

Voltage Regulation and Overcurrent Protection Issues in Distribution Feeders with Distributed Generation – A Case Study

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Abstract

The installation of distributed generation (DG) on distribution feeders is known to have an impact on voltage regulation. A DG can provide voltage support in some cases, but can also cause an overvoltage or an undervoltage, depending on the several variables including relative DG size and location, distribution line and load characteristics, and method of voltage regulation. This paper shed some light the impact of DGs on voltage regulation and on overcurrent protection. These impacts are investigated on a feasibility study concerning the installation of a 5 MW grid-tied PV system to a local distribution system.

1. Introduction

Distributed generation is defined as energy sources (ranging in size from few kilowatts to approximately 10 MW) connected to distribution systems. The main advantage of DG units is their close proximity to the load that they serve.

Various technologies are being used in DG applications with a variable degree of success. Many DG technologies utilize renewable energy due to growing attention to air pollution and greenhouse effects. With the assistance of government subsidiary programs, grid-connected photovoltaic (PV) is a prospering market in some European countries, and the same expected in the US as many electric utilities encourage such systems through significant rebates. For example, the local utility company provides \$5 per installed peak PV watt in rebate – literally paying for the cost of the PV panels and the customer is responsible only for balance-of-system and installation cost. Wind power is even more competitive where wind resources are abundant, but wind farms are often connected to sub-transmission or transmission systems, rather than distribution systems.

Others DGs, such as reciprocating engines, and fuel cells, utilize a continuous source of fuel thus making them dispatchable power sources. Internal combustion engine-generators are often used for increased reliability (i.e., back-up power source) and peak shaving applications

during periods of high energy demand and/or high energy cost. These engine-generator sets, however, are noisy, use expensive fuel, and have high polluting emissions. Fuel cells, on the other hand, are quiet and pollution-free, but have a very limited level of penetration at present due to their high cost and availability of hydrogen.

Widespread proliferation of DG can have positive effects such as reliability improvement through backup generation, reduce equipment loading and enabling load transfer from adjacent feeders experiencing outages [1]. On the other hand, DG can increase the complexity of controlling, protecting and maintaining distribution systems [2]-[8]. Thus, it is critical that such impacts be assessed to avoid degradation of service.

This paper focuses on impact of DG on voltage regulation, and overcurrent protection issues. A feeder with uniformly distributed load and a discrete number of DGs is analyzed in an effort to shed light on when an undervoltage or an overvoltage can occur. Then the main concerns associated with the impact on overcurrent protection are briefly reviewed. This is followed by a case study of a 5 MW PV system that is being considered for installation on the rooftop of a local large customer.

2. Impact on voltage regulation

Voltage regulation practice on distribution systems is based on radial power flow from the substation to the load. This is often achieved through Load-Tap-Changing (LTC) transformers at the substation. Voltage regulation is also enhanced by switched capacitor banks (and in some cases voltage regulators) placed along the feeder. Line Drop Compensators (LDC) are seldom used except in rural areas where load density is low, or in substations where each feeder is fitted with an independent voltage regulator.

To illustrate the impact of DG on voltage regulation, consider a feeder of length l with a uniformly distributed load as shown in Fig. 1(a). Three distributed generators DG_1 , DG_2 , DG_3 are added at locations d_1 , d_2 , d_3 , respectively. Like conventional large power system generators, distributed generators using synchronous machines can generate as well as absorb reactive power

(i.e., operate at both leading and lagging power factor). On the other hand, DGs utilizing induction generators can only absorb reactive power, and inverter-based DGs are normally designed to operate near unit power factor. In any case, the standard requirement is that all DGs are expected to operate at a power factor of at least 85% (lead or lag) [9].

