Seasonal Cost-Benefit Analysis of Automated Distribution Feeder Upgrades with Advanced Mitigation Technologies

Michael Emmanuel and Yingchen Zhang

National Renewable Energy Laboratory

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Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

List of Acronyms

ADMS	advanced distribution management system
ANSI	American National Standards Institute
DER	distributed energy resource
DERMS	distributed energy resource management system
DISCO	Distribution Integration Cost Options
DPV	distributed photovoltaic system
EID	edge intelligent device
NPPF	nodal photovoltaic penetration factor
NREL	National Renewable Energy Laboratory
PV	photovoltaics
SCADA	supervisory control and data acquisition
VAR	volt ampere reactive

Executive Summary

The increasing deployment of distributed solar photovoltaics (DPV) to meet clean energy goals can trigger adverse grid operation issues, such as voltage excursions and violation of thermal loading constraints of the power delivery elements (e.g., lines and transformers) on the evolving electricity infrastructure. Such integration issues would require distribution upgrades with associated costs to mitigate them and to maintain reliable and resilient grid operating conditions. Traditional distribution network upgrade approaches use a specific single-snapshot analysis that is overly conservative. This study considers a multi-time point analysis to capture both moderate (probable bounds) and extreme grid operating conditions using time points such as minimum load with minimum photovoltaics (PV), maximum load with maximum PV, maximum load with minimum PV, and minimum load with maximum PV.

Further, this study investigates seasonal variation impacts and associated distribution upgrade costs for a spring season case (March, representing a low load and high PV scenario) and a summer case (July, representing a high load and high PV scenario). Such seasonal analysis will allow system operators to characterize upgrade requirements and associated costs across various periods.

Because the spatial distribution of DPV can impact upgrade and associated costs, this study investigates three common DPV deployment scenarios—randomly deployed, close to the substation, and far from the substation—at different penetration levels. Apart from spatial distribution impacts, this project evaluates the techno-economic impacts of the nodal photovoltaic penetration factor (NPPF) for generating the various DPV deployment scenarios at increasing penetration levels. This project investigates the impact of varying nodal PV-to-load ratios using conservative and extreme NPPF values of 3 and 10, respectively.

This study investigates the deployment of traditional infrastructure upgrade strategies, such as installing new voltage regulating equipment, transformers and lines replacements, and the activation of advanced inverter functionality (e.g., autonomous volt/var) in expanding PV hosting capacity. Existing DPV systems are assumed to operate with the legacy unity power factor, and we considered the possibility of retrofitting such systems with the activation of volt/VAR control as integration standards and regulations continue to evolve to allow such functions.

The cost-benefit analysis metrics used in study include distribution upgrade costs, average cost per watt of the upgrade cost, average marginal cost per watt of the upgrade cost, and power losses.

Key Findings

From the technical perspective, in the spring case, the feeder experiences more violations to grid operating conditions than in the summer case. For instance, there are more lines, transformers, and nodes with violations in the spring case than in the summer case. The reduced number of upgrades required during the summer months can be caused by high PV generation offsetting local loads, whereas during the spring months, overgeneration with minimum load can result in adverse grid conditions, such as lines and transformers overloads.

Nodal PV-to-load ratios and the spatial distribution of DPV can significantly impact distribution system operations, infrastructure upgrade requirements, and the cost of distribution upgrades and associated costs. As shown in Figure ES-1, a higher NPPF value increases the tendency of an early violation of line and transformer loading constraints; the violation severity is illustrated in red. Consequently, the NPPF value can impact distribution network upgrade requirements and associated costs. An emerging pathway to hosting capacity expansion is to limit the NPPF value of various DPV deployments in a distribution network.

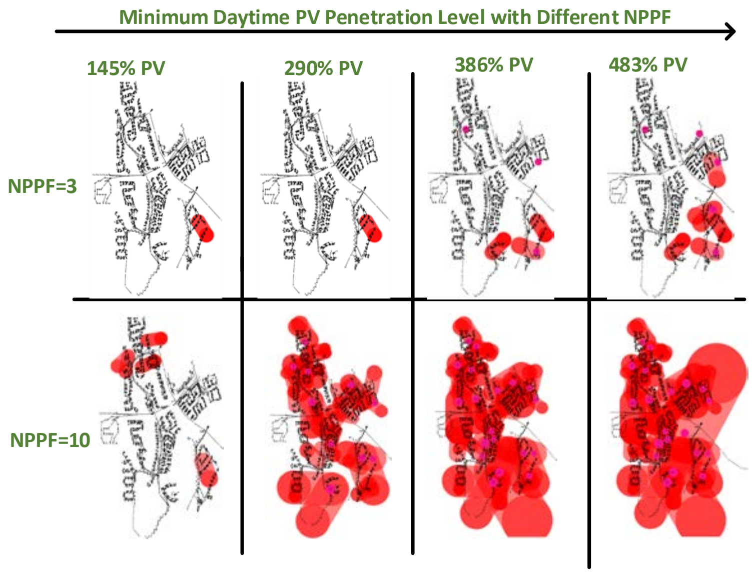

Figure ES-1. Impact of varying NPPF at different penetration levels

Although loading increases with increasing penetration levels, the DPV installed close to the feeder head experiences the highest transformer and line overload, followed by far DPV deployment, and then random installations, indicating a spatial diversity impact on thermal overloads. Also, VAR requirements for maintaining system voltage in volt/VAR control deployment can result in initial line and transformer overloads before upgrades; however, after distribution upgrades are performed, violations of thermal constraints are completely resolved. Even after upgrades, the unity power factor case still experiences higher thermal loading, especially for an NPPF value of 10.

In general, violations are easier to mitigate with volt/VAR control than by using the legacy unity power factor.

The deployment of local volt/VAR control significantly reduces the number of overvoltage violation buses outside Range B limits compared with legacy unity power factor deployment across all DPV scenarios. With volt/VAR control, the difference in nodal violations between both the spring and summer cases is significantly reduced. This shows that an investment in advanced inverter controls can maintain distribution upgrade costs across different seasons. Also, with volt/VAR control, the number of lines and transformers with violations is reduced to zero after upgrades, whereas with unity power factor, significant amounts of these elements still experience violations. This implies that with unity power factor, utilities might need to curtail PV production or apply system-wide solutions, such as advanced distribution management system

(ADMS) and supervisory control and data acquisition (SCADA) upgrades. The use of advanced inverter functions, such as volt/VAR, can limit the use of these system-wide solutions to mitigate thermal and voltage violations.

Figure ES-2 shows the distribution upgrade costs across investigated scenarios, with higher NPPF values and legacy unity power factor control resulting in higher upgrade costs.

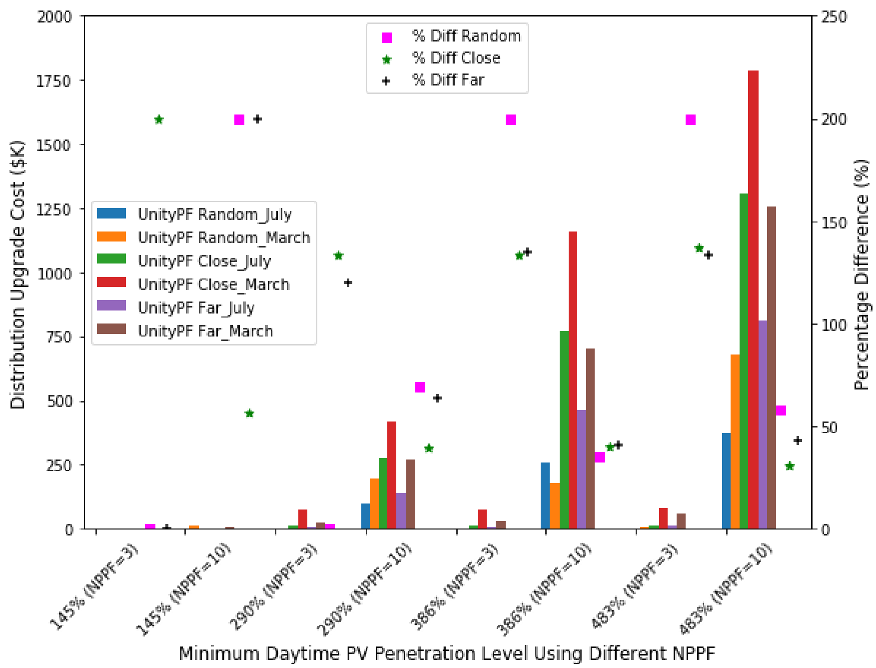

Figure ES-2 Distribution upgrade costs for legacy unity power factor cases

In all cases for unity power factor, the costs of upgrades during spring are higher than summer. For instance, for the close DPV systems, at 483% penetration with an NPPF value of 10, the difference in the upgrade costs between these two cases is 58%.

Figure ES-3 shows the distribution upgrade costs for the volt/VAR control cases across both seasons and NPPF values. This shows the impact of volt/VAR control on upgrade costs across different seasons. The use of advanced inverter control tends to maintain upgrade costs with less variations across both seasons. For instance, in both DPV systems deployed close to and far from the feeder head and operating with an NPPF value of 10, investment in advanced inverter control maintains the percentage cost difference between spring and summer at approximately 10%, compared to 58% for the unity power factor case. This shows that the utility's investment in advanced inverter control can maintain the upgrade cost across seasons.

With legacy inverters, the maximum distribution upgrade cost exceeds $1.75 million, whereas for volt/VAR control, the cost is less than $500,000 for the same season and scenario for the close DPV systems. Upgrade costs for unity power factor control are underestimated because there are still violations of the thermal and voltage constraints after upgrades. This implies that with unity power factor, utilities might need to curtail PV production or apply system-wide solutions, such as ADMS and SCADA upgrades.

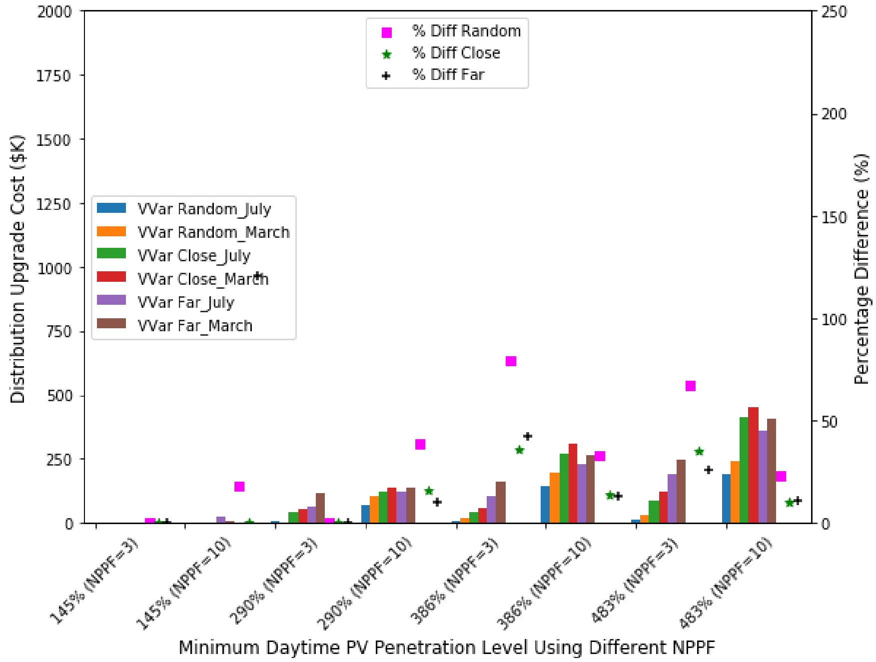

Figure ES-3. Distribution upgrade costs for volt/VAR control cases

As shown in Figure ES-4, the spring case with DPV systems operating with unity power factor and an NPPF value of 10 results in the highest average cost of upgrades, with a maximum average value of $0.23/W at a 483% penetration level, whereas the counterpart in summer has a maximum average value of 0.17/W for DPV systems close to the feeder head. This results in a percentage difference of 30.7%. For the volt/VAR case, as shown in Figure ES-5, the maximum average costs are 0.059/W and 0.053/W for spring and summer, respectively, resulting in a 10% difference. In general, for volt/VAR control, the differences in the average costs for both seasons are minimal. Further, this clearly implies that the combination of a high NPPF value and unity power factor is a more expensive solution than volt/VAR control and an optimal NPPF value. Also, the randomly deployed DPV systems result in the lowest average costs of upgrades.

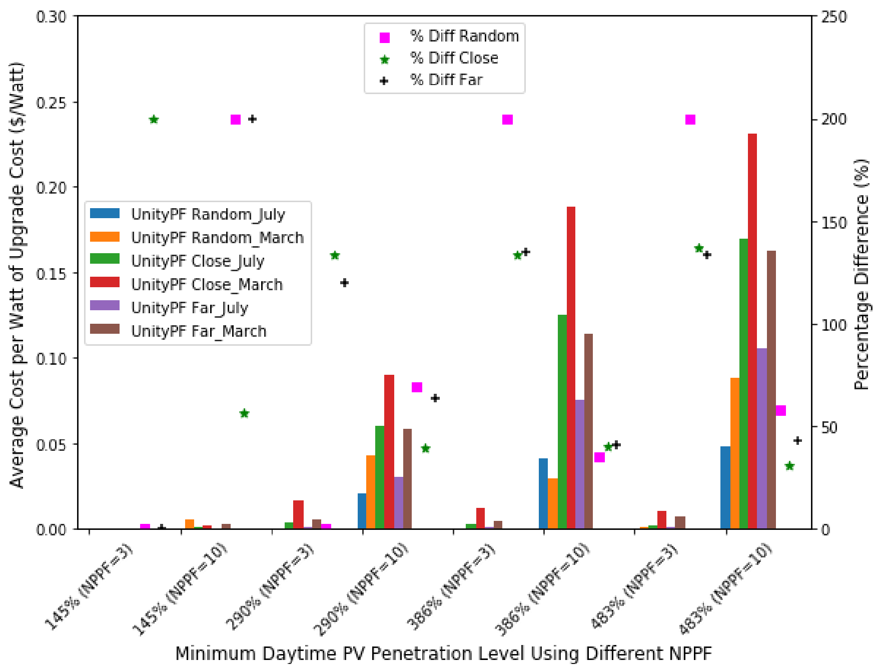

Figure ES-4. Average costs per watt of distribution upgrades for legacy unity power factor cases

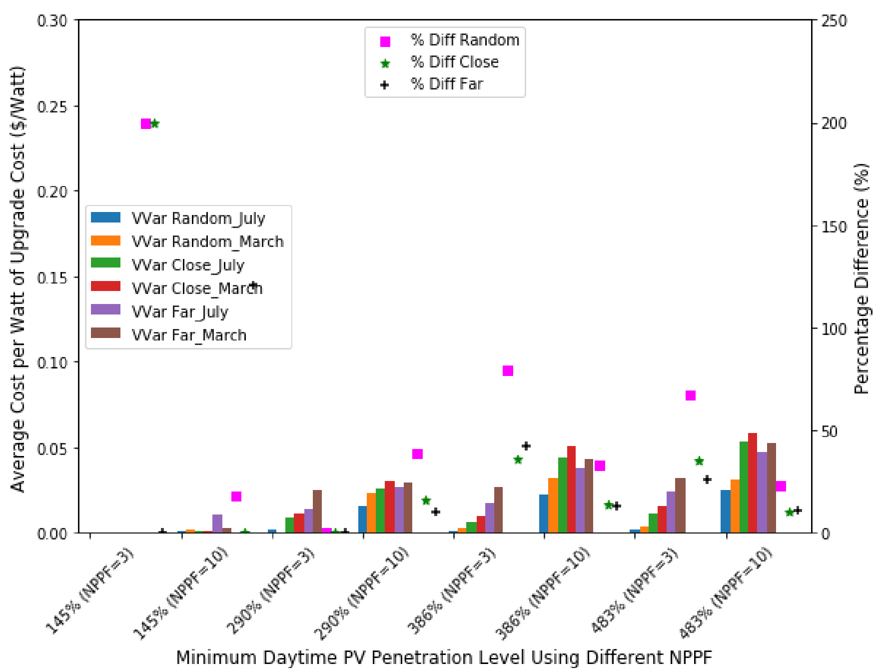

Figure ES-5. Average costs per watt of distribution upgrades for volt/VAR control cases

As shown in Figure ES-6, the integration of DPV systems reduces power losses as the penetration increases for all deployment scenarios except the far DPV system, which experiences a power loss increase from 386% during spring. Power losses are higher during the spring months than the summer months as the penetration increases except for the low penetration case, at 145%.

