MICROGRID VALUE STACKING TO DEFER DISTRIBUTION CAPACITY UPGRADES OF RADIAL FEEDERS

Hamideh BITARAF
ABB – USA
hamideh.bitaraf@us.abb.com

Britta BUCHHOLZ
ABB – Germany
britta.buchholz@de.abb.com

Pablo ASTORGA
ABB – Spain
pablo.astorga@es.abb.com

John GLASSMIRE
ABB – USA
john.glassmire@us.abb.com

ABSTRACT

Distribution utilities facing growing demand in feeders need to consider approaches for capacity upgrades. The conventional approach is to upgrade capacity with an extension of the substation and related assets. However, non-wire alternatives (NWA) like a microgrid are a viable solution. Radial feeders are often the most unreliable part of a distribution system, so in addition to deferring substation capacity investments, the microgrid adds islanding functionality that can decrease outages. Microgrid approaches also assists feeders with high renewable generation or fluctuating loads to actively manage voltage challenges. This business case compares the microgrid alternative with numerous stacked values against the conventional capacity upgrade scenario from the perspective of a distribution utility. The results of this business case are that the microgrid is more economic than the distribution capacity upgrade due to the multiple stacked operational cost savings the battery energy storage (BESS) provides. The distribution utility not only benefits from distribution capacity upgrade deferral, but also improves reliability performance, voltage regulation, and peak demand reduction. The payback period for the microgrid scenario is 4 to 6 years less than the conventional upgrade investment.

INTRODUCTION

Distribution utilities' roles and responsibilities vary across markets, but a common responsibility is to carry electricity from the transmission system to individual customers and collect electricity from distributed generation. Radial feeders are the most common architecture among distribution systems. They provide a simple, single pathway for electricity supply. Because of their simple architecture, they also have high risks and challenges for operation and management (O&M).

When electricity demand exceeds a radial feeder's substation capacity, distribution utilities have traditionally upgraded the substation capacity and related system expansions. However, these expansions can be costly, and they offer limited additional value. Demand growth increases capacity and transmission charges for the distribution utility. Hence, the utility not only pays the investment for substation capacity upgrades, but also the increased demand charges. The feeder will still be subject to outages when the transmission system has an outage, and it will have limited capability to manage increasing levels of solar photovoltaic and other distributed generation.

Another solution for distribution utilities is to invest in microgrid technologies with a BESS as a non-wire alternatives (NWA). Microgrids and BESS provide multiple benefits to manage demand growth, improve reliability, regulate voltage, and shave feeder peak loads. BESS are becoming a cost competitive alternative for distribution utilities compared to standard distribution capacity upgrade tactics, particularly as part of a microgrid. Microgrids have the capability to seamlessly transition to an island mode in case of power outage on the main grid. The BESS offers dynamic benefits to mitigate over voltage and voltage fluctuations. The BESS microgrid alternative can provide multiple cost savings including the distribution capacity upgrade deferral, reliability and resiliency improvements, voltage regulation, and peak demand reduction.

A microgrid with BESS as a NWA offers the following values for distribution utilities:

- Distribution capacity upgrades can be deferred while demand growth is managed
- Reliability can be improved on radial feeders that provide uninterrupted power to the isolated loads during an outage
- Reduce O&M costs by providing voltage regulation
- Decrease capacity and transmission charges by peak shaving services

This business case will first describe the challenges for radial feeders based on a hypothetical example in the US, then explain the methodology, and finally present the results and discussion. This business case will provide the cost benefit analysis of microgrid solutions compared to distribution capacity upgrades for a distribution utility with radial feeders facing growing demand, high photo voltaic (PV) penetration and reliability issues.

RADIAL FEEDER CHALLENGES

Radial feeders typically provide low reliability performance due to their configuration. With only one connection to the main network, they are more susceptible to outages. Radial feeders are often located in more remote portions of a utility's system making them more difficult to maintain. A parallel/meshed feeder is likely to provide greater level of reliability, but at a higher cost. Parallel/meshed feeders are more common in urban areas or for feeders with high reliability requirements.