For diversity purposes, let DG_1 , DG_2 , DG_3 operate at a lagging power factor, unity power factor, and leading power factor, respectively. Their corresponding real and reactive power production are $(P_{G1}, -Q_{G1})$, $(P_{G2}, 0)$, (P_{G3}, Q_{G3}) . Note that Q_{G1} denotes the magnitude of reactive power consumed by DG_1 since a negative sign is placed in front of it. The resulting real and reactive power flow along the feeder are shown in Figures 1(b) and 1(c), respectively. Herein, P_s and Q_s represent the total feeder active and reactive power loading without the DGs.

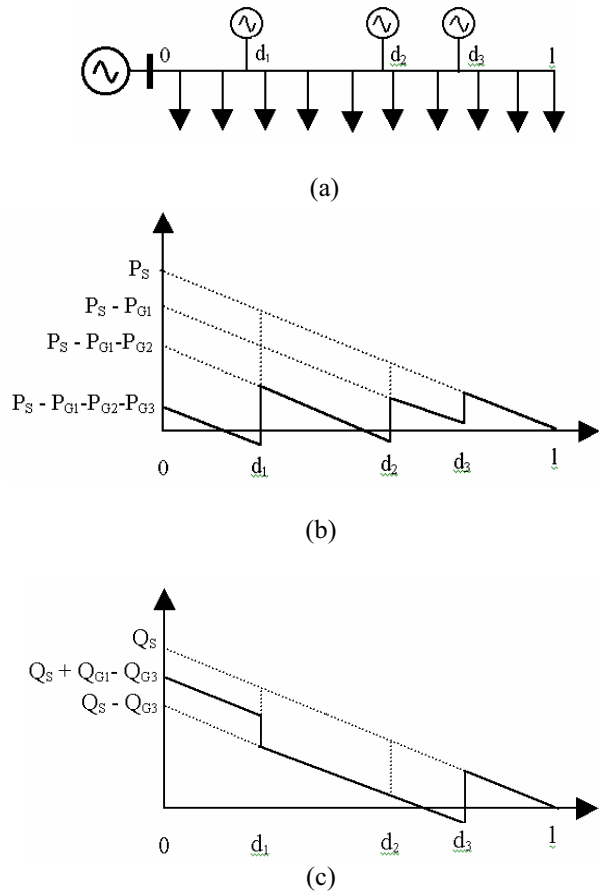


Fig. 1. (a) Feeder with uniformly distributed load and 3 DGs, (b) active power profile, (c) reactive power profile.

The voltage drop (or rise) along the feeder can be computer at each line segment defined by the DG locations, assuming that the voltage at the secondary substation transformer V_0 is known. Starting with the first segment between the substation and DG_1 , i.e., $0 < d \leq d_1$, the voltage drop (rise) can be decomposed in two

components: The component due to the load downstream is given by

$$VD_{d1} = d_1 \frac{RP_{d1} + XQ_{d1}}{V_{d1}} \quad (1)$$

right before d_1 , i.e.,

$$P_{d1} = P_s \left(1 - \frac{d_1}{\ell}\right) - P_{G1} - P_{G2} - P_{G3} \quad (2)$$

and

$$Q_{d1} = Q_s \left(1 - \frac{d_1}{\ell}\right) + Q_{G1} - Q_{G3} \quad (3)$$

The second component is due to the lumped-sum load upstream located at half the distance,

The total voltage drop (rise) is then computed by

$$VD_{b1} = \frac{d_1}{2} \frac{R(P_s - P_{d1}) + X(Q_s - Q_{d1})}{V_{d1}} \quad (4)$$

summing (1) and (4),

$$VD_{d1} = VD_{d1} + VD_{b1} = V_0 - V_{d1} \quad (5)$$

Solving for the voltage at d_1 yields

$$V_{d1} = \frac{1}{2} \{V_0 + (V_0^2 - 4a_{d1})^{1/2}\} \quad (6)$$

Where

$$a_{d1} = \frac{d_1}{2} \{R(P_s + P_{d1}) + X(Q_s + Q_{d1})\} \quad (7)$$

Knowing the voltage at d_1 , the above procedure can then be extended to determine the voltage drop across the line segments downstream by simple substitutions. For instance, to compute the voltage drop in the middle segment $d_1 < d \leq d_2$, replace (P_{d1}, Q_{d1}) by (P_{d2}, Q_{d2}) in (1) and (4), (P_s, Q_s) by (P_{d1}, Q_{d1}) in (4) and (7), and V_0 by V_{d1} in (5) and (6). Here, (P_{d2}, Q_{d2}) are computed as in (2) and (3) while ignoring the powers generated by DG_1 and replacing d_1 with d_2 .