A higher NPPF value tends to result in higher power losses (line and transformer losses) in the distribution system as the DPV penetration level increases, as shown in Figure ES-6. This becomes very significant at a high penetration level of 483%, where DPV systems clustered far from the feeder head cause an increase in power losses—a 26% increase over the base case.

In terms of deployment scenarios, DPV systems deployed far from the feeder head cause the highest power losses than those close to the feeder head and random deployments. These losses can be translated into costs to determine the cost savings where power losses decrease or to determine the costs incurred due to increased losses with DPV deployment.

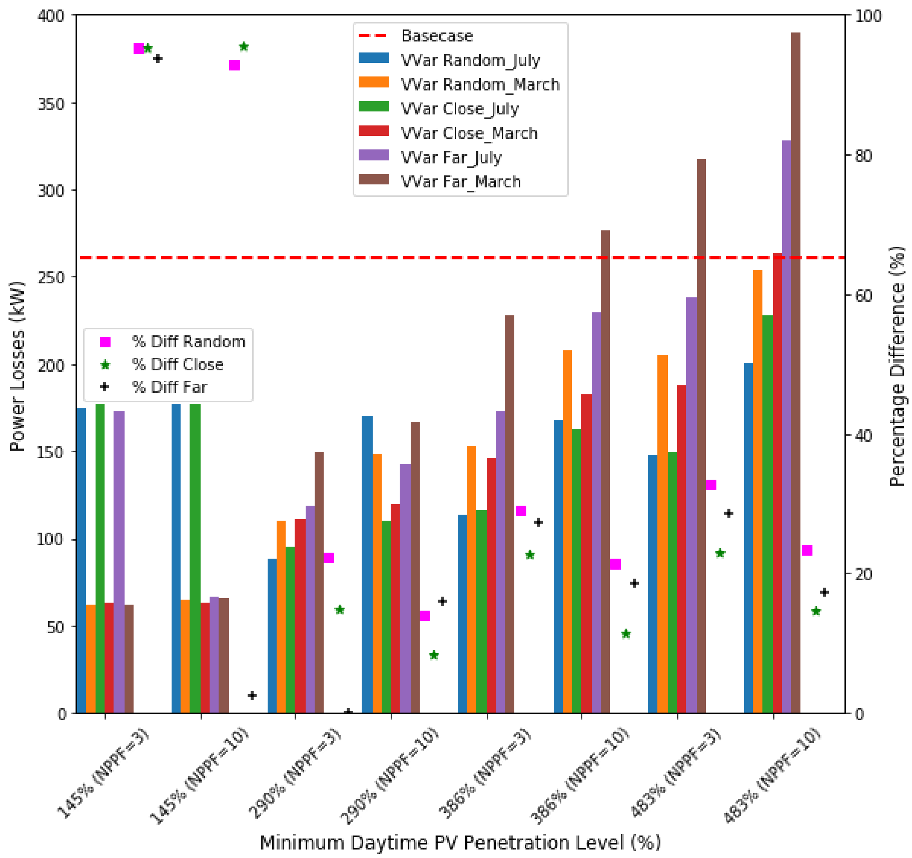

Figure ES-6. Power losses compared to the base case as DPV penetration level increases

Figure ES-7 shows the sensitivity of the distribution upgrade costs to thermal loading limits. In general, increasing the short-duration thermal loading limits from 100% to 125% of the nameplate rating decreases grid condition violations (thermal and voltage) and the associated upgrade costs. The 100% limit appears to be overly conservative, and increasing the short-term overloading limit can become an optimal pathway to hosting capacity expansion for the distribution network.

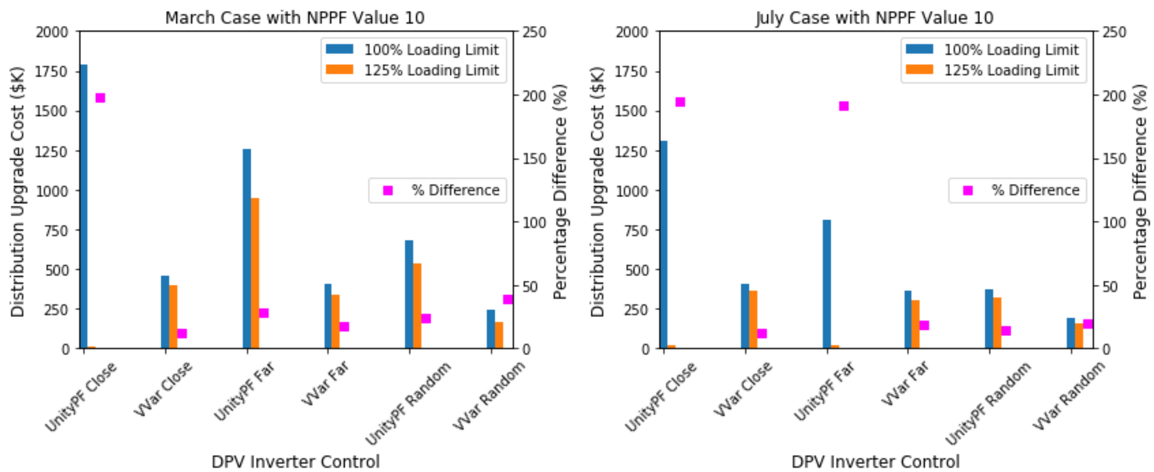

Figure ES-7. Sensitivity of distribution upgrade costs to thermal loading limits

This research shows that distribution upgrade costs can be minimized using autonomous volt/VAR control and siting DPV units in low-impact regions. High DPV penetrations can be achieved by changing the legacy unity power factor to advanced inverter controls, a solution that might have zero or near-zero marginal cost. Although we used heuristics to determine the NPPF values, using an optimal NPPF value can both delay the need for upgrades and minimize distribution upgrade costs.

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1 Introduction

The integration of distributed photovoltaic (DPV) systems has been projected to increase rapidly in the United States. For instance, the recent LA100 study projects an increasing deployment of DPV systems between 2.8 GW and 3.9 GW accompanied with storage integration by 2045 (Cochran et al. 2021), and Hawaiʻi's electric grid is predicted to achieve a renewable portfolio standard of 100% by 2045 (Hawaiian Electric 2017). This increasing penetrations of grid-connected DPV systems can be caused by a number of factors, such as the declining cost of photovoltaic (PV) modules; the scalability of deployment; demand for carbon-free power generation; and favorable policies, such as the solar investment tax credit (Mill et al. 2016).

The increasing deployment of DPV systems can trigger adverse grid operation issues, however, such as voltage excursions, disruption of network protection coordination, and violation of thermal loading constraints of the power delivery elements (e.g., lines and transformers) on the evolving distribution network (Horowitz et al. 2020). Such integration issues would require distribution upgrades to mitigate them and to maintain reliable and resilient grid operating conditions. The costs required to mitigate the violation of normal grid operating conditions are referred to as distribution upgrade costs. These costs include purchasing new lines transformers, reconductoring, changing control set points on existing equipment, and converting feeder voltage levels (e.g., from a 4.8-kV system to a 12-kV–15-kV system).[1]

Further, apart from distribution upgrade costs, other costs and benefits associated with DPV grid interconnection include:

- Protection equipment upgrade costs: Costs due to the upgrades required in distribution network protection coordination as a result of high penetrations of DPV systems. High penetrations of DPV systems can introduce reverse power flow, which could require protection equipment upgrades or redesigns of protection coordination within the distribution system (Horowitz et al. 2020).
- Power losses are in power delivery elements such as lines and transformers. The integration of DPV systems can either increase or decrease power losses, depending on siting and penetration levels. These losses can be translated into costs to determine cost savings where power losses decreased or costs incurred due to increased losses from DPV deployment (Emmanuel et al. 2017a; Horowitz et al. 2020).
- DPV production curtailment: The activation of advanced inverter functions such as volt/VAR and volt/Watt can lead to DPV energy curtailment. Ideally, this would require a time-series simulation to compute annual DPV energy curtailed (Giraldez Miner et al. 2018).
- Upgrade deferrals: DPV integration scenarios with a high coincidence factor between load and solar irradiance can provide capacity relief for power delivery elements, thus resulting in potential infrastructure upgrade deferrals (Emmanuel et al. 2017a).

[1] In general, older 4-kV networks are gradually being converted to 15-kV systems (e.g., 12.47-kV and 13.2-kV networks), which provide network advantages, such as increasing distributed energy resource penetrations, higher load-serving capacities, and decreases in power losses (Cochran et al. 2021).

- DPV soft costs: These are non-hardware cost components associated with DPV system integration, such as sales tax, installation labor, permitting, inspection, and interconnection (DOE 2021).
- Interconnection costs: These are costs associated with integrating DPV projects with the distribution network, including engineering and study costs, such as the cost of equipment to electrically and physically connect DPV units to the grid and determining suitable advanced inverter set points (Horowitz et al. 2018; Horowitz et al. 2020).

1.1 Hosting Capacity Expansion Pathways and Cost of Upgrades

Although mitigating adverse grid operating conditions caused by DPV system integration carries a cost, this could result in increased DPV hosting capacity that can be accommodated on the distribution network. Figure 1 shows that there are different pathways to achieving hosting capacity expansion.

1.1.1 Business-as-Usual Approach

A business-as-usual approach includes operating DPV systems with unity power factor coupled with traditional upgrade solutions, such as reconductoring; purchasing new lines and transformers; changing voltage regulating equipment set points; and installing, removing, or relocating equipment, including voltage regulators and capacitor banks.

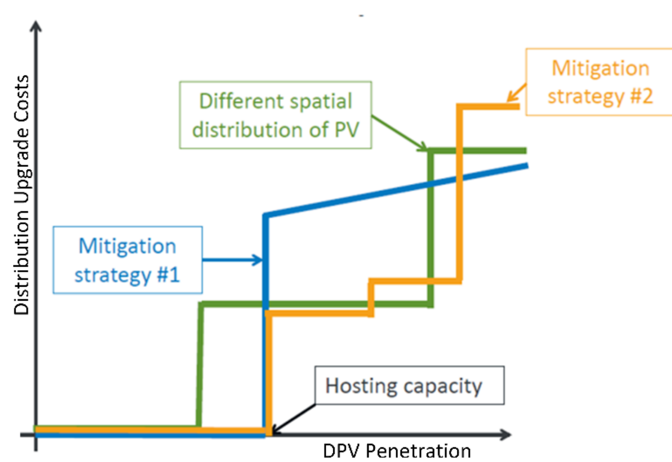

Figure 1. Distribution upgrade costs as a function DPV penetration

Adapted from Gensollen et al. (2019)

1.1.2 Distributed Energy Resource Pathway

Another possible pathway is the activation of grid support functions, such as volt/VAR and volt/Watt, for both existing and new DPV systems. Several studies have shown that, when activated, these grid support functions can increase hosting capacity by reducing the adverse effects of high penetrations of DPV, such as voltage rise (Giraldez Miner et al. 2018). The integration of diverse distributed energy resources (DERs) (e.g., hybrid DERs) can be considered another option to increasing DPV hosting capacity—for instance, DPV-plus-storage hybrid scenarios and exploring the complementarity of PV and wind. Another alternative under this pathway is the spatial distribution of DPV systems. DPV hosting capacity is sensitive to the DPV deployment scenarios—such as close to the feeder head, far from the feeder head, and randomly deployed—and to the nodal photovoltaic penetration factor (NPPF) values, which are discussed in a greater detail in Section 2: Methodology and Assumptions and Section 3: Results and Discussion.

1.1.3 System-Wide Solutions Pathway

System-wide solution approaches to increasing DPV hosting capacity include supervisory control and data acquisition system (SCADA) software upgrades, advanced distribution management system (ADMS), and distributed energy resource management system (DERMS) deployments. ADMS and DERMS applications provide advanced platforms for the utility to manage and control various DPV projects on distribution networks.

1.2 Context Within Larger Project Objectives

This study is part of the "Enhancing grid reliability and resilience through novel DER control, total situational awareness, and integrated distribution-transmission representation" project. One core objective of this project is to deploy edge intelligent devices (EID) colocated with DERs, as shown in Figure 2, to enable extreme levels of DER penetration and to enhance total situational awareness. This project proposes this system-wide alternative pathway, which aims at implementing an end-to-end solar energy optimization platform (e-SEOP) for solar situational awareness, integrating EIDs with cloud-based analytics using advanced algorithms and tools. The EIDs can be used to control multiple inverter set points to improve grid operating conditions. This report presents the cost of EIDs required for different DPV deployment scenarios at different penetration levels within the modeled distribution network.

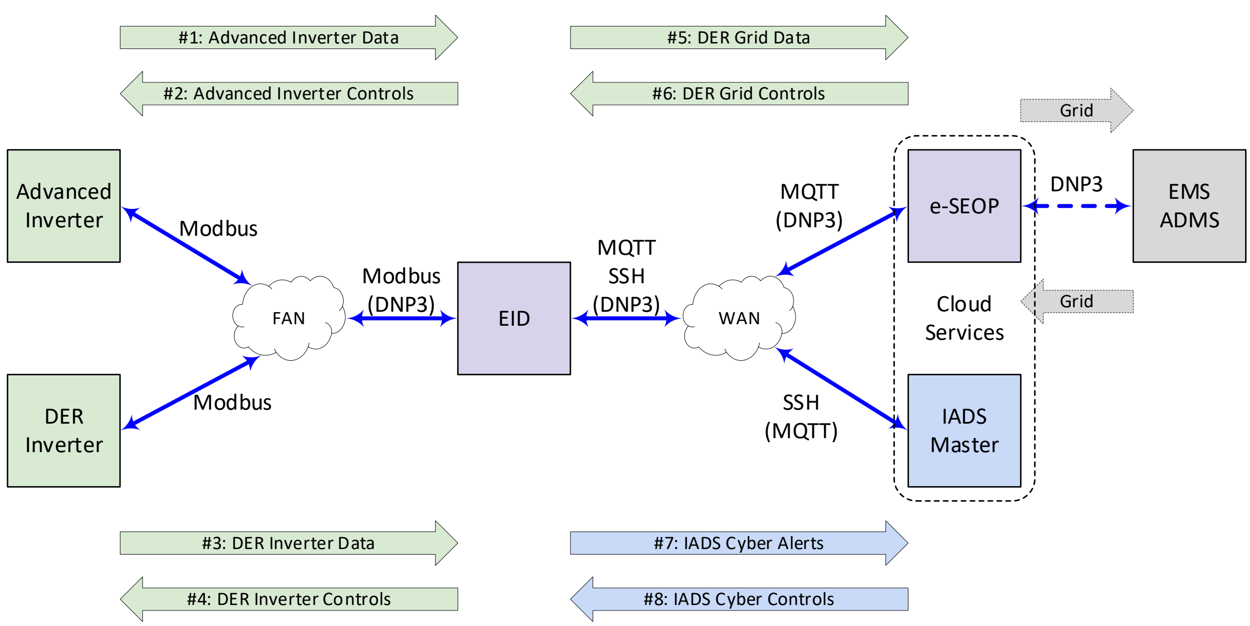

Figure 2. Architecture of an EID with an advanced inverter network

Utilities can choose to combine these various pathways to achieve hosting capacity expansion depending on several factors, such as customer needs, network topology, security, resilience and reliability requirements, and cost implications.

Key stakeholders—including customers, PV project developers, and utilities—are impacted by the costs and benefits of increasing DPV systems on the grid. The existing market structure and regulatory framework determines who incurs costs or receives accompanied benefits. Also, the need to enhance system reliability and resilience can increase these costs for both utilities and customers.

This study uses a real distribution feeder in the United States to investigate possible pathways for such DPV feeders to achieve hosting capacity expansion from the business-as-usual scenario. Detailed descriptions of the methodology and assumptions are presented in the following section.

2 Methodology and Assumptions

This study investigates various mitigation techniques for addressing the violation of grid operating conditions, mainly voltage and thermal constraints, as utilities continue to seek to expand DPV hosting capacity within the distribution network. As presented in the previous section, this project considers both business-as-usual and advanced mitigation strategies, such as the deployment of inverter-based grid support functions (e.g., volt/VAR), in curtailing adverse DPV impacts and facilitating higher DPV penetration levels. This study presents estimates of upgrade costs required to achieve target DPV hosting capacities on the modeled distribution network. Although this study considers only voltage and thermal constraints, other distribution network aspects can also be studied, such as protection and power quality.

2.1 Single-Snapshot Versus Multi-Time Point Analysis

Traditionally, distribution network upgrades are done by conducting a single-time snapshot analysis, which might not capture other contingent time points necessary to characterize system operations. This is currently the standard utility practice, and several studies have used this static, worst-case power flow scenario corresponding to minimum feeder load and maximum output from the DPV systems, usually at their rated power (Horowitz et al. 2018)**;** however, this provides overly conservative estimates without capturing other pivotal grid operating time points and conditions.

