Minimizing Impacts of PV Solar Generation in Distribution Grids

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As large fossil fueled central station power plants are forced into retirement due to government policies and worldwide concern of global warming, non-carbon producing renewable generation in the forms of wind and solar are the logical replacement.

Large wind farms have already spread widely across the world and continue to be installed at a fast pace. From the grid's perspective, these plants are very similar to base load fossil generation and their impact on the distribution system is minimal. Solar generation however is different in that the majority of the installations are on the distribution system. Distributed energy resources (DER) in the form of utility level PV or roof top solar installations are beginning to take over the distribution grids where it is either very sunny, where buy-back rates are very high, or where existing utility rates are very high.

Today's distribution system was never built with this much DER in mind. With the changing landscape, there will be power quality, voltage stability, and reverse power flow issues caused by increasing levels of DER. Today's grid of conventional control equipment like tap changers, voltage regulators, and shunt capacitor banks do not solve the problems that are beginning to be experienced on today's grid and will certainly be on the grid of tomorrow. A unique array of distribution FACTS devices, built with the latest inverter technology, will be part of the smart grid initiative to vastly improve the control, the voltage, and the power quality of the distribution system's grid of tomorrow. This presentation will outline and show how innovative technologies with advanced controls and communication abilities are being developed for application in the distribution grid that would allow seamless integration of these DERs and also allow extended life and usage of conventional equipment that utilities have invested.

Keywords-DER, STATCOM, WTG, PV Solar

I. INTRODUCTION

Wind and PV solar generation are quite different with respect to abrupt changes in their MW output. Typically, the wind at the heights where the wind turbine generators (WTGs) are positioned does not typically die down quickly. Also, the generator and blades of a WTG have significant rotational inertia. Thus, the slowing down of the wind and the corresponding reduction in a wind farm's real power output does not typically impact transmission voltages much.

The **TEAL** colored line in Figure 1 shows a large wind farm's MW output on a steady wind day while the **DARK GREY** colored line shows the wind farm's MW output on a variable windy day. On this variable windy day, some of the wind changes can equal a drop from full generation to zero generation.

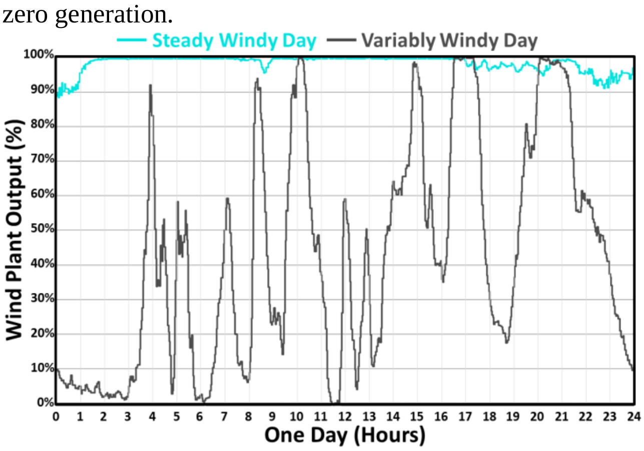

Figure 1. Variations in a large wind farm's real power output.

As Figure 1 shows, it can take minutes for a large wind farm, spread out over many square miles, to have its generation decline from full generation to zero generation. Yet, the MW output of a single WTG can change much faster and if it is located on a distribution feeder, it can impact the voltage significantly.

On sunny cloudless days, PV solar generation is highly predictable. Thus, PV solar generation is highly predictable with no rapid changes or fluctuations in its MW output. On days like this, distribution PV solar generations impact on the voltage is minimal because existing distribution equipment can easy adjust for any slow changes in voltage. However, even in areas of North America that are extremely sunny, most days have some period of local cloud cover. These partly cloudy days can result in highly variable solar irradiance, which in turn leads to rapid fluctuations in MW output from the PV solar generation. The fast changing PV solar generation can significantly impact the distribution system voltage and the frequency of these cloud impacts can certainly become a great annoyance to customers that have significant amounts of PV solar generation on the feeder that serves them.

A small distribution PV solar plant's power output is shown in Figure 2[1]. The **YELLOW** colored line in Figure 2 shows the output on a clear sunny day while the **GREY** colored line shows the output on a day with intermittent clouds. On this partly cloudy day, some of the variations in the plant's output exceeded an 80% reduction in plant output for short periods of time.