Distribution utilities that have long radial feeders are most likely to have operational issues. These feeders often have demand growth that exceeds the substation and feeder capacity. Such feeders are often on the outskirts of distribution utility systems in more isolated areas, typically with more difficult terrain. As such, they are often more threatened by outages brought on by wildlife, tree falls and other localized natural events.

High PV penetration can create overvoltage and voltage fluctuations on these feeders, creating operational challenges for distribution utilities. Traditional voltage control devices like switched capacitor banks or line voltage regulators can mitigate slow-moving fluctuations, but these devices need to operate more frequently than their design-life due to the high fluctuations from PV generation. The frequent operation of these voltage control devices will reduce their life expectancy and increase maintenance costs.

These challenges impact the distribution utility business:

- Distribution capacity needs management to control demand growth on the line that exceeds, or is expected to exceed substation capacity
- Low reliability circuits that lead to customer and regulator discontent
- Increased feeder O&M costs due to voltage fluctuations caused by high solar PV penetration
- Increased fees and charges for load growth

Demand Growth

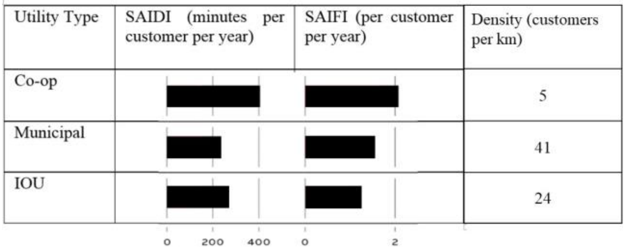
Distribution utilities having peak load at feeders that will reach the capacity limit soon must plan to take action. Whether due to new customers, increased customer electrical use due to electric vehicles, or industrial expansion, a feeder with more load than it can handle will experience operational issues, and potentially reliability impacts.

Reliability Performance

A disadvantage of radial feeders is the difficulty of maintaining supply during a fault event on the feeder. A fault or any equipment failure often results in the loss of power to customers on the entire radial feeder. This power outage continues until the fault is located and cleared or the failed equipment is replaced. As a result, customers connected to radial feeders are more likely to experience reliability issues than customers on other feeder types.

Two common reliability metrics used by distribution utilities are the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) indexes, which measure the duration and frequency of electric service interruption to customers. In the United States, outage frequency and duration values are reported for any interruptions lasting longer than five minutes. [1]

Among the three major categories of utility ownership models in the US, municipal utility customers experienced the lowest duration of power outages in 2016 as shown in Figure 1. Investor-owned utilities', IOU, customers averaged 265 minutes without electricity, while co-op customers averaged 397 minutes without power service. The co-op utilities have the lowest density of 5 customers per km of distribution. On the other hand, municipal utilities have a density of 41 customers per km. The low-density co-op utilities have significantly more reliability issues than both municipal and IOU utilities. [2]



Utility Type	SAIDI (minutes per customer per year)	SAIFI (per customer per year)	Density (customers per km)
Co-op			5
Municipal			41
IOU			24

Figure 1 US utility reliability and customer by utility type

Distribution utilities are increasingly receiving incentives and penalties for reliability in their networks. For example, for 2012 through 2016, Germany assessed distributed system operators (DSOs) 0.18€ per minute of interruption per customer above or below a reference SAIDI value. The Czech Republic also incentivizes reliability with a program for DSOs implemented beginning in 2013. [3] It should be recognized that each country may have slightly different metrics both for calculating reliability, as well as distinct approaches for incentivizing it in DSO networks. In addition, many utilities in Europe and globally use radial feeders for serving remote areas and could benefit from the microgrid/BESS described in this paper.