Note that the introduction of DG reduces the amount of power that must be supplied from substation, hence reduces the voltage drop across the feeder. In the even that the DG produces more power than the local demand, the net power will flow upstream (towards the substation). If this reverse flow is sufficiently large, its will overcome the voltage drop caused by the reactive power flow (i.e., the XQ part in (1) and (4)) and may result in an overvoltage. On the other hand, if sufficient DG is installed close to the substation, it can lead the LTC to operate at a lower secondary voltage, and this can result in an undervoltage towards the feeder end.

There are a number of methods by which over- or under-voltages caused by DG can be mitigated [10]-[14]. Some of these include adjusting the sending end voltage,

installing voltage regulators on the line, upgrading the network, and constraining the DG. But each method has a cost implication and many jeopardize the financial viability of DG projects.

3. Impact on overcurrent protection

Overcurrent protection schemes for radial distribution systems are designed based on the available short circuit ratios, maximum load currents, system voltage and insulation levels. The addition of generation on the feeder results in altered currents flowing in various parts of the feeder for faults at different points on the feeder. The primary concerns for DG interconnection are typically sympathetic tripping issues, failure of fuse-saving schemes, and reduction of reach - potentially resulting in undetected faults. These issues are briefly addressed separately next.

3.1. Sympathetic tripping

Sympathetic tripping occurs when a protective device operates unnecessarily for faults in other protection zones. This can occur with distributed generation due to unexpected fault contributions from the DG. An example of how sympathetic tripping might occur is shown in Fig. 2. The relays at breaker "A" and the recloser are not directional. Thus, sufficient fault current infeed from the distributed generation would cause either of these devices to operate in "sympathy" with "B" which actually sees the fault.

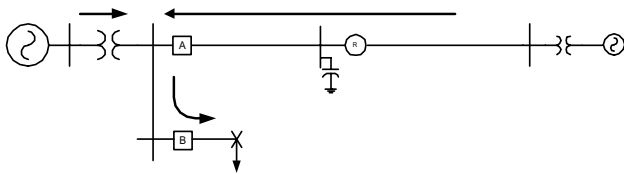


Fig. 2. Schematic illustrating sympathetic tripping.

3.2. Fuse-Saving Disruption

Many distribution companies employ fuse-saving schemes for their line reclosers that are installed at the urban/rural boundary. Fuse-saving is the practice of coordinating the feeder breaker or recloser to operate quickly relative to lateral fuses. This is accomplished by setting the first one or two recloser operations on "fast" curves, followed by two or three "delayed" operations. The fast shots are designed to beat the fuse melting time so that temporary faults caused by lightning, conductor slaps, or tree branches can be cleared without blowing a fuse. The presence of DG downstream from the fuse will

obviously contribute to fault current during breaker or recloser operation, hence fuse saving may not be possible.

3.3. Reduction of station breaker reach

Another potential overcurrent protection disruption is de-sensitization of the feeder overcurrent protection, also referred to as the reduction of reach of the feeder protective devices. "Reach" refers to the distance downline of the protective device to which the device can detect a fault. Without DG, only the utility source feeds a fault, and the currents flowing into the fault on a radial circuit are easily calculated. Utility protection engineers typically coordinate protective devices by setting the pickup current so that the device will operate for the a selected smallest minimum fault current expected, which correlates corresponds to the highest impedance fault to be detected.