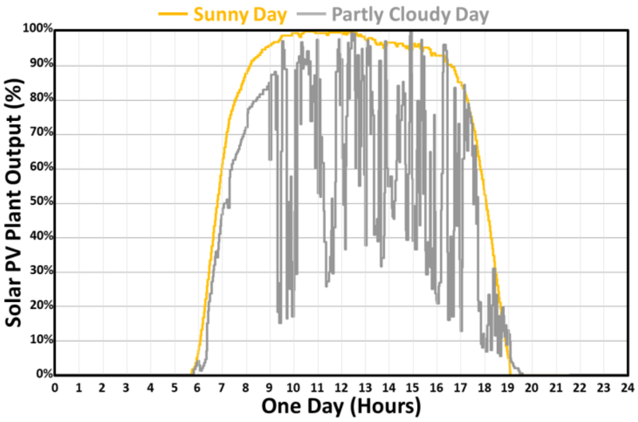

Figure 2. Variations in a distribution PV solar plant's real power output.

Larger renewable generating plants are connected to transmission facilities. Because of both their large size and being interconnected with the transmission facilities, they have to conform to strict government (FERC), ISO, and/or utility grid codes. Smaller renewable plants, usually less than 20 MW, tend to gravitate toward distribution facilities. At these smaller amounts of generation, the grid codes often do not apply. However, other utility criteria may be brought to bear upon these smaller renewable generation facilities.

Many utilities have some type of step voltage criteria that determines the sizing of shunt reactive devices on their systems. Usually, it's the maximum size of a capacitor bank that can be switched or the rating of the largest induction motor that can be started on their distribution system (direct-on-line). It is set by the impact of the change in voltage when the capacitor bank is switched or the motor is started. A typical rule of thumb for determining step voltage changes depends on the fault MVA (short circuit ampacity) at the connection point of the capacitor bank and the MVAR size to be switched.

$$Step\ Voltage\ Change = \frac{MVAR\ Size\ of\ Bank\ Being\ Switched}{Fault\ MVA} \quad [1]$$

Typically, utilities will not allow a capacitor bank to be switched on their system that causes a step voltage change > 2%. A few utilities do use a value of 3% or slightly more. It is generally accepted that keeping the step voltage change to < 2% will keep the utility's customers from being able to observe and/or experience the voltage change and also not impact the power quality of distribution system.

A primary concern with renewable generation on the distribution system is the unexpected loss of the source of that generation. For that sole WTG, the wind can suddenly drop off fast. Clouds can cover the sun which can considerably interfere with PV solar generation. For these distribution connected renewable facilities, the loss of wind or the blocking of the sun by clouds can cause large abrupt changes in generation output and a corresponding rapid change in voltage. These changes in renewable generation can cause step voltage changes that exceed a utility's 2% limit and can certainly cause excess wear on utility equipment trying to maintain a stable distribution voltage.

II. Solutions – Current Technology

The current technologies used by distribution engineers to solve voltage problems on the distribution system have been around for decades. They would typically install one or more of the following three types of voltage control equipment:

1. A load tap changer (LTC) on the main substation power transformer
2. Voltage regulators with in the substation and/or along the distribution feeder - possibly at multiple locations
3. Distribution capacitor banks at several locations along the distribution feeder

While these three technologies have been relied upon over the years maintaining distribution voltages, they are having difficulty in the new era of distribution energy resources (DER) especially with renewables generation sources like PV solar and wind. The intermittency of the wind for WTGs and the sun for PV solar plants causes voltage fluctuations/flicker that they are not designed to and cannot fix.

Transformer LTCs and voltage regulators normally see a voltage change, wait a bit, and then change their taps to compensate for the voltage change. Typically, the wait time can be anywhere between 30 to 60 seconds. The renewable intermittency caused voltage fluctuations can certainly happen much faster. This causes these devices to chase the problem and not fix it. Certainly the wait time could be lowered for them, but this would cause these mechanical devices excess wear and tear. They would at the least require much more maintenance let alone being replaced with new devices more often.

Voltage controlled capacitor banks are much the same story. The switch or circuit breaker that controls the capacitor bank operates fairly infrequent during a typical day. If it has to chase renewable voltage fluctuations on a daily basis, it can wear out in months of time. Capacitor banks have a limit of only being able to increase the voltage by turning on and can only decrease the voltage by turning off. Obviously, they cannot go inductive. Once a capacitor banks has been switched off-line, it typically cannot return-to-service for a number of minutes whiles its trapped charge dissipates. These mechanical voltage control devices were not made to control the voltage for this new Distribution Grid of Tomorrow.