This project considers four different time points to represent moderate (probable bounds) and extreme grid operating conditions:

- Minimum load with minimum PV
- Maximum load with minimum PV
- Minimum load with maximum PV
- Maximum load with maximum PV.

The maximum load with minimum PV and minimum load with maximum PV time points represent bounding extreme conditions, whereas the minimum load with minimum PV and maximum load with maximum PV show moderate or probable grid operating conditions with integrated DPV systems. These time points impact the feeder loading conditions as the net demand changes with increasing adoption of DPV systems. As the hosting capacity increases, the net load decreases, and the power flow direction changes.

This study uses a customer-based PV penetration approach with the assumption that all customers have equal access to the grid except for flagged areas on the grid by the utility. Existing DPV units are assumed to operate with unity power factor and can also be retrofitted to operate with volt/VAR. This research work considers three DPV deployment scenarios—close to the feeder head, far from the feeder head, and randomly deployed—at different penetration levels. These scenarios have been chosen to show the impacts of DPV spatial distribution on distribution grid operating conditions and integration costs, and they capture a wide range of potential cost implications. Previous studies have shown that because the distribution grid is electrically weaker at the feeder end, DPV systems installed at such locations tend to exacerbate voltage conditions, and they are less severe when connected close to the feeder head (Emmanuel et al. 2017b; Palmintier et al. 2016). These scenario analyses can help guide the utility with low-cost and low-impact locations on the feeder for future DPV deployment.

In addition, we performed sensitivity analyses with different values of NPPF[2] for generating various DPV deployment scenarios at increasing penetration levels to evaluate the impacts of varying the nodal PV-to-load ratios. For this study, we used conservative and extreme NPPF values of 3 and 10, respectively. Figure 3 shows an example DPV deployment scenario with NPPF values of 3 (left) and 10 (right). As shown in Figure 3, an NPPF value of 3 has smaller-sized DPV units with larger spatial distribution, whereas the case of an NPPF value of 10 has larger-sized units and densely integrated DPV systems.

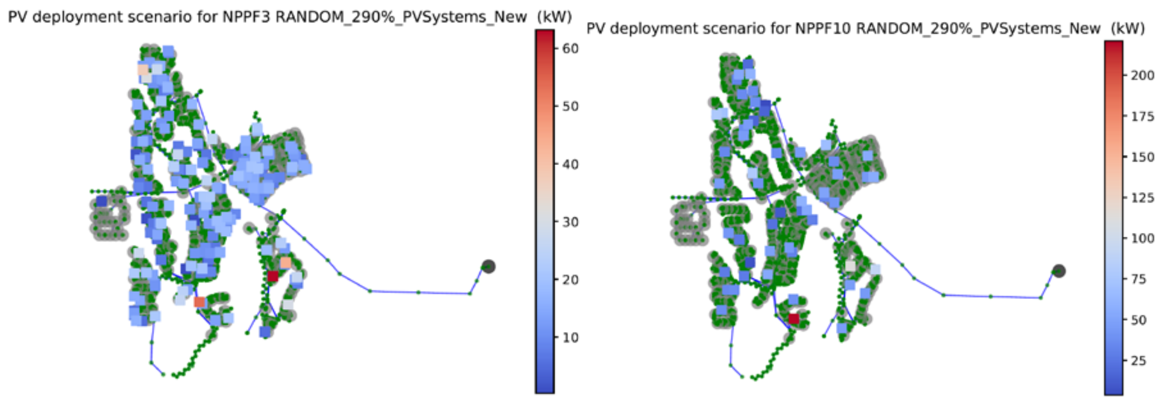

Figure 3. An example DPV deployment scenario with NPPF values of 3 (left) and 10 (right)

2.2 Feeder Characteristics

This study uses a real distribution feeder modeled and validated in OpenDSS for DPV system integration and analysis. We have leveraged a previous task that performed detailed primary and secondary distribution feeder modeling based on advanced metering infrastructure data supplied by the utility (Montano-Martinez et al. 2021). Figure 4 shows the distribution feeder with the existing DPV systems and other circuit elements. The detailed characteristics are presented in Table 1.

[2] A detailed methodology describing the scenarios of DPV generation with various values of NPPF is presented in Sedzro, Emmanuel, and Abraham (2022).

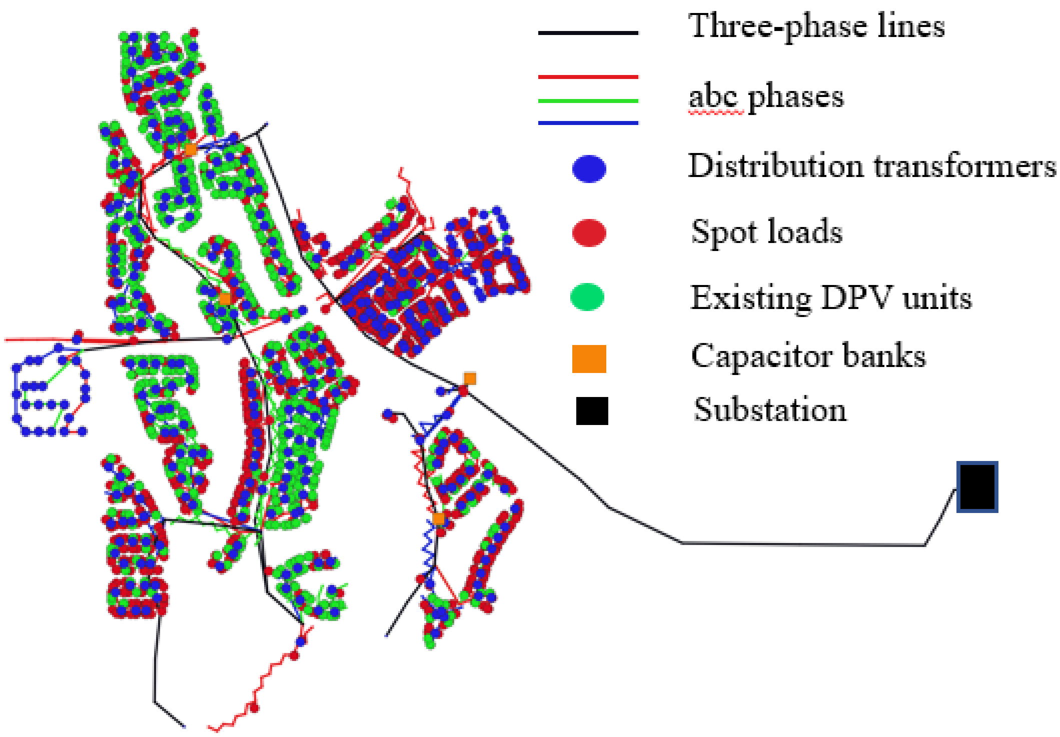

Figure 4. A real distribution feeder model

Table 1. Feeder Characteristics Used in the Analysis

Parameter	Value
Primary voltage (kV)	12.47
Maximum load (MW)	7.35
Maximum reactive power (MVAr)	1.15
Number primary section	1790
Number secondary section	5700
Number of distribution transformers	371
Number of customers	1715
Number of capacitors	4 (1.2 MVAr each)[3]
Maximum distance from substation to feeder node (km)	9
Existing DPV system total capacity (kW)	2091.56

This study uses volt/VAR advanced inverter control with full VAR at 0.44 p.u. of the inverter rating, which corresponds to a power factor of 0.9, as shown in Figure 5. The volt/VAR curve

[3] For the summer case, only one capacitor is turned on, whereas all four are turned off in the spring case.

has a deadband of ±0.03, with a full VAR injection and absorption at 0.94 p.u. and 1.06 p.u., respectively.

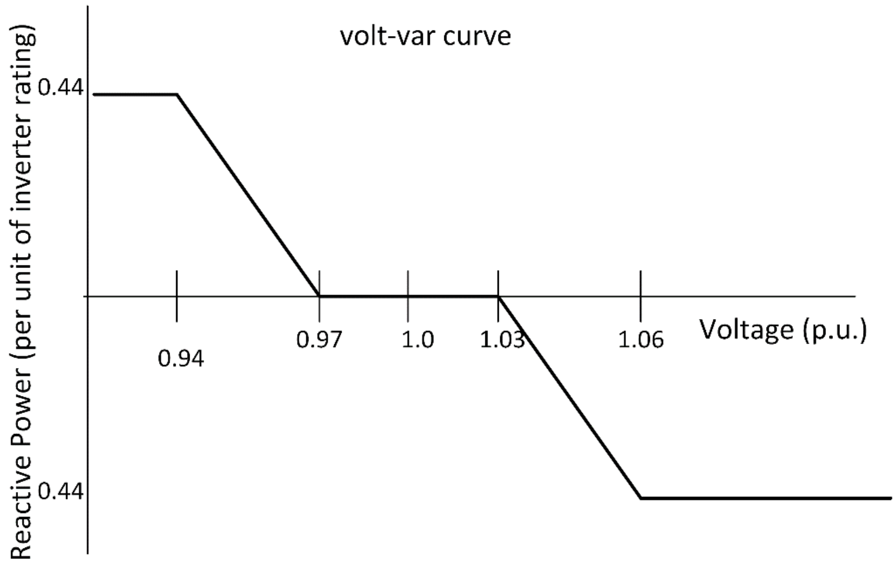

Figure 5. A volt/VAR curve used for DPV systems integration in this study

2.3 Power Flow-Based Limit Settings for Impact Identification

This study considers the following violation types and settings that would trigger the need for distribution upgrades:

- Overvoltage: any voltage value greater than the American National Standards Institute (ANSI) C84.1 Range B upper limit (1.058333). The overvoltage criterion is a limiting factor that can affect DPV hosting capacity because most distribution feeders are designed with the assumption that increasing demand would cause a voltage drop (Smith and Rylander 2012); however, depending on the deployment scenario and penetration level, DPV systems can cause significant high voltages.
- Undervoltage: any voltage value less than the ANSI C84.1 Range B lower limit (0.9167)
- Transformer overload: any value greater than 140% of the power rating. Distribution transformer loadings vary more widely than substation units. Some utilities greatly overload distribution transformer nameplate ratings without increases in failure rates (Grigsby 2007). Also, this is with the assumption that such overloads occur for a limited number of hours and is consistent with short-duration ratings for equipment.
- Line overload: any value greater than 100% of the power rating.

2.4 Cost and Benefit Metrics

- Distribution upgrade cost: These are costs incurred to mitigate the violation of grid constraints as well as voltage and thermal limits. They are estimated as a function of NPPF values and DPV system penetration levels.
- Power losses: These include line and transformer losses. DPV systems integration can either decrease or increase compared to the base case (no DPV case), depending on

several factors, such as DPV deployment scenario, penetration level, NPPF value, and inverter control function deployed.

- Average cost per DPV watt of upgrade cost: This cost is estimated as the ratio of the upgrade cost to the total rated (DC) watts of all PV units on that feeder at the target hosting capacity. This average cost metric can be used to characterize the economic viability of the upgrade cost under various cost allocation schemes. It can also be used to develop a fair scheme in allocating costs among various DPV systems (Horowitz et al. 2018).
- Average marginal cost per DPV watt of upgrade cost: This cost is calculated as the ratio of the upgrade cost to the marginal increase in the DPV hosting capacity or penetration level. This metric provides an evaluation of the upgrade's effectiveness relative to its cost (Horowitz et al. 2018).

2.5 Modeling Tools and Cost Database

PyDSS[4] is used to simulate the modeled 12.47-kV real distribution feeder with DPV systems integrated at increasing penetration levels. PyDSS provide a high-level Python package wrapped over OpenDSS[5] to expand upon its organizational, analytical, and visualization capabilities. It also uses opendssdirect.py[6] to provide a high-level Python interface for OpenDSS. PyDSS ensured accurate modeling of the volt/VAR inverter function used for DPV system control and provided enhanced convergence of controllers of all elements using a heavy-ball algorithm to manage fluctuations that characterizes a network with a large number of advanced inverters (Cochran et al. 2021; Giraldez Miner et al. 2018).

Distribution Integration Cost Options (DISCO)[7] is a Python-based software platform capable of conducting techno-economic distribution upgrade analysis. DISCO is used to generate DPV system scenarios for cases that are close to the feeder head, far from the feeder head, and randomly deployed, with different values of NPPF and penetration levels. Although DISCO can be used for sequential upgrades, this study uses DISCO for parallel upgrades to help the utility achieve the target hosting capacity.

2.6 Input Unit Cost Database

This task leverages the National Renewable Energy Laboratory (NREL)-compiled Distribution Grid Integration Unit Cost Database[8] that contains grid component data and cost estimates from a variety of sources, including utilities, developers, engineering consultants, and technology vendors. This database covers the hardware and software costs of various grid units and grid-related services, such as equipment removal and relocation. The proposed cost estimation is mainly driven by upgrade requirements and does not include operation-and-maintenance costs. The costs considered in this effort include the costs of new lines, transformers, reconductoring, changing of control set points, controller replacements, equipment relocation, and removal. This task uses the grid component costs from NREL's publicly available Distribution Grid Integration

[4] See https://github.com/NREL/PyDSS.
[5] See https://www.epri.com/pages/sa/opendss.
[6] See https://dss-extensions.org/OpenDSSDirect.py.
[7] DISCO will be released as open source shortly and will be available at https://github.com/NREL/disco.
[8] See https://data.nrel.gov/submissions/101..

Unit Cost Database (Horowitz 2019). This study computes the cost implications for the various upgrade needs for different DPV deployment scenarios at varying penetration levels.

2.7 Approach

Figure 6 shows the distribution upgrade cost framework adopted to estimate the costs and benefits of increasing the DPV hosting capacity of the studied distribution system from the current case[9] to the target hosting capacity.

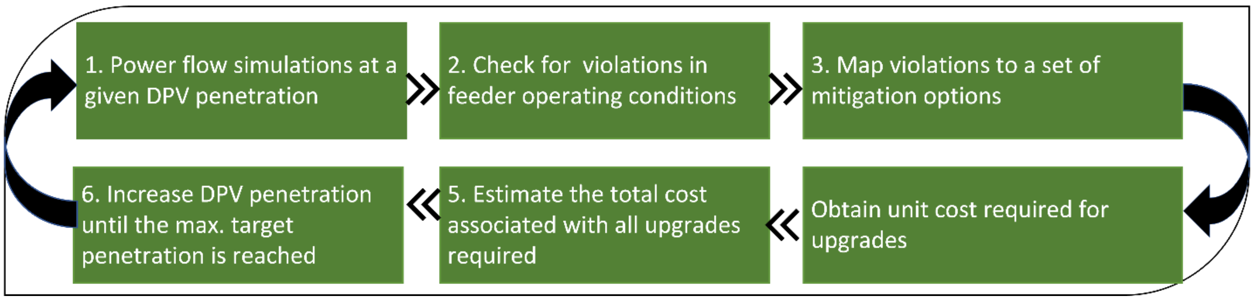

Figure 6. Distribution upgrade cost framework

Voltage and thermal constraint violations determined from the power flow performed using the NREL-developed PyDSS are passed on to an NREL-developed automated upgrade algorithm (Palmintier et al. 2021). The current capability allows upgrades such as upgrading existing transformers and reconductoring lines to increase their capacities, installing new transformers and lines, changing set points on voltage regulating devices, and installing new line voltage regulators.

The upgrade algorithm applies the PV and load and solves the power flow to first detect any thermal constraint violation on the lines and transformers. Usually upgrades triggered by overload conditions are performed first because such solutions tend to fix some voltage issues. The algorithm then stores the maximum loading from the power delivery elements from all time points. If there are any violations, upgrades are determined from the library built from the feeder model, and if the required upgrade is not available, parallel upgrades are applied. After fixing the overload-driven upgrades, the algorithm checks for remaining voltage violations and performs additional upgrades, starting from cheaper applications, such as adjusting voltage regulating device set points, before installing a new device.

[9] This represents the current system architecture with existing legacy DPV systems operating at unity power factor. The existing DPV system amounts to a penetration level of 131%.

3 Results and Discussions

This section presents results of the analysis performed on the studied distribution feeder. The impact of the NPPF value on the grid operating conditions and associated costs for required upgrades are discussed. Integral to this study is the deployment of EIDs as a system-wide solution to enhance DPV system visibility and situational awareness, consequently increasing its penetration level. Also, this section highlights the limitations of the approach used and future research studies.

3.1 Loading Impacts

Thermal loading constraints with DPV system integration have to do with changes in the feeder net demand. As the amount of DPV units increases, especially during minimum load conditions, the system net load can change drastically, and the resulting reverse power flow can cause adverse grid issues. Also, higher NPPF values can impact loading conditions and power flow directions.

