of Pittsfield Critical Offices, including Pittsfield City Hall, Pittsfield Police Department, and City offices on the mezzanine level of 100 North St.

As a general matter, under normal conditions, both zones in the revised microgrid design will perform two primary functions. First, microgrid control systems will monitor and manage PV production to optimize BESS state of charge for customer resiliency objectives. Second, the microgrid control system will support customer economic objectives by coordinating load management programs among BEMS and managing economic dispatch of DERs within the constraints of applicable operating use cases. For example, the microgrid operator may apply an economic dispatch protocol to reduce facility peak demand, which temporarily would seek to minimize customer energy costs with reduced priority on maintaining BESS state of charge for resiliency purposes – *e.g.,* the control system would cease BESS charging and dispatch all PV output to reduce building loads. However, for purposes of this assessment, BESS capacity is assumed to be reserved entirely to support resiliency objectives.

During emergency conditions, such as when utility power is interrupted, the microgrid systems will enter island-mode operations, applying active load management and DER dispatch to support applicable island-mode use cases. Such use cases include, for example, planned and unplanned outages of short and long durations. During outages that are expected to be brief (*e.g.,* 15 minutes or less), the microgrid will seek to maintain semi-normal operations within buildings served by the microgrid, actively managing discretionary loads such as air conditioning to keep peak demand within available supply capacity. The City of Pittsfield has indicated that brief outages and black-start requirements are acceptable if necessary to reduce costs for advanced system automation and fast switching. BESS capacity, however, is expected to be fully adequate to support seamless transition to island-mode operations if procured microgrid controls will support it. For outages of longer duration, the microgrid will dispatch resources and loads to support any of several possible operating protocols, including for example: enabling safe evacuation and orderly shutdown of non-critical business; modulating and curtailing non-critical loads to indefinitely maintain minimum service level for critical loads; and extending time to refueling for onsite standby fossil-fueled generation units. Upgrades to BEMS including circuit-level and load-level controls will be required to enable microgrid load management capabilities.

Fig. 3.7: CPDM Use-Case Summary (Zones 1 and 2)

Use Case*	Battery-Only Duration	Rationale	Pros	Cons	Assessment Outcome
Minimum Resiliency	15 min.	Minimum battery capacity for microgrid islanding; Covers majority of short-duration outages actually experienced	Least cost; Sufficient for daytime solar-powered islanding for several hours; Storage could be expanded in future	Solar-powered daytime resiliency may not justify cost of investment in parallel infrastructure.	Selected for further study; Zone 1 configuration to prioritize economic objectives (peak shaving); Zone 2 to prioritize resiliency objectives
Moderate Resiliency	4 hours	Covers majority of short -and- long-duration outages experienced at the site	Major resiliency upgrade supports investment in parallel microgrid infrastructure	Higher cost	Rejected due to high capital cost and inability to support timely payback

**Key constraints: 1) PV limited to rooftop capacity; 2) No new fossil-fired generation to be considered except cleaner standby capacity to displace or replace existing standby capacity; 3) BMC existing CHP and standby generation will retain current configuration and will not be used to energize the microgrid.*

Figure 3.7, "CPDM Use-Case Summary (Zones 1 and 2)," summarizes assessment factors and outcomes that led to the selected use cases. The Task 3 resource model and preliminary technical design are based on supporting similar operational use cases at Zones 1 and 2, with some key differences as discussed below.

<u>*Zone 1:*</u> The BMC microgrid zone will rely on 2,160 kW of proposed new rooftop and covered-parking solar PV capacity combined with 4,000 kW/1,000 kWh of BESS capacity. The primary objective for the Zone 1 system is to reduce charges for utility-delivered electricity and demand. Additional objectives include substantially eliminating outages of 15 minutes or less for building loads served by the microgrid and reducing the effects of long-duration outages lasting longer than one day. Brief outages are experienced by Zone 2 facilities several times each year, and longer-duration outages once or twice a year. The utility reports Customer Average Interruption Duration Index (CAIDI) performance on Feeders 30-B1 and 15-E2 at 85 minutes and 69 minutes per year, respectively (*See Figure 3.11*). BESS capacity is sized to support the peak load (3,719 kW) at BMC for a minimum of 15 minutes, but in estimated average loading conditions (1,410 kW) the BESS capacity can support full loads for approximately 40 minutes.

Fig. 3.8: Zone 1 – PV Layout

The Project Team proposed that generation assets should be integrated behind the relevant utility meters to serve critical loads that are not served by the hospital's existing natural gas-fired CHP system.[5] This approach would enable BMC to use PV production to maintain adequate battery state of charge for resiliency objectives and to reduce the hospital's peak demand as well as annual consumption of utility-delivered electricity (by approximately 2,600 MWh/yr., or 13.6 percent of BMC's 19,000 MWh annual consumption of utility power supplies). During some conditions of high production and low onsite loads, PV output could exceed onsite consumption, and either will be exported to the grid (via net-metered interconnection) or curtailed.

The Project Team had proposed to energize the hospital microgrid with four PV arrays to be located on BMC-owned properties across either Charles Street and Wahconah Street, respectively. This approach to integration of generation behind critical load meters would reduce the customer's grid energy consumption and demand charges while also supporting microgrid islanding. However, the utility indicated it would not support a project that would serve customer loads with customer-owned generation located across a municipally defined public way. The utility indicated it could support the

[5] Berkshire Medical Center operates an existing 800 kW CHP system to support electric (725 kWe) and thermal (75 kWt) loads at one building on the BMC campus. This system is fully committed to serving critical loads, and consequently cannot energize the microgrid to support additional BMC loads. Proposed new systems therefore would be entirely dedicated to serving other critical loads at the BMC campus, and would not be integrated with the existing CHP system.

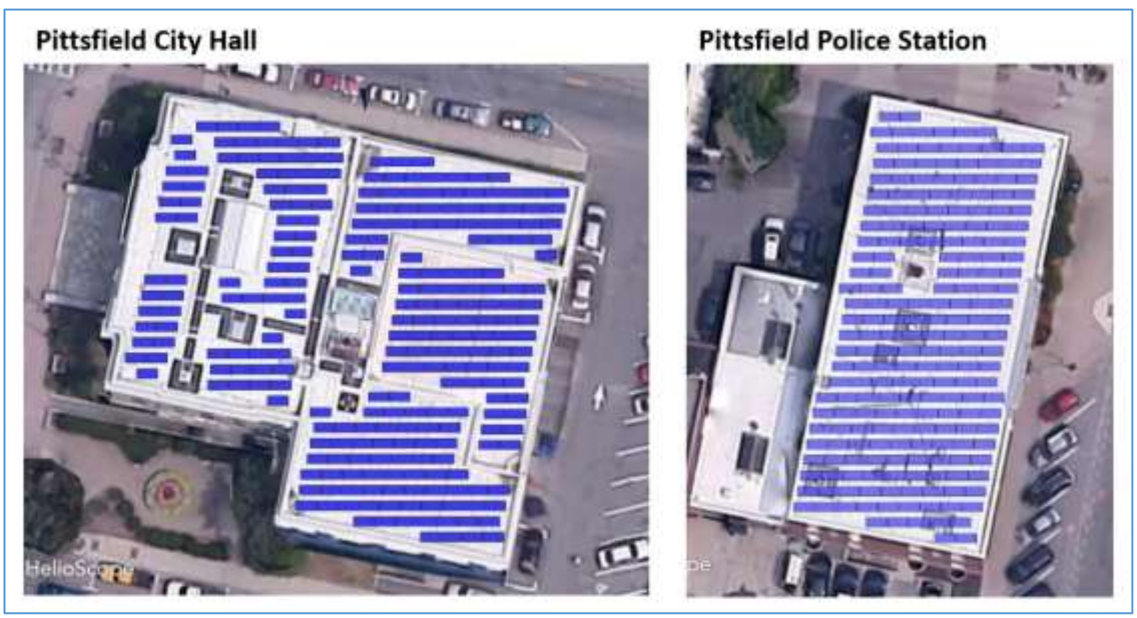
project if the facilities instead were connected directly to Feeder 30-B1, behind the distribution system switch that would isolate the microgrid segment rather than behind the customer meter.

During island-mode operations, microgrid controls and BEMS would actively manage building energy loads to keep demand within operating PV+BESS capacity and extend the time required for refueling standby generators. In island mode, when PV generation exceeds onsite energy loads (including BESS charging), it would be curtailed.

BESS resources were sized to support grid forming and balancing, with sufficient capacity for microgrid-managed building-wide loads for 15 minutes or longer during a utility outage. When microgrid BESS state of charge is depleted to approximately 20 percent, the microgrid would alert operators so they can ramp up standby generation, which would support emergency loads via existing automatic transfer switched (ATS) configuration. Assuming PV production would be available to recharge the BESS, when the state of charge reaches approximately 80 percent, the microgrid controls would restore building-wide island-mode operations. The microgrid controller and BEMS would actively manage non-emergency building loads to maintain electric service at a reduced level, subject to operator control.

<u>*Zone 2:*</u> The primary use case defined for Zone 2 would be to provide resilient renewable electricity service for critical City of Pittsfield loads. Consideration of multiple scenarios led to a system design that would integrate 120 kW of proposed new rooftop PV capacity and 200 kW/50 kWh of BESS capacity. These rooftop PV systems would be interconnected for net-metered operation, but production rarely would exceed onsite building loads. The rooftop PV systems are expected to produce 145 MWh/year, serving approximately 30 percent of annual consumption at the City Hall and Police Station where the PV systems would be installed.

Fig. 3.9: Zone 2 – PV Layout



For the revised Zone 2 design, new underground cables would be installed behind the meters at three (3) buildings to enable parallel grid formation during a utility outage. PV systems would be located on the rooftops of two City-owned buildings (City Hall and Police Department), and a single BESS would be located near the City Hall building. A new 150 kW natural gas-fired standby generator also would be installed near City Hall.

The 150 kW gas-fired generator would be necessary for two reasons. First, the City Hall's existing 20 kW standby generator is nearing the end of its useful life, and soon will require replacement. Second, a larger gas-fired generator would enable the microgrid to substantially reduce reliance on diesel fuel to operate the Police Department's existing 125 kW standby generator, and thereby would reduce net emissions. The aging 20 kW generator at City Hall either would be removed or left in place as a redundant ATS-switched backup. The Police Department 125 kW diesel-fueled ATS-switched standby generator would be left in place in its current ATS-switched configuration, and would not be integrated into the microgrid.

Microgrid control functionality would allow building management personnel to apply operating modes appropriate for various supported islanding scenarios – from a brief systems test to a long-duration regional emergency. Microgrid control requirements are described in greater detail in Sec. 3.5. As a general matter, the Zone 2 energy storage capacity would be sufficient to support grid formation and to serve building loads at an average demand level during the majority of short-duration outages experienced at the site – less than 15 minutes. A default operating mode would support 15 minutes of full-load operation using BESS and PV resources only. In this default mode, when BESS capacity is depleted to approximately 20% of optimal charge, the microgrid control system would dispatch gas-fired generation capacity, and would maintain service at reduced levels by actively managing building energy loads (via upgraded BEMS) to keep demand within available combined capacity of PV, BESS, and new gas-fired standby generation. In this way the microgrid would use PV resources to defer startup of standby diesel generation, extend time to refueling, and reduce overall fuel consumption and emissions. Additionally, the 150 kW gas-fired generator would be specified and integrated to support grid formation in situations when BESS capacity is unavailable.