The sensitivity of the feeder protection is reduced, however, by inclusion of DG between the protective device and the fault. This is because the DG unit will hold up the voltage profile across the up-line portion of the feeder. This reduces the current seen by the protective device and reduces its sensitivity to the fault such that the fault must be closer to the protective device to be detectable. Another way of describing this situation is that the fault appears farther away as a result of the DG.

4. Case Study

The State of Nevada requires that 7% of the electric energy consumed this current year must come from renewable energy sources (this fraction will increase by 2% every other year till 2015). As part of meeting the State's Energy Portfolio Standard (RPS), a 5 MW of photovoltaic (PV) solar generation plant is considered for installation on the rooftop of the Las Vegas Convention Center (LVCC). The purpose of this study is to evaluate what impact the PV system might have on the local utility company's distribution system operation, namely, voltage regulation and overcurrent protection.

A simplified one-line diagram of the distribution system feeding the LVCC is shown in Fig. 3 (where details such as load taps along some feeders, distribution transformers and shunt capacitors are not shown for simplicity). The LVCC is fed from 3 substations (A, B, C) through six circuits (1, 2, 3, ... 6). Each circuit is rated at 12.47 kV and provides primary service to some portion of the load. These primary feeds are short dedicated circuits that consist of 940 MCM cables. This study arbitrarily assumes that the photovoltaic generation is located at the end of feeder 4.

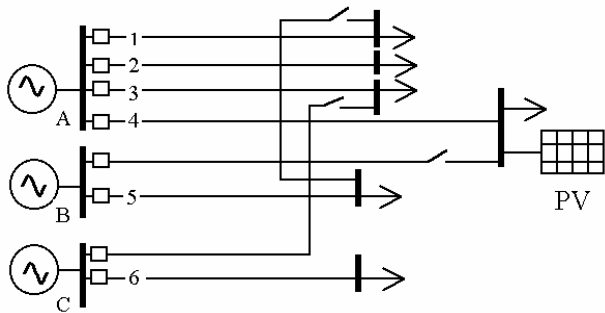


Fig. 3. One-line diagram of system under study.

The above circuit is modeled for various simulations and analyses using a distribution system software package, which is designed for analyzing distributed generation on distribution systems. The following subsections describe the simulated results.

4.1. Impact on feeder voltage

Disruption of system voltage regulation is often the most limiting constraint to the amount of distributed generation that can be interconnected to a distribution system. The addition of generation to feeder will affect the steady-state voltages across the circuit by an amount that depends on generation output and loading levels, as illustrated in the previous section. In addition to the steady-state impact, voltage regulation will be dynamically affected as PV output varies over time and interacts with the voltage regulation controls on the system. The voltage along feeder 4 is mainly regulated by a load tap changer (LTC) located at the substation B. Furthermore, voltage regulating capacitor banks located on several of the adjacent feeders also indirectly effect voltage regulation of feeder 4. The varying generation output of the 5 MW of PV will require these other system voltage regulating devices to not only regulate the voltage as system load fluctuates but also as the PV generation varies.

It should be noted that photovoltaic generation typically utilizes inverters that produce currents at near unity power factor to interface with the AC network. For this study, it is assumed that the PV generation in this case will be similarly interfaced. In this subsection, both simulated steady-state and dynamic voltage regulation impacts are discussed.

4.1.1. Steady-state voltage regulation. Fig. 4 shows the steady state voltage profiles computed for feeder 4, from Substation A to the interconnect point for the PV under extreme loading and generation conditions (i.e., 0% and 100% generation output at 100% of rated load). Note that PV generation lowers the current flow through the substation transformer, thus resulting in less voltage drop,

hence higher voltage at the substation end. Because the PV system is located at the end of the feeder, the largest voltage variations are expected at this point. However, due to the short length of the feeder and the electrical strength of the conductor, the voltage at the interconnection point for the PV does not vary more than 2% at steady-state.