This study shows that the NPPF value is a key factor in DPV integration for all deployment scenarios because of its resulting impacts on thermal loading and associated upgrade costs. As shown in Figure 7 for randomly deployed DPV systems, the higher NPPF value shows more loading impact with larger feeder sections affected by the integrated DPV than a lower NPPF value at the same penetration level. The shaded portions of the feeder represent areas with violations of thermal loading constraints caused by DPV systems integration.

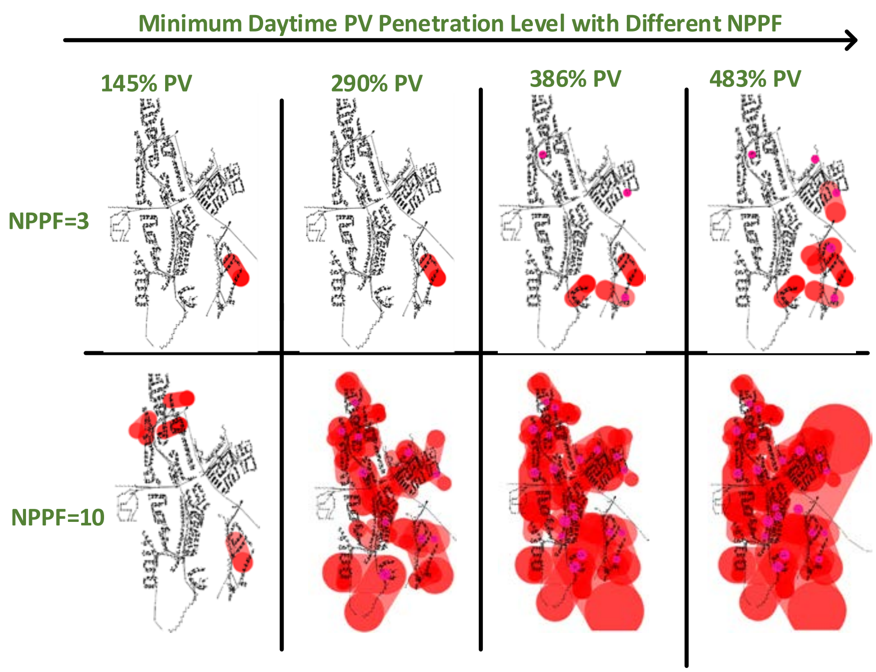

Figure 7. Impact of varying values of NPPF at different penetration levels for the randomly deployed DPV systems

Figure 8 shows the NPPF loading impact of DPV systems deployed close to the feeder head. Feeder sections close to the head are affected, and they are not as distributed as shown in Figure

7 for the random deployment. Again, an NPPF value of 10 results in greater sections of the feeder impacted by increasing deployments of DPV systems.

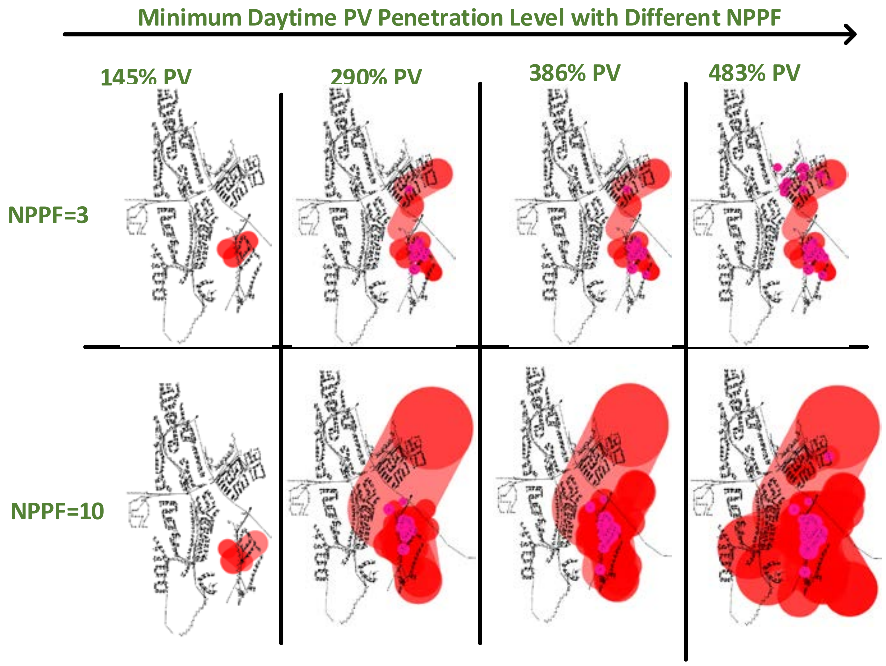

Figure 8. Impact of varying values of NPPF at different penetration levels for the close DPV systems

Figure 9 illustrates the loading impacts at increasing penetration levels of DPV systems deployed far from the feeder head. This deployment scenario appears to have the least loading impact compared with the other scenarios.

The results presented in Figure 7–Figure 9 show that a careful selection of the NPPF value is pivotal in limiting loading impacts, other adverse grid operating conditions, and the associated upgrade costs on the distribution feeder.

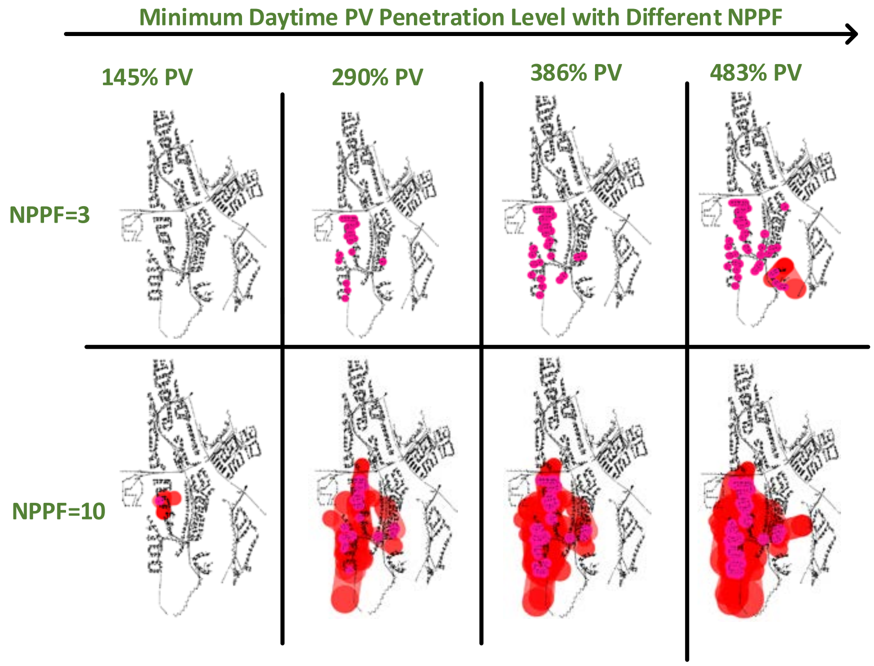

Figure 9. Impact of varying values of NPPF at different penetration levels for the far DPV systems

3.1.1 Transformer Loading Impacts

Figure 10, Figure 12, and Figure 14, respectively, show the maximum transformer loading observed for the DPV systems close to the feeder head, far from the feeder head, and randomly deployed at different penetration levels and for NPPF values of 3 and 10.

Figure 10 shows the maximum transformer loading observed for the close DPV deployment scenario operating with unity power factor at different penetration levels and for NPPF values of 3 and 10 across both seasons. The counterpart volt/VAR case is shown in Figure 11. For both inverter controls and seasons, an NPPF value of 3 results in lower transformer loading than an NPPF value of 10 at various penetration levels, which implies that a utility plagued by such overloads can increase its DPV hosting capacity with a lower cost by using a lower NPPF value. As shown in Figure 10 and Figure 11, higher transformer loading impacts occur in March than in July, with increasing DPV systems. Even after upgrades, the unity power factor case still experiences higher transformer loading, especially for an NPPF value of 10, as illustrated in Figure 10, whereas with volt/VAR control, the transformer loading reduces to approximately 100% of rating after upgrades, as shown in Figure 11. This shows that violations are easier to mitigate with volt/VAR control than with unity power factor.

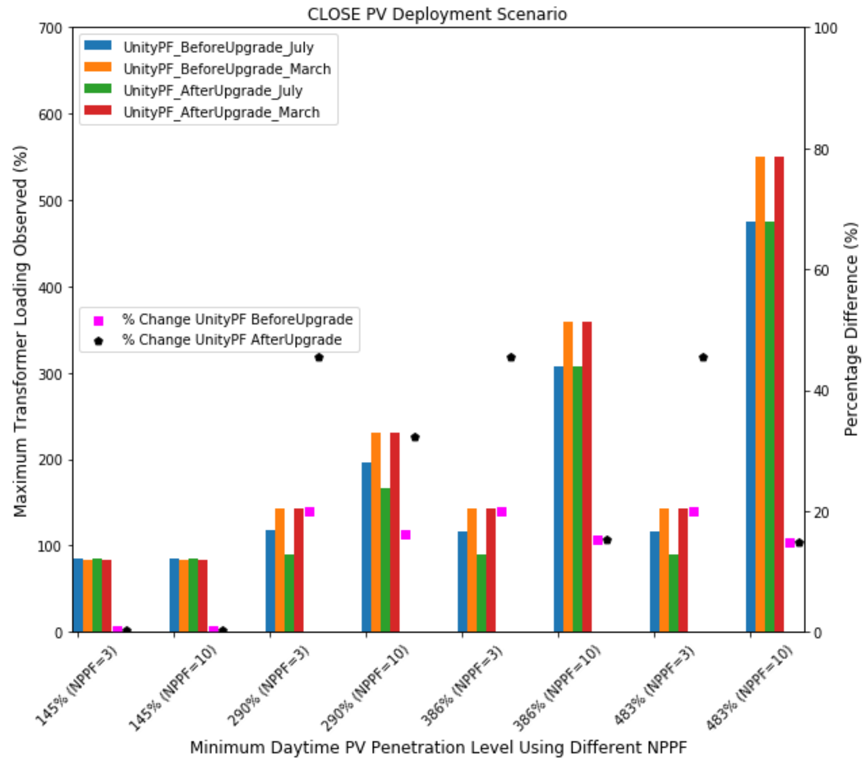

Figure 10. Maximum transformer loading for the close DPV scenario operating with unity power factor

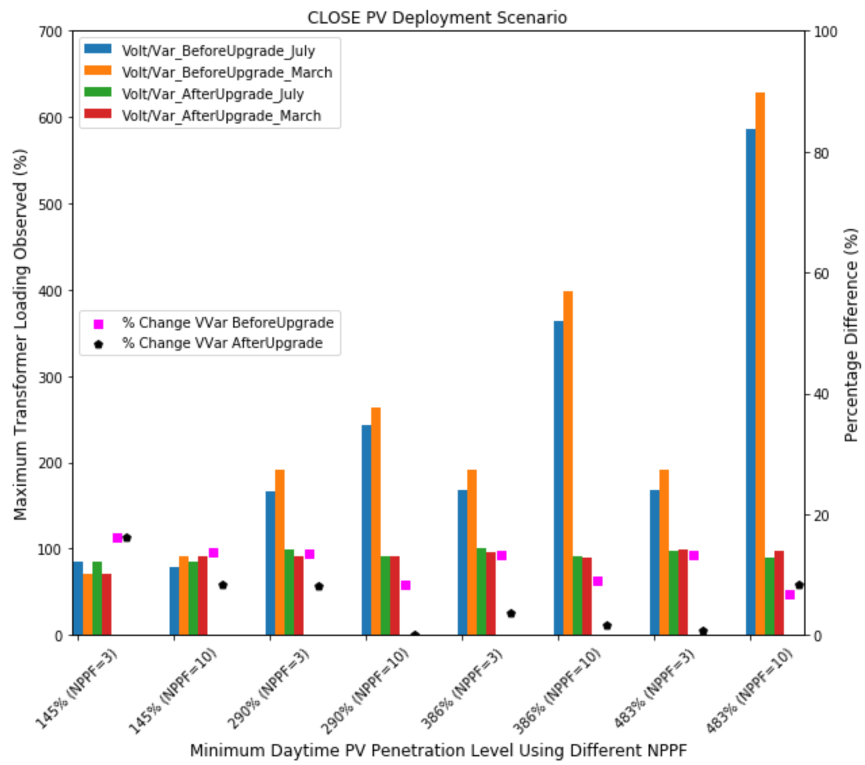

Figure 11. Maximum transformer loading for the close DPV scenario operating with volt/VAR control

Figure 12 and Figure 13 show the maximum transformer loading observed for the far DPV systems operating with unity power factor and volt/VAR control, respectively, at increasing penetration levels and for NPPF values of 3 and 10 across both seasons. DPV units deployed far from the feeder head show lower transformer loading than those deployed close to the feeder head.

The randomly deployed DPV units, as shown in Figure 14 and Figure 15, for unity power factor and volt/VAR controls, respectively, indicate the least transformer loading impacts compared to other deployment scenarios. Figure 11, Figure 13, and Figure 15 show that advanced inverter controls can be used to mitigate transformer overloading conditions after upgrades. This further indicates that thermal violations are easier to mitigate with volt/VAR control than with unity power factor.

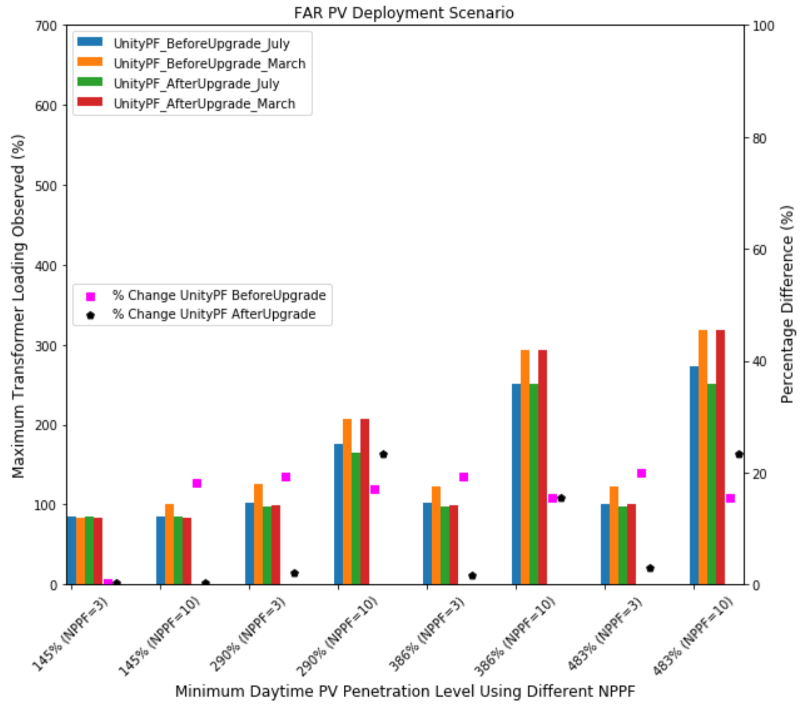

Figure 12. Maximum transformer loading for the far DPV scenario with unity power factor

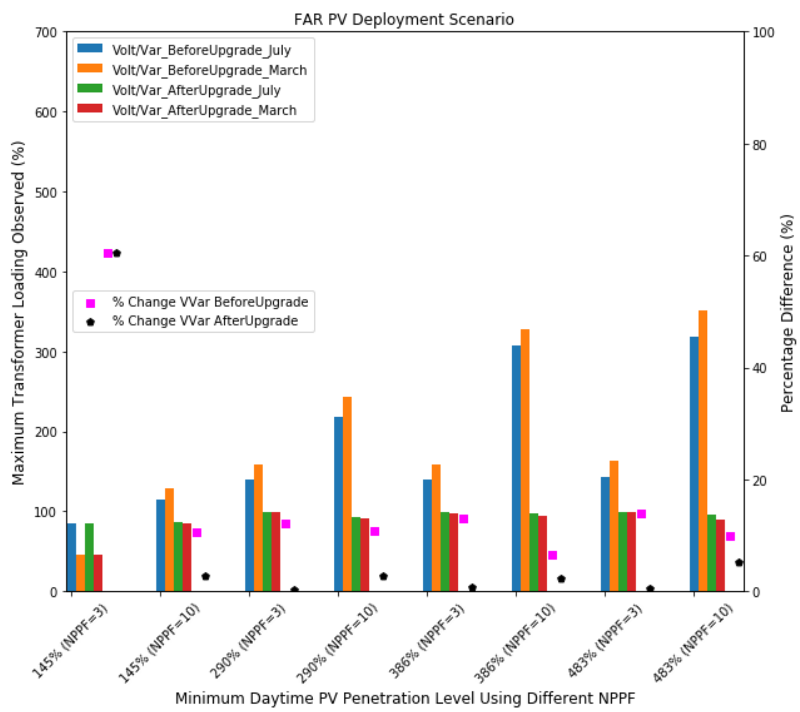

Figure 13. Maximum transformer loading for the far DPV scenario with volt/VAR control