III. Solutions – New Technology

What is this new technology for the distribution system? It is power electronics. PV solar system and modern WTGs all use power electronics to convert their generated power to a 60 Hz AC wave form. While these power electronics often have the capability to generate capacitive or reactive power, often significant limitations arise in practice. The following are a few reasons as to why:

- The inverters are an older design and do not have the capability
- The inverter control system does not have the capability
- The inverters are sized too small to generate any useful amount of reactive power
- They are not in the right location on the feeder to provide the most benefit
- The distribution utility does not want non-utility sources controlling its distribution voltage

If these renewable systems cannot control the voltage or are limited in their capability to do it, what can be added to the distribution system to do it? One highly-effective solution is STATCOMs designed specifically for the distribution system. A STATCOM, static compensator, is a device that came from EPRI FACTS (Flexible AC Transmission Systems) program to support the transmission system in the late 1980s. A STATCOM is a power electronic device comprised of power inverters that inject reactive current into a power system for the purpose of controlling the system voltage or the power factor. STATCOM solutions have historically been rather large in size (ranging from a few MVAR up to 100s of MVAR) and have been limited to installation within substations.

IV. SOLUTIONS – DISTRIBUTION STATCOMS

To address these fast voltage control regulation problems on the distribution feeders, AMSC® has designed a new distribution class STATCOM called the "D-VAR VVO™". This distribution STATCOM is shunt connected directly to medium voltage (up to 15 kV) distribution systems (meaning there is no need for a step-up transformer for 15 kV class installations). It can be placed at any location along the feeder and it can provide both steady state and transient voltage regulation, power factor correction, or a fixed amount of capacitive or inductive reactive capability. In a voltage control mode, it can operate with a droop setting anywhere between a 0.5% and 10%. Since the STATCOM is a power electronic device, its reactive output is continuously variable from full inductive to full capacitive and its speed of response is in milliseconds.

The AMSC D-VAR VVO™ STATCOM is available with three-phase ratings of either ±500 kVAR or ±1000 kVAR. If higher ratings are needed, two systems can be installed at one site for a ±2000 kVAR rating. It is also available with single-phase ratings of +/-167 kVAR or +/-333 kVAR. This STATCOM also has short term overload capability that can increase its output to 1.3 times its continuous rating for up to 1 minute. See Figure 3. This overload capability is especially valuable when addressing short-term or transient events like voltage swells or sags, or for voltage support during a motor starting period.

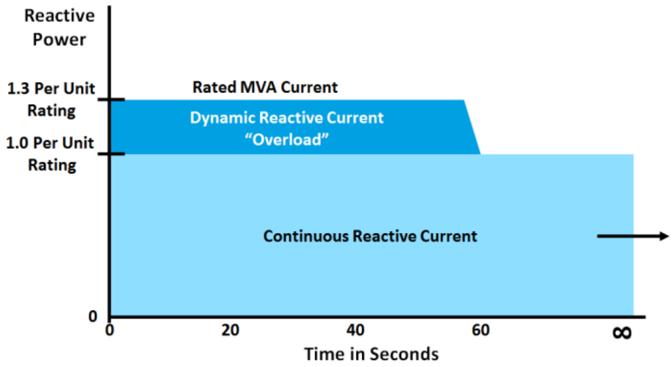

Figure 3. Reactive Power Capability of the D-VAR VVO™

Figure 4 shows the typical utility distribution connection for the D-VAR VVO installed in a three-phase distribution feeder.

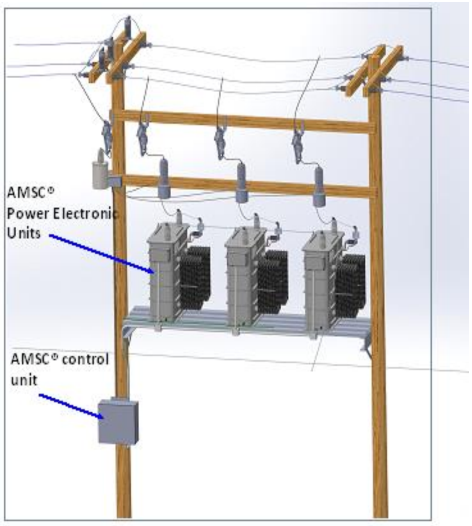

Figure 4. D-VAR VVO connection to a 15 kV class distribution grid

The STATCOM would typically be owned and operated by the local distribution utility. The H-Frame structure that is needed is designed to use standard utility parts that would be used similarly for installing three single-phase transformers or three single-phase voltage regulators.

