CAN SMART INVERTERS ON THE DISTRIBUTION CIRCUIT PROVIDE TRANSMISSION VOLTAGE SUPPORT?

National Grid Solar Phase II Program Report

October 2020

THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

NOTE

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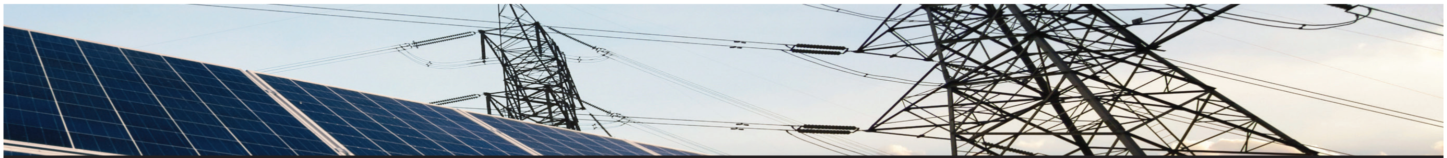

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Introduction

Inverter-based distributed energy resources (DERs) such as photovoltaics (PV) are becoming more commonplace in the distribution system. Massachusetts, in particular, is experiencing record amounts of solar PV deployment. In the Spring of 2017, the state of Massachusetts introduced the Solar Massachusetts Renewable Energy Target (SMART) program which introduced tax credits for solar sites up to 5MW in size with the goal of incentivizing up to 1,600MW of solar deployment in the state.[1] By 2019, a record amount of 950MW+ of interconnection requests for solar PV were submitted to National Grid as seen in Figure 1. In April 2020, the size of the SMART program was doubled to 3,200MW.

These resources are bringing challenges and opportunities to electric transmission and distribution service providers. The planning and operational challenges include coping with the adverse impacts to power quality and reliability, while the opportunities include leveraging the DER to mitigate both DER and non-DER related impacts.

In 2017, Massachusetts Electric Company d/b/a National Grid and the Electric Power Research Institute (EPRI) initiated a col-

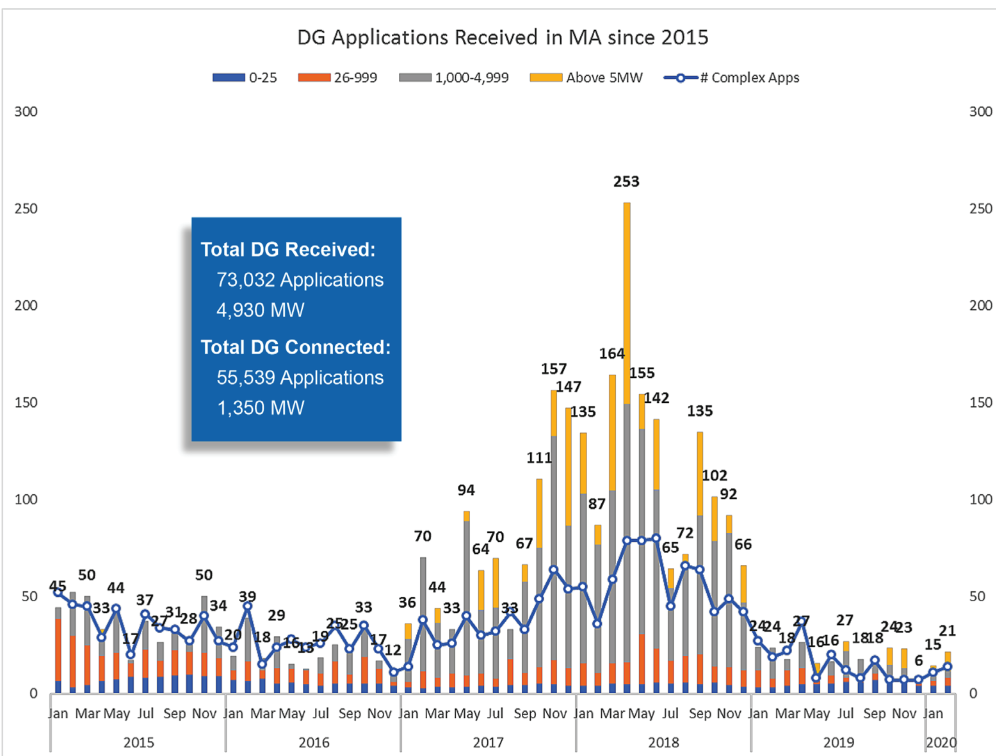
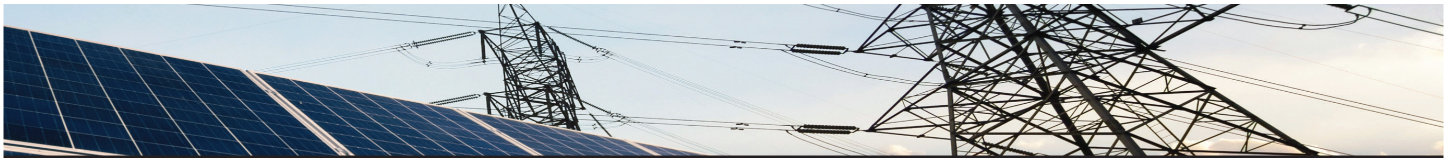


Figure 1. DG applications received by National Grid in Massachusetts[2]

1 https://www.mass.gov/solar-massachusetts-renewable-target-smart
2 Source: National Grid Central & Western MA Cluster Study Update presentation, May 30, 2019, (https://ngus.force.com/s/article/MA-Seminars)



laborative multi-year research project to select candidate solar PV sites from actual field deployments, calculate smart inverter settings for the selected sites, and then monitor the performance of the PV systems as the sites operate with and without those settings in the field.[3,4]

In 2019, the research extended further into examining the use of smart inverter functionality for bulk system benefits. To achieve high penetration of distributed solar PV connected to the distribution system, inverters could also be used as grid assets to help manage voltage on the bulk transmission system. Areas that have low population density may be initially perceived to be ideal for solar farms given available open land area, but large penetration levels of PV in these areas as indicated in Figure 2, can be susceptible to overvoltage conditions, in part due to under-loading of very long transmission lines – a phenomenon known as the Ferranti effect. Some solutions, such as installing shunt reactors on the transmission system to reduce voltages, may be cost prohibitive to achieve high PV penetration levels. This solution also does not mitigate the potential adverse impacts that may also occur on the distribution system.

Alternatively, a potential solution lies in the utilization of the reactive power absorption function of the inverter-based energy resources connected to the distribution system to reduce this transmission system overvoltage condition. This solution could also help mitigate potential adverse distribution system impacts from the high penetration of PV. As such, the aim of this project is to investigate the feasibility of utilizing smart inverter advanced grid support functionalities to alleviate transmission voltage issues while also avoiding the potential adverse impacts to the distribution system. The adverse distribution system impacts from use of smart grid support functions may include thermal and voltage violations due to the requirement to absorb reactive power.

Objective and Scope

Consistent with the ISO-NE planning procedures, the local transmission company New England Power Company (NEP) performed the Central and Western MA Cluster Study. This transmission study revealed potential overvoltage scenarios due to under-loading of long transmission lines caused by the increased penetration of DER supplying loads locally. The traditional method of mitigating overvoltage is to install shunt reactors to help balance the reactive power on the transmission lines. As part of the initial stage of the cluster study NEP identified the need to resolve voltage issues which included the potential installation of shunt reactors near a group of DER along the transmission line.