Control functionalities and technologies required to support emergency and business-as-usual objectives are described in greater detail in "3.5.4 – Microgrid Operation," below.

3.1.3 Interconnection and Protection Systems

Zone 1 would integrate supervisory control and data acquisition (SCADA) capabilities in an existing gang-operated switch (e.g., a single switch actuated to open or close multiple circuits) on feeder 30B1 (23 kV) to isolate the underground three-phase circuit on the BMC campus. Once isolated, that circuit effectively would serve as a virtual bus that can be energized locally by microgrid central BESS and distributed PV resources on the hospital campus. Additional switches would be installed to allow disconnecting non-microgrid BMC meters and loads. PV systems proposed for Zone 1 would be interconnected for net-metered operation.

PV systems would be provided with dedicated breakers and protection/control measures such as over/under frequency/voltage on their interconnections to be able to detect unintended islanding situation and detach from the grid according to IEEE 1547 standard. BESS interconnection would be configured to support grid forming on the virtual microgrid bus. Bi-directional protection schemes should be implemented on the microgrid's protective devices in order to selectively detect and isolate the faulted part of the network when the microgrid is operating in the grid-connected and islanded mode.

PV systems proposed for Zone 2 also would be interconnected for net-metered operation, but would not be expected to export power to the utility distribution system except during unusual conditions when loads are very low and solar production is high. PV resources would be provided with dedicated breakers and protection/control measures such as over/under frequency/voltage on their interconnections to be able to detect unintended islanding situation and detach from the grid according to IEEE 1547 standard. BESS interconnection would be configured to support grid forming on the virtual microgrid bus. Bi-directional protection schemes should be implemented on the microgrid's protective devices in order to selectively detect and isolate the faulted part of the network when the microgrid is operating in the grid-connected and islanded mode.

Reviews of the utility's distribution capacity data indicated the proposed generation in both zones could, in principle, be interconnected at this time without exceeding the utility's fault-current limits on the affected feeders; future changes in either area could reduce that capacity and create needs for additional capacity upgrades.

3.2 Load Characterization

The CPDM – Phase 1 deployment is designed to serve building-wide electricity loads in Zones 1 and 2. No thermal generation resources were included in the proposed design, given project constraints to avoid utilizing any new fossil-fired generation systems – except gas-fired standby generation required to support long-duration islanding and to defer standby diesel startup and time to refueling. The proposed gas-fired generation would operate only when needed to maintain BESS state of charge during long-duration outages, as opposed to generation that would be operated during blue-sky conditions for revenue generation purposes.

3.2.1 Description of Loads Served by the Microgrid

Facilities to be served by the microgrid produce predominately daytime loads, mostly involving regular five-day weekly business hours, plus 24-hour/7-day cooling loads. Exceptions include nighttime and weekend emergency room and in-patient services at BMC, and 24-hour police operations.

The Zone 2 facilities are a subset of those included in the preliminary Zone 2 design, with the addition of City office loads[6] at 100 North Street, adjacent to City Hall. Other facilities formerly considered for Zone 2 (*i.e.,* Pittsfield Fire Department, Pittsfield Housing Authority buildings, and Pittsfield High School) were removed from Phase 1 consideration when Task 3 assessments showed that no technically viable

[6] The City of Pittsfield leases 8,890 square feet of office space at the 32,170 sq-ft 100 North Street Building owned by Scarafoni Associates. City offices at 100 North St. include the Health Dept. and Building Inspector's offices.

solution exists to enable serving them in a single islanding zone. The facilities in the preliminary Zone 2 design were dispersed across a 0.5-mile area that is served by multiple distribution feeders from two different substations, and with many intervening non-critical loads between the facilities considered for the microgrid. Bypassing non-critical loads during island-mode operations would require substantial investments in switching and remote connect/disconnect functionality, or new underground cables at a cost of millions of dollars. However, the Project Team identified resiliency needs at each of the facilities in the preliminary design based on their specific functions. Those resiliency needs merit future consideration (beyond the scope of this study) of onsite PV+BESS systems.

The Project Team considered options for targeting facilities for smaller clusters within the original wide-area zone, and found that at the current phase of study the most technically viable option – and the one with the greatest resiliency need downtown – would include in Zone 2 only the selected cluster of the City Hall and Police Station, plus City offices in the adjacent 100 North St. building. However, even this small cluster of buildings would be relatively complex to isolate as a power island within the utility distribution system. The reason is that the area's distribution system is designed to operate as a mesh network – with multiple feeder segments interconnected throughout the area. In the case of CPDM Zone 2, it would require substantial new switching and reconfiguration investments, at greater cost and complexity than the selected option of connecting the three adjacent buildings behind the meter with new underground cables.

Figure 3.10 provides a quantitative summary of the loads served by the microgrid.

Fig. 3.10: Microgrid Load Summary

Zone	Annual Consumption (kWh)	Peak Demand (kW)	Average Demand (kW)
1	19,796,434	3,719	1,410
2	584,953	269	102
Total	20,381,387	3,988	1,477

According to Eversource reliability metrics, customers in the two microgrid zones were interrupted for between 59 minutes and 204 minutes in 2018 (*see Figure 3.11*). As explained in Figure 3.7, BESS capacity was sized to support average critical loads for approximately 15 minutes without dispatching fossil generation. This use case was based on BESS capacity required to support grid formation in any scenario, and on anecdotal reports by customers indicating that the most common outages experienced last about 15 minutes. During outages of longer duration, microgrid controls in both zones will maintain service by actively managing loads to keep them within available supply capacity. In Zone 1, the microgrid would shut down when BESS capacity reaches the minimum state of charge, signaling ATS-switched standby generators to energize emergency hospital circuits. In Zone 2 the controls will dispatch the proposed 150 kW of natural gas-fired generation to support microgrid loads when PV resources are insufficient to maintain BESS state of charge.

Fig. 3.11: CPDM Eversource Circuit Reliability Metrics

SAID/FI = System Average Interruption Duration/Frequency Index; CAIDI = Customer Average Interruption Duration Index

Circuit		SAIDI (minutes)	SAIFI	CAIDI (minutes)
30B1	2016	146.54	1.6023	91.46
	2017	8.94	0.077	116.10
	2018	32.57	0.1594	204.33
	2019	0.71	0.0084	84.52
30B2	2016	204.11	2.87	71.12
	2017	72.09	0.9601	75.09
	2018	56.41	0.3788	148.92
	2019	13.8	0.1345	102.60
30B3	2016	50.8	0.8765	57.96
	2017	41.88	0.7073	59.21
	2018	59.91	0.4792	125.02
	2019	9.57	0.1981	48.31
30B4	2016	57.65	1.1069	52.08
	2017	29.32	0.8525	34.39
	2018	12.49	0.1327	94.12
	2019	1.15	0.0109	105.50
15-E2	2016	26.03	0.4078	63.83
	2017	27.05	0.2939	92.04
	2018	91.64	1.5583	58.81
	2019	4.36	0.0634	68.77

Note: 2019 metrics as of 7/8/2019

3.2.2 Hourly Load Profile

Monthly consumption and peak demand information comprised the only available metering data. The Project Team used HOMER Pro software to model hourly loads based on HOMER's library of representative load profiles. The Team selected profiles for a typical Massachusetts hospital for Zone 1 and office loads for Zone 2, and then scaled those profiles on the basis of actual peak demand values obtained from utility monthly metering data.[7]

[7] All electric loads at 100 North St. are served via a single utility meter. As noted, BEMS upgrades would enable curtailing non-City loads during island-mode operations. Consumption and demand for City offices were estimated as the product of their share of total occupied space in the building – 27.6 percent – applied to the building's total metered loads.