The business impact of reliability on a distribution utility is a product of their regulatory environment. In some cases, there may be direct incentives/penalties for reliability performance. In other cases, there may not be any direct relationship but there is always public and regulatory commission attention given to reliability. For example, San Diego Gas and Electric in California, USA, pays a 125 kUSD penalty if the SAIDI and SAIFI of its worst circuit are above the target. On the other hand, the utility receives a 125 kUSD reward if the SAIDI and SAIFI are below the target. [4]

One additional impact of reliability issues on utilities is the loss of energy sales due to an outage, otherwise known as non-delivered energy (NDE). Customer outages means lost sales. In some markets it can also mean penalties. According to the Finnish Electricity Market Act, Finnish utilities must pay customers 10% of the annual network fee for 12-24 hour service disruptions, and up to 200% of the annual network fee for outages longer than 12 days. [5]

Voltage Challenges

As the penetration of distributed generation on the distribution system grows, grid operators face several opportunities and challenges. Challenges regarding network operation occur due to the inherent variability in solar irradiance for cloud transients and diurnal effects.

High PV penetration in distribution system can cause reverse power flow, impact thermal ratings, lower power quality, impact protection schemes, as well as voltage issues. [6] The voltage issues may be split into two major categories:

- Over voltage: The PV generation increases the line voltage at the feed-in point
- Voltage fluctuations: In the case of cloud transients, significant voltage fluctuations can occur on the distribution system and depends on PV penetration, PV location, and distribution system configuration

In a traditional distribution system, voltage rise due to the PV output impacts a feeder's voltage regulators (VR). These devices typically have operational delays in the range of 30 to 90 seconds. When voltage fluctuation occurs in this time scale, these devices can detect and adjust. But voltage fluctuations due to high PV penetration can be more frequent. Hence with significant PV these devices will operate more frequently to keep the voltage within the desired limits, which lessens their lifetime.

In a case study performed by National Renewable Energy Laboratory, PV penetration created a situation where VRs are operated hundreds of thousands of times over one year. Some of the VRs were found non-operational later and had to be replaced by the distribution utility. Accordingly, traditional voltage devices are not well suited for managing circuit voltage with high PV penetration. [7]

Charges for Peak Demand

Distribution utilities, like their customers, often pay fees based their peak power demand. Reducing this peak demand, or *peak shaving*, can reduce utility costs. In the United States, many utilities pay transmission charges for transmission services provided by their Independent System Operator (ISO) or Regional Transmission Operator (RTO) based on their demand during the system-wide coincident peak demand hour. ISO/RTOs may also have an additional annual capacity charge. This is often determined by the utility's demand during the coincident system peak demand. Utilities can find significant cost savings by finding ways to reduce these peak demand charges. The American Power Reference Case has ABB's 25-year electricity and fuel price forecast and can be used to find applicable demand and capacity charges. ABB Reference Cases and market data bases are also available for Europe and Middle East and Asia-Pacific. [8]

PROBLEM DEFINITION

The radial feeder line in this study is suffering from reliability and voltage issues from significant amounts of solar PV, in addition to demand growth beyond substation capacity. The distribution utility is deciding between distribution capacity upgrades or a microgrid with BESS. The distribution utility can own microgrid assets.

The feeder has 8 MW peak load and 5.5 MW average load with expected 1% load growth rate each year. The substation capacity is 8.5 MW, which will be less than the peak load in 5 years. The feeder has 10% distributed solar PV penetration. The utility rate is 0.12 USD per kWh with 2% inflation rate. The distribution utility receives 50% of the electricity sales as a contribution to fixed costs.

The distribution utility is subject to a penalty/reward structure for reliability of the feeder. If the reliability of the feeder exceeds the target, it will receive a reward of 125 kUSD per year. If the reliability is worse, it will pay a penalty 125 kUSD per year. These penalty and reward schemes are expected to escalate 2% each year. Finally, the distribution utility is a participant in a regional ISO for which it pays a $100 USD/kW-year transmission capacity charge based on its demand during the ISO's annual coincident peak. It also pays a $12/kW-month generation demand charge for its demand during the ISO's monthly coincident peak. These rates have 2% growth annually. The system O&M cost is assumed to be 425kUSD per year which includes the extra maintenance required for voltage regulators (VRs). The summary of power system assumptions for the radial feeder is shown in Table 1.