Given the large cost and time required for these traditional solutions, this research assessment is investigating the feasibility in the future of the coordinated utilization of the reactive power absorption/injection capability of distribution connected inverters to mitigate adverse effects on the area transmission and distribution sys-

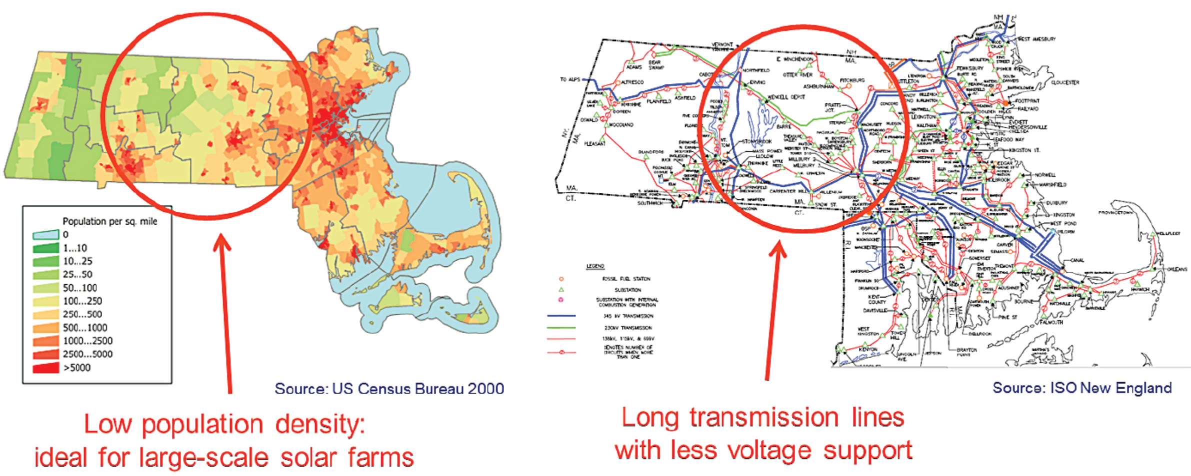
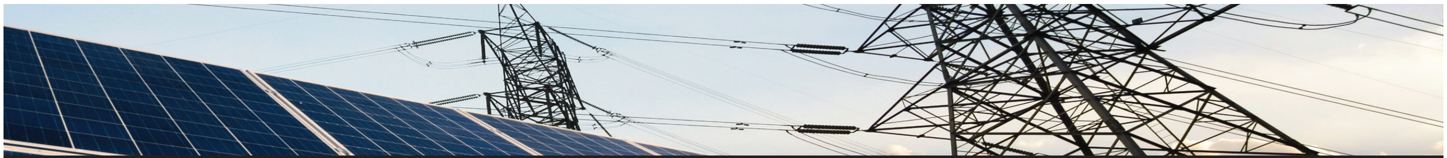


Figure 2. Location of many large-scale solar farms

3 *Field Performance Assessment of Advanced Grid Support Functions Implemented via Plant Controllers: National Grid Solar Phase II Program Report*. EPRI, Palo Alto, CA: 2020. 3002019417

4 *Recommended Smart Inverter Settings for Grid Support and Test Plan: Interim Report*. EPRI, Palo Alto, CA: 2018. 3002012594



tems, utilizing the intelligence gained from other ongoing research under Solar Phase 2 with EPRI. The high saturation conditions of the Western MA Cluster Study were used for illustrative purposes.

Given the ability for smart inverters to modulate their reactive power, they can be used to provide voltage support for the grid. As illustrated in Figure 3, a collection of smart inverters on a distribution feeder could in theory be seen from the transmission system perspective as a "virtual shunt reactor" and sent commands by controllers at each substation to absorb reactive power when necessary. This could come either from local voltage readings at the substation (automatic mode) or via commands sent by the transmission system operator (TSO) or independent system operator (ISO) as determined by a short-term load forecast (manual mode).

The research question is: **Can inverters on the distribution system absorb the required amount of reactive power to the extent of service that and at a lower cost than a reactor on the transmission system would provide**. A reactor on the transmission system might be invoked at any time and left online for an unknown span of time. Therefore, a collection of inverters providing the same service as a reactor would need to be able to be online at any time and remain online for an unspecified length. This requires the inverter reactive power output to be available at all times regardless of the inverter producing real power if that inverter is called upon to mitigate the impact caused by another generator. This also requires that the inverter reactive power output does not cause unwanted voltage or thermal impacts under any load or generation condition. Depending on the DER and inverter design, reactive power output may also impact the energy yield of the plant. All of which cases are examined within this project.

Site Selection and Scenario Development

Two representative National Grid distribution feeders in Massachusetts were selected to be studied for this project based on the following factors:

1. Located in areas where the potential issue of under-loaded transmission lines due to DER penetration is paramount: Central and Western Massachusetts.
2. Be one of 18 feeders with a National Grid-owned DG site that has smart inverters installed and which EPRI had studied through a previous effort.[5]
3. Site selection was also dependent on the penetration of current and pending (as of December 2018) solar PV. The existing and pending PV was also used to develop the PV scenarios analyzed in the study.

Substation and Feeder Selection

Based on the feeders examined, two stood out as primary candidates for this study. These two feeders, F1 and F2 (anonymized names), have a high and low impact factor due to PV, respectively.[6] The range in impact factors indicates that the two feeders should present diverse impacts from PV and thus reactive power

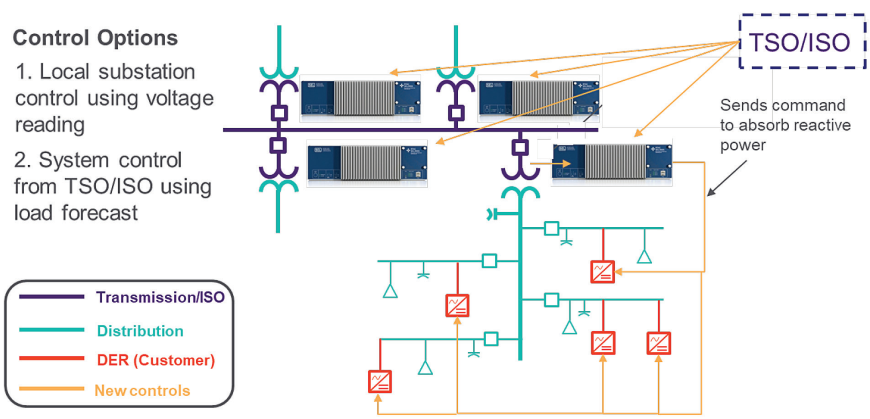
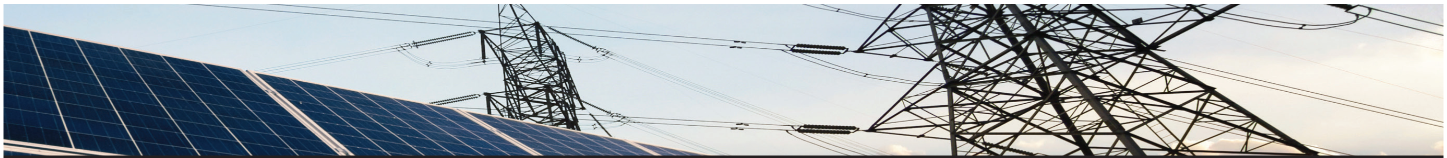


Figure 3. Illustration of potential control hierarchy for using smart inverters to provide reactive power support to the transmission system

5 National Grid, through the innovative Solar Phase 1, 2, and 3 research initiatives, owns and operates 31 DG sites across Massachusetts. Twenty five of these sites have smart inverters installed.