V. PROBLEM – HIGH PENETRATION OF PV SOLAR SYSTEMS

A case study utility has a 13.2 kV distribution feeder with voltage fluctuations greater than its 2% flicker limit. A three-phase diagram of the feeder is shown in Figure 5(a). The feeder has PV solar systems (◎) throughout the feeder's three phases. Loadflow analysis showed that the **A-phase** and **C-phase** feeders did not have any voltage flicker problems, but the **B-phase** feeder, with almost 50% of feeder's PV solar systems by kW, did. Figure 5(b) shows the **B-phase** feeder, the generation of the PV solar systems, and its X-axis voltage recording **locations** for Figures 6 and 7.

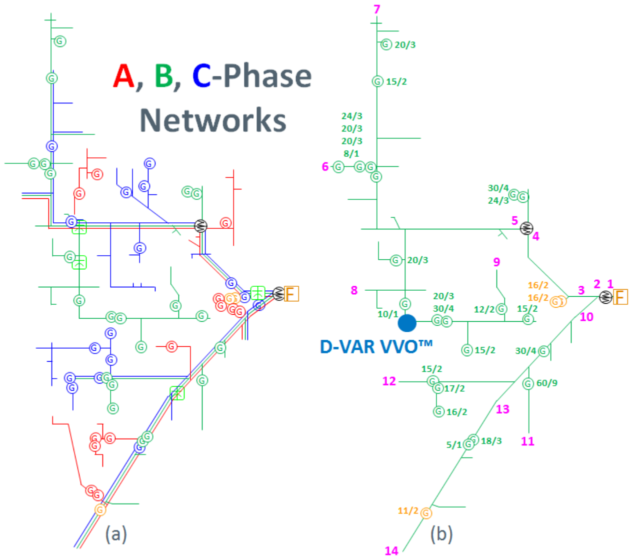

Figure 5. Distribution feeders with PV Solar Generation

As the PV solar power output changes throughout a cloudy day, loadflow analysis at peak load showed that the fast voltage dips could cause significant flicker on the feeder at different locations along the feeder. See Figure 6. At Point **9**, the flicker can be as high as 3.8% (Voltage at PV 100% - voltage at PV 20%). In the loadflow analysis, no voltage control devices on the feeder are operated since these flicker events can occur faster than they can typically operate.

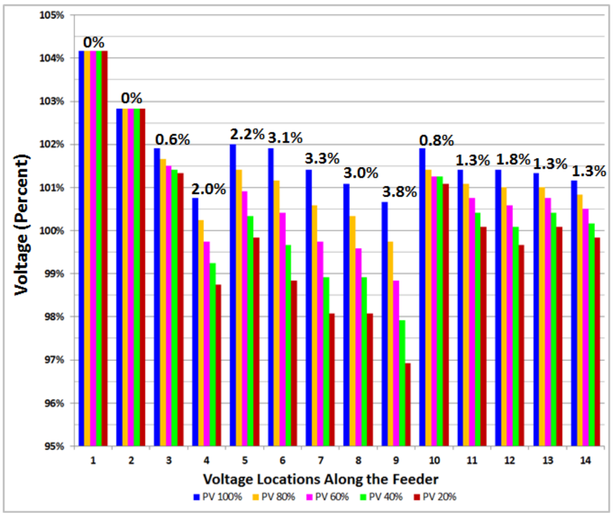

Figure 6. Loadflow Results for the Problem

Based on feedback from the utility, these smaller PV solar systems are all operated at a slightly fixed capacitive power factor (PF).

VI. Solution – Single-Phase Distribution STATCOM

The feeder has two main branches that go northwest and southwest from the source. Figure 6 shows that the **B-phase** northwest branch has the more significant voltage flicker problems (Points **5** thru **9**). Loadflow analysis showed that the most effective location for a single-phase D-VAR VVO™ STATCOM was between Points **8** and **9**. Operating at that location, **see figure 5(b),** in its voltage control mode using a 1% droop the loadflow analysis, shown in Figure 7, illustrates that the flicker at Point **9** could be reduced from 3.8% to 1.1% - well below the 2% flicker limit.