Fig. 3.12: Zone 1 – Hourly Load Profile

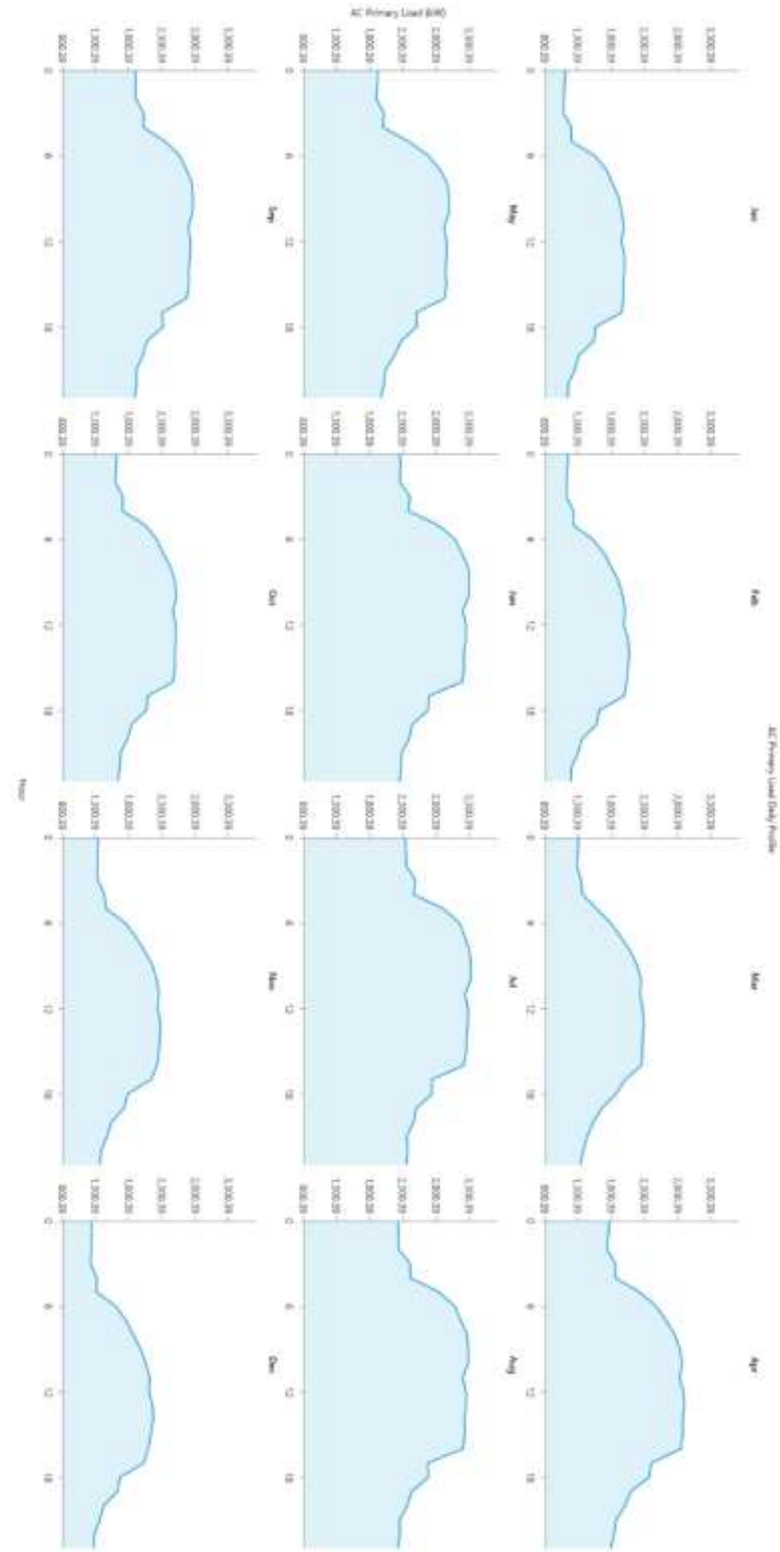
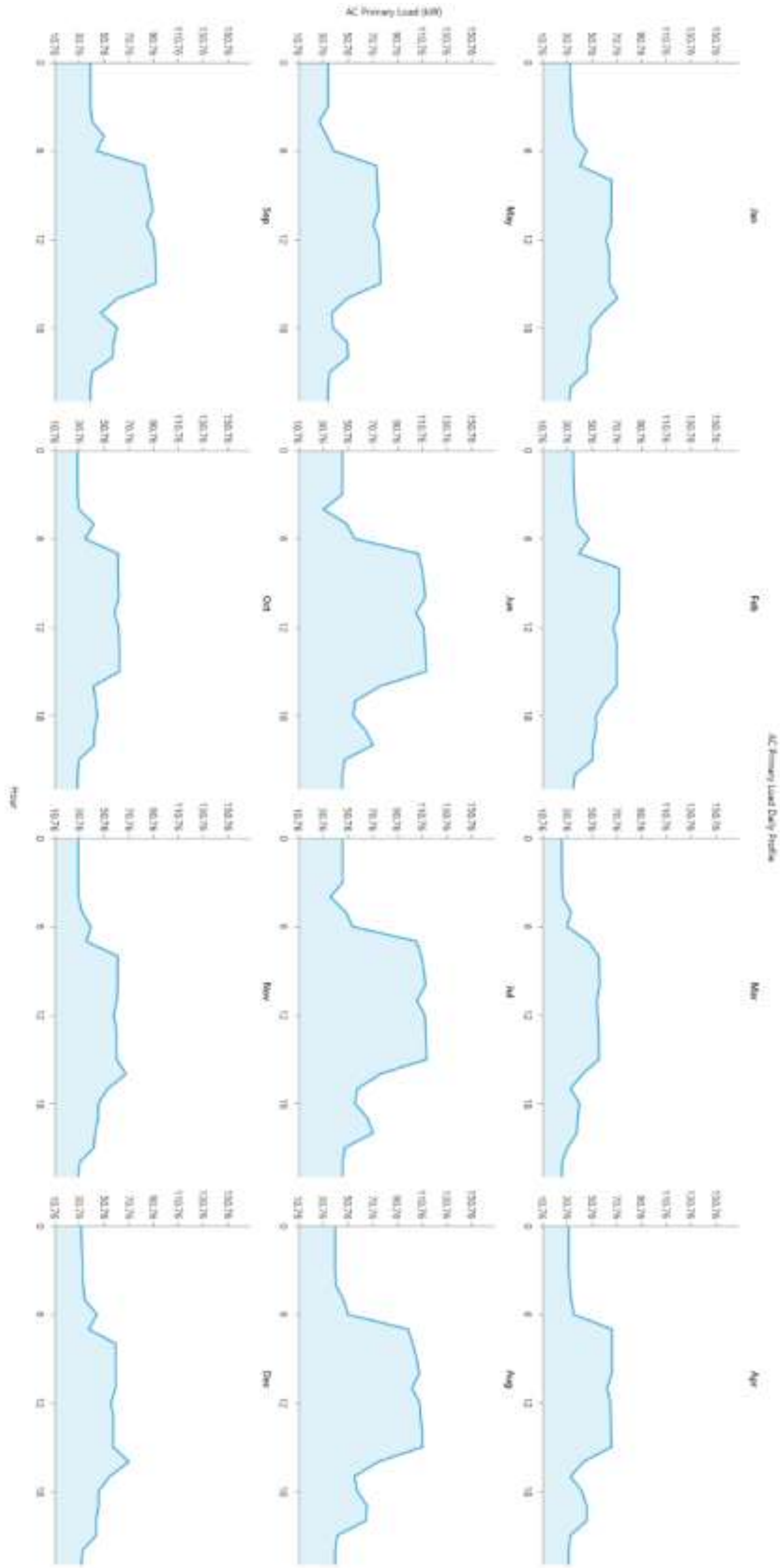


Fig. 3.13: Zone 2 – Hourly Load Profile



3.3 Distributed Energy Resources Characterization

The CPDM design includes solar PV, BESS, and natural gas-fueled standby generation systems in locations as summarized in Figure 3.14, plus existing diesel-fueled standby generation. Rooftops, parking lots, and interior and exterior locations for each specified system were determined to be adequate for the purpose with no major siting flaws at this stage of study.

Fig. 3.14: CPDM DER Summary

Zone	Location	Type	Capacity (AC)	Fuel Capacity	Existing/ Proposed
1	Hospital building rooftops and parking lots	PV	2,160	NA	Proposed
1	Hospital grounds	BESS	1,000	NA	Proposed
		Zone 1 Total*	***3,160***		
2	City Hall and Police Dept. rooftops	PV	120	NA	Proposed
2	City Hall basement or exterior	BESS	200	NA	Proposed
2	City Hall exterior	Natural gas standby generator	150	NA	Proposed
2	City Hall basement utility space	Natural gas standby generator	20†	NA	Existing
2	Police Dept. grounds	Diesel standby generator	125†	100 gal.	Existing
		Zone 2 Total	***595***		
		CPDM Total	**3,755**		

**Excludes 800 kW CHP system, 2,000 kW gas-fired standby generator, and a 700 kW fuel oil-fueled standby generator with 15,000 gal. fuel tank; none of these fossil-fueled resources will be available to energize the microgrid.*

† Neither of the two existing ATS-switched standby systems will energize the microgrid. Existing Police Department diesel generator to be left in place as configured, and 2002-vintage City Hall 20 kW natural gas-fired generator either to be removed or left in place as configured.

3.3.1 DER Adequacy to Meet Demand

For both Zones 1 and 2, advanced microgrid controls and BEMS would actively manage non-critical loads to ensure they remain within the microgrid's operating capacity. DERs for both systems were sized to support the proposed use cases. Specifically:

Zone 1: PV systems were specified for every available rooftop and sizeable parking area – including both ground parking and parking structures – to maximize system potential to offset higher-cost utility delivered power. BESS capacity was sized to support 1,000 kW of demand for a period of 15 minutes, assuming maximum charge at the beginning of an outage. Although 1,000 kW of demand is lower than the typical daily peak demand of Zone 1 loads served by the microgrid, it would be sufficient in most scenarios, when the combined BESS and PV capacity would meet or exceed the average demand.

Zone 2: PV systems were specified for the rooftops of both buildings to be served by the microgrid. Those rooftops are capable of supporting up to 120 kW of PV capacity, which, combined with 200 kW/50 kWh of BESS capacity would be adequate to support Zone 2 peak loads for at least 15 minutes in any foreseeable scenario.

3.3.2 Resiliency of DERs to Natural Forces

The specified DERS would be designed to withstand severe weather conditions that typically affect the project area. None of the resources would be sited in flood-prone areas. Snow cover would not be expected to have a substantial effect on PV output, given the angled orientation of panels and the tendency for PV panels to heat up with even minimal solar irradiance and shed snow quickly in almost all snow conditions.

3.3.3 DER Fuel Sources

All proposed new DERs would use solar energy. Existing standby generation in Zone 2 burns natural gas and diesel fuel. The Police Station's 125 kW diesel generator is equipped with a 100-gallon fuel tank, sufficient to operate the standby generator for approximately 9.5 hours at full load. Depending on the timing of an outage and the available solar irradiance, Zone 1 PV resources would extend time to refueling substantially, effectively avoiding diesel consumption during periods of high solar irradiance.

3.3.4 DER Capabilities

As variable renewable resources, the proposed PV systems would be integrated behind the meter to reduce onsite loads and to recharge depleted BESS capacity. BESS systems were specified to support all required microgrid operations, including black starting the microgrid, and following dynamic loads, serving partial or full loads within their capacity. Advanced microgrid controls and inverter control systems would manage voltage and frequency, balancing loads and dispatching generating capacity to maintain service during island-mode operations. Ride-through capabilities would enable uninterrupted service during voltage and frequency events, and would manage resynchronization upon utility restoration, consistent with IEEE and utility standards.

3.4 Electrical Infrastructure Characterization

In Zone 1, both microgrid and non-microgrid loads on the BMC campus are served by the same switch on Eversource circuit 30-B1 (*See Figures 1-3*). In addition to replacing or upgrading the switch to enable controllability, additional controllable switches would be added to disconnect the non-microgrid meters, such as the 725 kW of electric loads in the main hospital building that currently are served by BMC's onsite 800 kW CHP system. That system is capable of supporting island-mode service for about 50 percent of the building load.

As noted in "3.1.3 Interconnection and Protection Systems," Zone 1 was designed to form a virtual microgrid bus on Feeder 30-B1 by isolating the downstream segments of the feeder that serve the BMC hospital buildings and medical arts complex.

Zone 2 would not rely on any part of the utility's existing electrical infrastructure during outages, because all microgrid resources would be interconnected behind the customer meters, where they would energize a parallel underground microgrid circuit. This circuit would require new conduit and conductors totaling approximately 450 feet in length, installed underground to connect the zone's three buildings. Figure 3.5 above illustrates the approximate routing of the new underground conduit and cables. Such cables are highly resilient to forces of nature.

3.5 Microgrid and Building Controls Characterization

3.5.1 Microgrid Control Architecture

Separate microgrid control systems in zones 1 and 2 would be responsible for control and monitoring of all distributed generation assets including PVs, BESS, BEMS, automated circuit breakers, protective relays, and metering infrastructure. The control system would be managed and operated via a custom user interface, which will visually illustrate the microgrid and provide real-time equipment data, system alarms, and historical data. Microgrid master and distributed controls would be installed and operated through communication systems as described below. The microgrid would be controlled by three integrated control systems ("layers") as follows:

- *Layer 1: Device-Level Control*

This layer consists of controllers and sensors that provide direct, fast control of each device, e.g. the BESS controlling active and reactive power output while islanded to maintain system nominal frequency and voltage. In addition to the BESS controller, switch controllers, PV local controls, protective relays would be integral to the equipment in this layer. Layer 1 protective devices would be responsible for protection of the DER assets and the distribution system and would interpret and execute commands issued by Layers 2 and 3, if the device determines that it is safe both for the DER and the system to do so. This layer also would include local control via BEMS, which control microgrid loads at a building level.

- *Layer 2: System-Level Control*

This layer consists of an automation controller platform or real-time automation controller (RTAC). This controller would connect to the Layer 1 control devices and other sensing devices as required to determine system status, and would issue commands to devices based on the desired operating state of the system. This layer would be responsible for issuing general system commands to each Layer 1 device such as opening/closing circuit breakers and dispatching the BESS.

- *Layer 3: Grid Operator Control*

This layer consists of SCADA controls issued by the utility operations center after evaluating the overall system conditions. This layer would communicate directly with the Layer 2 control platform to enact system control if required.

3.5.2 Locations of Microgrid and Building Controls

In Zone 1, microgrid and building controls would be located in the BMC electrical control room. In Zone 2, microgrid and building controls would be located in the City Hall electrical room, and additional BEMS would be located in the electrical rooms at the Police Station and 100 North St. buildings. BEMS-integrated switching capabilities at 100 North St. would enable the microgrid to curtail non-City loads during utility outage events to enable the microgrid to energize only critical City loads. In both zones, telemetry and switching devices would enable BEMS dynamic control over loads.