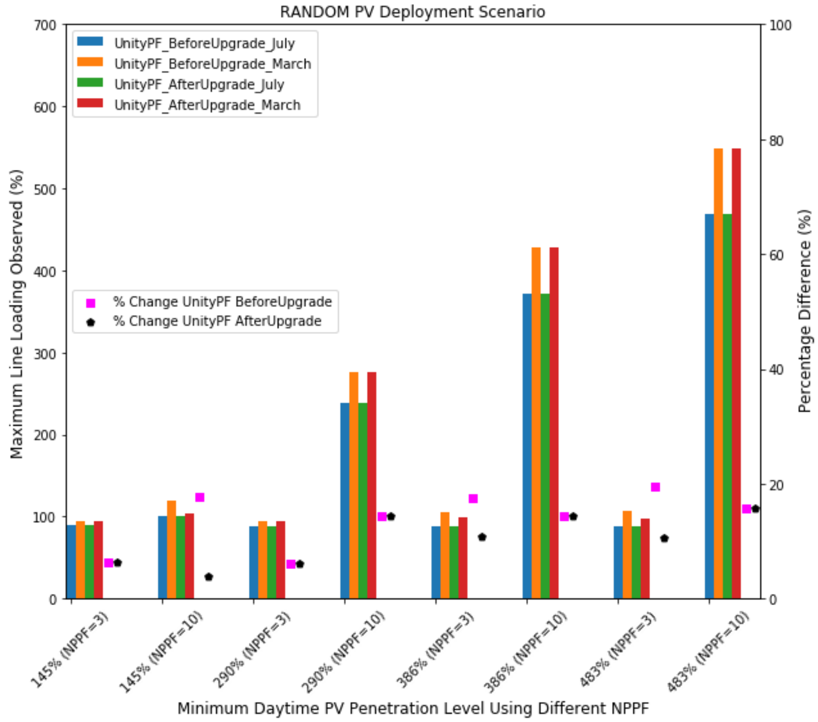

Figure 14. Maximum transformer loading for the randomly deployed DPV scenario with unity power factor

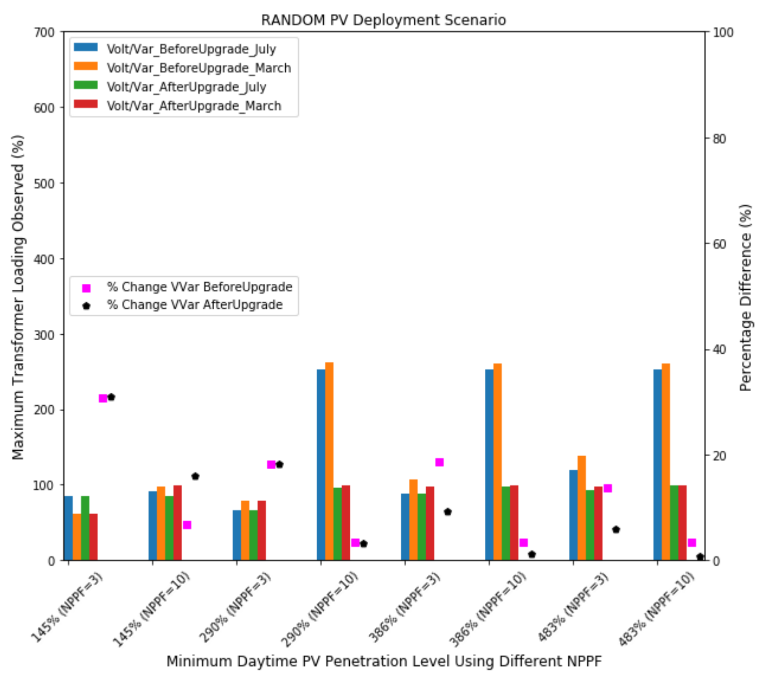

Figure 15. Maximum transformer loading for the randomly deployed DPV scenario with volt/VAR control

Although transformer loading increases with increasing penetration levels, the DPV installed close to the feeder head experiences the highest transformer overload, followed by far DPV deployment, and then random installations, indicating a spatial diversity impact on thermal overloads.

For all DPV deployment scenarios, an NPPF value of 3 results in lower transformer loading than an NPPF value of 10 at various penetration levels, which implies that a utility plagued by such overloads can increase its DPV hosting capacity with a lower cost using a lower NPPF value. Before transformer upgrades, especially at higher penetration levels, volt/VAR slightly increases the transformer loading more than unity power factor because of the VAR requirement needed to maintain voltage, and then after upgrades, the loading drops significantly for all deployment scenarios.

Even after transformer upgrades at higher penetration levels , unity power factor control still has violations, with loading exceeding the set threshold of 100% of the nameplate rating, as shown in Figure 10, Figure 12, and Figure 14. This implies that with unity power factor, utilities might need to curtail PV production or apply system-wide solutions, such as ADMS and SCADA upgrades.

3.1.2 Line Loading Impact

Figure 16–Figure 21 show similar tendencies with transformer loading concerning the impact of conservative and extreme NPPF values on line loading.

Figure 16 shows a high line loading condition, especially with an NPPF value of 10 and unity power factor, which will restrict the capacity of the DPV system deployed close to the feeder head. For instance, for DPV penetration levels from 290%–483%, line loading increases up to approximately 600% during the spring and approximately 500% of nameplate rating during the summer before and after upgrades, as illustrated in Figure 16. After upgrades, however, for the volt/VAR control case, the maximum line loading reduces to less than 100% of rating, as shown in Figure 17. Similar outcomes are obtained for the far and randomly deployed DPV systems, as shown in Figure 18–Figure 21.

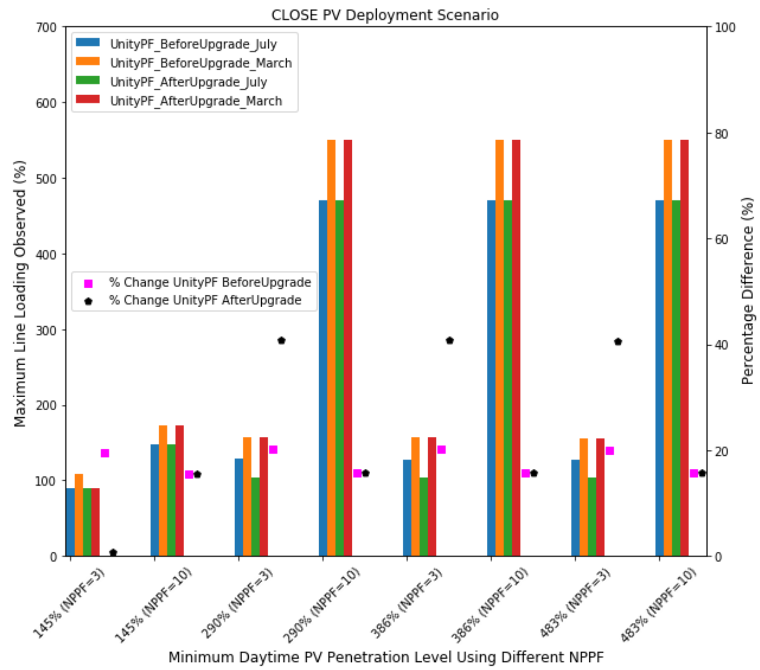

Figure 16. Maximum line loading for the close DPV scenario with unity power factor

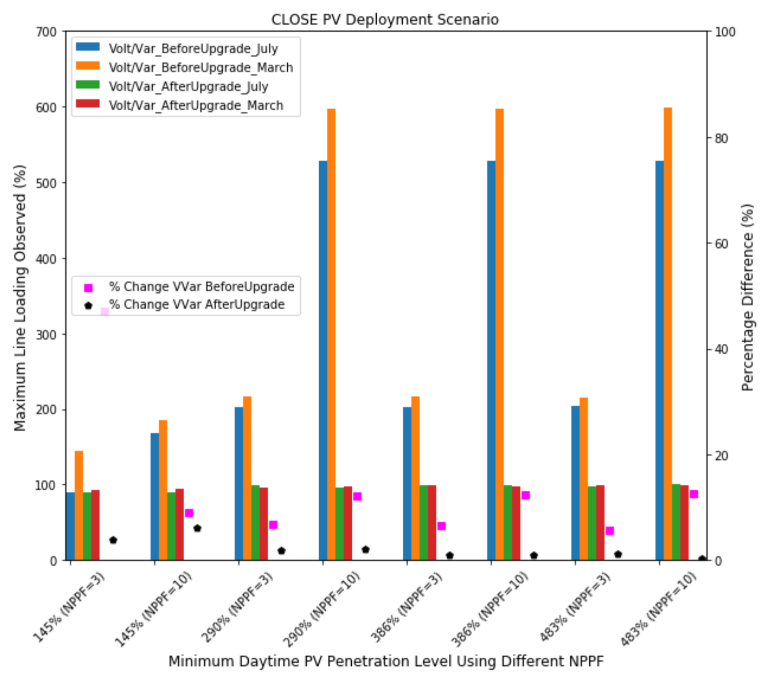

Figure 17. Maximum line loading for the close DPV scenario with volt/VAR control

DPV systems installed far from the feeder head, as shown in Figure 18 and Figure 19, experience the least line loading compared to the close and random deployments. Also, because of the VAR requirement, volt/VAR control results in a slight increase in line loading before upgrades, and after upgrades, loading is significantly reduced.

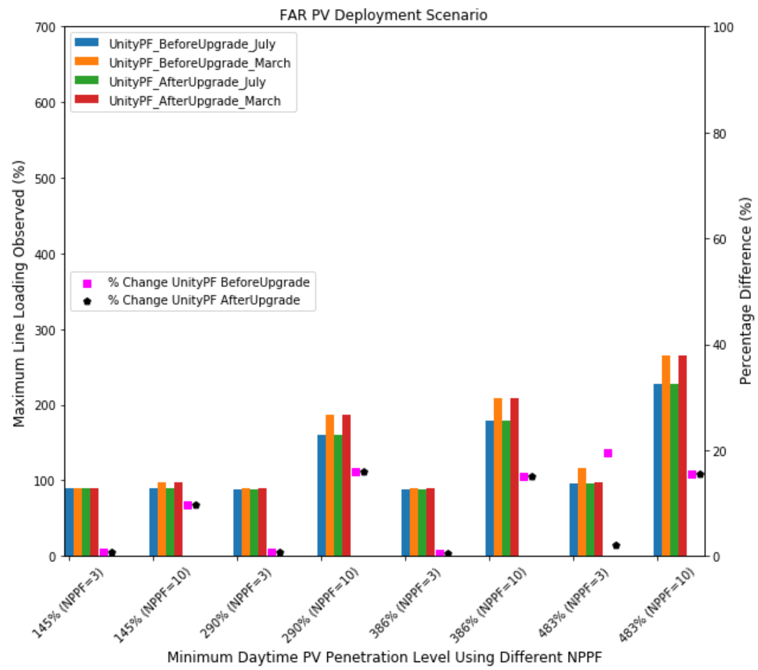

Figure 18. Maximum line loading for the far DPV scenario with unity power factor

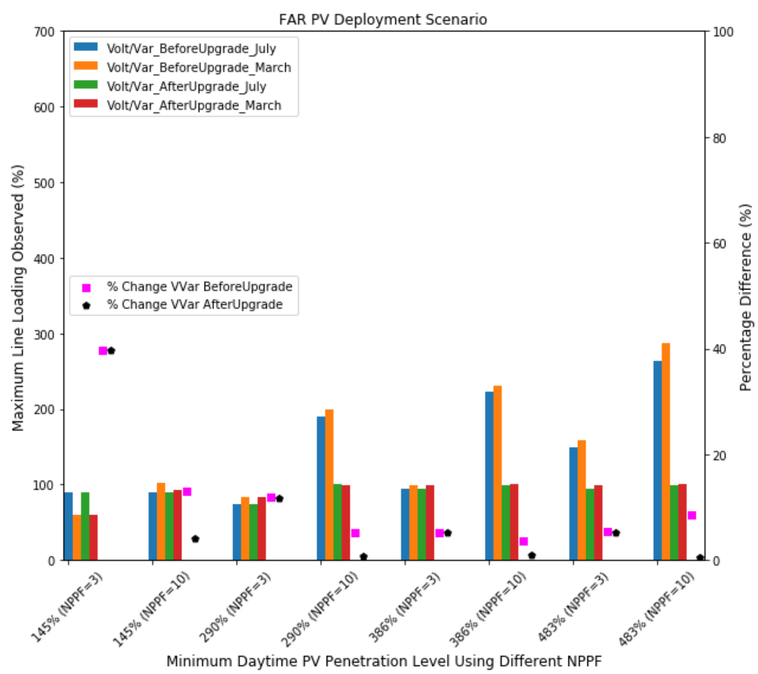

Figure 19. Maximum line loading for the far DPV scenario with volt/VAR control

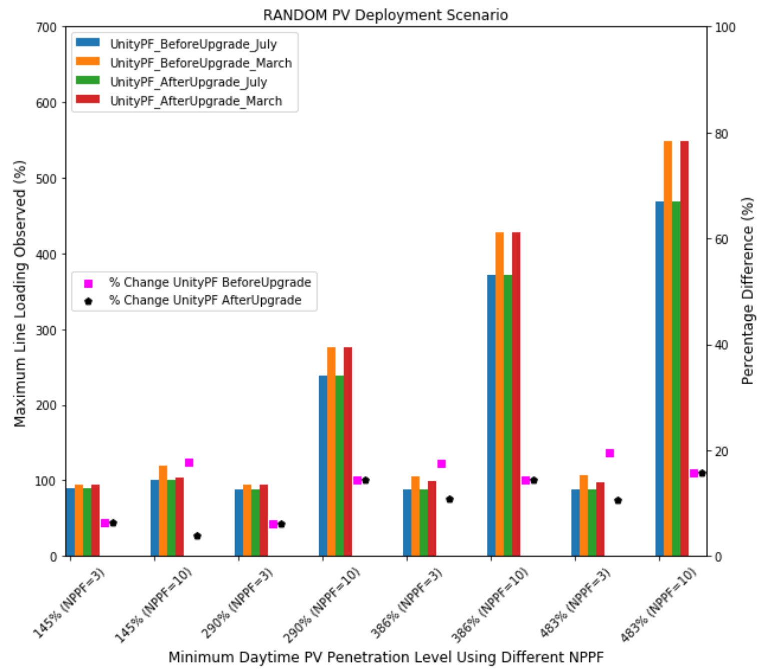

Figure 20. Maximum line loading for the randomly deployed DPV scenario with unity power factor

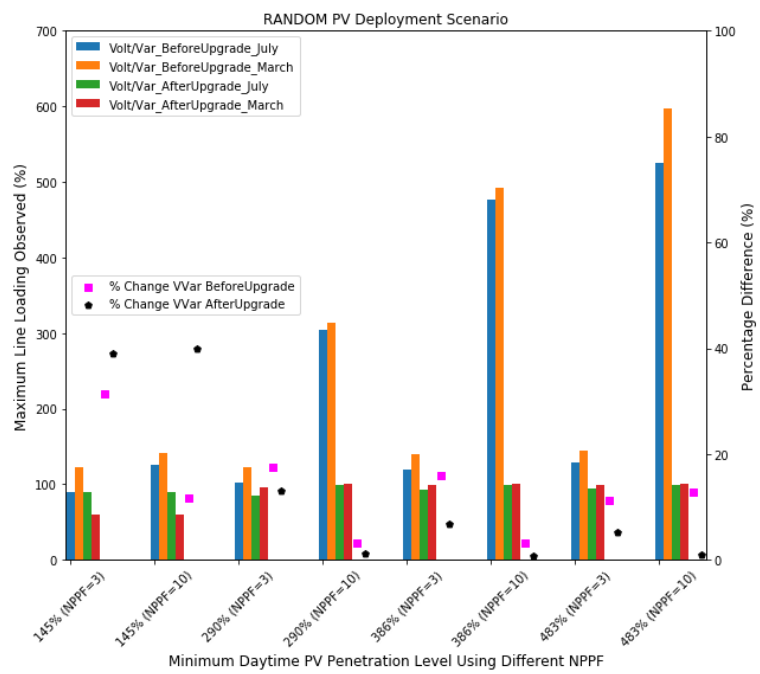

Figure 21. Maximum line loading for the randomly deployed DPV scenario with volt/VAR control

In general, loading limit violations tend to be resolved better with volt/VAR control after the required upgrade is carried out than with unity power factor control. As mentioned, a possible fix for such a rigid legacy solution with unity power factor control could be achieved by curtailing DPV system production and/or by using system-wide mitigation alternatives, such as deploying ADMS and SCADA software upgrades.