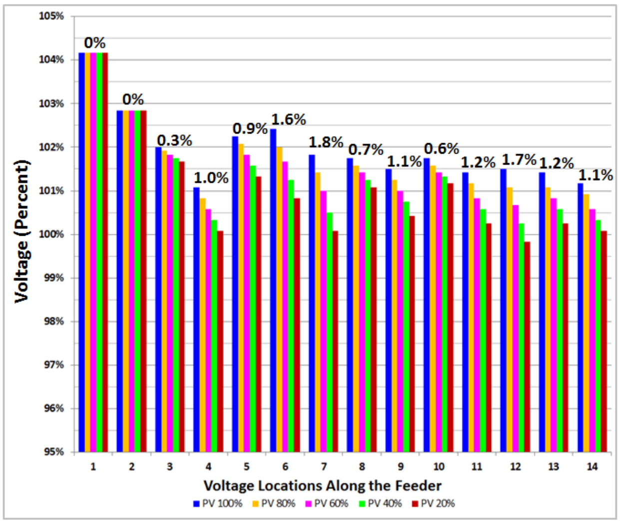

Figure 7. Loadflow Results for the Solution

The effects of operating on the 1% droop are shown in Figure 8. The x-axis shows the STATCOM's ±343 kVAR reactive capability while the y-axis shows the range of voltage that the STATCOM can regulate. The midpoint voltage, where the STATCOM's output is 0 kVAR is 101.9%. At full capacitive output, the voltage is 100.9% and at full inductive output, the STATCOM's voltage is 102.9%. For voltages below or above these values, the STATCOM remains fixed at its full capacitive or inductive output. Figure 8 shows the loadflow results for the following three different load levels: 100% (peak) load, 70% of peak load, and 40% of peak load. As the PV solar generation changes from 100% to 20%, the STATCOM's reactive output changes. At peak load, the STATCOM's reactive power changes from -49 kVAR to -210 kVAR. At 40% of peak load, the STATCOM's reactive power changes from 90 kVAR to -101 kVAR. Thus, the STATCOM's capacitive and inductive capability is required to maintain the voltage within the STATCOM's voltage regulation range. If the droop were steeper, the voltage would vary over a wider range and the STATCOM would output fewer kVAR. If the droop were shallower, the voltage would vary over a smaller range and the STATCOM would output more kVAR. A 0.5% droop could cut the flicker to ~0.6%.

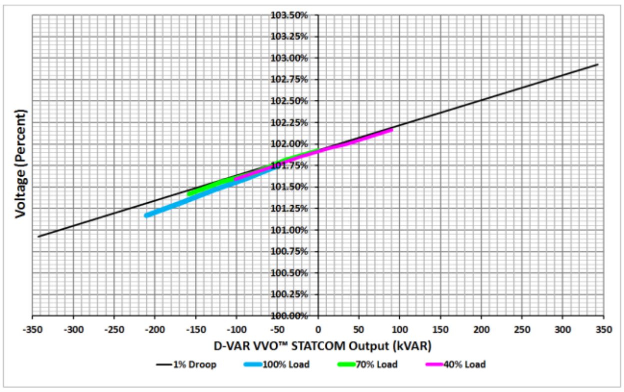

Figure 8. Effects of Droop Control on Voltage

VII. The Problem – Two Wind Turbine Generators

A utility has a 12.5 kV distribution feeder with voltage fluctuations greater than its 2% flicker limit. A three-phase diagram of the feeder is shown in Figure 9. As the two 1200 kW WTGs power changes throughout the day, they cause significant voltage regulation issues on the feeder. See Figure 10.

As discussed previously, most utilities do not want renewable generation controlling their distribution system voltage. Typically, larger renewable generation on the distribution system is set to operate at a 0.98 fixed lagging power factor (PF). Analysis has shown that this PF value is a good compromise with respect to not dragging the voltage down too low and minimizing changes in the voltage as the wind power changes.