See Figures 1 and 5, above, for locations of microgrid and building control systems.

3.5.3 Existing and New Controls

In addition to microgrid master controls for each zone, other required new control devices include DER controls. In general, BESS and PV inverters would be equipped with automation controllers. Also load control would be accomplished by existing and new or expanded BEMS. Any such BEMS would be integrated to enable microgrid signaling and execution of established operating protocols for managing load.

3.5.4 Microgrid Operation

Services supported by the microgrid controls include the following:

- *Transition to Islanded Mode*

Transitioning from idle mode to islanded mode would happen automatically upon a loss-of-utility event. When a disturbance causes loss of utility voltage, the relay or switch control associated with the isolating circuit breaker would detect the loss of voltage and trip open the isolating circuit breaker. At this stage, the BESS would be connected to the microgrid in idle mode and PVs would be expected to trip due to under-voltage or under-frequency protection. After the isolating circuit breakers and switches open, the BESS controller would receive a command from the microgrid controller to engage the BESS in voltage-source mode to restore the power on the microgrid bus. At this stage, the second layer of control would monitor the loads, BESS, and PV systems' power output continuously, and would apply load-management schemes appropriate to the status of generation resources and loads to maintain the voltage and frequency at normal values. In this method, following a utility outage, the "black start" of the microgrid would be carried out without the need for a reference voltage from the utility source.

- *Islanded Operation*

Under the islanded mode of operation, the system would dispatch BESS to establish the new voltage and frequency references. Once these references are established, PV systems would resume generating. The PV generation would not need to be curtailed and it could exceed the load while the excess electricity charges the BESS. Metrics required to properly monitor the overall system health during islanded mode would be included in the microgrid operation center SCADA interface. These metrics may include system's phase unbalance level, real power, reactive power, historical real power, historical reactive power, and historical phase imbalance on the substation feeders. Real-time load measurements and SCADA alarm would inform microgrid operators whether the system is operating overloaded. When BESS reaches its minimum optimal state of charge, the microgrid would either shut down and allow standby generators to energize emergency circuits only (Zone 1), or it would shift into reduced-load operating mode and dispatch available gas-fired capacity to maintain BESS state of charge, supporting island operations for extended durations (Zone 2).

- *Transition to Grid-Connected Mode*

After utility voltage recovers, the microgrid operation center would automatically initiate the process of transition back to the grid in an "open transition" as follows: 1. Microgrid operations center opens feeder ties; 2. BESS switches back to idle mode; and 3. Layer 2 controller commands isolating circuit breaker to close.

Fig. 3.15: Proposed Microgrid Capabilities

Capability	Comment
Automatically connecting to and disconnecting from the grid	Yes (via isolation circuit breakers such as S&C Vista Underground Distribution Switchgears)
Load shedding schemes	Yes (via BEMS)
Black start and load addition	Yes (refer to section above)
Performing economic dispatch	Yes, via BEMS load management only. PV output is expected to be consumed mostly onsite, with some net-metered exports at Zone 1. BESS is expected to be dispatched only during islanded mode to ensure stored resources are adequate for resiliency objectives. However, BESS charging may be managed to optimize use of PV production during critical peak pricing periods. BESS capacity and operation may be adjusted in future project phases as required to meet customer requirements.
Performing load following	Yes (DERs operate in a strategy that they produce only enough power to meet the primary load)
Demand response	Yes via BEMS
Storage optimization	No (Because the BESS is dispatched only in islanded mode and BESS is intended to operate at voltage mode with frequency reference, and PV operates at current mode, no optimization is required. In general, the PV systems will serve the load as much as possible and during island operations the rest of the load is served by BESS based on droop control.)
Maintaining frequency and voltage	Yes, during island-mode operations only (achieved with BESS). In principle the BESS capacity could be operated to maintain frequency and voltage of building energy supplies during blue-sky conditions, but for purposes of this assessment BESS is reserved for resiliency objectives and will not be discharged for other purposes.
PV observability and controllability; forecasting	PV performance metrics, control, and irradiance forecasting can be integrated into microgrid controls to support advanced operating protocols.
Coordination of protection settings	Protection settings can be coordinated through advanced microgrid control functionality.
Selling energy and ancillary services	PV resources are expected to be interconnected in net-metered configuration. Storage resources are intended to support resiliency objectives and not ancillary services, but they could be operated to provide grid support services and perform generation shifting at a higher lifetime cost.
Data logging features	Yes

3.5.5 Island Contingency Generation Management

In the case of BESS failure, in Zone 1 the microgrid would shut down because the BESS functions as the voltage and frequency reference for the microgrid electric system. Critical circuits then would be served by existing standby generation at BMC. In Zone 2, the 150 kW gas-fired generator would be specified and integrated to support grid formation in situations when BESS capacity is unavailable.

In the case of PV failure, since these generation resources function as current source, the net load observed by the BESS would increase (if additional charge in the battery is available). The BEMS may be used to reduce the load consumption, or the BESS would be discharged at a higher rate. In Zone 1, once BESS is depleted the microgrid would shut down and existing standby systems would begin serving critical loads. In Zone 2, the microgrid would dispatch the integrated 150 kW of gas-fired standby generation to maintain microgrid service indefinitely.

In case of failure of the gas-fired standby generation in Zone 2, the microgrid would shut down. Loads at City Hall and 100 North Street would be interrupted, while the Police Department diesel-fired standby generator would begin serving emergency circuits at that facility.

3.5.6 Resilient Microgrid and Building Controls

The electrical distribution systems of both microgrid zones would be located underground or in weather enclosures, and therefore would be resilient against severe weather conditions. Modular tie switches on the Zone 1 circuit have higher resistance to severe weather conditions since they are not exposed to open environment and are in enclosed modules.

3.6 Information Technology (IT)/Telecommunications Infrastructure Characterization

3.6.1 Description

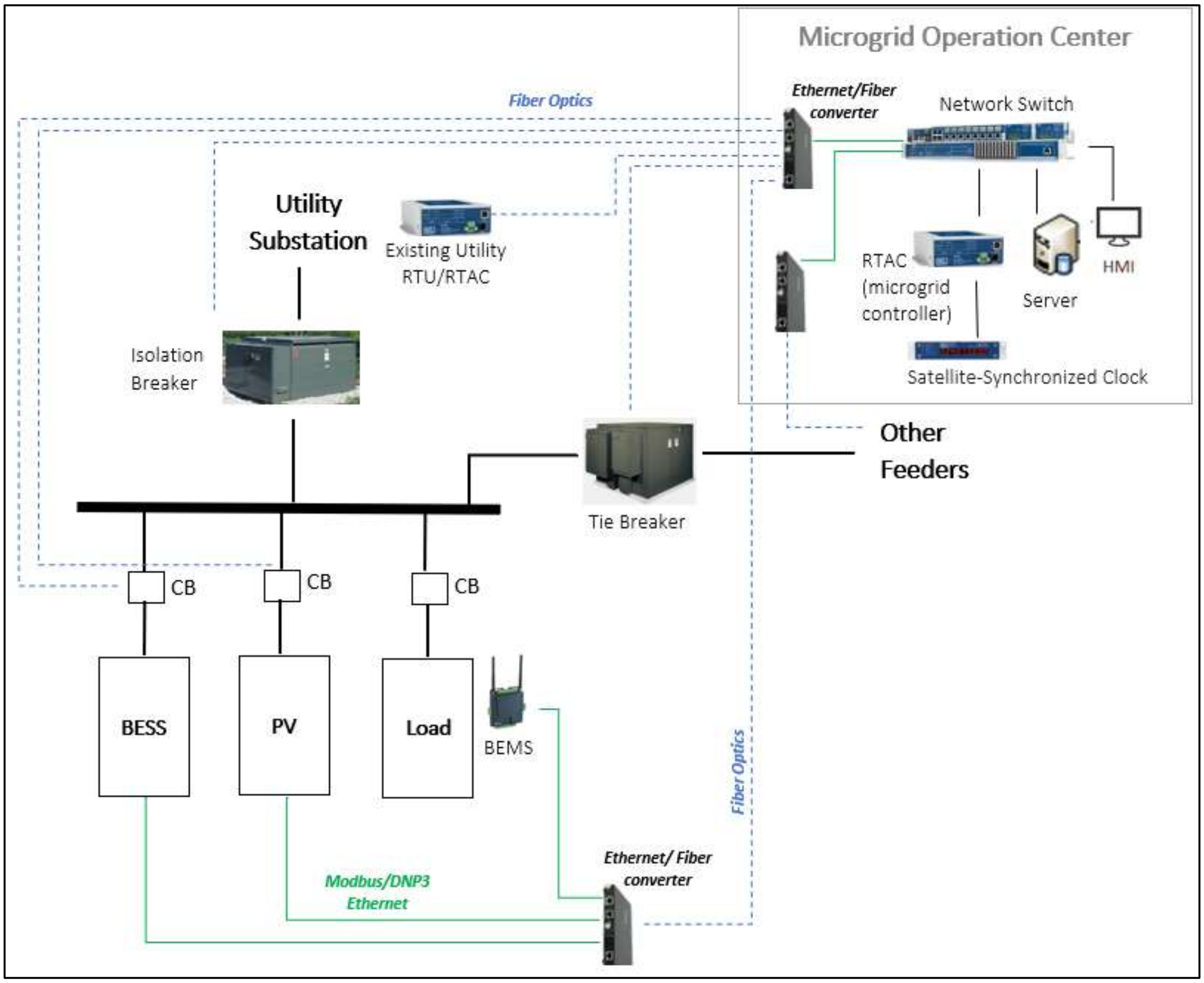
The microgrid control system consists of hardware and software designed to monitor and control microgrid components. A fiber-optic based network could be implemented to facilitate communications between the microgrid relays, microgrid controllers, DERs, loads, and SCADA devices. The microgrid devices and controllers would report to the microgrid controllers via SCADA protocol of Modbus or Distributed Network Protocol (DNP3) over fiber-optics or copper Ethernet networks. The microgrid controller would issue commands to the DERs, BEMS, other controllable loads, and relays via the same network. Fiber-optic transceivers would be required to make conversion to fiber-optic Ethernet connection between different parts of the network. Fiber optics are recommended to connect the devices rather than radio-based communication to ensure robust and secure communication. This solution is flexible and simple to deploy and maintain. Ideally, each RTU would be equipped to obtain real-time location and weather analysis.

The communication between the computers would be performed via proprietary, encrypted protocols. Communications with human-machine interfaces (HMI) also would be encrypted. Servers would be provided for log collection and time synchronization.

3.6.2 IT and Telecommunications Infrastructure

Figure 3.16 presents a conceptual IT and telecommunications infrastructure on the simplified equipment layout diagram.

Fig. 3.16: Conceptual IT and Telecommunications Infrastructure



3.6.3 Utility Communication

In this Project, as noted, the communication channel between the utility and the microgrid could be designed for monitoring or future expansion purposes. A fiber optics-based communication platform could be used to interconnect utility remote terminal units to the microgrid controller. This communication channel from layer 3 to layer 2 control generally is designed for grid-connected operations such as economic dispatch or demand response requests from the utility, as well as coordinating seamless transitions. The microgrid automatically would detect loss of the utility source and the microgrid controller would directly interoperate with Layer 1 devices and controllers.