Table 1 Power System Assumptions

Load	8 MWp, 5.5 MW avg, 1% growth
Substation Capacity	8.5 MW
Transmission Charge	100 USD/kW-Year
Capacity Charge	12 USD/kW-Month
SAIDI	420 minutes per customer per year
SAIFI	3 times per customer per year
Reliability Impact	125 kUSD-Year as a Penalty/ Reward
Solar PV	800 kWp
System O&M Cost	425 kUSD, including maintenance for VRs.
Utility Rate	0.12 USD/kWh

Scenario 1: Distribution Capacity Upgrade

There are several potential upgrades that can be undertaken to manage demand growth, improve reliability, increase hosting capacity, and mitigate the distributed generation voltage issues. In this scenario the distribution utility evaluates an option to upgrade the substation, cables and devices to boost capacity as shown in Figure 2.

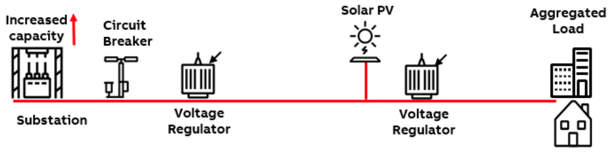


Figure 2 Distribution Capacity Upgrade Scenario

The cost is assumed to be $625k USD per km for construction, permitting and real estate costs. [9] The distance is assumed to be 8 km and the entire project will take five years inclusive of permitting. With this lead time, the distribution utility needs to invest in capacity upgrade 5 years before than the time demand forecast reaches the substation capacity in Table 2.

Table 2 Costs of Distribution Capacity Upgrade Scenario

CAPEX	5 MUSD
OPEX	No additional cost
Lead time	5 years

The impacts of distribution capacity upgrade are:

- Manage the expected demand growth
- Peak demand charges remain high
- Reliability performance is not improved
- Voltage regulation is not improved

Scenario 2: Microgrid/BESS Solutions for 3h with reliability reward

Micrograms manage distributed energy resources and loads in a controlled, coordinated way either connected to the main power grid or in island mode. Microgrids often occupy a concentrated geographic area with a low or medium voltage grid.

The microgrid/BESS solution is added to the system with the objectives of reliability improvement, peak shaving, and voltage regulation, as shown in Figure 3.

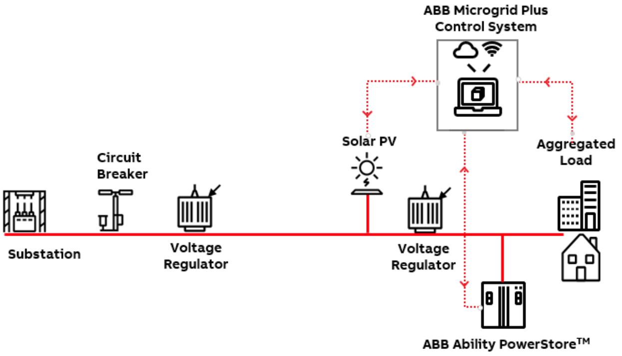


Figure 3 Microgrid and Energy Storage Scenario

The battery is sized according to the average load and the average outage duration for each instance. During a power interruption, the microgrid can transfer to island mode with the battery providing power to average 5.5 MWh over 3 hours. This increases the resiliency of the feeder.

We assume 98% availability for the energy storage (P_{ES}), a 100% probability of successfully transitioning to island mode (P_{MG}), and 0 minutes are required for the seamless transition to the islanding mode (t_{MG}) due to the ABB Ability PowerStore and Microgrid Plus Control System. [9] The SAIFI and SAIDI can be calculated as $SAIFI = SAIFI_{Base}\ [P_{MG}P_{ES} + (1 - P_{ES})]$, and $SAIDI = SAIFI_{Base}P_{MG}P_{ES}t_{MG} + SAIDI_{Base}(1 - P_{ES})$. The SAIFI evaluates to 0.06 outages per customer per year and SAIDI reaches 8 minutes per customer per year.