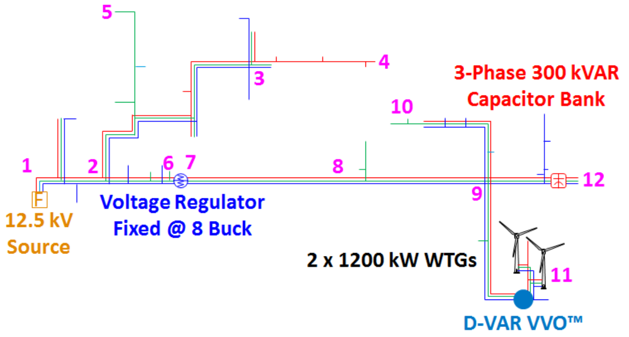

Figure 9. Distribution Feeder with WTGs

To try and get the feeder's voltage control equipment to survive because of the frequently changing voltage, the utility has done the following modifications to its voltage control equipment:

- The voltage regulator is operated fixed at its 8th buck step.
- The 300 kVAR switchable capacitor bank has a maximum of 25 operations per day and then it locks out until the next day

The loadflow analysis results, shown in Figure 10, are for generation levels of **2400**, **1200**, **600**, and **0** kW. Figure 10's X-axis points are the **number locations** shown in Figure 9. As the wind generation changes throughout the day, analysis showed that the voltage can vary over 6%.

VIII. Solution – Three Phase Distribution STATCOM

To solve the widely varying voltages, a ±1000 kVAR D-VAR VVO™ was added to the system to regulate the distribution feeder voltage. The effectiveness of the D-VAR VVO was analyzed at three different locations - being located by the two WTGs (Point **11**), by the 300 kVAR capacitor bank (Point **12**), and just east of the voltage regulator (Point **7**). It was identified that the location by the two WTGs, Point **11**, was by far the best location. Figure 11 shows these loadflow results. As the wind generation changes throughout the day, analysis showed that the D-VAR VVO reduced the voltage variation to less than 1.3% which is below the 2% step voltage/flicker limit.

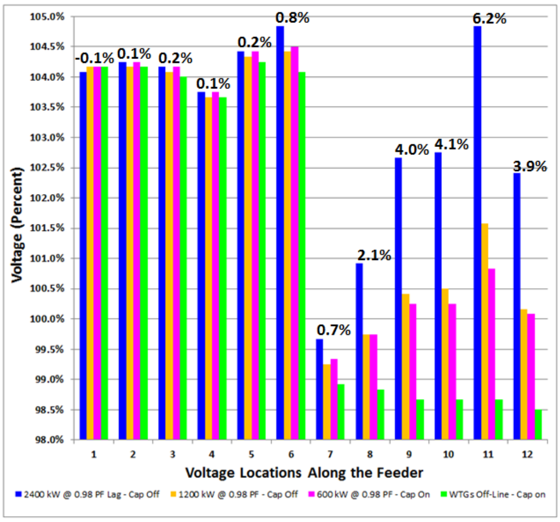

Figure 10. Loadflow results for the problem

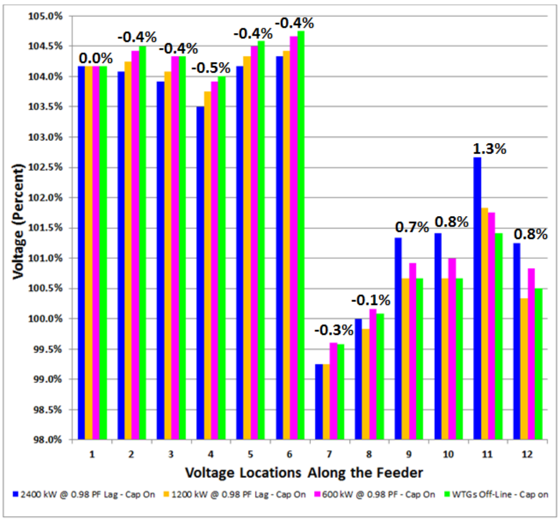

Figure 11. Loadflow results for the solution

IX. Conservation Voltage Reduction Program

Additional loadflow analysis was conducted to observe the impact of a ±1000 kVAR D-VAR VVO™ on conservation voltage reduction (CVR). To maximize CVR capability, the objective is to create a flat voltage profile along the feeder. With the 300 kVAR capacitor bank fixed off-line and the voltage regulator fixed at its unity tap, the 12.5 kV line voltage profile becomes very flat along the entire distribution line, as illustrated in Figure 12. The maximum voltage change between full generation and no generation is now is 1.2%. This showed that the STATCOM could assist this feeder in the implementation of a CVR program.