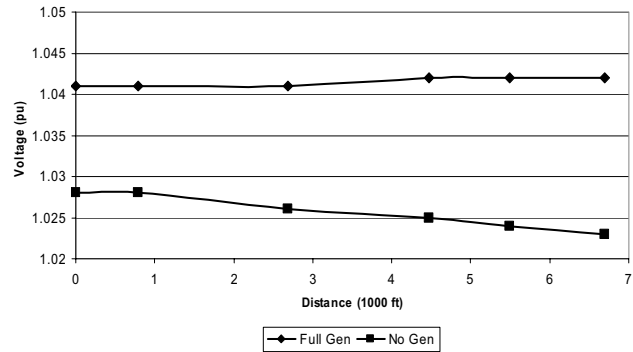


Fig. 4. Steady-state voltage profile across feeder 4 at peak load.

4.1.2. Dynamic voltage regulation. To evaluate the potential dynamic voltage regulation issues associated with interaction of the varying PV output at the LVCC with the variation of system load and system voltage regulation controls, five days of continuous operation are simulated using the same circuit model. The time-varying response of the load models are based on measured load data collected over a five-day period. This load shape, shown in Fig. 5 is assumed for all loads in the model with each load scaled by its maximum measured loading. The per-unitized PV generation output profile for the same 5-day period in August 2003 is shown Fig. 6. This output profile is based on simulations performed to provide the PV output at the convention center during the same five-day period. The estimations for PV output are derived from atmospheric conditions, solar irradiance, and location of the PV.

In addition to the time-varying load and PV generation models, the simulation model also includes the timing and control parameters of all the capacitor banks and the substation LTC controls.

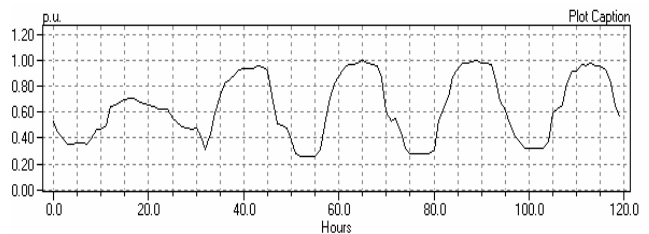


Fig. 5. Assumed 5-day load shape applied to all system loads.

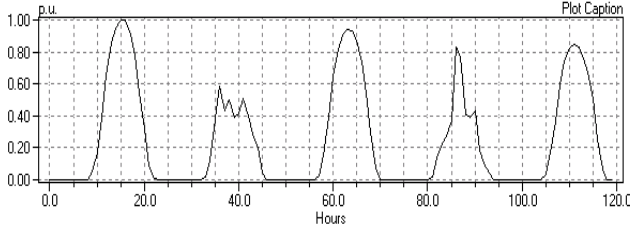


Fig. 6. Assumed 5-day PV generation output profile.

With all system loads set to vary according to the 5-day load shape curve and PV output above, dynamic hourly-resolution simulations are performed, and the simulated voltage as seen at the utility side of the PV interconnect transformer at the end of feeder 4 is shown in Fig. 7. The voltage profile is provided for simulations with the PV generation in service and out of service. Note that the PV generation does provide some loading relief during the daylight hours, which results in an increase in the utility side voltage. There is obviously no voltage difference during the nighttime hours. In total, the PV has only a minor effect while the loads and regulation equipment have a more significant role in driving the utility-side voltage profile. This is mainly due to the near unity constant power factor operation of the PV inverter.

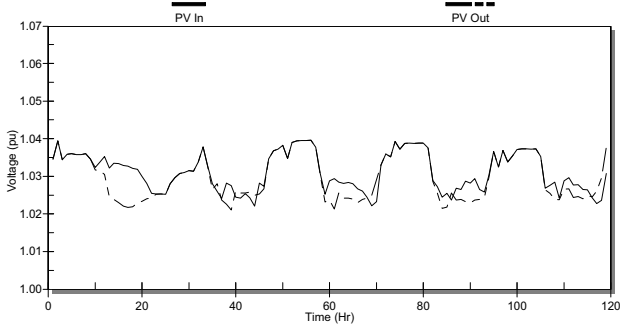


Fig. 7. Voltage profile at utility side of PV interconnect transformer.