3.6.4 IT and Telecommunications Infrastructure Resiliency

Resilient networks are characterized by providing and maintaining an acceptable level of service when facing failures and faults, which affect their normal operation. The communication infrastructure considered for this microgrid is a conventional hierarchical design. Such a design is sufficient for microgrid systems of this scale, with relatively few sources and loads to manage.

A direct connection between layers of controllers would not be as resilient, however, as having multiple communication paths. An alternative communication network approach could be applied to address the issue of resiliency and reliability of system controls. A distributed control architecture, such as IPERC GridMaster, uses a series of controllers, which eliminates the traditional master controller concept, and enables extensibility to accommodate future system expansion. At any time, only one controller functions as the lead controller to ensure safe operations. Should that controller become unavailable, the system would sense the loss and automatically reconfigure the microgrid to maintain operations. Such an approach would eliminate the single point of failure and provides optimum redundancy under adverse conditions.

IV Chapter 4: Assessment of Microgrid's Commercial and Financial Feasibility

4.0 Summary of Task 4 Findings

As described in Task 3, the CPDM Zone 1 and 2 proposals offer renewable energy production to support resilient energy service for critical public services in downtown Pittsfield. The systems proposed for both zones offer potential economic benefits for their customers – Berkshire Medical Center and the City of Pittsfield, respectively. However, both zones also pose cost challenges and regulatory uncertainties that may affect their ability to achieve the envisioned resiliency objectives.

As noted above, the preliminary Zone 1 design envisioned installing PV generation on several Berkshire Medical Center properties (including parking lots and rooftops) and interconnecting those systems behind utility meters at targeted critical facilities (main hospital and Medical Arts Complex). Several of the proposed PV sites, however, are located across a public street from the targeted critical facilities, which leads to additional utility costs for conduit and cabling. This additional integration cost may be difficult to justify for a relatively modest resiliency benefit.

In Zone 2, the proposed scope and consequently the potential benefits for Pittsfield residents have diminished from the initial project proposal. The City had asked the utility to consider reconfiguring its downtown network to enable formation of a wide-area utility distribution microgrid. As initially proposed, the microgrid would support a variety of critical community loads by integrating existing, planned, and prospective future local solar generation with proposed new energy storage capacity, together with active load control to curtail non-critical loads during outage events. The utility rejected this approach as being technically complex and costly. The Project Team assessed options for scaled-back microgrid zones, and ultimately omitted all of the originally considered low-income housing, emergency public shelter, and fire-response facilities, leaving only a cluster of facilities in the vicinity of Pittsfield City Hall.

With many vital loads omitted, the revised Zone 2 proposal would offer less community benefit than originally envisioned for the Project, and therefore it may attract less community interest in supporting development. Further, the remaining loads in the down-scaled zone would bear a disproportionately high administrative cost for development and management, diminishing the project's benefit-cost potential.

Enabling the CPDM project to move forward would require utility cooperation, as well as external financial support from the State and third parties. In general, the project assessment illustrates that achieving Massachusetts goals for community resiliency, sustainability, and economic development will require continued progress to remove regulatory barriers to innovation and to encourage productive collaboration among utilities and the communities they serve.

4.1 Commercial Viability – Customers

Contractor shall describe the commercial terms/relationship between participants in the microgrid

project, products expected to be produced by the microgrid and arrangements for sharing of benefits by addressing the following:

> *a. Identify the number of individuals affected by/associated with critical loads should these loads go unserved (e.g. in a storm event with no microgrid).*

- *How many people are employed at the project facilities?*

Zone 1: Berkshire Medical Center employs about 3,000 people.

Zone 2: The City of Pittsfield employs about 170 people at three buildings (City Hall, Police Station, and 100 North Street).

- *How many clients (customers, etc.) are served by those facilities on a daily basis?*

Zone 1: Each day, on average, BMC serves approximately 500 people with in-patient and out-patient services.

Zone 2: The City serves approximately 185 people onsite at the three buildings each day, and manages off-site public services and law enforcement for Pittsfield's population of 44,000.

> *b. Identify any direct/paid services generated by microgrid operation, such as ancillary services, or indirect benefits, such as improved operation, to the utility or ISO New England.*

In principle, the microgrid or its resources could be configured to provide distribution ancillary services. For example, the microgrid could be managed in the same way the utility would manage any similarly sized demand-response (DR) resources. The utility could signal for the microgrid to disconnect and enter island-mode operations, treating the microgrid as a single dispatchable load.

As proposed, however, the project's opportunities to do this would be limited for three reasons: 1) the proposed battery energy storage system (BESS) was sized to support the defined resiliency requirements, and is intended to be reserved for that purpose; 2) economic analysis showed that using the batteries for peak-shaving and demand charge reduction would produce energy cost savings, but not enough to cover the costs of battery degradation, as well as higher installed prices per unit for smaller distributed batteries behind each applicable meter, versus central BESS systems as proposed for microgrid islanding; and 3) the City of Pittsfield agreed to contemplate gas-fired generation only to support microgrid islanded operations during utility outages, to the degree it would defer diesel consumption. Using the project's proposed new fossil assets for ancillary services could increase fuel consumed and emissions produced in the project area, and so would impair one of the primary project objectives.

Accordingly, neither the project's batteries nor its fossil-fueled generation are expected to provide meaningful or economical resources for the utility or for ISO New England.

c. Identify each of the microgrid's customers expected to purchase services from the microgrid.

Zone 1: Berkshire Medical Center is the sole customer.

Zone 2: The City of Pittsfield is the sole customer.

d. Identify other microgrid stakeholders; what customers will be indirectly affected (positively or negatively) by the microgrid?

The project will provide substantial benefits for the 44,000 residents of the largest city in Massachusetts's western-most county, and for many of Berkshire County's 130,000 residents. Improving energy resiliency for critical services provided in both Zones 1 and 2 will help to minimize the effects of long-duration utility outages, improve public health and safety, and accelerate recovery in the aftermath of disruptive events such as hurricanes and winter storms affecting western Massachusetts.

Additionally, the project will support the City of Pittsfield in its commitment to sustainability and renewable energy investment, as part of the City's efforts to attract and retain businesses and restore the community's environmental legacy. The project will offset fossil-fueled electricity consumption, reduce the City's climate footprint, and contribute to local experience and expertise with clean and resilient energy systems.

e. Describe the relationship between the microgrid owner and the purchaser of the power. Indicate which party/customers will purchase electricity during normal operation and during islanded operation. If these entities are different, describe why.

In the proposed hybrid utility and customer ownership model, the utility would own and operate microgrid distribution infrastructure that crosses any designated public ways, and microgrid customers would own and operate (or contract third parties to own and operate) onsite distributed energy resources (DER) including generation, storage, and load-management systems.

During normal operations, the microgrid customers in Zones 1 and 2 would continue purchasing electricity supplies from the utility, with consumption and demand reduced by generation from proposed new PV systems, which are expected to be interconnected and operated under net energy metering (NEM) or Solar Massachusetts Renewable Target (SMART) program tariffs.

During islanded operations, the proposed onsite DERs would energize the microgrid bus and provide service for critical loads. In both Zones 1 and 2, in addition to planned rooftop PV systems, dispatchable microgrid-connected resources would include new BESS assets. Zone 2 also would include proposed new gas-fired standby generation to assure resilient energy service during long-duration outages, and to defer startup of diesel standby generation at the Pittsfield Police Department.

As noted, PV and dispatchable assets in each zone could be owned either by the zone's customer or by a third party. If the customer owns the DERs, then energy services will be monetized internally through utility bill offsets, including through NEM or SMART program tariffs administered by Eversource. If a third party owns the DERs, then energy services from those DERs would be compensated through a power purchase agreement (PPA). Third-party ownership of PV assets in particular will improve cost-effectiveness by providing access to tax-incentive financing.

f. What are the planned or executed contractual agreements with critical and non-critical load purchasers?

New contractual arrangements may include the following:

If DERs are owned by third parties and not the respective customer, then PPAs and similar agreements would be executed between the customer and third-party owner of proposed onsite DERs.

A new utility tariff for microgrid customers would allow Eversource to recover reasonable and necessary capital and operating costs associated with required upgrades to utility-owned infrastructure. Establishing a new tariff would provide the advantages of appropriate regulatory oversight and customer protections. By comparison, a surcharge may be simpler to implement for recovering up-front capital costs, but it may be inappropriate for ongoing recovery of operations and maintenance (O&M) costs, if any are incurred. Also, a surcharge would provide less regulatory oversight and customer protection than a special tariff would, and it would not advance the regulatory framework for community microgrid development in the future.

g. How does the Project Team plan to solicit and register customers (i.e. purchasers of electricity) to be part of their project?

Each zone would be developed and implemented with leadership by the zone's sole customer. As proposed, system designs and business models would not support serving additional customers. Consequently, additional customer onboarding is not contemplated for the proposed project. Notably, however, control and communications systems for the proposed microgrid could readily be configured and extended to include additional DERs, including generation, storage, and load controls, enabling the system to be expanded to support changing community requirements in the future.

h. What other energy commodities (such as steam, hot water, chilled water) will the microgrid provide to customers?

Project objectives are defined address electric loads only. Notably, the City of Pittsfield indicated it would not support a project that sought to add new fossil-fueled generation except for gas-fired standby generation as required to support island-mode operations and defer diesel-fired standby generator startup and fuel consumption.

4.2 Commercial Viability - Value Proposition

Contractor shall describe the value the microgrid is expected to provide directly to its participants, to the community at large, to the local electric distribution utility and to Massachusetts by addressing no less than the following questions:

a. What benefits and costs will the community realize by the construction and operation of this project?

Benefits:

Resiliency, higher operating uptime, improved public safety: The proposed microgrid will reduce disruption to critical public services from short-duration outages, and will increase the operability of those services during long-duration outage events.

Local renewable energy production value: The proposed microgrid will add substantial new PV generation capacity in the Downtown Pittsfield area, where very little solar energy capacity currently exists. Further, this new renewable energy capacity will be integrated into a resilient energy system with BESS capacity that could be expanded in the future to extend the value of renewable resources by making them available during high-demand periods.

Reduced customer demand charges with DERs: The PV generation specified for the microgrid will serve to reduce customer demand for utility-supplied energy. To the degree the utility's monthly peak demand charges are assessed on the basis of daytime peaks, the new PV generation will reduce customer demand charges.

Reduced carbon footprint and reduced emissions: The proposed PV generation can be expected to displace utility-supplied power responsible for 1,900 tons of CO_2e per year, or approximately 38,000 tons over the lifetime of the proposed PV assets.

Reduced diesel consumption: The system will serve to defer startup of diesel-fueled standby generation. Particularly in Zone 2, new gas-fired standby generation is sized to effectively eliminate the need for diesel consumption during outages affecting the Pittsfield Police Department.

Greater energy cost stability: Onsite PV generation will displace consumption of utility electricity that is subject to periodic price changes (usually upward).

Costs:

Renewable energy purchases and utility bill offsets: For energy production from DERs owned by third parties, customers will incur costs for that production, with corresponding utility bill offsets expected to yield net energy cost savings.

Utility tariffs for recovery of incremental microgrid costs (upgraded switching and underground cable infrastructure and O&M): Customers will pay any incremental costs for utility distribution system upgrades that the utility would not otherwise incur. Incentives and grants will first be applied to any capital cost requirements to reduce net costs that must be recovered through utility bills.

Installation, O&M, and replacement costs for the proposed BESS in both zones and the gas-fired generator in Zone 2: Customers will incur capital and operating costs for battery systems installed to support the microgrid. Incentives and grants will first be applied to reduce net costs of BESS installation.

Project development and management costs: Microgrid customers may incur costs for development and project management, in the form of labor hours for customer scope associated with microgrid project development. Any third-party or utility development and management costs will be included in other capital costs.

b. How would installing this microgrid benefit the utility (e.g. reduce congestion or defer upgrades)? What costs would the utility incur as a result of this project?

The microgrid would directly benefit the utility in at least three ways. First, it would provide the utility with direct experience supporting the design and implementation of microgrid systems within its distribution system, and developing business processes and tools that facilitate utility collaboration with municipal and private customers in making optimal use of distributed energy resources. Second, it would support utility operational and investment goals regarding renewable resources, grid modernization, and environmental and climate mitigation. Third, the microgrid would add behind-the-meter (BtM) energy storage and load-management functionality to reduce the potential impact of new PV generation on the distribution system in the project area.

The utility would incur costs for the following:

- Upgrading existing functionality at the distribution switch serving Zone 1; and
- Installing, operating, and maintaining new underground cable[8] in both zones to connect proposed BtM PV and storage systems.

For assessment purposes, the Project Team assumes the site host will reimburse the utility for those costs as part of the Project's long-term financing. Rate-based financing was rejected based on utility inputs, but could be revisited to help fund assets used for research, development, and demonstration of resilient and sustainable community energy systems.

c. Describe the proposed business model for this project. Include an analysis of strengths, weaknesses, opportunities and threats (SWOT) for the proposed business model.

The proposed project relies on a hybrid business model that combines utility ownership and financing of distribution infrastructure with customer (or non-utility third-party) ownership and financing of renewable generation, BESS, standby generation, and microgrid controls. Implementation of the CPDM project using the proposed model may be affected by the following SWOT factors.

Strengths:

1. The utility has indicated general support for a proposed asset-ownership model in which the utility – and not the customer – would own any electric assets placed in a public way.

[8] As an alternative to utility investment in new underground cable, the customer in each zone could incur the costs of installing, operating, and maintaining new underground cable in a behind-the-meter parallel system, to allow serving its own loads using DERs located on its own real property. However, the utility stated that it would only consider supporting a project approach that involved utility ownership and operation of any electric assets placed in a public way, irrespective of who owns the relevant generation assets, energy loads, or sites.

2. The model would facilitate customer investments in solar PV assets in an area that currently has only limited solar generation.
3. The model is comparatively simple and would avoid complex procurement and contracting structures.
4. Starting with a relatively small project, the proposed Zone 2 approach demonstrates a replicable model for municipal customers seeking to serve clusters of municipal loads with a single microgrid.

Weaknesses:

1. As noted, the project scope and potential benefits for Pittsfield residents diminished during Task 3 assessments. Zone 2 in particular would bear a relatively high administrative cost for development and management, challenging the project's benefit-cost potential.
2. Cost savings are paramount concerns for project customers. To the degree incremental microgrid costs – including energy storage and network infrastructure – reduce direct cost savings that the customer could achieve with onsite PV generation alone, either customer might decline to support development. External financing for the project's resilient energy systems likely would be required to overcome this weakness.
3. The City of Pittsfield is required to competitively procure all services under Massachusetts law, which presumably would include all behind-the-meter assets for microgrid Zone 2. The utility has asserted the right to own and operate any electric assets placed in public ways,[9] even if those assets connect behind a single customer's meters to serve that customer's loads using the same customer's generation, as proposed in both CPDM zones. However, the utility's exclusive dominion over electric assets in public ways has not been clearly established as a matter of Massachusetts law. As a consequence, sole-source procurement of assets from the utility could subject the municipality to legal challenges under Massachusetts public procurement law.[10]
4. Current regulatory policies in Massachusetts lack clarity on energy storage and grid modernization, creating uncertainties for initiatives like the proposed microgrid that could support State objectives. Most notably, depending on how they are to be financed, owned, or used, BESS and infrastructure upgrades might not qualify for state incentives for energy storage or grid modernization.

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[9] Recent legal scholarship raises doubts about Massachusetts utilities' exclusive right to place electric assets in public ways. *See for example:* http://clinics.law.harvard.edu/environment/files/2014/09/masschusetts-microgrids_overcoming-legal-obstacles_final12.pdf

[10] Massachusetts General Laws, Part I, Title III, Ch. 30B, §7c states "(c) A procurement officer may procure without competition water, gas, electricity, sewer or telephone services from a regulated industry company as defined in section three of chapter twenty-five if the procurement officer certifies in writing that ***only one practicable source exists***." [*emphasis added*]. In the absence of a clear legal basis for the utility's assertion of exclusive franchise rights, the municipality could face legal challenges over sole-source procurement of BtM assets for utility ownership.

Opportunities:

1. Customer investments in PV would both displace utility delivered power with onsite renewable energy and also increase resiliency, as opposed to non-microgrid PV, which is inoperable during a utility outage and provides no resiliency benefits.
2. The proposed project gives the utility an opportunity to collaborate with the City to support its goals for energy resiliency, sustainability, and cost savings.
3. The proposed project may provide the City with an opportunity to demonstrate Pittsfield's vision and leadership by redefining the City Hall area as a discrete campus for development of resilient and sustainable public services.

Threats:

1. The utility reports that its position on supporting microgrid island-mode operations on utility distribution systems is under review and may be changing. Ongoing uncertainty about the utility's role could prevent timely project progress, especially in Zone 1 which proposes to form a microgrid on a segment of an existing utility feeder.
2. A lack of legal clarity on utility franchise rights in effect may constrain Home Rule authority established in the Massachusetts Constitution (*Article 89*). Utility claims of exclusive dominion over locally designated public ways stand as *de-facto* public policy, since local governments, in practical terms, cannot risk a path that leads toward litigation.
3. By installing and operating BtM energy assets required to serve a customer's loads on the customer's premise using the customer's generation, the utility's franchise effectively may expand beyond the traditional boundary of public utility control. Such a precedent could increase utility market power to the detriment of competition and innovation in serving customers with BtM energy services.

d. Are there any characteristics of the site or technology (including, but not limited to, generation, storage, controls, information technology (IT), automated metering infrastructure (AMI), other) that make this project unique?

The system is intended to rely on commercially available and warranted technologies integrated in standard configurations. It does however include some novel approaches.

First, the design supports multiple operating modes depending on the outage scenario. In general, the approach to dispatch is intended to minimize the amount of BESS capacity that must be provided and reserved for microgrid customers' resiliency objectives, thereby minimizing project costs. In Zone 2, for example, battery storage is specified with sufficient power and energy capacity to cover outages of short duration – approximately 15 minutes – after which the system will dispatch gas-fired standby generation and apply active load controls to maintain reduced electric service for indefinite periods of time.

Second, in Zone 2 the project will serve a single customer's loads in three buildings, two of which are owned by the City of Pittsfield (City Hall and Police Department). In the third building (100 North Street), load controls would enable the microgrid to curtail non-City loads. This approach would isolate the customer's critical loads from non-critical loads for microgrid service.

e. What makes this project replicable? Scalable?

The proposed project demonstrates an approach that is scalable both in terms of technical systems and customers.

Scalability in the project area is limited by the configuration of the existing utility distribution system as well as by the proximity of critical loads requiring resilient electric service. However, the basic Zone 1 approach of installing remote switching capabilities at key points in the distribution system is inherently replicable and scalable, to the extent system design and configuration would support it. Likewise, the Zone 2 approach of installing new underground cable and connecting it behind the customer's meter is inherently scalable to the degree loads are sufficient to support the costs of new underground cabling and switching infrastructure. Further, the types of energy resources and controls and configuration approaches to achieving island-mode operations in both zones are readily replicable and scalable.

The proposed business model is based on standard approaches that can be readily replicated, and are technically scalable to support additional services and loads, given the right circumstances. A microgrid virtual bus, as proposed for Zone 1, technically could be formed in a distribution area larger than the targeted segment, or could be expanded with additional DERs and new cable to reach additional facilities. Given such expansion, the same business model could accommodate additional loads or be applied in analogous projects. However, the business model is not intended to support the loads of more than one customer. Such an approach could be feasible with utility support, but would represent a fundamental adaptation of the proposed approach.

f. What is the purpose and need for this project? Why is reliability/resiliency particularly important for this location? What types of disruptive phenomena (weather, other) will the microgrid be designed for? Describe how the microgrid can remain resilient to disruption caused by such phenomena and for what duration of time.

The microgrid investments proposed in Zones 1 and 2 would strengthen the resiliency of energy services for critical community facilities in the largest city in Berkshire County. In addition to being a Gateway City, the Pittsfield Downtown area (including both project sites) has been designated an Opportunity Zone for special federal investment tax treatment as an economically disadvantaged area. Development of sustainable and resilient energy systems to serve critical assets in downtown Pittsfield would substantially enhance the community's ability to protect public health and safety during emergency conditions that cause extended utility outages.

The microgrid is designed to support two primary resiliency objectives: 1) Substantially eliminate service interruptions caused by periodic short-duration utility outages originating outside the microgrid boundary; and 2) Provide sustainable and resilient energy service for critical loads during long-duration outage scenarios. The second resiliency function is more challenging, involving such events as hurricanes, derechos, and severe winter weather that can damage both local and regional grid infrastructure.

In Zone 1, the proposed system would support resiliency against long-duration outages by utilizing PV resources to defer startup of the hospital's automatic transfer-switched diesel-fueled standby systems and thereby extend time to refueling. The Zone 1 microgrid control platform could be augmented in the future with additional energy storage capacity to extend the microgrid's duration of battery autonomy.

In Zone 2, the proposed system would support critical loads in island mode for indefinite periods of time by:

- Signaling BEMS and building staff to reduce non-critical building loads and prevent coincident peaks; and
- Dispatching gas-fired standby generation as necessary to serve loads and maintain battery state of charge as needed when PV generation is insufficient.

The system would be resilient against localized flash flooding events of the kind that occasionally affect the project area. In Zone 1, the utility's pad-mounted switching systems are vulnerable to extreme flash floods or sustained flooding. The downtown Pittsfield area is not at risk of sustained flooding.

g. Describe the project's overall value proposition to each of its identified customers and stakeholders (including, but not limited to, the electricity purchaser, the community, the utility, the suppliers and partners, and Massachusetts).

Both microgrid zones would produce value for customers and the community in multiple ways:

- Increasing public safety by improving energy resiliency for critical facilities in Pittsfield's downtown area.
- Enabling utilization of rooftop PV generation during utility outages.
- Reducing diesel fuel consumption and related emissions.

Developing a clean-energy microgrid in Pittsfield – a designated opportunity zone – would support local and State goals for sustainable energy development and community resiliency improvements.

The project would provide the utility with direct experience implementing an advanced microgrid in its western Massachusetts distribution system, and with developing business processes and tools that facilitate utility collaboration with municipal and private customers to optimize use of DERs.

The project would create value for suppliers and partners by establishing experience and replicable models for community microgrids, which heretofore have been difficult to develop except for limited uses.

In addition to enhancing resiliency for the heart of a vital city, the project would benefit the Commonwealth by advancing goals for renewable energy and grid modernization. The project supports local grid modernization with improvements in resiliency and reliability. Local experience executing these improvements will support the City's economic development and opportunity zone objectives for the seat of Berkshire County.

h. What added revenue streams, savings, and/or costs will this microgrid create for the purchaser of its power?

Microgrid customers would incur capital costs and operating costs associated with installation of DERs and microgrid control systems.

In addition to avoiding lost productivity during utility outages, microgrid customers would save annual electricity costs by offsetting utility purchases with solar PV production. Additionally, to the degree the microgrid defers standby generator startups, customers also would reduce fossil fuel consumption and costs.

Microgrid customers may incur charges under a special tariff to recover utility costs for installing and operating new infrastructure not financed by other sources (*e.g.,* grants or other external funding for investment in renewables, energy storage, grid modernization, or research and development).

i. How does the proposed project promote state policy objectives (e.g. RPS, Global Warming Solutions Act)?

The proposed project would promote state policy objectives in several ways:

- Facilitating development and optimizing integration of approximately 2,300 kW of new solar PV production in an urban area with little existing renewable generating capacity;
- Displacing 1,900 tons of CO_2e per year, or approximately 38,000 tons over the lifetime of the proposed PV assets;
- Supporting deployment of 4,200 kW/1,050 kWh of dispatchable battery energy storage capacity;
- Demonstrating community energy resiliency solutions and a hybrid utility-customer business model for potential replication by other Massachusetts communities;
- Advancing utility grid-modernization goals and utility experience with advanced grid technology systems designed to address local resiliency and clean energy goals; and
- Advancement of efficiencies through technology and innovation.

j. How would this project promote new technology or technologies developed or manufactured by Massachusetts-based companies (including, but not limited to, generation, storage, controls, IT, AMI, other)? What are they?

Products referenced in Task 3 system conceptual design and modeling are intended as examples of commercially available technologies, and not as pre-approved equipment for specification. Advanced engineering design and procurement scope for the proposed project could include Massachusetts content preferences, to the degree such preferences are consistent with Project objectives and procurement requirements and practices.

4.3 Commercial Viability - Project Team

Contractor shall address the following in describing the structure of the Project Team and the roles, strengths and resources of its members and other necessary partners:

> *a. Describe the current status and approach to securing support from local partners such as municipal government, community groups, residents, and other relevant stakeholders.*

Municipal Government: The City of Pittsfield initiated the project and continues supporting it. Outcomes of the current feasibility assessment will influence the City's interest in pursuing the project through community energy and sustainability planning and development processes.

Berkshire Health Systems: The sole Zone 1 customer expressed general support for the project and has provided substantial information about hospital energy consumption and costs. Outcomes of the current feasibility assessment will influence the customer's interest in pursuing the project as a prospective capital improvement at Berkshire Medical Center.

Community Groups and Residents: The City maintains ongoing engagement with local community groups and individuals, maintaining interest and support for the proposed project. In future deployment phases, additional community engagement efforts likely would include a public outreach campaign and informational meetings.

Other Relevant Stakeholders: The City is committed to maintaining an open engagement with the utility, supporting a process to develop a workable framework for collaboration.

> *b. What role will each team member (including, but not limited to, applicant, microgrid owner, contractors, suppliers, partners) play in the development of the project? Construction? Operation?*

Applicant: In each zone, the host customer would be expected to procure the microgrid controls as well as the proposed DERs – likely under contract with third-party owner-operators to capture investment tax credit benefits in the first five years of operation. In Zone 1, BMC would be the sole customer of the microgrid, and would host DERs including rooftop PV systems on multiple buildings and parking areas. For assessment purposes, BMC is assumed to be the Project's development sponsor and long-term owner and operator in years 6 through 25. In Zone 2, the City of Pittsfield would be the sole customer, and would host DERs including rooftop PV on two buildings. The City likewise would be the Zone 2 system's development sponsor and long-term DER owner and operator.

Microgrid Owner: The utility would install and own microgrid switching and distribution infrastructure.

Contractors: Various contractors would be involved in the project, including consultants to facilitate collaboration among microgrid stakeholders; and microgrid contractors to support system engineering, procurement, civil engineering, system installation, configuration and integration, and O&M services.

Suppliers: Suppliers of microgrid technologies and services would be selected during project procurement phases, consistent with Massachusetts public procurement law.

Additional team members may include providers of legal, regulatory, and financial services to support project structuring, permitting, and financing.

c. Are public/private partnerships used in this project? If yes, describe this relationship and why it will benefit the project.

The project does not envision formalizing a P3 corporate entity. However, public and private entities would collaborate, as described above, to finalize system design, operational plans, and financial arrangements that support their organizational objectives for participating in the project.

d. For identified Project Team members (including, but not limited to, applicant, microgrid owner, contractors, suppliers, partners), what are their qualifications and performance records?

Applicant: The City of Pittsfield is the municipal government of the largest city and historic county seat of Berkshire County. The City government delivers public services for a community of more than 44,000 people, including departments managing such functions as water and wastewater, streets and highways, streetlights and signals, public health, and police and fire protection, etc. The City of Pittsfield has initiated and executed sustainable energy projects, including solar PV and anaerobic digester and combined heat and power systems at the City's wastewater treatment plant.

Owner: The microgrid would utilize distribution infrastructure owned by Eversource, the largest electricity delivery company in New England. The company's Massachusetts electric service territory includes 140 towns and covers 3,192 square miles. Eversource has collaborated with the City of Pittsfield and other Massachusetts municipalities on locally beneficial projects, including a utility-owned ground-mounted solar array.

Contractors and Suppliers: No contractors or suppliers have yet been identified for project implementation. All contractors and suppliers would be selected through compliant procurement processes to ensure they bring competitive pricing as well as exemplary qualifications and performance records.

Partners: The feasibility assessment was led by Microgrid Institute with subcontractor S&C Electric. Inputs also were provided by Skyview Ventures and Umass-Amherst. Prospective participation of each in future project progress has not been established and would be subject to the City's procurement processes and compliance obligations.

e. Are any of the contractors and suppliers identified? If yes, who are they, what services will each provide and what is the relationship to the applicant? If no, what types of team members will be required and what is the proposed approach to selecting and contracting?

No contractors or suppliers have yet been identified for project implementation. Likely team members would include:

- Consultants to facilitate project development, procurement, and collaboration among microgrid stakeholders;

- Technical contractors to support system engineering, civil engineering, installation, configuration, integration, and O&M;
- Suppliers of microgrid technologies and services, including PV, BESS, standby generation, distributing switching, and microgrid controls; and
- Providers of legal, regulatory, and financial services to support project structuring, permitting, and financing.

All contractors and suppliers would be selected through compliant procurement processes to ensure they bring competitive pricing as well as exemplary qualifications and performance records.

f. Are any of the project financiers or investors identified? If yes, who are they and what is their relationship to the applicant? If no, what is the proposed approach to securing proposed financing? Will other members of the Project Team contribute any financial resources?

Financing partners have not been selected at the current project phase. Financing would be required for three primary asset groups, each of which may require separate financing partners and structures.

1) *Rooftop PV systems:* In each zone, these investments can be treated like any other onsite renewable energy asset, for which financing may come from various sources. Common and likely approaches include: tax-benefit financing for generating assets to be owned and operated by third-party solar and BESS developers, with costs recovered through PPAs with project hosts; and bank financing for customer capital investments, with costs recovered through monthly electricity cost savings. Each customer will determine the best structure and funding source for its situation, which may vary substantially between the private and public customers in Zones 1 and 2. All of the PV systems in the project would be integrated behind customer meters to enable onsite offsets of demand and energy consumption. None of the PV systems would be expected to overproduce on an annual basis.
2) *Utility Infrastructure:* In addition to upgraded switching and communications capabilities in Zone 1, the project design requires new underground cables in both zones. The utility would be expected to finance, own, and operate this infrastructure, and for financial modeling purposes the Project Team assumed the utility would charge the capital costs directly to the customer in each zone. However, these costs could be reduced if the utility were to leverage other potential funding sources, including:
    a) Grants and incentive financing for grid modernization and technology demonstration investments from the State of Massachusetts;
    b) Utility revenue bonds for project costs funded together with other utility system investments to achieve a better scale proposition for raising capital;
    c) General rates, with approval from the Massachusetts DPU; such general rate recovery would be justified by the value the Project provides to ratepayers by demonstrating technical approaches and business models for utility distribution microgrids to support critical community assets; and
    d) Some portion of the utility's capital expenditures and O&M costs could be recovered through a special tariff paid by microgrid customers. The availability of funding from any

source would depend on development plans and scheduling to be established in subsequent project implementation phases.

3) *Dispatchable DERs and Controls:* Under the proposed approach, customers in Zones 1 and 2 would procure microgrid control systems as well as new BESS capacity (and in Zone 2, gas-fired standby generation) proposed for the project. BMC and the City of Pittsfield, respectively, would utilize third-party tax-benefit financing for initial investments in PV and BESS, and corporate and municipal bonds for long-term financing. Microgrid DERs and controls could be owned and operated by the customer, or by a third-party entity that would recover the costs through long-term PPAs with the customer. Financing sources for customer-owned microgrid assets would be subject to customer procurement processes and compliance obligations.

g. Are there legal and regulatory advisors on the team? If yes, please identify them and describe their qualifications. If no, what is the proposed approach to enlisting support in this subject area?

The feasibility assessment team includes legal and regulatory advisors, most notably Microgrid Institute Counsel Michael Zimmer. Mr. Zimmer is an energy industry attorney with more than 40 years of experience. He has national and international experience in serving energy/utility projects in 35 states and over 20 foreign countries during his legal career. However, he is not admitted to practice in Massachusetts and so his guidance in the project is comprised of general consultative support and not legal advice.

During future project phases, inside and outside counsel would be expected to support customer activities associated with installing onsite renewable generation and executing contracts for microgrid service. Additionally, the City of Pittsfield likely would engage inside counsel to address issues related to procurement of assets and services.

One of the critical roles of counsel would be to facilitate, update, and provide guidance in modernizing regulatory policy and guidance and interpretations to support further needs of the City and its stakeholders, as well as to resolve legal uncertainties. Ultimately, the City's plans and strategies for Zone 2 or other related investments may require codification of decisions and interpretations in codes, ordinances, and statutes to ensure the community can effectively serve the 21st century needs of energy customers, stakeholders, and constituents.

V. Chapter 5 Information for Cost-Benefit Analysis

5.1 Facility and Customer Description

Describe all facilities that will be served by the microgrid. For each facility, indicate: Rate class to which the facility belongs; Economic sector to which the facility belongs; Whether multiple ratepayers are present at the facility; Whether there will be any financial criteria for prospective customers; Average annual electricity demand (MWh) and peak electricity demand (MW); Percentage of the facility's average demand the microgrid would be designed to support during a major power outage; In the event of a multi-day outage, number of hours per day, on average, the facility would require electricity from *the microgrid; Quantified value of resiliency for each facility that would receive electricity from the microgrid during an outage.*

As assessed, the CPDM Project includes two separately islanding zones, each of which would be financed and designed independently to serve different operating objectives.

The Zone 1 system would serve the Berkshire Medical Center campus, including a 302-bed hospital and maternity unit. Zone 2 includes City of Pittsfield electric loads at three facilities: City Hall and Pittsfield Police Department, both owned by the City, and 100 North St., owned by a private party with space leased to the City.

Fig. 5.1: CPDM Facility and Customer Description

	Berkshire Medical Center	Pittsfield City Hall	Pittsfield Police Department	100 North St.*
Zone	1	2	2	2
Rate Class	Large commercial	Small commercial	Small commercial	Small commercial
Economic Sector	Medical services	City services	City services	City services
Multiple Ratepayers?	No	No	No	No*
Financial Criteria	NA (Sole customer would be project sponsor)			
Annual Avg. Electricity Consumption	19,000 MWh	245 MWh	233 MWh	106 MWh
Peak Demand (Annual)	3,700 kW	96 kW	55 kW	28 kW
Average Demand	1,410 kW	36 kW	20 kW	11 kW
% of Avg. Demand Supported by Microgrid	100	100	100	100
Avg. Hours/Day of Microgrid Reliance	15 min – 8 hrs.†	24 hrs.		
Resiliency Value	Reduced consumption of natural gas (~25,000 MMBtu/hr)	24 hours/day of continued critical services w/load management		

*Multiple tenants are located at 100 North St., but the proposed project will serve only City of Pittsfield electric loads.

†The Zone 1 microgrid ESS is sized for battery-only autonomy for approximately 40 minutes at average load, or 15 minutes at 4,000 kW peak (*See Chapter 3, Fig. 3.7 "CPDM Use-Case Summary (Zones 1 and 2).* Daytime solar-powered microgrid service duration is estimated at six to eight hours, depending on time of outage, PV production, battery state of charge (SoC), and electric loads. When battery SoC is depleted, Zone 1 system would switch to existing standby generation to maintain emergency service.

In Zone 2, ESS capacity is sufficient for about 45 minutes of service at average load, or less than 30 minutes at peak demand. New gas-fired standby capacity is specified to enable full service for all loads even when battery SoC is depleted and PV is not producing.

New dispatchable resources (ESS or generators) may be integrated into either microgrid zone in the future, to replace existing standby generators reaching the end of their service lives, and to support more critical loads and longer-duration microgrid service. New generators and ESS in the future may be integrated to support microgrid load sharing, and to enable switching from microgrid service to existing emergency standby circuits.

5.2 Characterization of Distributed Energy Resources

Describe the DERs the microgrid would incorporate, including for each: Energy/fuel source; Nameplate capacity; Estimated average annual production (MWh) under normal operating conditions; Average daily production (MWh/day) in the event of a major power outage; For fuel-based DER, fuel consumption per MWh generated (MMBtu/MWh); Amount of onsite fuel storage capacity.

Both microgrids would rely primarily on solar resources to support foreseen daytime loads, with nighttime loads supported by natural gas-fueled generation – either through current ATS-served circuits (Zone 1) or microgrid bus (Zone 2) energized by gas generation.

Fig. 5.2: DER Operating Characterization – CPDM Zone 1

DER	Covered Parking PV - BMC	Rooftop PV - BMC	BESS - BMC
Capacity / Type	1,265 kW	894 kW	4,000 kW/1,000 kWh
Existing or Proposed	Proposed	Proposed	Proposed
Fuel Storage*	NA	NA	NA
Annual PV Production	1,564 MWh/yr	1,106 MWh/yr	NA
Daily Production	4.29 MWh/day	3.03 MWh/day	1.00 MWh/day

**BMC has 15,000 #2 fuel-oil tank that supplies 2,000 kW of dual-fuel generators that are not integrated into the microgrid.*

Fig. 5.3: DER Operating Characterization – CPDM Zone 2

DER	Rooftop PV - City Hall	Rooftop PV - Police Station	BESS - City Hall	Standby NG - City Hall
Capacity / Type	67 kW	54 kW	200 kW/50 kWh	150 kW
Existing or Proposed	Proposed	Proposed	Proposed	Proposed
Fuel Storage	NA	NA	NA	NA
Annual PV Production (MWh/yr)	80.51	64.49	NA	NA
Daily Production (MWh/day)	0.22	0.18	0.05	2.52
Fuel Consumed/kWh (MBtu)	NA	NA	NA	0.010812
Fuel Consumed/day (MBtu)	NA	NA	NA	27.25

5.3 Capacity Impacts and Ancillary Services

Contractor shall provide estimates of the following services/value the microgrid is expected to provide, as applicable: Impact of the expected provision of peak load support on generating capacity requirements (MW/year); Capacity (MW/year) of demand response that would be available by each facility the *microgrid would serve; Associated impact (deferral or avoidance) on transmission capacity requirements (MW/year); Associated impact (deferral or avoidance) on distribution capacity requirements (MW/year); Ancillary services to the local utility (e.g., frequency or real power support, voltage or reactive power support, black start or system restoration support); Estimates of the projected annual energy savings from development of a new combined heat and power (CHP) system relative to the current heating system and current type of fuel being used by such system; Environmental regulations mandating the purchase of emissions allowances for the microgrid (e.g., due to system size thresholds); Emission rates of the microgrid for CO2, SO2, NOx, and PM (emissions/MWh).*

As indicated in Figure 5.4, demand response (DR) and other grid-services capacity technically is constrained by the maximum output capacity of the ESS and inverters, but in practical terms that capacity is reserved to meet the resiliency objectives defined for microgrid operation. As discussed in earlier phases of study, the customers' objectives for the CPDM prioritized increasing customer energy resiliency and reducing fossil fuel consumption during outages. ESS capacity was sized to meet minimal microgrid requirements to support a stable transition to islanded operating mode. Supporting that objective means the currently specified storage would not be sufficient to support substantial DR or other ancillary services.

Fig. 5.4: CPDM Capacity Impacts and Ancillary Services

	Zone 1	Zone 2	Notes
Peak load support (MW/yr)	2.16	0.12	PV nameplate peak output
DR Capacity - Technical (MW/yr)	4	0.2	ESS 15-min. capacity
DR Capacity – Practical (MW/yr)	0	0	ESS reserved for resiliency
Transmission Capacity Impact (MW/yr)	0	0	
Distribution Capacity Impact (MW/yr)	0	0	
Ancillary Services to the Utility	0	0	
Environmental Regulations	NA	None	Standby gen below permit threshold
Emissions Rates (kg/MWh)	NA	CO_2: 170,249 SO_2: 1 NO_X: 6,315 PM: 0	BMC and Police Department standby generators are not integrated into microgrid

5.4 Project Costs

Provide the following cost information for the microgrid: Fully installed costs and engineering lifespan of all capital equipment; Initial planning and design costs; Fixed operations and maintenance (O&M) costs ($/year); Variable O&M costs, excluding fuel costs ($/MWh); Maximum amount of time each DER would *be able to operate in islanded mode without replenishing its fuel supply; and Amount of fuel the DER consume during this period.*

Fig. 5.5: CPDM Project Cost

	Zone 1	Zone 2	Notes
Capital Cost	$6,701,518	$972,935	Includes tax credits
Financing Cost	$1,281,883	$201,580	Estimates based on MassDevelopment bond rate tracker, City of Pittsfield inputs, and Bankrate.com
Total Financed Cost	$7,983,401	$1,174,515	
Initial Design Costs	$654,137	$171,467	Includes planning, studies, designs, and preliminary engineering
Project Lifespan	25 years	25 years	BESS and controller replaced in year 11
Fixed O&M ($/year)	(negligible)	(negligible)	
Variable O&M ($/MWh)	(negligible)	(negligible)	
Max Operating Time w/o Refueling	NA	NA	Zone 1 microgrid includes no fueled DERs; Zone 2 standby generator is fueled by natural gas pipeline.

Cost components are conservatively budgeted. However, some costs – including for switching and building energy management system upgrades – may be higher if design engineering shows a need for more complex systems.

Estimates in Figure 5.5 assume PV and ESS costs are financed by a third-party developer using tax credit financing, assuming a 5-year term and 7% interest rate. Capital costs include 20% tax credits for PV and ESS costs, assuming 2022 10% federal investment tax credit plus equivalent 10% depreciation benefit. Costs would be reduced if tax credit sunset dates are extended or if the project can meet earlier milestone requirements.

In Zone 1, remaining costs are assumed to be financed using 10-year corporate bonds with an effective 4% interest rate. In Zone 2, remaining costs are assumed to be financed with a combination of 10-year tax-exempt municipal bonds with a 4% rate ($692,215) and earmarked state budget allocation ($100,000). Additional external financing through grants or state budget allocation would reduce financing costs and improve the benefit-cost outcome for the site host.

5.5 Current Costs to Maintain Service During a Power Outage

For each facility the microgrid would serve, describe its current backup generation capabilities, if any.

The microgrid would not integrate the 2,000 kW of dual-fueled standby generation currently installed at BMC, or the Police Department's 125 kW standby diesel. Figure 5.6 nonetheless includes inputs for the standby generators where applicable.

In a scenario where neither microgrid assets nor standby generation is available, none of the microgrid facilities could be operated, and would require evacuation and relocation of critical services. Hospital emergency costs are based on an estimated evacuation cost of $1,000 per patient at full capacity (302 beds), and cessation of all hospital services, resulting in lost income totaling $2.9 million per day on average. In Zone 2, costs of standby power are based on gas-only operation at average load for 24 hours. Emergency costs if standby power is unavailable are characterized as major disruptions to City of Pittsfield business, including first response, law enforcement, 911 emergency dispatch, and management of emergency and recovery operations.

The indirect financial impacts of extended facility outages are difficult to quantify, but in some emergency scenarios they could be extremely high in the project area. Impaired first-response capabilities, for example, could result in substantial financial costs associated with reduced productivity, property damage, injuries, and deaths.

Fig. 5.6: CPDM Costs to Maintain Service during Outages

Standby Generator	BMC	City Hall	Police Station	100 North St.
Fuel Type	Dual fuel (NG and #2 fuel oil)	Natural Gas	Diesel	None
Capacity (kW)	2,000	150	125	-
Avg. Load Factor during Outage (%/nameplate)	70%	70%	70%	-
Avg. Daily Production during Outage (MWh/day)	33.6	2.52	2.1	-
Fuel Used during Outage (MBtu/day)	348	27.25	22.71	-
One-Time Costs	None	None	None	-
Daily Non-Fuel Costs	Negligible	Negligible	Negligible	-
Emergency Costs w/Standby* Power ($/day)	$3,544	$277.41	$231.19	-
Emergency Costs w/o Standby Power ($/day)	$3.26 million	Major disruptions to City services		

*Standby generation only, irrespective of microgrid.

5.6 Services Supported by the Microgrid

For critical facilities, including those that provide fire, emergency medical, hospital, police, wastewater, or water services, estimate the population serviced by each facility and describe how a power outage would impact each facility's ability to provide services. If possible, estimate a percentage loss in the facility's ability to serve its population during a power outage, relative to normal operations (e.g., 20% service loss during a power outage), both when the facility is operating on backup power and when backup power is not available.

In Zone 1, Berkshire Medical Center serves patients from across much of Berkshire County (pop. 130,000) and some communities in New York. Pittsfield City services serve the entire community of about 44,000. Facilities in both sites require electricity to continue any level of services.

Fig. 5.7: Services Supported by the Microgrid

	Zone 1	Zone 2
Population Served	130,000	44,000
Service Lost during Outage w/Standby Power	0%	0%
Service Lost during Outage w/o Standby Power	100%	100%

-END REPORT-