The peak shaving capability of the BESS depends on the load profile and BESS capacity. It is assumed that the microgrid provides 20% monthly and annual peak shaving. The ABB Ability PowerStore provides voltage regulation for issues caused by solar PV, reducing switching on conventional voltage regulators like tap changers. There is no need to replace voltage regulators every year with the ABB Ability PowerStore, reducing system O&M costs 25% compared to the capacity upgrade in Scenario 1.

This microgrid cost is assumed to be 470 USD/kWh fully installed including battery, control and automation system, and Information and Communication Technology. [11] The battery gets replaced after its ten-year assumed lifetime at a cost of 175 USD/kWh. The summary costs of microgrid project are shown in Table 3.

The multiple value streams for the microgrid scenario are:

- Manage the expected demand growth by peak shaving
- Reduce peak demand charges by 20%
- Improve reliability to receive 125kUSD/yr reward
- Decrease system O&M costs of VRs by 25%

Table 3 Costs of Microgrid Scenario

CAPEX	7.8 MUSD
OPEX	0.2% Microgrid CAPEX
Lead time	1 year

Scenario 3: Microgrid/BESS Solutions for 2h without reliability reward

As a variation to Scenario 2, the microgrid/BESS solution in Scenario 3 is added to the system with the objective of improving reliability, peak shaving, and voltage regulation for a slightly different load profile, as shown in Figure 4.

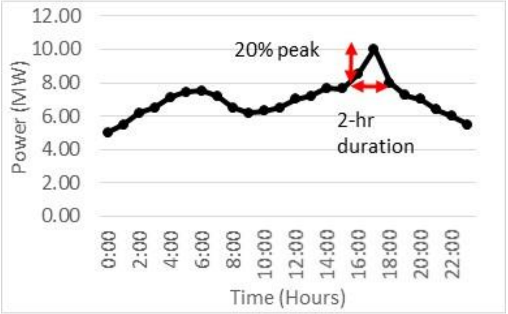


Figure 4 Load forecast for Scenario 3

It is assumed that the battery will shave 20% peak for a duration of 2 hours. During a power interruption, the microgrid can transfer to island mode with the BESS providing average 5.5 MWh for 2 hours.

DISCUSSION AND RESULTS

The techno-economic results for a 20-year project life and 9% discount rate are shown in Table 4. A microgrid is the economic solution for radial feeders with capacity issues.

In present dollars, the CAPEX for microgrid Scenario 2 is 2.8 MUSD more than the one for capacity upgrade Scenario 1. The OPEX for Scenario 2 is 5.4 MUSD less than Scenario 1, due to the decreased O&M cost related to voltage regulators and reduced peak demand charges. The microgrid O&M cost shown includes battery replacement and microgrid maintenance cost. The total revenue of the microgrid Scenario 2 is increased 1.3 MUSD for the reliability reward, in addition to the revenue from grid fees. The total net present value for the microgrid Scenario 2 is 3.9 MUSD more than the upgrade scenario 1 and has both a higher IRR and 4 years shorter payback period.

Table 4 Comparison of Scenarios

	Scenario 1: Distribution System Upgrade	Scenario 2: Microgrid 3h Battery with reliability reward	Scenario 3 : Microgrid 2h Battery, no reliability reward
CAPEX	5 MUSD	7.8 MUSD	5.2 MUSD
OPEX	27.3 MUSD	21.9 MUSD	21.5 MUSD
Revenue	32.7 MUSD	34 MUSD	32.7 MUSD
Net Present Value	0.4 MUSD	4.3 MUSD	6.0 MUSD
Internal Rate of Return	10%	15%	21%
Payback Period	10 years	6 years	4 years

The NPV for Scenario 3 is the highest with 4 years of payback time. This is due to the lower CAPEX cost comparing to the one in Scenario 2 with higher energy storage capacity while there was no reliability reward considered.