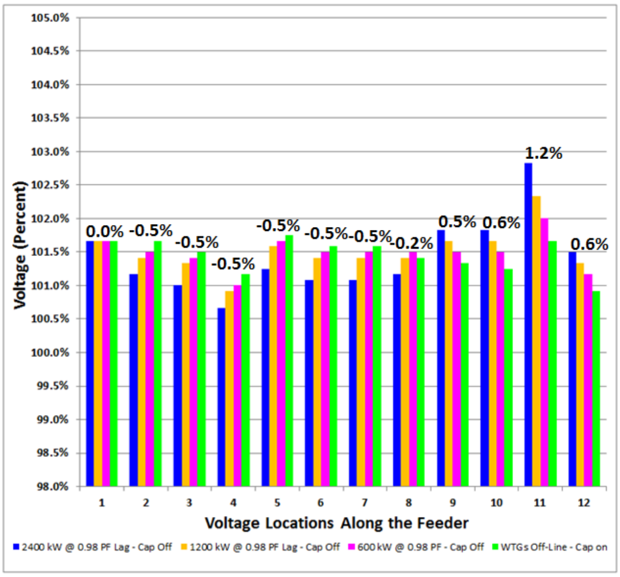

Figure 12. Loadflow Results for the Optimized Solution

X. CONCLUSIONS

In summary, STATCOMs can effectively solve voltage problems, be they step voltage changes or just voltage regulation issues, on distribution feeders. Whether the renewable generation is located near a substation or on the tail end of a feeder, STATCOMs are more than capable of dynamically regulating a distribution line's voltage profile to keep it within a 2% step voltage/flicker limit.

The D-VAR VVO™ STATCOM significantly lowered the flicker on two different feeders that were analyzed with two types of renewable generation located on them. The utility case study loadflow analysis established the following four conclusions:

1. Distribution STATCOMs can significantly improve supply power quality by reducing any fast voltage flicker problems on a distribution feeder.
2. STATCOMs can react to changes in voltage much quicker than any conventional voltage control equipment
3. STATCOMS can operate continuously over their full rated kVAR range without any negative impacts to their reliability.
4. STATCOMs can be used very effectively to enhance CVR performance on a distribution feeder.

REFERENCES

[1] J.A. Diaz de Leon II and B.L. Agrawal, "Meeting Utility Step Voltage Change Requirements by Providing Precise Voltage Control for a PV Plant on a Distribution Feeder," Solar Intergration Workshop, October 2013

BIOGRAPHICAL INFORMATION

John Diaz de Leon joined AMSC® in 1999 after working for Alliant Energy/Wisconsin Power and Light Co. for 20 years as a transmission and distribution planning engineer. One of the founding members of the Network Planning group within AMSC, he has been very instrumental in the product development efforts of our FACTS products starting with the initial D-SMES units, followed by the D-VAR® systems and the AMSC SVC. At AMSC, he performs planning studies to analyze utility systems for voltage, capacity, stability, transfer capability, harmonic and power quality problems. He also conducts studies to analyze wind and solar farm interconnection requirements that include LVRT and HVRT capabilities, harmonic and power quality problems, voltage regulation and power factor control. He earned his B.S. degree in Electrical Engineering in 1978 from the University of Wisconsin. He received his P.E. license from the State of Wisconsin in 1983, was elected to Senior Member of the IEEE in 2008 and has co-authored and presented papers at IEEE, EUCI and other professional forums.

Narend Reddy is currently Managing Director of FACTS Products and Planning at AMSC. He joined AMSC® in 2001 as a Transmission and Distribution Planning Engineer working on planning studies to analyze systems for voltage, capacity, stability, transfer capability, power quality, wind and solar interconnections and applications of superconductor cables for transmission and distribution systems. Prior to AMSC® he worked for Fiji Electricity Authority for 11 years in the generation and network planning divisions. He earned a B.E. degree in Electrical Engineering and Computing from Monash University, Melbourne, Australia and an M.B.A. degree from Cardinal Stritch University, Milwaukee, Wisconsin. He is a Registered Professional Engineer in Wisconsin and a member of the Institute for Electrical and Electronics Engineers (IEEE). He has co-authored and presented papers at IEEE, EUCI and other professional forums.

Jayateerth Managoli is Country Sales Manager of AMSC, India. He joined AMSC in December 2009. Prior to this, he was working with Siemens, India in the field of Transmission and Distribution and has more than 20 years of experience holding a variety of sales, product management, business development, marketing, strategic planning, product and system engineering including production management roles. He was heading the High Voltage Instrument Transformer Business in Siemens before joining AMSC. He has co-authored and presented papers at many conferences and other professional forums on Superconductors, Smart Grid and Renewable Energy.