While the effects of PV generation on the utility side voltage are minimal, this is not necessarily the case for the customer side voltages. Fig. 8 shows the voltages on the customer's 480V side of the PV interconnect transformer during the same five day period discussed previously. Due to the impedance of the interconnect transformer, a number of high voltage peaks result occur on the LVCC side of the transformer during periods of high PV output. A number of these voltage peaks may not be acceptable for other loads within the convention center, as they exceed 1.05 pu. One solution to this would be to distribute the PV generation among the different service points for the LVCC rather than interconnecting all the 5 MW system at a single bus.

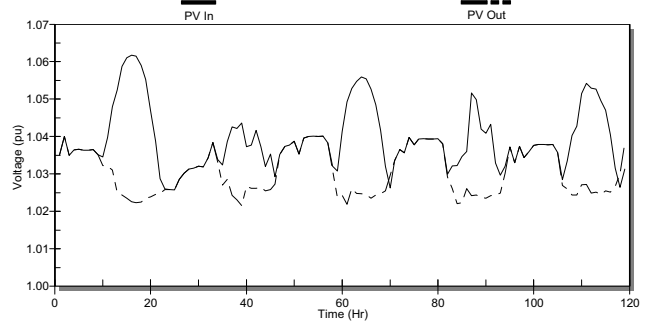


Fig. 8. Voltage profile on low side (480 V) of PV interconnect transformer.

4.2. Impact on transformer tap changes

Another voltage regulation concern is the increased wear on the LTC due to frequent tap changes in response to the variation of output associated with the daily output cycle of a variable generation source such as PV. A comparison of the tap-changes during the five-day period, with and without the PV generation, is shown in Fig. 9. During this period, the total number of tap changes is almost the same; however, the operation of the LTC is clearly affected by the level of generation as can be seen from the fact that the days with higher PV generation requiring less tap changes than days with less generation.

When the LTC operation is compared with and without the PV in service, there are periods where the generation supplies enough of the load to keep the LTC from operating as frequently. For example, in day three of the simulation, the PV supplies enough of the load to reduce the number of LTC taps by two. In any case, as the PV generation correlates with increases in the load, the operation of the PV should generally be beneficial to the overall number of operations of the LTC. It should be noted, however, that the total number of tap changes discussed here does not take into account any tap changes due to voltage changes on the primary side of the substation transformer. Therefore, the actual number of tap changes could be much higher if the transmission voltage were to vary significantly.

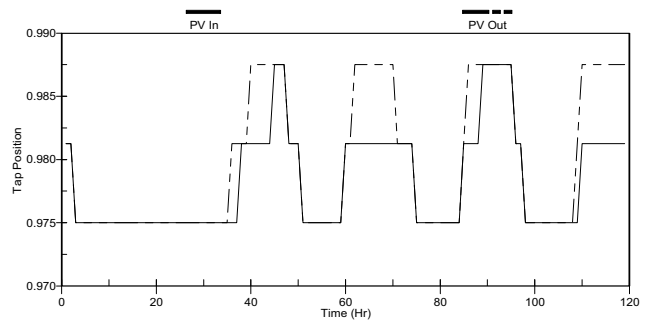


Fig. 9. LTC operation with and without PV generation for continuous five-day period.

4.3. Voltage after PV disconnect

The simulations summarized thus far provide a good understanding of the voltage conditions along the feeder and at the convention center for normal system conditions. Overvoltages and/or undervoltages that occur after system changes, but before the operation of regulation equipment, however, are not represented in these results. One condition that is especially of interest to the utility is when the distributed generation output raises the feeder voltage enough to cause the LTC to operate at a lower tap position than required for operation without the generation in service. When the distributed generation controls act quickly to separate from the system in response to a system disturbance as dictated by interconnection requirements [9], the system voltage realized after the disturbance is cleared can be unacceptably low without the support of the distributed generation. These low voltages will remain until the LTC is able to boost the voltages by changing the taps.