3.2 Number of Lines and Transformers Required for Upgrades

Figure 22 and Figure 23 show the number of lines and transformers required for upgrades for DPV systems deployed close to the feeder head for unity power factor and for volt/VAR control, respectively. More lines and transformers are required for upgrades in March than in July, and an NPPF value of 10 requires more lines and transformers than an NPPF value of 3. With unity power factor, thermal constraints are still violated after upgrades; however, with volt/VAR control, the number of lines and transformers required for upgrades is reduced to zero. Similar trends occur with other deployment scenarios—with DPV far from the feeder head and with randomly distributed DPV systems, as shown in Figure 24–Figure 27.

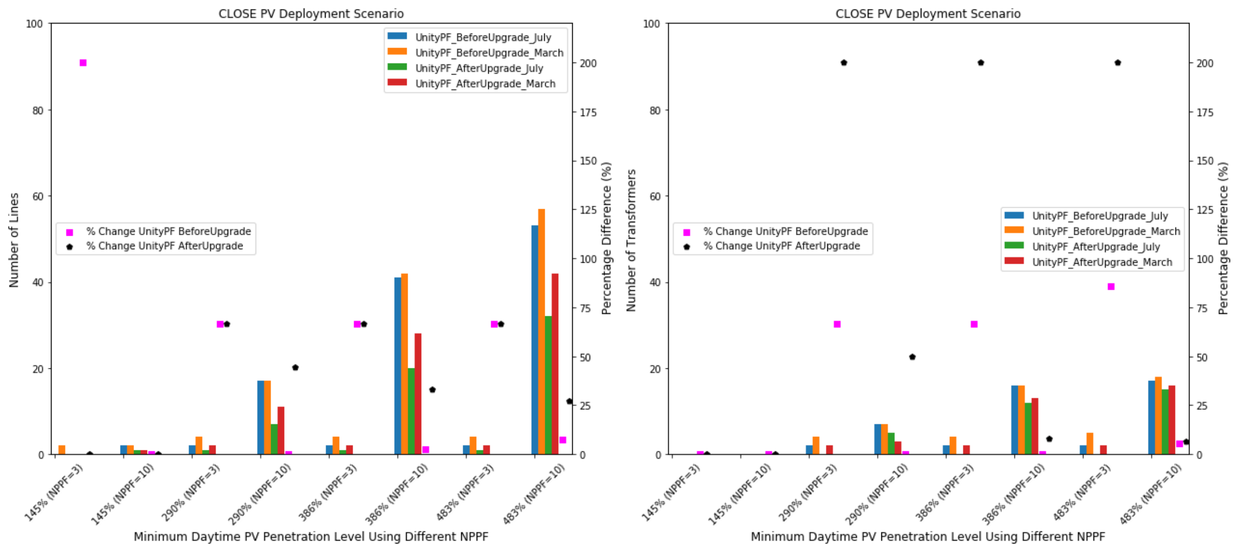

Figure 22. Number of lines (left) and transformers (right) for the close DPV scenario for unity power factor

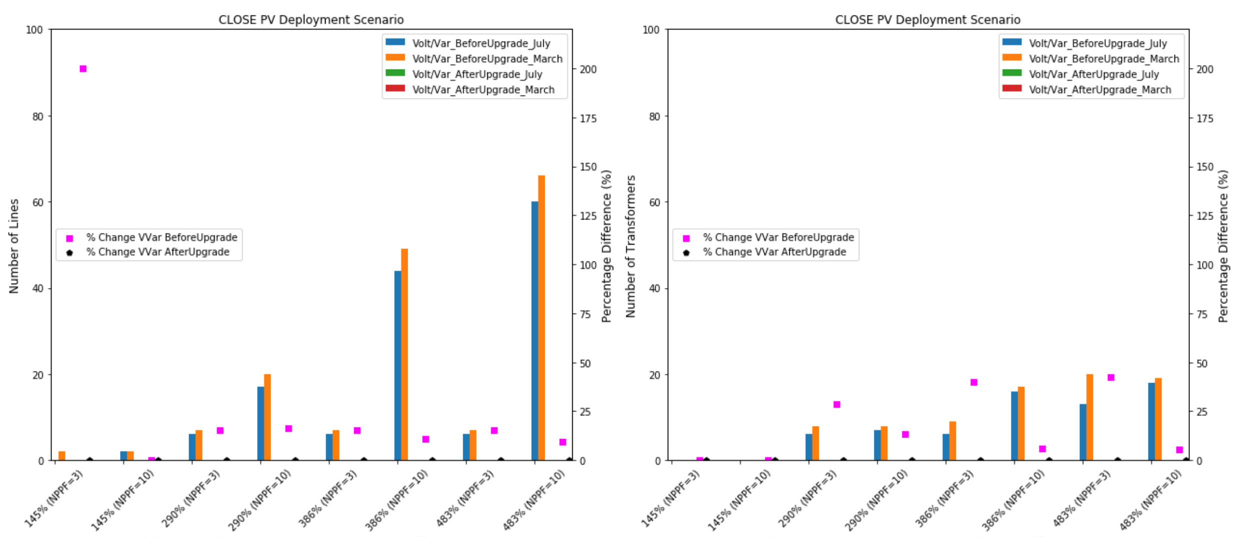

Figure 23. Number of lines (left) and transformers (right) for the close DPV scenario for volt/VAR control

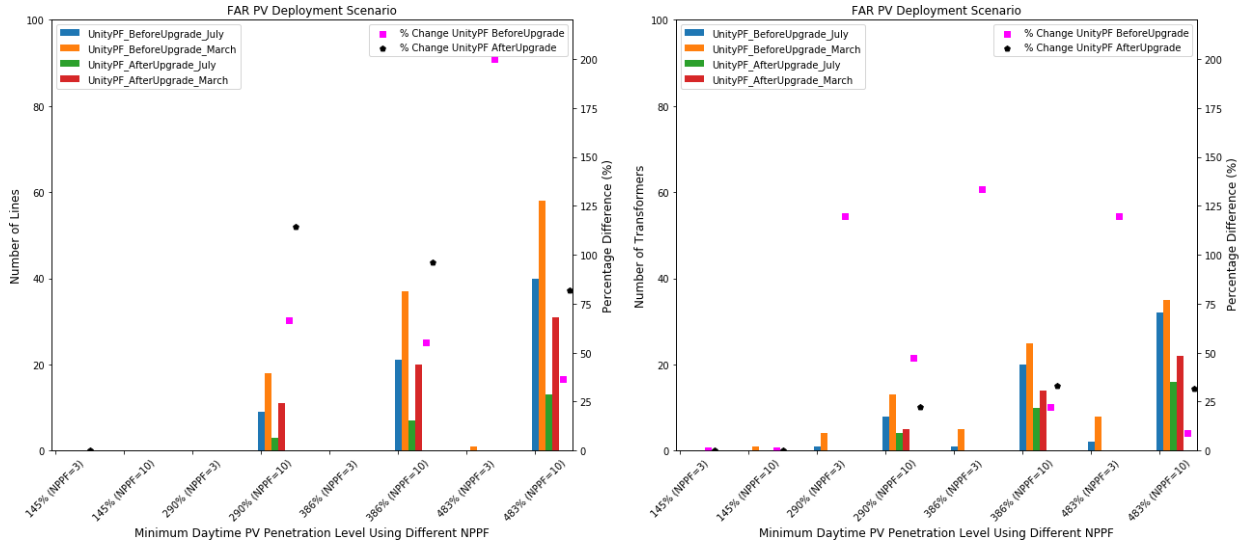

Figure 24. Number of lines (left) and transformers (right) for the far DPV scenario for unity power factor

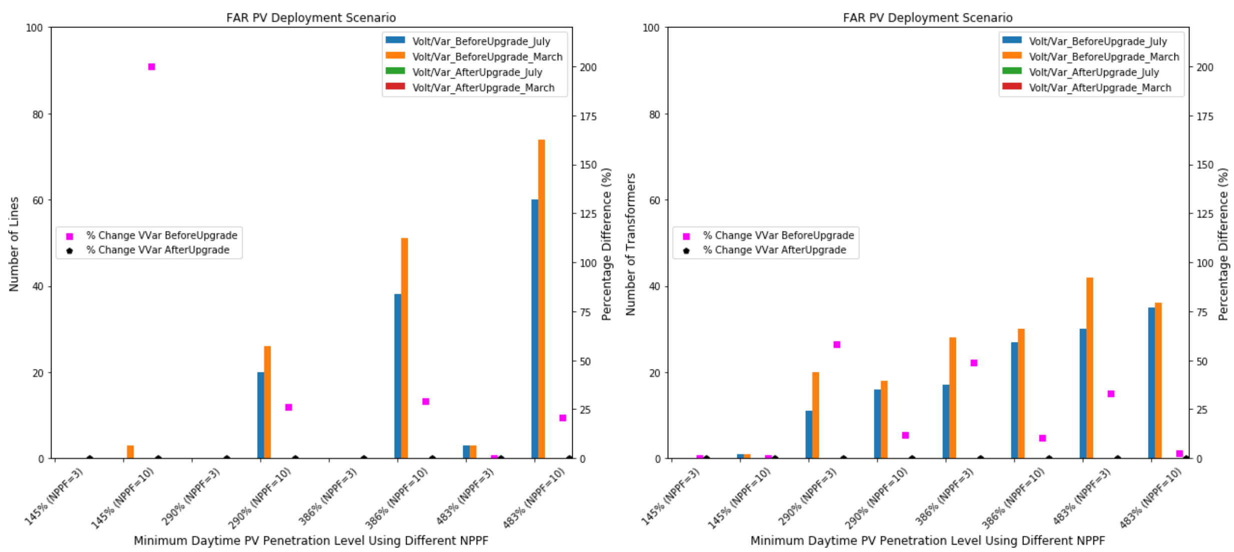

Figure 25. Number of lines (left) and transformers (right) for the far DPV scenario for volt/VAR control

As the penetration level increases, an NPPF value of 10 requires more lines and transformer upgrades than the lower NPPF value of 3 for all scenarios, as shown in Figure 22–Figure 27. This is consistent with the illustrations in Figure 10–Figure 21, which show the thermal overload impact of the different NPPF values.

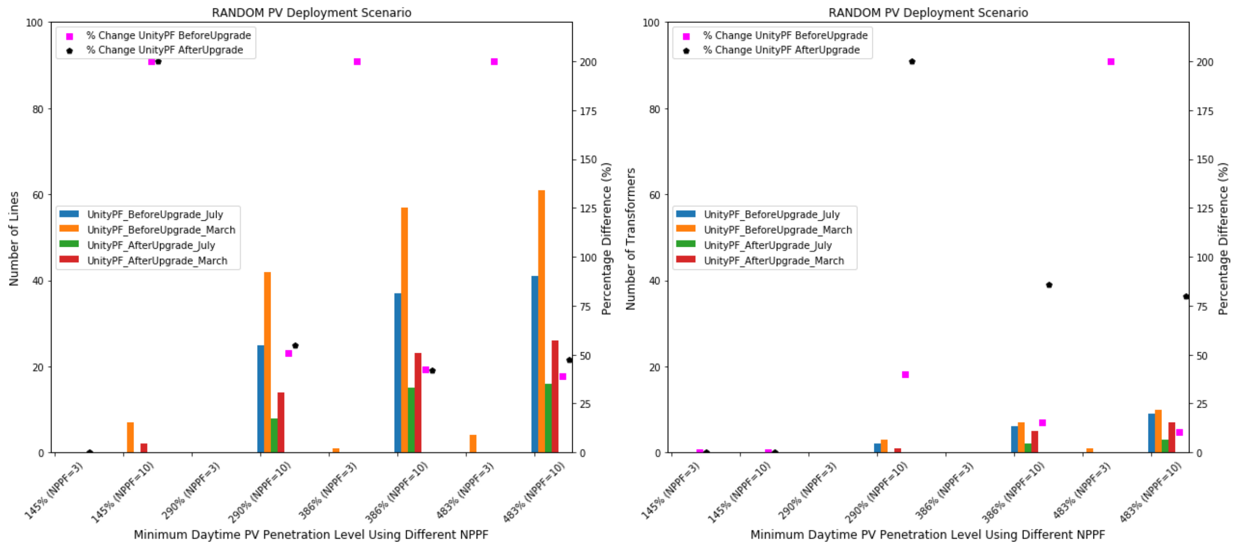

Figure 26. Number of lines (left) and transformers (right) for the randomly deployed DPV scenario with unity power factor

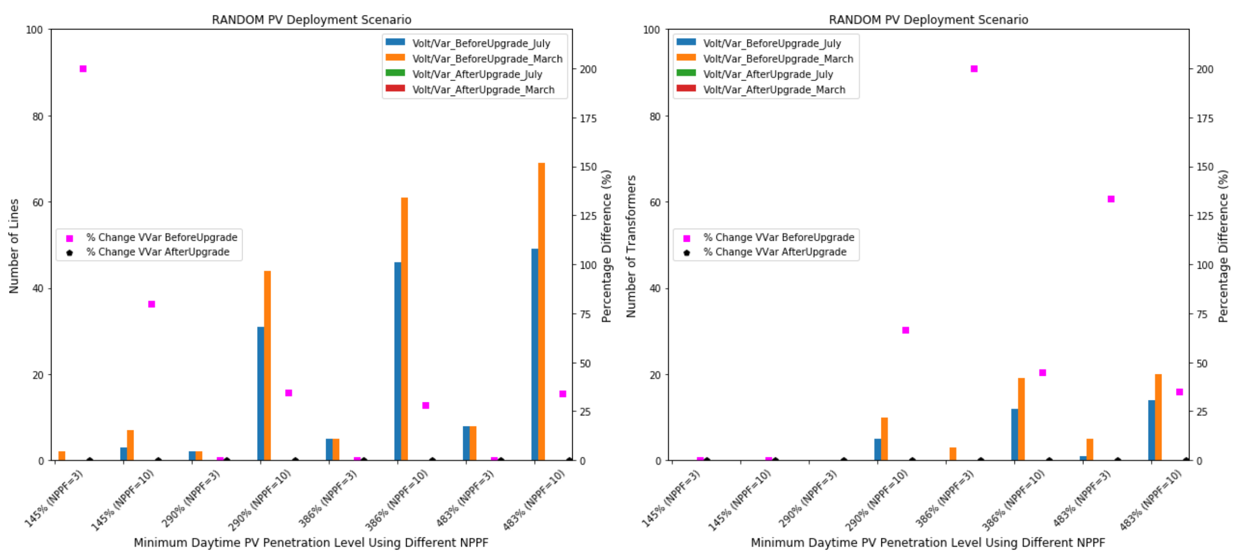

Figure 27. Number of lines (left) and transformers (right) for the randomly deployed DPV scenario with volt/VAR control

With volt/VAR control, the highest number of transformers with violations occurs for the far DPV systems and an NPPF value of 3 at 483% penetration, as shown in Figure 25. At this deployment level, there are 36, 19, and 20 transformers with violations for the far, close, and randomly deployed DPV systems, respectively, during the spring case. For the counterpart summer case, 35, 18, and 14 transformers experience violations for the far, close, and randomly deployed DPV systems, respectively. The random case experiences the largest percentage decrease, 35.3%, during summer compared to 5.4% and 2.8% for the close and far DPV systems, respectively.

As shown in Figure 25, at 483% penetration with an NPPF value of 10 and volt/VAR control, the far DPV scenario experiences the highest number of lines with violations compared to the other scenarios in both seasons.

For all DPV deployment scenarios, even after upgrades, the unity power factor case still experiences higher line loading, especially for an NPPF value of 10. In general, loading limit violations tend to be resolved better with volt/VAR control after the required upgrades are carried out than with unity power factor. As mentioned, a possible fix for such a rigid legacy solution with unity power factor control could be achieved by curtailing DPV system production and/or using system-wide mitigation alternatives, such as deploying ADMS and SCADA software upgrades.