6 *Recommended Smart Inverter Settings for Grid Support and Test Plan: Interim Report*. EPRI, Palo Alto, CA: 2018. 3002012594



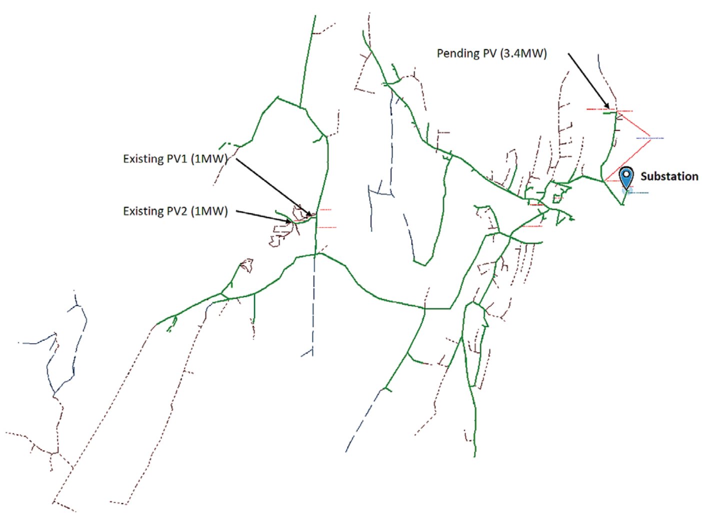
absorption. The impact factor is a normalized quantity describing the potential to experience voltage related impacts due to PV on the feeder. The other factor that makes the F2 a good initial candidate for this study is because the feeder currently has the most significant amount of existing and pending PV.

Substation 1 and Feeder 1

Substation S1 serves Feeder F1 chosen for this study. The feeder and the existing/pending PV is shown in Figure 4. The size and location of PV examined in this study is depicted in the figure. Alternative PV locations and active power penetrations are not examined. Beyond the amount of PV and the location depicted on F1, additional PV served from the substation is also considered as indicated to the right of the dashed line. The parallel feeders are not modeled in detail, thus the impacts to those feeders are assumed similar to the detailed feeder under study. What is captured from the parallel feeders is that there is additional PV that can absorb reactive power, which could ultimately help reduce transmission voltage near the substation. In total, S1 serves a considerable amount of inverter-based PV which could supplement the need of transmission reactors if absorption of reactive power from distributed PV systems does not cause adverse impacts.

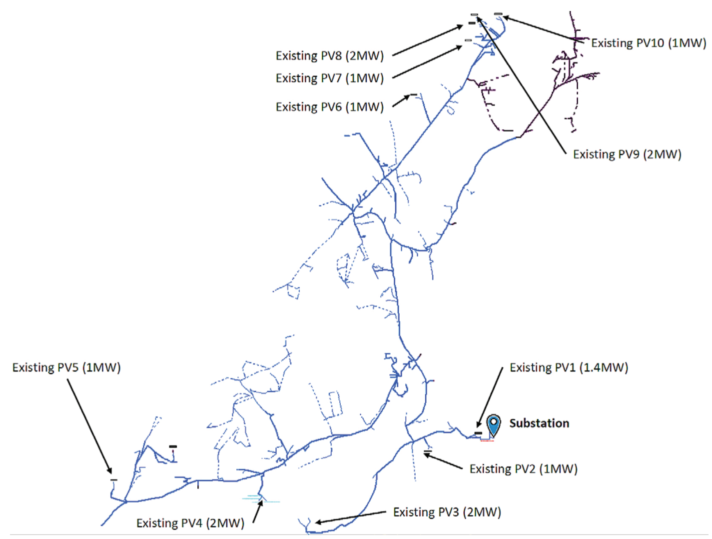
Substation 2 and Feeder 2

Unlike the first feeder, Substation S2 serves a considerable amount of PV on Feeder F2 as shown in Figure 5. The deployment of PV depicted in the feeder creates the scenarios examined in this study.



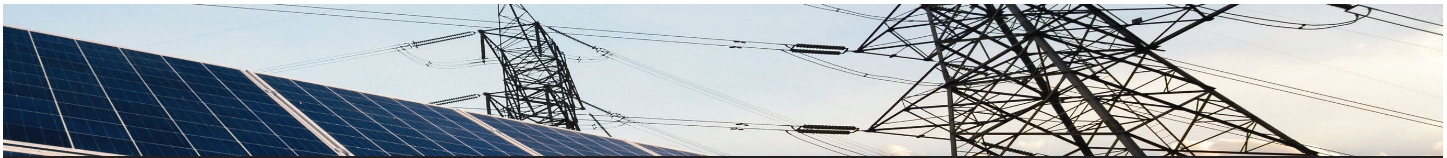
Substation 1, Feeder 1	Generation	Existing PV1	1.0MW
	Generation	Existing PV2	1.0MW
	Generation	Pending PV	3.4MW
	Generation	Small DER	1.3MW
	Load		8.4MW
Substation 1, Parallel Feeders	Generation	Existing DER	16.2MW
	Generation	Pending DER	23.1MW
	Generation	Small DER	9.5MW
	Load		14.9MW

Figure 4. Substation S1 and Feeder F1



Substation 2, Feeder 2	Generation	Existing PV1	1.4MW
	Generation	Existing PV2	1.0MW
	Generation	Existing PV3	2.0MW
	Generation	Existing PV4	2.0MW
	Generation	Existing PV5	1.0MW
	Generation	Existing PV6	1.0MW
	Generation	Existing PV7	1.0MW
	Generation	Existing PV8	2.0MW
	Generation	Existing PV9	2.0MW
	Generation	Existing PV10	1.0MW
	Generation	Small DER	1.4MW
	Load		3.6MW
Substation 2, Parallel Feeders	Generation	Existing DER	15.2MW
	Generation	Pending DER	39.4MW
	Generation	Small DER	5.7MW
	Load		25.3MW

Figure 5. Substation S2 and Feeder F2



Solar PV Deployment Scenarios

Solar PV scenarios could be developed to consider a wide range in random conditions, however, the size and location of existing and pending PV systems were used to identify several key scenarios that represent realistic conditions, but they are not likely the most optimal or least optimal conditions that could occur.

Reactive power could be absorbed by either the "pending" PV systems (those which have requested to interconnect to the system but are not connected as of December 2018) or from "all" PV systems (a combination of existing PV systems and those pending interconnection). The scenarios also examined if only the specific feeder under study participated in the providing the reactive power service (Feeder case) or if all feeders served from the substation participated (Substation case).

This analysis assumed only large PV systems greater than 1 MW would participate (in the analysis the limit was set to 950kW to include systems that are just below the requirement to install circuit breakers). All small PV systems (≤1 MW) remain operating at a unity power factor.

Distribution System Impact Assessment

The distribution system impact assessment was conducted by thoroughly examining the range of conditions that could occur as outlined in Figure 6 and described below.

1. The reactive power requested by the transmission system was defined and communicated to the distribution system operators. This ranged from 0-24 Mvar (in fixed reactive power mode), but in some cases went higher.
2. Specific solar deployment scenario is defined. This includes the four combinations of Pending or All (Pending+Existing) PV and Feeder-specific PV or All-substation PV.
3. Depending on the magnitude of considered PV, additional inverter-based reactive power sources may be required. It was assumed that the considered inverter-based generation could absorb up to 80% power factor based on inverter MVA rating.
4. Each condition developed in (1)-(3) is analyzed against all load and generation conditions. Load was varied from 25-100% in 25% increments, while the generation output was varied from

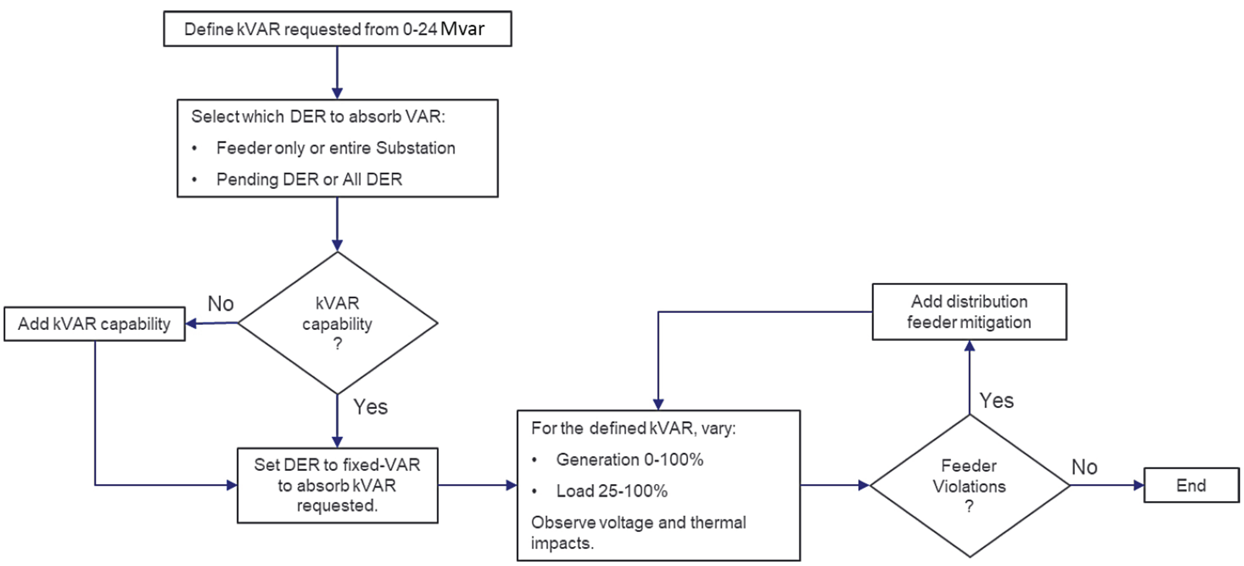
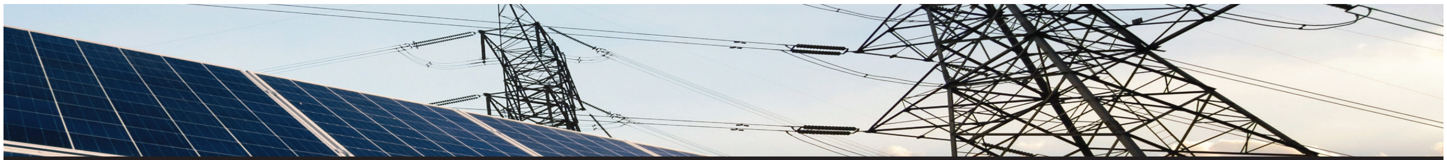


Figure 6. Assessment flowchart



0-100% in 25% increments. The full range in load and PV output, in conjunction with automated capacitor/regulator controls, must be considered because the transmission system reactive power request could occur at any time irrespective of what is happening on the local distribution system.

5. Voltage and thermal impacts were then recorded and if any violations occur, mitigated measures would be applied and then (1)-(4) reanalyzed such that increase in reactive power absorption could be determined.

Violations and observations on the distribution system caused by meeting the needs on the transmission system included the following quantifiable metrics:

- Magnitude and violation count
  - Voltage (ANSI +/- 5% of p.u.)
  - Thermal (nameplate rating of equipment/loading limit of conductors)
- Additional reactive devices required
- Curtailment of generation
- Substation power factor
- Regulator tap changes

An example of low-voltage magnitude for the four solar deployments is shown in Figure 7 by the different colored markers. The x-axis indicates the various reactive power requested, while the y-axis indicates the lowest feeder voltage. This figure specifically shows the condition at peak load and no generation.

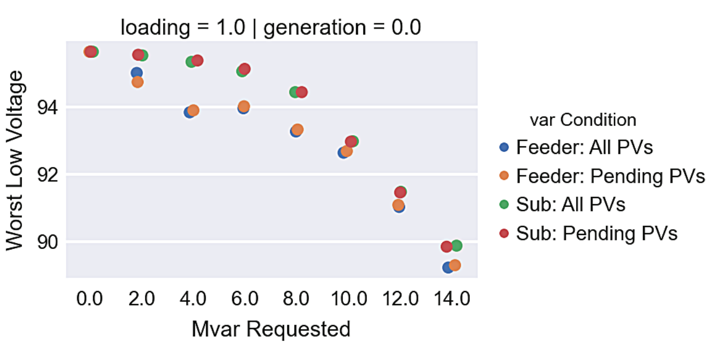


Figure 7. Example results

Impact Assessment Results

The impact assessment considered the four combinations of pending/all (pending and existing) PV and feeder-specific/all-substation PV, however, the results presented in this section focus on the all-substation results where solar deployment scenarios do not require the addition of devices to meet the reactive demand. Furthermore, the deployments scenarios considered in this section focus on all (pending and existing) PV such that the highest active power penetration is considered as well as PV furthest out on the feeders.

Feeder 1

The main takeaway from F1 study is that the inverters on the feeder cannot absorb any reactive power because voltages on the feeder begin to decrease below the ANSI lower limit when reactive power is requested as shown in Figure 7. These under-voltages become more widespread for as little as a 2 Mvar request during low generation and high loading conditions. Therefore, undervoltage is the limiting factor on the feeder and must be mitigated.

Adding a voltage regulator as shown in Figure 8 can mitigate the low voltages. This upgrade further allows the transmission system to request up to 10 Mvar from all (pending and existing) inverters across all feeders served from the substation. Slightly more reactive power could be requested (12 Mvar) if the transmission operator sends a request upon the distribution feeder in real-time when local transmission voltages are high. Therefore, more frequent and shorter duration reactive power request calls would need to be issued.

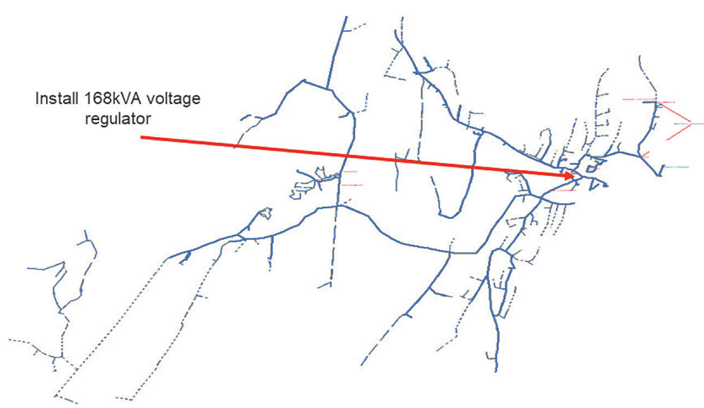
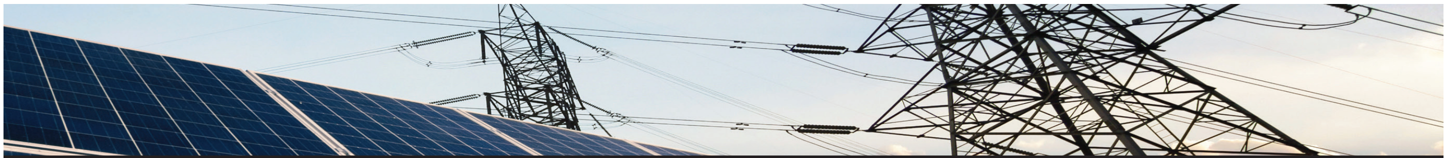


Figure 8. Feeder 1 mitigation measure applied



Additional takeaways from the baseline assessment include:

- Using just the PV on the specific feeder to absorb the requested reactive power would require the addition of reactive power devices such as reactors to meet to full request of the transmission operator. However, relying on the PV connected to the parallel feeders on the same substation may eliminate the need for additional devices.
- PV power curtailment occurs at full generation for all PV scenarios. This happens because the apparent power rating of most inverters is similar to the maximum active power output of the respective PV systems and thus the inverters cannot produce full active power and absorb full reactive power simultaneously.[7]
- The substation power factor will fluctuate considerably with the variation of active power generated and reactive power demanded by the inverters on the feeders.
- Approximately 10 additional regulator tap changes would occur for a 10 Mvar reactive power request by the transmission operator (based on modified steady-state power flow). The actual number of additional operations would depend on the actual magnitude of the reactive power requested and the number of times that the request from the transmission operator occurs over time.

Feeder 2

Feeder 2 is stiffer than Feeder 1, thus less impacted by distributed PV. The deployment condition of focus remains on all (pending+existing) PV served by all feeders at the substation. In this PV deployment, under-voltages begin to occur for a 12 Mvar request by the transmission system, while overloads begin with a 20 Mvar request. This important result highlights that S2 can theoretically perform the reactive power absorption equivalent of a 12 Mvar shunt reactor with no upgrades to its current set-up.

The mitigation required to alleviate these under-voltages involves adding a line regulator as shown in Figure 9. This mitigation measure prevents additional under-voltages until beyond a 24 Mvar request. To reach that magnitude of request, however, a 1,100 feet section of the feeder must also be reconductored to alleviate the overloads.

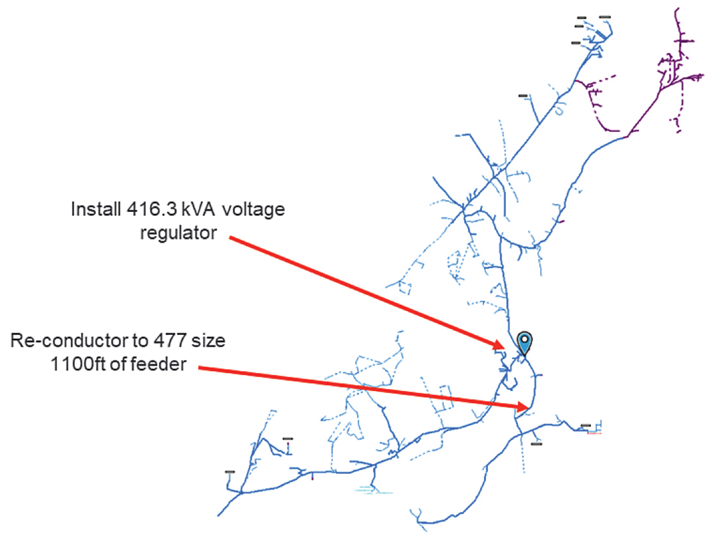


Figure 9. Feeder 2 mitigation measures applied

Additional takeaways from this feeder study are aligned with those described for F1 except that the additional regulator operations for a 12 Mvar request of reactive power would only induce approximately 4 additional tap operations during a single change in reactive power demand.

Summary of Results

Substation 1 can meet up to 12 Mvar of reactive power adsorption using all the PV connected to all it's feeders. This substation requires an upgrade in the form of voltage regulator at Feeder F1 as shown in Table 1 (on page 10) to eliminate all negative impacts on the distribution system.

On the other hand, Substation 2 can meet up to 12 Mvar without the need for any upgrades on it's feeders. Substation 2 can further meet up to 24 Mvar with a voltage regulator and reconductoring upgrade.

7 *Understanding Watt and VAR Relationships in Smart Inverters*. EPRI, Palo Alto, CA: 2019. 3002015102

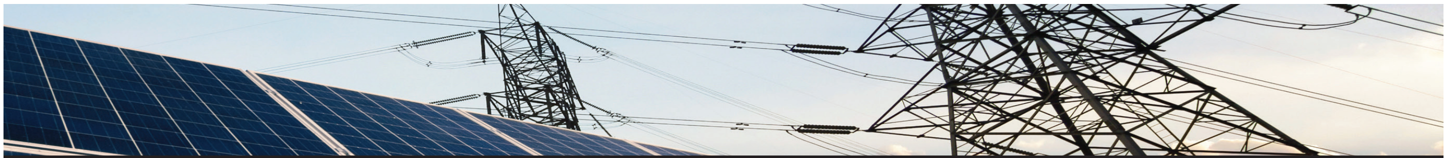


Table 1. Summary of required feeder level mitigation measures to reach a certain level of reactive power

Substation	VAR capability w/ no mitigation	VAR capability w/ mitigation	Type of mitigation	MW of DER needed	No. of DER sites needed
S1	0	12 Mvar	-168kVA voltage regulator	44.65	24
S2	12 Mvar	24 Mvar	-413.8kVA voltage regulator -1,100 ft reconductoring	69.11	30

Cost-Benefit Analysis

Once distribution level mitigation measures are determined for each feeder, the costs of smart inverter solution are compared to the costs of the shunt reactor to determine which is the least cost option. EPRI provided research estimates for costs in this analysis including asset costs, annual O&M costs, costs associated with accelerated equipment wear (related to potential for additional distribution regulator tap operations), energy costs due to PV curtailment, and communication and controls costs[8] for the smart inverter solution.[9] Given results from the impact analysis, only scenarios including all (pending and existing) PV were analyzed. This work does not consider the rate structure or other funding mechanism to implement such a solution.

Illustrative Mitigation Cost Assumptions

Asset Costs

Given assets have different expected lifetimes, mitigation costs shown in Table 2 are annualized based on EPRI's economic carrying cost methodology.[10] The economic carrying cost accounts for asset lifetime and replacement costs based on a 2%/year escalation rate.

Mitigation Scaling Factors

Given only one feeder was analyzed in detail per substation, feeder level mitigation costs are scaled to estimate total mitigation costs for a given substation location since DER on parallel feeders were also participating in reactive power absorption. For example, if mitigation analysis resulted in the need for 1,100 feet of reconductoring for the feeder analyzed, there is still uncertainty about the need for reconductoring on other feeders connected to the substation. Scaling feeder level costs gives an estimate for total mitigation costs needed across all feeders. The scaling factor is based on a high and low estimate from 4 different scaling options using data about the modeled feeder in comparison to all feeders connected to the substation. This includes:

- The number of feeders connected to the substation,
- The percent requested Mvar from the analyzed feeder compared to the total for the substation,
- The percent of PV penetration from the analyzed feeder compared to the total for the substation,
- The percent of load from the analyzed feeder compared to the total for the substation.

Table 2. Summary of mitigation asset costs used in the cost-benefit analysis

	Description	Unit	Cost[11]
Shunt Reactor[12]	Materials, Installation	per Mvar	$13,000
	Reactor Pad Containment and Foundation	per each	$4,200,000
	Annual Maintenance	per year each	$5,000
Reconductor to 3ø 477	Materials, Installation	per 1 mi	$792,000
	Annual Maintenance	per year each	$2,000
New Regulator[13]	Materials, Installation	per each	$20,000
Regulator Upgrade[14]	Materials, Installation	per each	$20,000

8 Given requirements of a communications and controls system were not assessed in this study, a communications and controls "cost ceiling" was used to show the maximum respective annualized cost for a communications and controls system to make the smart inverter solution more cost effective than the shunt reactor solution.

9 This economic analysis considers total capital and operating costs but does not consider who pays for the costs.

10 *Cost-Benefit Analysis of Grid-Connected Customer-Sited Distributed Energy Resources: Application Guidebook*. EPRI. Palo Alto, CA: 2019. 3002015765

11 Costs are based on EPRI estimates.

12 Costs are averaged across estimates of reactor sizes and types (oil vs dry).

13 For simplicity of analysis, an average regulator cost was assumed regardless of size.

14 From increased tap operations: assumes the regulator operates twice as often and fails in half the time it would otherwise. Represented as the difference in annualized cost between the original 25-year asset and a 12-year asset.

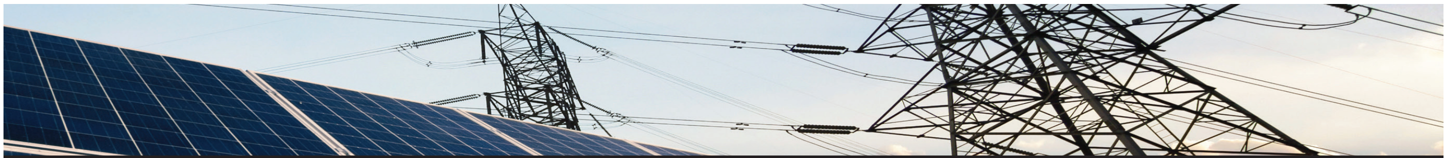


Table 3. Feeder and substation metrics used to estimate scaling factors

Scenario	# of Feeders	Requested Mvar	All Large PV (MW)	Load (MW)
Feeder 1	1	3.37	5.4	8.4
Substation 1	7	10	44.7	23.3
Feeder 2	1	5.64	14.4	3.6
Substation 2	5	12	69.0	28.9

A seen in Table 4, the high scaling estimate was 8.28 based on the percent of PV penetration from the feeder F1 – All PV case while the low estimate was 2.13 based on the percent of requested Mvar from the feeder F2 – All PV case. Thus, a range of 2x and 8.5x is used to scale mitigation costs. These scaling factors only apply to the cost of adding new regulators, the cost associated with miles of reconductoring. The costs associated with the accelerated regulator life is scaled for each scenario based on the number of feeders.

Table 4. Calculated scaling factors based on feeder and substation metrics

Scaling Factors by Different Scaling Options				
Scenario	**# of Feeders**	**% Requested Mvar**	**% Large PV**	**% Load**
F1 - All PV	7	2.97	8.28	2.77
F2 - All PV	5	2.13	4.79	8.03

High estimate per scenario
Low estimate per scenario
High/low estimate selected (rounded up/down respectively)

Illustrative Energy Costs

Given solar PV has no marginal cost of supplying energy, there is an economic cost associated with curtailing PV output because alternative sources of energy must be supplied instead. To estimate the cost of PV curtailment due to the reactive power request, energy costs used were based on the average market rate for marginal energy costs and renewable energy certificate costs.[15] As shown in Table 5, the total marginal energy cost used in this study was $50.84/MWh.

Table 5. Total marginal energy cost used in the cost-benefit analysis

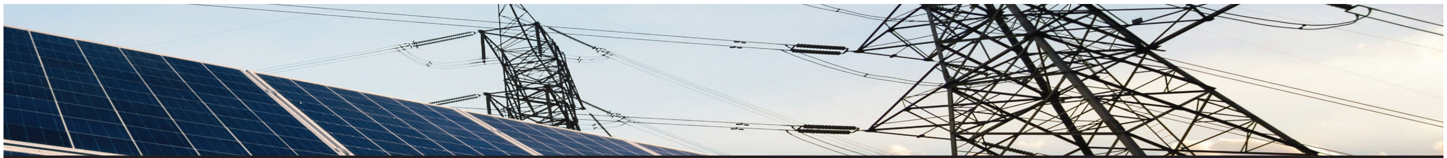
Marginal Cost	$/MWh
Average Marginal Cost of Energy[16]	$20.00/MWh
Average Marginal Cost of Renewable Energy Certificate[17]	$30.84/MWh
Total Marginal Energy Cost	$50.84/MWh

Estimating Solar PV Curtailment

A significant limitation of this study was estimating how often and how much reactive power would need to be absorbed by the smart inverters to adequately mitigate transmission level constraints. This has a direct impact on estimating how much real power might be curtailed from the solar PV systems. Therefore, a very conservative approach was used to assume that the reactive power request was always needed, resulting in a worst-case scenario for energy curtailment. To ensure reactive power absorption is available when needed, reactive power priority mode of operation of the PV inverter must be used. Reactive power priority operation would limit active power if the apparent power rating of the inverters is exceeded. Thus, a worst-case scenario assumes reactive power is needed during all times of high PV power output.

However, as illustrated in Figure 10 on the following page, the required power factor from each PV system changes for each scenario based on the PV capacity (MW) being used to absorb reactive power, and the amount of reactive power (Mvar) being requested. Thus, to estimate the amount of PV curtailment, NREL's system advisory model (SAM)[18] was used to simulate a fixed-tilt 30° south facing PV plant using 8,760 weather data for a typical year at a location in Massachusetts using typical meteorological year (TMY3[19]) data. SAM was used to simulate the annual energy production based on six different PV plant designs with different DC/AC ratios ranging from 1.0 to 1.5 in increments of 0.1.

[15] This is lower than the SMART tariff rate of about $188/MWh, which is what a solar PV developer gets paid per unit of energy generation based on the average pay-out for 1MW+ solar PV sites from the national grid SMART program administration.
[16] Based on averaged hourly (7am-5pm) ISO-NE Wholesale Price LMP at .H.INTERNAL_HUB. Source: ISO-NE.
[17] Based on averaged MA Class I REC Index 2020. Source S&P Global Market Intelligence.
[18] https://sam.nrel.gov/
[19] https://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/



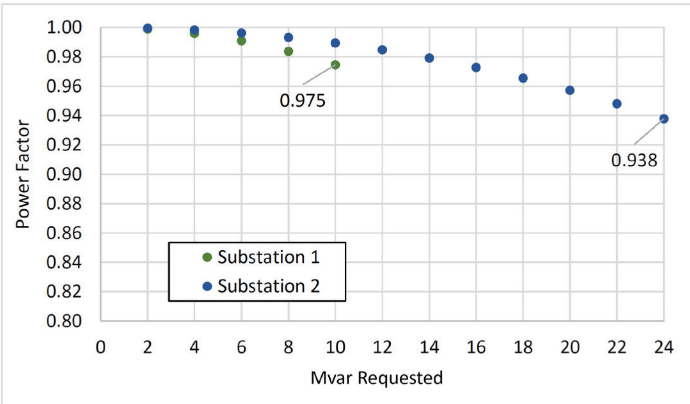


Figure 10. Required PV system power factor for different scenarios

Each of the resulting 8,760 profiles is analyzed to find how much energy would be curtailed for various power factor settings as shown in Figure 11.[20] These percentages were used to estimate the total MWh curtailment for each scenario in the cost-benefit assessment.[21] As shown in Figure 11, using a higher DC/AC ratio results in a higher level of curtailment. Thus, this study assumes a 1.5 DC/AC ratio for the high cost estimate and uses a 1.3 DC/AC ratio for its low cost estimate which is more in line with typical PV system designs in 2019.

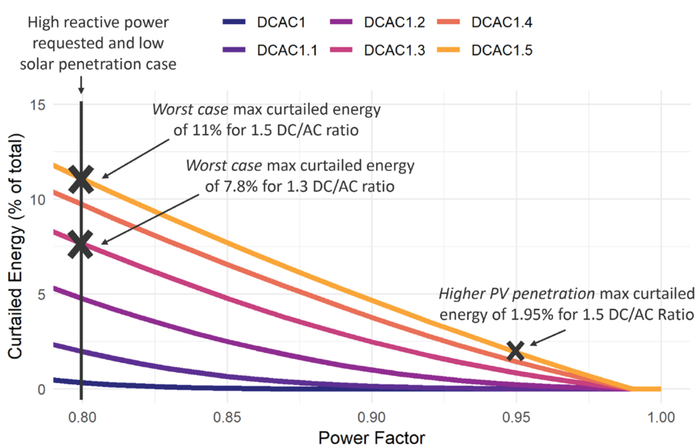


Figure 11. Estimated energy curtailment at different power factor settings and DC/AC ratios

Substation 1 CBA Results

Figure 12 shows the annualized costs for two different solutions to achieve 10 Mvar of reactive power request from the transmission system based on modeling results from S1. The shunt reactor is estimated to cost $331k per year based on EPRI's annualized cost estimates. Using a high cost estimate for the smart inverter solution, which assumes a scaling cost of 8.5x for new regulators and a DC/AC ratio of 1.5, results show an annualized cost of $76k per year. This results in a communication and control cost ceiling of $255k per year. Again, this is the required cost ceiling for a communications and controls system for the smart inverter solutions to be more economic than the shunt reactor solution. This study did not investigate the investment costs of distributed energy resource management system (DERMS) and/or advanced distribution management system (ADMS) that might be needed to implement the smart inverter solution nor does it consider the rate structure or other funding mechanism to implement such a solution. These costs can vary significantly from one implementation to another and hence is very difficult to estimate. The cost of the new regulators is estimated to be approximately $30k per year while the cost associated with the accelerated regulator upgrade due to additional tap operations is a negligible cost of approximately $3k per year.

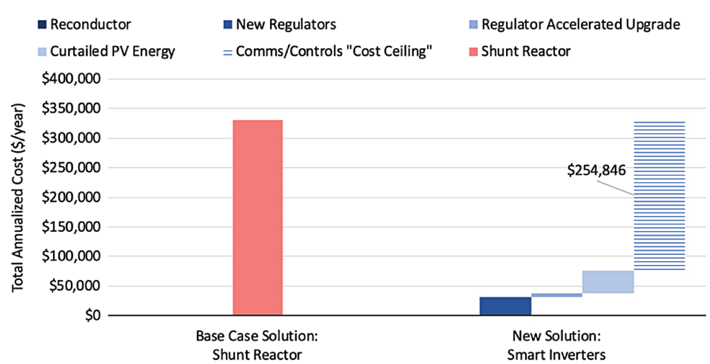
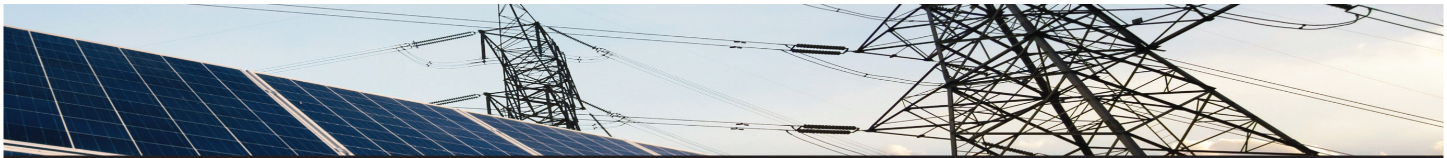


Figure 12. CBA results for Substation 1 using a conservative estimate of 8.5x mitigation costs, a 1.5 DC/AC ratio, and 10 Mvar of reactive power request

While the results for this single scenario using the high cost estimate and a reactive power request of 10 Mvar show that there is potential for the smart inverter solution to be more economic than the shunt reactor solution, a range of sensitivities looking at differ-

[20] This analysis was based on historical data to estimate total curtailment amounts and not to define set operating schedules based on forecasted operating conditions.
[21] This study assumed all inverters had a 1:1 KVA:KW ratio. Results may vary if the inverter KVA:KW ratio is different.



ent reactive power request levels and different cost scaling assumptions was examined. Figure 13 shows the results for the estimated communications and controls cost ceiling for each of the different smart inverter solution scenarios for a range of reactive power requests. The results reveal that for each scenario, the smart inverter solution could be more economic than the shunt reactor solution as long as the cost of communications and controls stays below approximately $250k per year. The low cost scenario shows that the communications and controls costs could be as much as $317k per year for the smart inverter solution to be more economic.

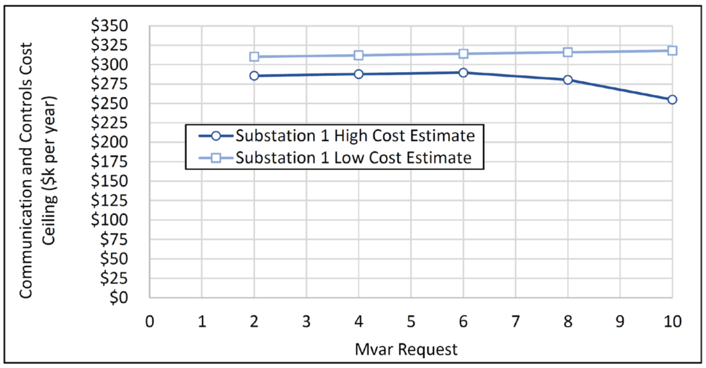


Figure 13. CBA results for Substation 1 using high and low cost estimates for a range of reactive power requests

Substation 2 CBA Results

Figure 14 shows the annualized costs for two different solutions to achieve 14 Mvar of reactive power request from the transmission system based on modeling results from the Substation 2. The annualized costs for the shunt reactor are estimated to be $335k per year. Using a high cost estimate for the smart inverter solution, which assumes a scaling cost of 8.5x for new regulators and

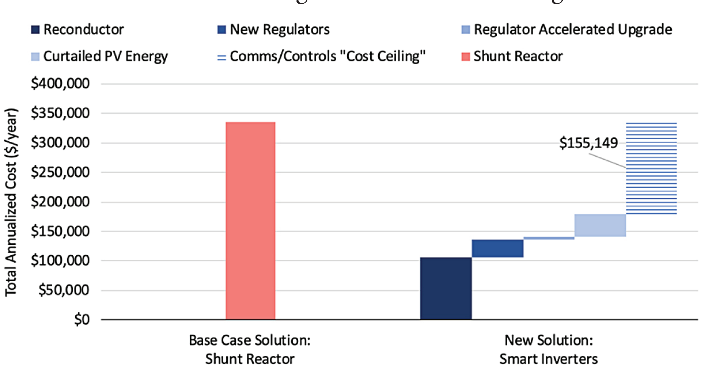


Figure 14. CBA results for Substation 2 using a conservative estimate of 8.5x mitigation costs, a 1.5 DC/AC ratio, and 14 Mvar of reactive power request

reconductor as well as a DC/AC ratio of 1.5, results show an annualized cost of $180k per year. This results in a communication and control cost ceiling of $155k per year. Similar to the results for Substation 1, the cost of the new regulators is estimated to be approximately $30k per year while the cost associated with the accelerated regulator upgrade due to additional tap operations is a negligible cost of approximately $3k per year.

Looking at a scenario with a larger amount of reactive power request, as show in Figure 15, the total amount of curtailed energy significantly increases, causing the estimate cost of curtailed PV energy to exceed to cost of the smart inverter to exceed the cost of the shunt reactor. Assuming a lower cost estimate using 2x mitigation costs and a 1.3 DC/AC ratio, as shown in Figure 16, results in a communications and controls cost ceiling of $207k per year.

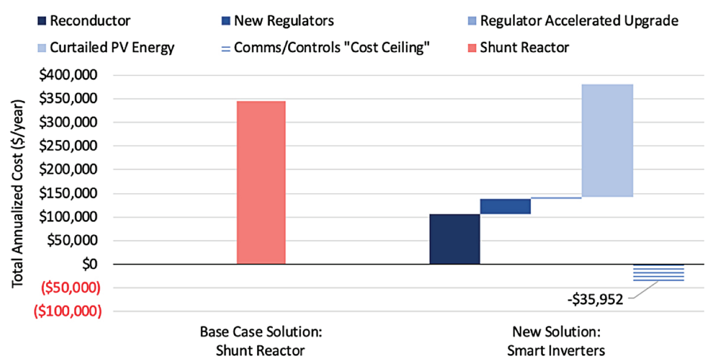


Figure 15. CBA results for Substation 2 using a conservative estimate of 8.5x mitigation costs, a 1.5 DC/AC ratio, and 24 Mvar of reactive power request

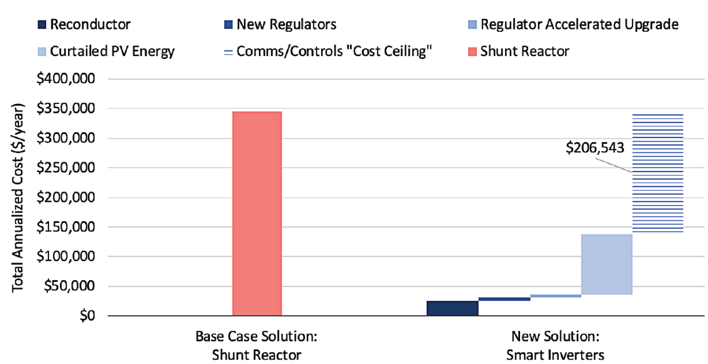
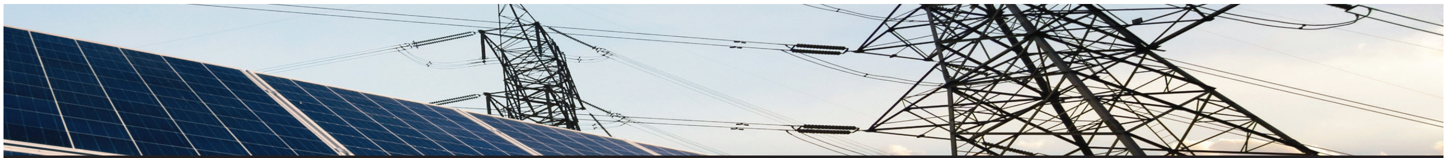


Figure 16. CBA results for Substation 2 using a lower estimate of 2.0x mitigation costs, a 1.3 DC/AC ratio, and 24 Mvar of reactive power request



Assessing the range of sensitivities at different reactive power request levels and different cost scaling assumptions as shown in Figure 17 reveals that only under the highest levels of reactive power requests is the smart inverter solution potentially more costly than the shunt reactor solution. The low cost scenario results could be more economic in all scenarios and shows that the communications and controls costs could be as much as $329k per year for the smart inverter solution to be more economic at a reactive power request level of 12 Mvar.

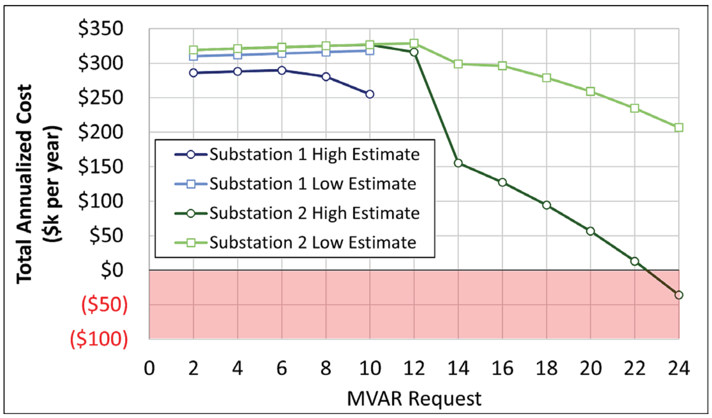


Figure 17. CBA results for Substation 2 using high and low cost estimates for a range of reactive power requests

Conclusions

Distribution connected PV can cause local voltage impacts that may be alleviated with smart inverters. At high enough penetration levels, these voltage impacts can also propagate to the transmission system. The use of the same smart inverters can also be used to alleviate the adverse transmission impacts, however, the control to do so must be coordinated with the distribution system such that the distribution assets do not cause additional adverse issues. This study is focused on identifying the extent for which inverter-based distribution resources can be used to alleviate transmission overvoltages.

The study examines how much reactive power can be drawn onto the distribution system before adverse distribution impacts occur, and furthermore, the mitigation required to increase the ability to draw more reactive power. The cost to achieve a desired distribution system reactive power request is ultimately compared to the cost of traditional reactor-based solutions on the transmission system.

The power system analysis found that significant amounts of reactive power can be absorbed on the two feeders studied. In many of the studied scenarios, using smart inverters coupled with a

General Findings

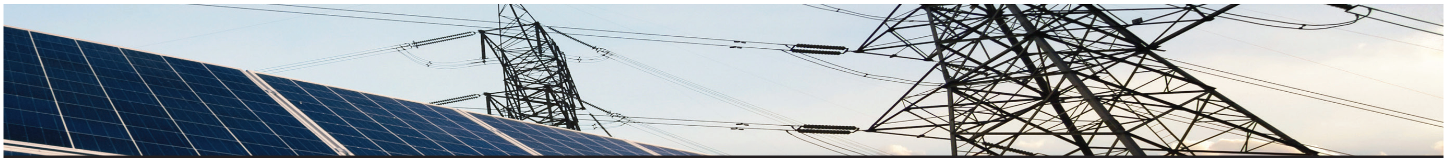
- High PV penetration is creating planning and operational challenges for transmission and distribution system operators.
- Smart inverters can possibly provide transmission solutions, however additional studies like the one presented here, certifications against standards like IEEE 1547-2018, and field demonstrations are needed to build confidence that distribution connected smart inverters can provide the required support reliably.
- The location of PV systems can significantly impact costs given that mitigation measures (e.g. reconductoring) are very dependent on location of interconnection.
- PV energy curtailment used in this analysis may overestimate real world curtailment. Using time series data to estimate when and how often the reactive power request is needed could help refine curtailment cost estimates.
- Results from this study show the smart inverter solution could be more cost effective at lower reactive power request levels because there is less PV energy curtailment required.
- Modeling impact requires major customization and study time, and tools that offer modeling for the interconnection of distribution and transmission are not readily available.
- Establishing a cost-effective, secured, and reliable communication and control system will likely be the most significant obstacle the utility will need to overcome to enable the smart inverter solution. The rate structure or other funding mechanism under which such a platform might be implemented was not considered as part of this study.

Findings from the Substation 1

- All scenarios show the smart inverter solution could be more cost effective than the shunt reactor as long as communication and controls costs remain below an annual cost of $250k per year to $318k per year.

Findings from the Substation 2

- Scenarios with 12 Mvar of requested reactive power or less resulted in the smart inverter solution being more cost effective than the shunt reactor as long as communication and controls costs remain below an annual cost of $315k per year to $329k per year.
- At higher requested reactive power levels, assuming worst case PV curtailment estimates, the shunt reactor solution may be more cost effective.



systemwide DERMS platform could be more cost effective than a reactor-based solution on the transmission system as long as the annualized cost of communications and controls is below approximately $250k to $300k per year. Note that the funding mechanism under which such a platform might be implemented was not considered as part of this study.

The study is limited to the examination of currently connected PV and pending PV on two different distribution feeders at two different substations. Alternative deployments of PV might have different capabilities and require different solutions. Similarly, required mitigation on adjacent feeders served off the same substation may be different than what was assessed on the two considered feeders. Overall, if a communications infrastructure were in place to assist in coordinating transmission and distribution system conditions, the analysis suggests that inverter-based distribution assets may have the ability to help mitigate transmission-based issues.

Future Work

The continuation of this work involves examining additional distribution feeders. The two examined in this report provide a range of potential impact. Analysis of additional scenarios would allow one to determine if the conclusions provided here are applicable at larger scale or limited to only certain conditions. Additionally, models containing all feeders served from a particular substation should be examined to quantify mitigation and costs across all feeders served. Furthermore, additional deployments of inverter-based generation should be considered along with its impact of load carrying capacity and losses. Limiting the analysis to the existing and pending generation does not capture the range in impacts that could occur on other feeders. Lastly, additional analysis examining the DERMS requirements for communication, control, and coordination between the transmission and distribution system, as well as an appropriate funding mechanism for its implementation, would be needed to develop and execute the smart inverter solution studied in this analysis.

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Distributed Energy Resources Integration (174)

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