In order to assess this generator disconnect impact, a 1-second resolution simulation is performed with the load and generation modeled as constant values. After 20 seconds of simulation, the PV generation is instantly removed from service representing the response of the PV controls to a system disturbance. The resulting simulated voltage response on both sides of the PV interconnect transformer are shown in Fig. 10. Also shown in Fig. 10 is the movement of substation A load taping changer. Note that the substation LTC initially bucks the voltage slightly as the PV is generating at rated output. Once the PV controls separates from the system, the utility side voltage drops slightly, less than 1% of nominal. After a 15 second delay, the substation LTC taps to boost the voltage back up.

Although rated PV generation output and peak load levels are modeled for this simulation to facilitate assessment of the largest voltage drop at the interconnection point, the impacts on system voltage are relatively insignificant -- less than 1% at the point of interconnection and less than that at the substation LV bus. The load side bus voltage drop is slightly more significant after the PV generation is switched out (almost 3% on the low side of the interconnect transformer). All system voltages, however, are within normal operating ranges for the duration of the simulation, including the time span between PV disconnect and the LTC acting to boost the voltage.

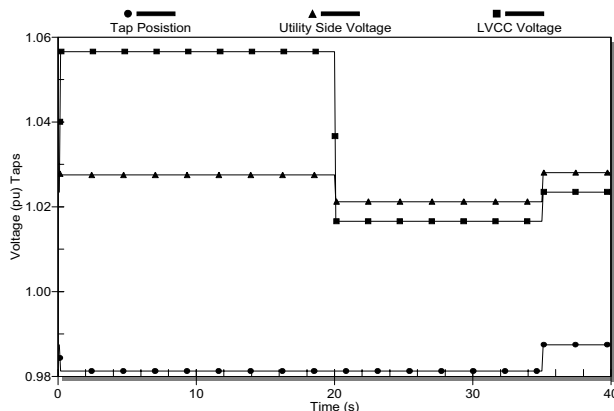


Fig. 10. Post disturbance voltage drop behavior at the interconnection point (100% rated PV generation and 100% rated load).

4.4. Impact on overcurrent protection

The impact of the proposed PV system on overcurrent protection, will likely not be a significant issue due to the limited fault contributions of the inverter. Inverter fault contributions are limited by the maximum current carrying capability of the power switching device used in the inverter as well as the short circuit current of the PV array. It is typically assumed that the total fault contribution for a PV inverter is less than twice the inverter's rated output current. As a result, the total fault contributions for the 5 MWs of photovoltaic generation would only contribute an estimated maximum of 800 amps of fault current during the very short period required to detect the disturbance. Furthermore, the constrained fault current contribution of the PV system reduces the probability of sympathetic tripping of adjacent breakers. Hence, the potential contribution of the PV system should have little impact when compared to the high fault currents associated with the relatively short, low-impedance circuits serving the LVCC.

Additionally, the interface inverter is also able to instantly cease operation after a disturbance is detected. Therefore, the duration of the fault current contributions is also limited to as long as required to detect that the disturbance which is typically less than one or two cycles. Finally, fuse-saving scheme disruption is not an issue for the PV interconnection, as the local utility company does not employ such a fuse-saving scheme.

5. Conclusion

This paper highlights some of the most important impacts of DG installation on distribution feeders; namely, voltage regulation and overcurrent protection issues. The impact on voltage regulation is quantified by simple analytical expressions for feeders with uniformly distributed load. Such impacts are analyzed for the case of

a proposed 5 MW PV generation to be located at the roof-top of the Las Vegas Convention Center. The entire 5 MW of PV was assumed to be interconnected at a single 12 kV bus to create the most significant impact on the primary feeder serving that bus. Due to the short length of the dedicated circuits serving the LVCC facility, the electrical strength of the conductors used for these circuits, and the fault contribution characteristics of the inverter-based PV generation, the effects on the voltage regulation and overcurrent protection devices are found to be minimal.

6. Acknowledgment

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