3.3 Voltage Impacts

In this subsection, we present the voltage impact of the DPV system deployment scenarios on the entire nodes of the modeled feeder. The voltage metric further highlights the impact of local volt/VAR control on maintaining the voltage within limits against the legacy unity power factor control. Exceeding the ANSI Range A and Range B upper limits is a major concern to system operators and can ultimately limit DPV capacity on the feeder because the grid is traditionally designed with the assumption that voltage will drop from the feeder head to the end with increasing load demand.

Figure 28, Figure 29, and Figure 30 show the number of overvoltage violation buses outside the Range B limits for the close, far, and randomly deployed DPV system scenarios, respectively. Here, the local volt/VAR control significantly reduces the number of overvoltage violation buses outside the Range B limits compared with the legacy unity power factor deployment across all DPV deployment scenarios. Again, an NPPF value of 3 results in a reduced number of buses with overvoltage violations compared with an extreme NPPF value. This implies that a high NPPF value can cause unacceptable high voltages and make hosting capacity expansion difficult.

As presented in Figure 30, for DPV systems operating at unity power factor, randomly deployed units cause the least number of buses experiencing overvoltage violations, whereas DPV deployed far from the feeder experiences the highest number of buses with voltage violations, as shown in Figure 29. This is because for most distribution systems, the feeder is electrically weaker at the far end, and therefore it would require minimal DPV power injection to increase the voltage than it would for DPV installed close to the feeder head. Again, voltage violations in March appear to be more severe than in July across the various scenarios for both seasons.

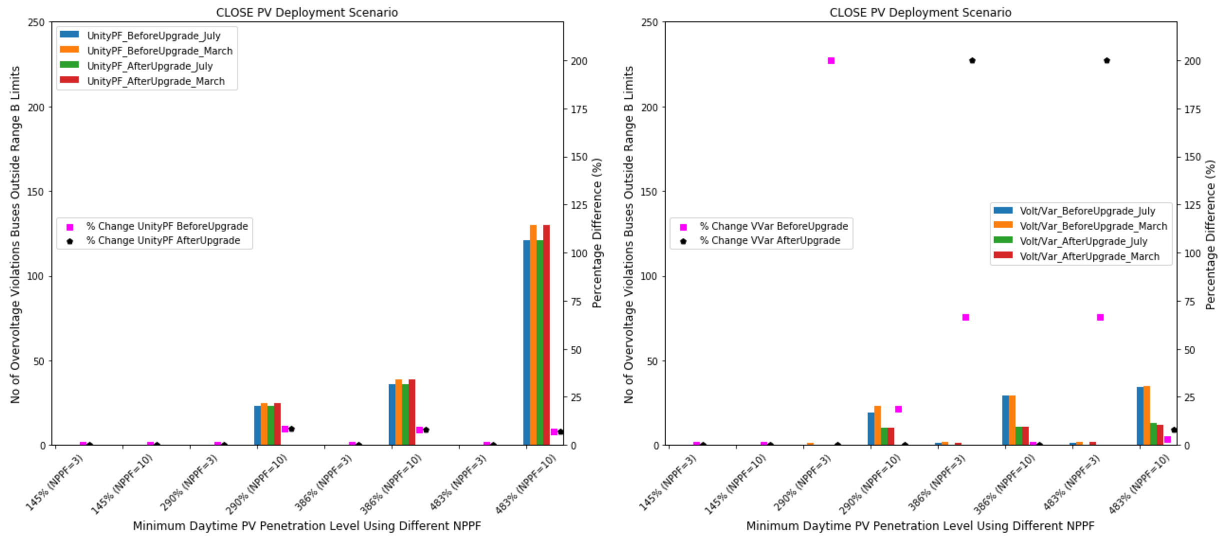

Figure 28. Number of overvoltage violation buses outside Range B limits for the close PV scenario for unity power factor (left) and volt/VAR control (right)

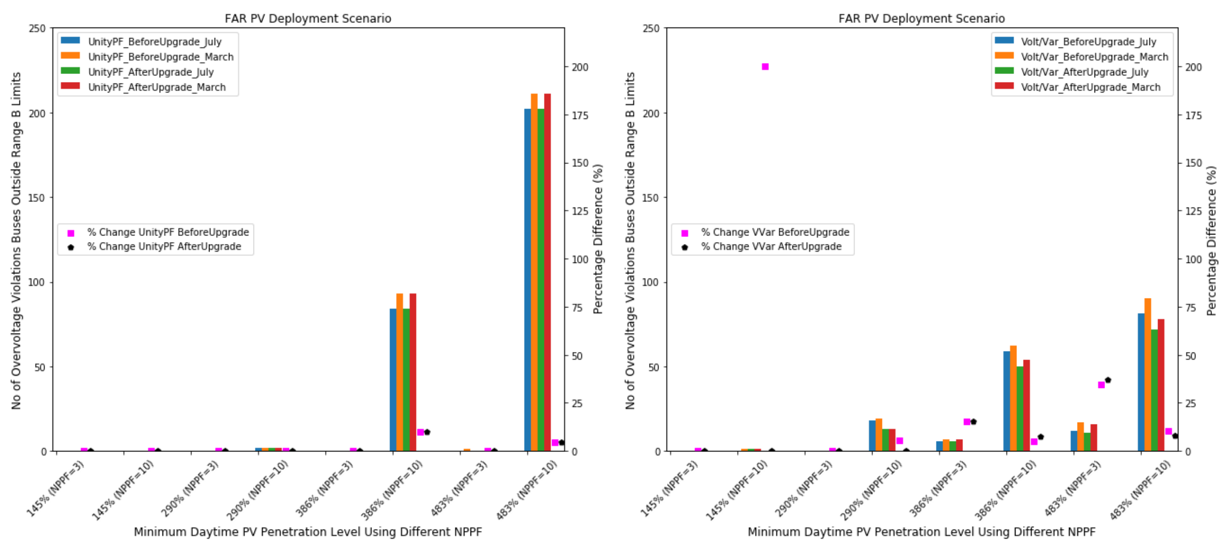

Figure 29. Number of overvoltage violation buses outside Range B limits for the far PV scenario for unity power factor (left) and volt/VAR control (right)

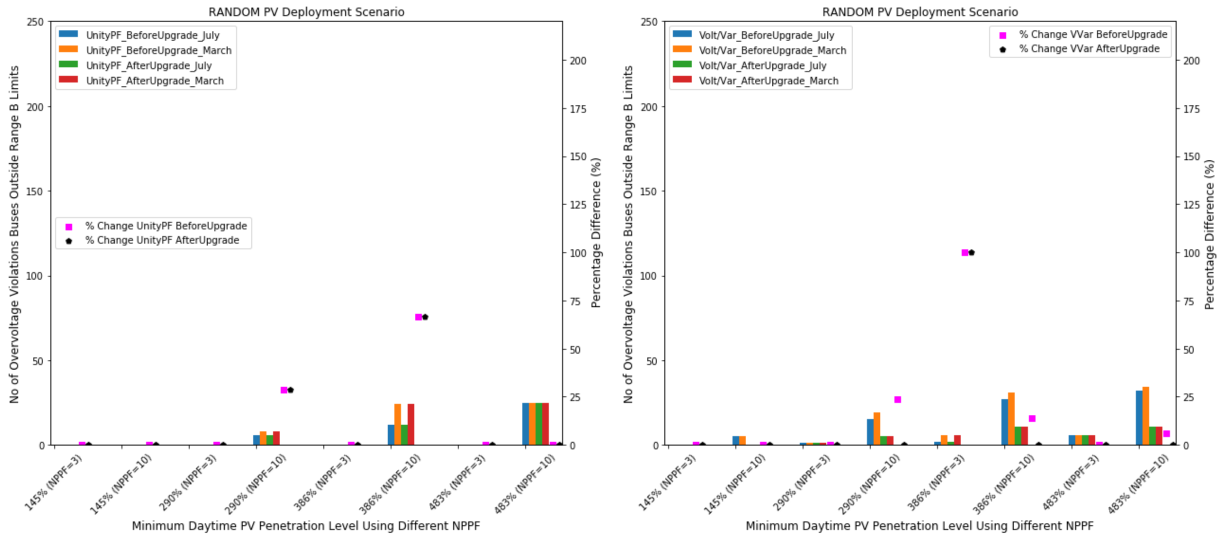

Figure 30. Number of overvoltage violation buses outside Range B limits for the randomly deployed PV scenario for unity power factor (left) and volt/VAR control (right)

In general, the higher the penetration level coupled with a higher NPPF value, the greater the tendency for nodes along the entire feeder to become vulnerable to overvoltage. Also, nodal voltages are susceptible to the spatial distribution of DPV systems. Further, unity power factor control increases the propensity of high nodal voltages as the DPV penetration level increases because DPV systems only inject active power.

3.4 Power Losses

The impact of various DPV deployment scenarios on total power losses (aggregated lines and transformer losses) in the feeder with volt/VAR control is shown in Figure 31. Power losses caused by an NPPF value of 10 are higher than those of the lower NPPF value. Figure 31 shows the total power losses of various DPV scenarios compared to the base case with no PV systems. For the close and randomly deployed DPV system scenarios, there is a decrease in total power losses compared to the base case except for the far units, where losses begin to increase from the 386% penetration level. Also, the reduction in power losses is highest with the randomly deployed DPV systems, as shown in Figure 31. Power losses are higher in March than in July except for the early low-deployment case, at a 145% penetration level.

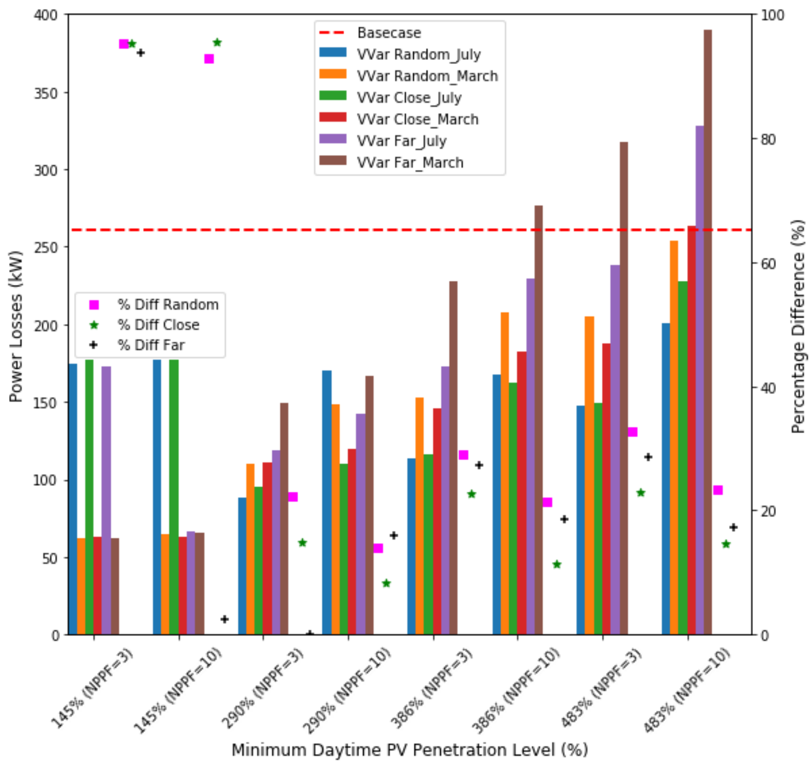

Figure 31. Total power losses of various DPV scenarios (with NPPF values of 3 and 10) operating with volt/VAR control compared to the base case with no PV

Figure 32 shows the percentage change in total power losses of various DPV scenarios (with an NPPF value of 3) operating with unity power factor and volt/VAR control compared to the base case with no PV in March (left) and July (right). In most cases, unity power factor control results in higher power losses than volt/VAR control. At a 483% PV penetration level, the DPV units deployed far from the feeder head cause an increase in power losses (21.8%) compared to the base case with no DPV systems in March. The same tendency is seen in July, with losses almost crossing the zero line for the far deployment case.

This becomes very significant at high penetration level of 483%, where DPV systems clustered far from the feeder head and close to the feeder cause an increase in power losses, approximate 30% and 11% increases over the base case, respectively.

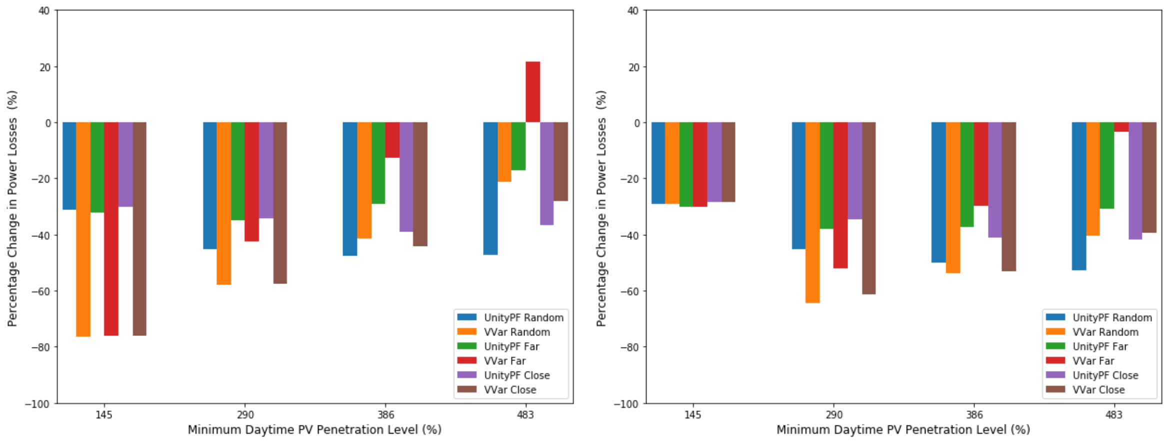

Figure 32. Percentage change in total power losses of various DPV scenarios (with an NPPF value of 3) operating with unity power factor and volt/VAR control compared to the base case with no PV in March (left) and July (right)

4 Cost Metrics

As described in Section 2.4, this research investigates three cost metrics associated with distribution infrastructure upgrades and hosting capacity expansion: distribution upgrade cost, average cost per watt of upgrade cost, and marginal cost per watt of upgrade cost

4.1 Distribution Upgrade Cost

Figure 33 shows the distribution system upgrade cost versus penetration level and NPPF values across all the DPV spatial scenarios for unity power factor (left) and volt/VAR control (right). This analysis shows the sensitivity of the upgrade cost to seasons, the spatial distribution of the DPV systems, inverter control, and the NPPF values. Figure 33 vividly shows the impact of a high NPPF value on upgrade cost, with a higher NPPF value and legacy unity power factor control resulting in the highest upgrade cost. DPV systems clustered close to the feeder head cause the highest upgrade cost, followed by the far and then random scenarios.

In all cases for unity power factor, the cost of upgrades during spring is higher than during summer. For instance, for the close DPV systems, at 483% penetration with an NPPF value of 10, the percentage difference of the upgrade cost between these two cases is 58%.

Figure 33 (right) shows the distribution upgrade cost for the volt/VAR control case across both seasons and NPPF values. This shows the impact of the volt/VAR control on upgrade costs across different seasons. The use of advanced inverter control tends to maintain upgrade cost with less variation across both seasons. For instance, in the close and far DPV systems operating with an NPPF value of 10, investment in advanced inverter control maintains the percentage cost difference between spring and summer at approximately 10% compared to 58% for the unity power factor case. With legacy inverters, the maximum distribution upgrade cost exceeds $1.75 million, whereas for volt/VAR control, the cost is less than $500,000 for the same season and scenario for the close DPV systems.

Upgrade costs for unity power factor control are underestimated because there are still violations of thermal and voltage constraints after upgrades. For example, at a 483% penetration level and an NPPF value of 10, there are still thermal overloads, as shown in Figure 10, and voltage violations, as shown in Figure 28–Figure 30.

In general, a higher NPPF value significantly increases upgrade costs for the unity power factor case, whereas volt/VAR control can manage violations and reduce upgrade costs with a higher NPPF value. This shows that a utility's investment in advanced inverter control can maintain the upgrade cost across seasons.

For unity power factor control with violations of grid operating conditions after upgrades, the concerned utility will need to deploy system-wide solutions (such as SCADA software upgrades and ADMS) or significantly curtail PV production. In cases where there are still violations with volt/VAR control after upgrades, the use of a more aggressive volt/watt can mitigate such voltage violations.

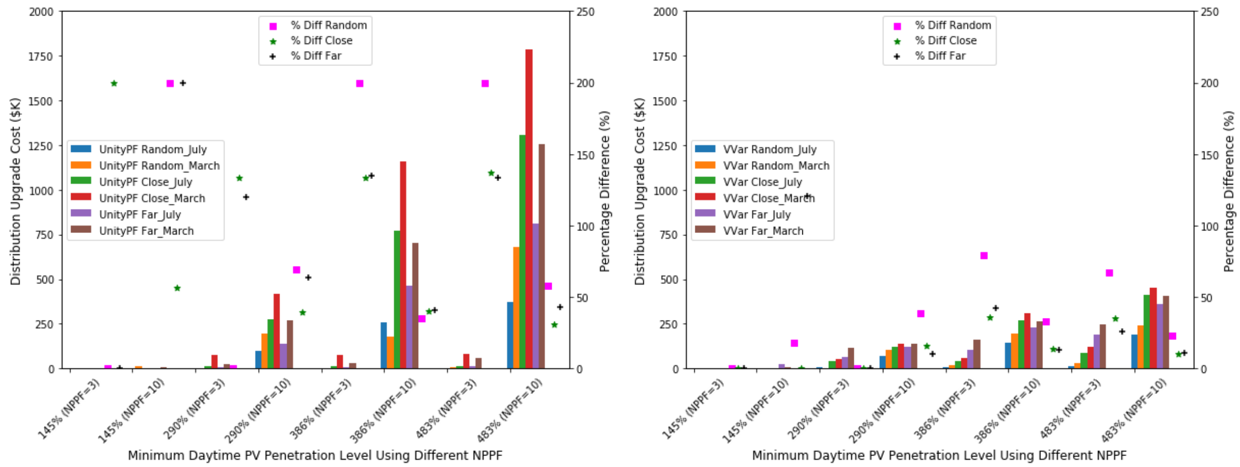

Figure 33. Distribution system upgrade costs versus penetration levels and NPPF values for unity power factor (left) and volt/VAR control (right)

4.2 Average Cost per Watt of Upgrade Cost

Figure 34 shows the average cost per watt of upgrade cost across different DPV deployment scenarios for unity power factor (left) and volt/VAR control (right). A higher NPPF value of 10 results in a higher average cost, with maximum values of $0.23/W and $0.17/W, respectively, in March and July at a 483% penetration level for the close DPV system operating at unity power factor. With the same NPPF value, the maximum average upgrade cost for the volt/VAR case is $0.058/W and $0.053/W for the close DPV scenario. For the unity power factor case, there is a 30.74% difference in the average cost across seasons, whereas the volt/VAR control case resulted in a 10% difference for this close DPV system scenario.

This implies that unity power factor control is a more expensive solution because of the higher average cost compared with volt/VAR control. The close DPV scenario has higher average costs, whereas randomly deployed DPV systems result in the lowest average cost of upgrades.

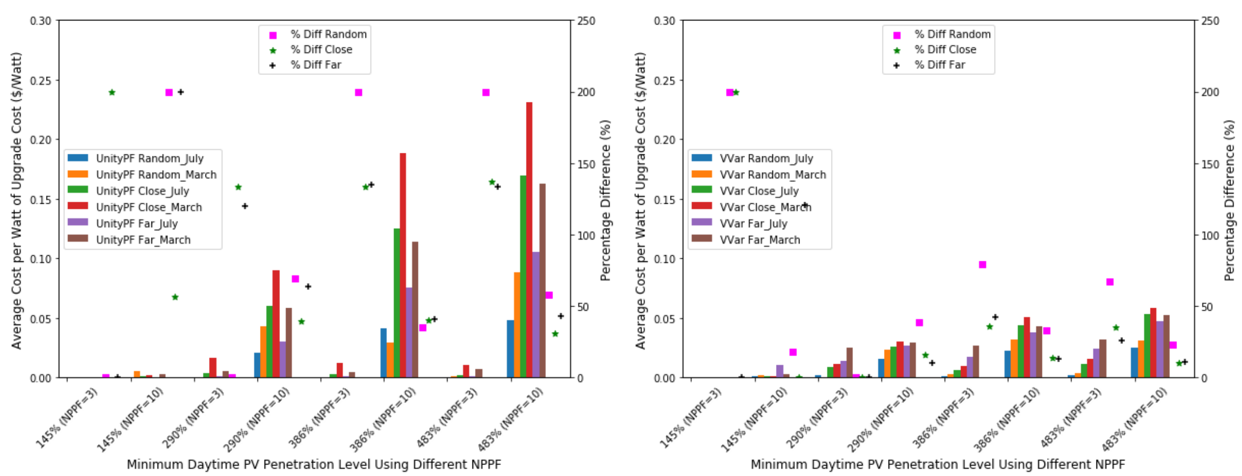

Figure 34. Average cost per watt of upgrade cost for unity power factor (left) and volt/VAR control (right)

4.3 Marginal Cost per Watt of Upgrade Cost

Figure 35 shows the average marginal cost per watt of the distribution upgrade cost across different DPV deployment scenarios for unity power factor (left) and volt/VAR control (right). Again, following the average cost shown in Figure 34, the close DPV scenario at a 483% penetration level operating with an NPPF value of 10 and unity power factor has the highest marginal cost, with maximum values of $1.16/W and $0.85/W in March and July, respectively. The volt/VAR counterpart has maximum marginal costs of $0.294/W and $0.266/W in March and July, respectively. Moreover, for economically viable projects, it is pivotal to maintain the marginal cost below the average cost, otherwise the project might be considered uneconomic. Apart from the far DPV system scenario at a penetration level of 483%, the lower NPPF value of 3 tends to be more economically viable than an NPPF value 10, as shown in Figure 35.

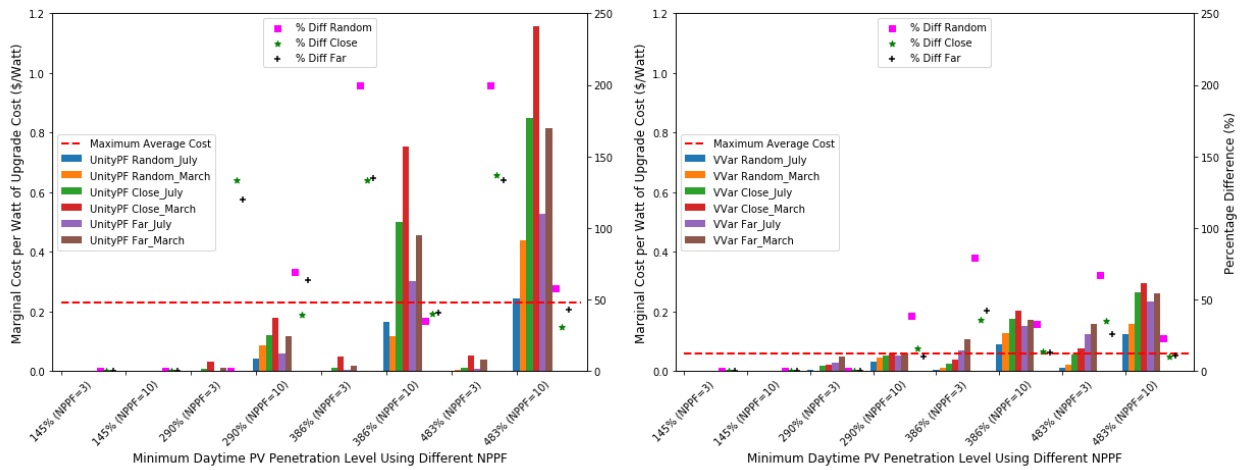

Figure 35. Average marginal cost per watt of upgrade cost for unity power factor (left) and volt/VAR control (right)

Figure 34 and Figure 35 show that the distribution upgrade costs can be minimized using autonomous volt/VAR control, a low NPPF value, and siting DPV units in low-impact regions. High penetrations can be achieved by changing the unity power factor to advanced inverter control, a solution that might have zero or near-zero marginal costs.

Figure 35 shows the sensitivity of distribution upgrade cost to thermal loading limits. In general, increasing the short-duration thermal loading limits from 100% to 125% of the nameplate rating decreases grid condition violations (thermal and voltage) and the associated upgrade costs. For instance, with a 125% thermal limit for the close DPV system case operating with unity power factor, the distribution upgrade cost is reduced by 198% and 195% in March and July, respectively, as shown in Figure 35 for the close DPV system case. For the counterpart volt/VAR case, the percentage reductions are 12.2% and 11.7% in March and July, respectively. The 100% limit appears to be overly conservative, and increasing the short-term overloading limit can become an optimal pathway to hosting capacity expansion for the distribution network.

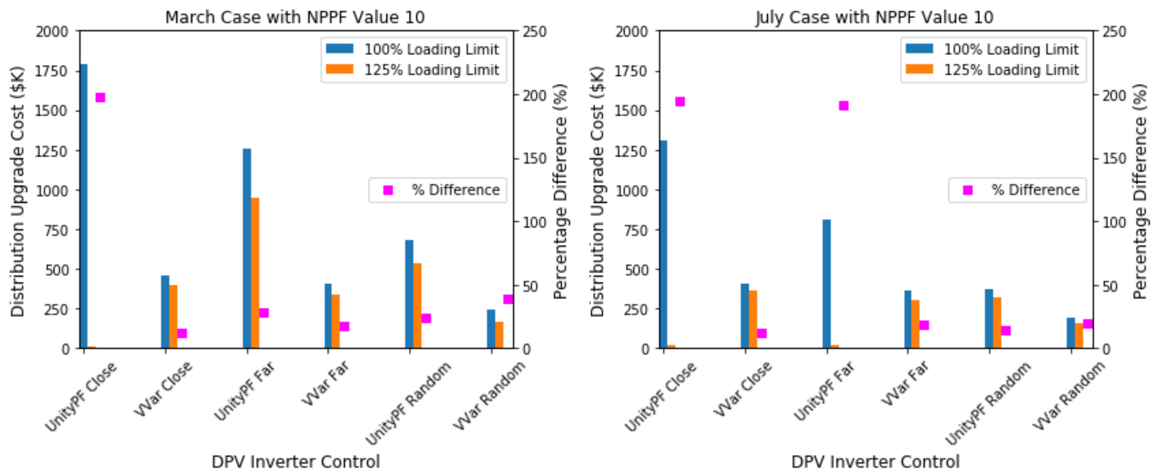

Figure 36. Sensitivity of distribution upgrade cost to thermal loading limit for March (left) and July (right)

4.4 Cost of Integrating Edge Intelligent Devices as a System-Wide Solution

As stated in Section 1.2, EIDs can be used to control multiple inverter set points to improve grid operating conditions. The spatial diversity and the NPPF of DPV systems might not impact the deployment and cost of EIDs. In all deployment scenarios—existing neighborhood, new development, single EID, multiple EID, and transformer-based EID—the cost will be determined by the number of DERs (in this case, DPV systems) connected to the EID. An easy way to ensure that spatial diversity does not impact cost is to limit the service area of each installer; however, this might be difficult in rural areas. Ideally, between 10–25 inverters can be connected to a single EID, with a manufacturing cost of $2000 per EID. Typical overhead and profit is 25%, leading to a sell price to the utility of approximately $2,700. To calculate the cost estimate for deployment scenarios and penetration levels, we assume a lower bounding limit of 10 inverters per EID.[10] Figure 36 shows the potential EID distribution upgrade cost for various DPV scenarios and increasing penetration levels. Variations in EID total cost at a given penetration level across scenarios are caused by different numbers of load nodes across scenarios on the respective feeder sections where DPV systems are connected. For example, at a 483% penetration level, there are 1,155, 1,105, and 1,179 DPV systems for the random, close, and far scenarios, respectively, which translates to different numbers of EIDs required. The higher the penetration level, the higher the upgrade cost, although this cost could be reduced if more than 10 inverters are connected to a single EID.

[10] Although one can connect up to 25 inverters to a single EID, from experience and from operating practice, 10 is considered practically feasible. Other distribution system architectures can allow more than 10 inverters per EID.

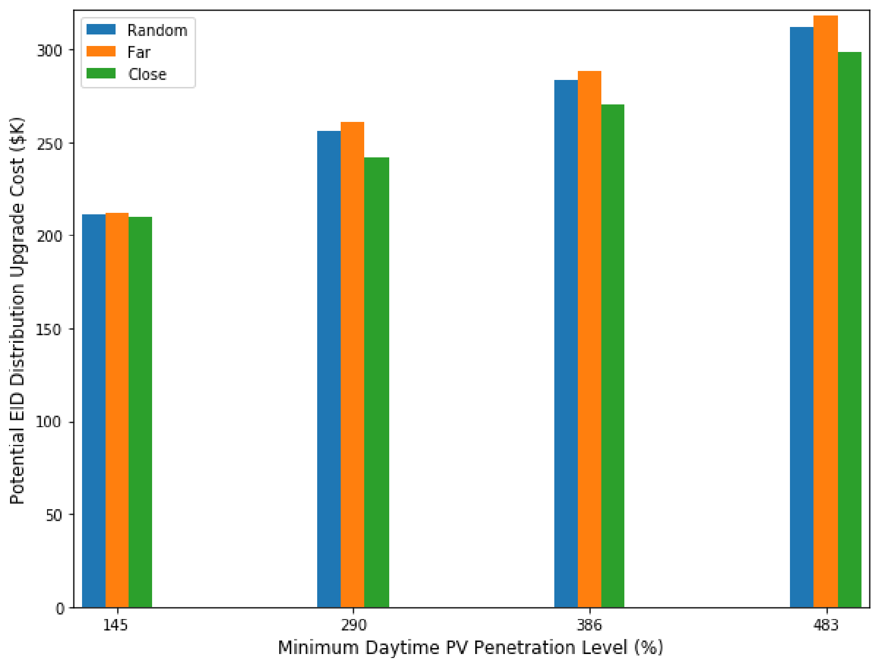

Figure 37. Potential EID distribution upgrade cost

4.5 Limitations and Future Work

This study attempted to go beyond the single-snapshot traditional analysis used for the techno-economic assessment of distribution upgrades by using multi-time point analysis. It is well established that single-snapshot estimates are overly conservative and do not include controller dynamics and other time-dependent aspects of the power flow, such as the interaction between the daily changes in load and PV output. Although we used multi-time point analysis, this is still limited in characterizing and capturing network dynamics that can affect grid operating conditions and associated costs of upgrades. Also, this might not allow for an accurate computation of DPV system energy curtailment, which is an important component of cost-benefit analysis, especially for an interconnection study such as this. In addition, incorporating the time-dependent aspects of the power flow in a quasi-static time-series analysis will enable the assessments of the impact of DPV systems on device operations and the associated effects on operation-and-maintenance costs.

5 Conclusions

This research performed a cost-benefit analysis of automated distribution feeder upgrades with advanced mitigation technologies to expand DPV system hosting capacity on a real distribution network in the United States. Although traditional distribution network upgrade approaches use a single-snapshot analysis, which is overly conservative, this study considered a multi-time point analysis to capture both moderate (probable bounds) and extreme grid operating conditions using time points such as minimum load with minimum PV, maximum load with maximum PV, maximum load with minimum PV, and minimum load with maximum PV.

Further, this work investigated seasonal variation impacts and associated distribution upgrade costs for a spring season case (March, representing a low load and high PV scenario) and a summer case (July, representing a high load and high PV scenario). Such seasonal analysis will allow system operators to characterize upgrade requirements and associated costs across various periods. This research has shown the sensitivity of DPV hosting capacity expansion and associated distribution upgrade costs to the spatial distribution of DPV systems, NPPF values, and inverter controls.

Very few studies have considered the impact of local or nodal grid constraints when generating DPV deployment scenarios at increasing penetration levels. This project considers bounds on customer-level PV-to-load ratios represented by NPPF. Although we used heuristics to determine the NPPF values, using an optimal NPPF value can both delay the need for upgrades and minimize distribution upgrade costs. This clearly implies that the combination of a high NPPF value and unity power factor is a more expensive solution than volt/VAR control and an optimal NPPF value.

From the technical perspective, the feeder experienced more violations to grid operating conditions in the spring case than in the summer case. For instance, there are more lines, transformers, and nodes with violations in the spring case than in the summer case. The reduced number of upgrades required during the summer months can be caused by high PV generation offsetting local loads, whereas during the spring months, overgeneration with minimum load can result in adverse grid conditions, such as lines and transformers overloads. In general, violations are easier to mitigate with volt/VAR control than with unity power factor, and the use of advanced inverter control can mitigate adverse grid conditions that occur during spring. Distribution upgrade costs will vary significantly across seasons if there are no deployments of advanced controls, and utility investments in such controls can maintain the distribution upgrade costs across seasons.

We have shown that the distribution upgrade costs can be minimized by using autonomous volt/VAR control, optimal NPPF values, and siting DPV units in low-impact regions. An emerging pathway to hosting capacity expansion is to limit the NPPF value of various DPV deployments. High penetrations can be achieved by changing the legacy unity power factor to advanced inverter controls, a solution that might have zero or near-zero marginal cost.

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