Sensitivity Analysis

For the sensitivity analysis the microgrid Scenario 2 has been analyzed for 10% change in the input parameters. This sensitivity analysis includes microgrid cost, peak demand reduction, reliability reward, and O&M cost reduction for voltage regulation as shown in Table 5.

Table 5 Sensitivity analysis on Scenario 2

Parameter reduced/increased in Scenario 2	ΔNPV with 10% reduction	ΔNPV with 10% increase
Microgrid Cost (USD/kWh)	+18%	-18%
Peak Demand Reduction (%)	-10%	+10%
Reliability reward (kUSD/yr)	-3%	+3%
O&M Cost Reduction for Voltage Regulation (%)	-2%	+2%

By increasing the microgrid cost by 10% (high case), the NPV for microgrid scenario is reduced by 18%. The 10% increase in peak demand reduction leads to 10% increase in microgrid Scenario 2 NPV. The increase of reliability reward by 10%, increases microgrid Scenario 2 NPV by 3%. If the microgrid scenario reduces the O&M cost of voltage regulation by 10%, NPV will be increased by 2%.

CONCLUSION

Radial feeders in need of capacity upgrades, or with significant amounts of distributed solar PV, can expose distribution utilities to penalties for inadequate reliability and power quality performances. High PV penetration at distribution system can increase O&M costs for voltage regulator replacements. Microgrids can provide multiple cost savings including improved reliability and power quality performances, peak shaving, and voltage regulation, while increasing the hosting capacity of the network. Given the stacked values of a microgrid, it can be more economic to consider a BESS for distribution capacity upgrades deferral.

The use of a flexible BESS with microgrid, such as ABB Ability PowerStore and the Microgrid Plus Control System, can increase the network hosting capacity, while providing a seamless transition to the islanding mode in case of power outage. It also can improve key reliability performance measurements SAIDI and SAIFI.

REFERENCES

[1] IEEE Guide for Electric Power Distribution Reliability Indices, IEEE Std 1366-2012, 2012.

[2] ABB Ability™ Velocity Suite, https://new.abb.com/enterprise-software/energyportfolio-management/market-intelligence-services/velocity-suite

[3] "6th CEER Benchmarking Report on the Quality of Electricity and Gas Supply", [Online], CEER, 2016 https://www.ceer.eu/documents/104400/-/-/d064733a-9614-e320-a068-2086ed27be7f

[4] "Decision Addressing the General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company and The Proposed Settlements", June 2016, [Online]. Available: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K606/164606603.pdf

[5] Finish Electricity Market Act, 2018, "Compensation for Power Cuts", [Online]. Available: https://www.kkv.fi/en/facts-and-advice/defects-and-delays/power-cuts/

[6] B. Buchholz, M. Maximini, A. Slupinki, L. Asgarieh, "Smarter Distribution: How to increase the capacity of distribution grids to host distributed generation", ABB Review 4/14, the corporate technical journal.

[7] J. Bank, B. Mather, J. Keller, and M. Codington, "High Penetration Photovoltaic Case Study Report," NREL, 2013. [Online]. Available: https://www.nrel.gov/docs/fy13osti/54742.pdf

[8] ABB NAM Reference Case, https://new.abb.com/enterprise-software/energy-portfolio-management

[9] Microgrid Knowledge Report for Berkley, published on August 17, 2018, [Online]. Available: https://microgridknowledge.com/california-microgrids-roadblocks

[10] CIGRE Technical Brochure (TB635) and ISBN: 978-2-85873-33835, "Microgrids 1 Engineering, Economics, & Experience", October 2015.

[11] Lazard levelized cost of storage analysis, [Online]. Available: https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf