DETERMINING PRACTICAL PLANNING LIMITS FOR DG ON DISTRIBUTION CIRCUITS

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ABSTRACT

It is expected that the amount of DG, particularly renewable DG, on distribution systems will increase with the development of the Smart Grid. Some utilities have already experienced operating problems with the voltage rise from large solar PV generation and have proposed tight limits. Distribution engineers are seeking practical methods to determine limits for DG that may be applied at the planning stage. Voltage criteria are often the best indicators of successful operation of proposed DG, but are not always easy to apply. There may not be sufficient headroom throughout the system to allow for the voltage rise from DG output. This paper describes our evaluation of planning methods proposed in the literature and from our own research. Capabilities of distribution system analysis tools to support DG limit evaluation are discussed.

INTRODUCTION

As the advancement of the Smart Grid continues, it is expected that the amount of DG, particularly renewable DG, on distribution systems will increase. This raises a number of questions, including:

- Are there any practical methods for utility engineers to easily determine limits for DG when planning their distribution systems?
- What planning criteria should be used?
- What type of analysis is needed to apply the criteria?

An EPRI research project under its Program 174, Enabling Integration of Distributed Renewables, explored these questions in 2010. This paper gives examples of applying some of the criteria identified in the report. [1]

The stochastic nature of renewable generation is a major concern. This can cause the voltage to fluctuate and be noticeable by other customers. It can also cause problems with utility voltage regulation in general and voltage rise in particular. Bollen, et. al,. describe many of the concerns in a 2008 paper. [2]

Some utilities in the US have already experienced operating problems with large solar PV generation and have placed stringent limits on how much DG can be connected to a given feeder. [3] This is a conservative planning strategy to protect the existing system. A capacity-based criterion is typically used. That is, a limit is placed on the maximum DG power output relative to the capacity of the system. The limit generally reflects the maximum DG capacity that can be accommodated without costly changes to the utility distribution system equipment and operating practices. This will work for some systems and particular situations, but not for others. Other DG limit criteria for planning purposes gleaned from the literature and our own experience performing DG interconnection studies include:

- Voltage rise due to DG output
- Change of voltage on loss of generation
- Voltage fluctuations
- Change short circuit current magnitude
- Percent change in fault current
- Percentage of minimum load demand
- Percentage of feeder design capacity

Voltage criteria are often the best indicators of whether a DG installation will operate safely and achieve the desired benefits. However, it is often difficult to determine what voltages that customers will experience if they, or nearby customers, install their own generation. Short circuit current contributions are commonly used to judge the impact on overcurrent protection practices. Fault current contributions vary significantly depending on DG technology and interconnection transformer, if any. There is generally no single criterion such as the VA rating of the generator that will always work.

The lack of coincidence between renewable DG output and load results in questions about capacity benefits. For example, solar PV generation has become quite popular in same areas and advocates often claim significant capacity benefits. However utility engineers may be reluctant to give solar PV generation any capacity credit if it does not reduce the load peak that often occurs about 1-2 hours after the generation output has ceased. The planner's concern is that the power delivery system must be built to supply the maximum demand. However, many capacity limits are thermal and solar PV actually does narrow the width of the peak and thus the thermal duty on many components. How is this captured in a relatively straightforward manner? Space does not permit a detailed discussion of this subject here; we will focus on some more straightforward voltage criteria. The question is explored in the EPRI report [1] and by Dugan and Price. [4, 5] The reader is referred to these resources for more details on this subject. Computing this incremental capacity was one of the original capabilities introduced in EPRI's OpenDSS computer program [6], which is used for the simulations described in this paper.

Voltage issues are common to all types of DG, dispatchable or not. Voltage criteria are usually the first violated when the DG is inappropriate for a given distribution system.

Therefore, the remainder of this paper will focus on applying voltage limits. We have been involved in developing capabilities in distribution planning tools to support the evaluation of DG. The examples will provide some ideas on the features of distribution system analysis tools needed to support DG planning issues and evaluate limits for hosting DG. In particular, the emphasis will be on solar PV generation due to its special issues and its popularity in Smart Grid efforts.

VOLTAGE CHANGE SCREEN

The simplest voltage limit to apply for any type of DG is to simulate the sudden disconnection of all DG on the system. This will occur when there is a fault on the utility distribution system and all DG must disconnect to allow the fault clearing and sectionalizing process to continue. The immediate voltage change prior to any tap changer or capacitor switch action remains one of the better indicators of the compatibility of a proposed DG installation and the power distribution system. A small voltage change is desirable.

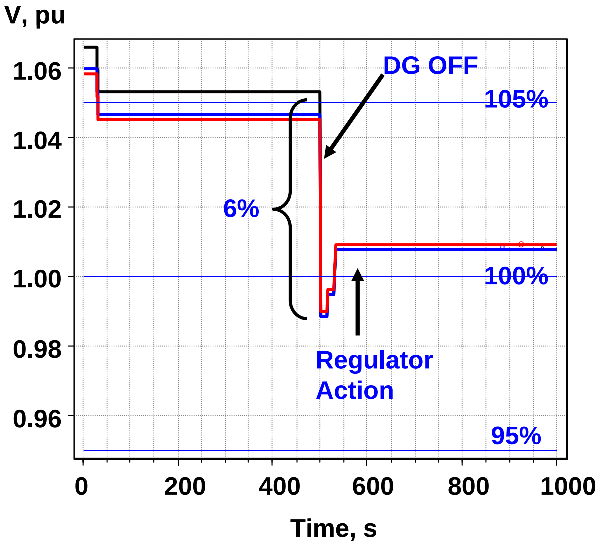

Figure 1. Voltage Change on Sudden Loss of Generation

Figure 1 shows the results of a simulation in which the initial voltage change was a drop of 6%. A change exceeding 5% is often an indication that the proposed active and reactive power output is inappropriate for the point of connection (POC). We generally prefer the change to be in the 2-3% range.

The 5% criterion is most often applied to constant, dispatchable generation for which this change is expected infrequently. For fluctuating, renewable generation, a change greater than 1% warrants further investigation.

This simulation was carried out by allowing the voltage regulator tap positions to stabilize from an initial starting point. Then all generation served from the bus of interest is disconnected and the simulation is continued until the regulator action once again stabilizes. The time step size is generally 1s to accurately capture the tap changes.

EVALUATING SOLAR RAMPING

Some of the difficulties dealing with renewable generation on the distribution system are illustrated by the characteristic shown in Figure 2. This is an actual 45-minute measurement of a series of cloud transients on the solar PV system spread out over EPRI's buildings in California. The data were collected with a 1-s sampling interval. The power typically ramps from near full power to 20% power, and back, at a rate of 10% per second. The "dead time" at minimum output is often as long as 2 minutes

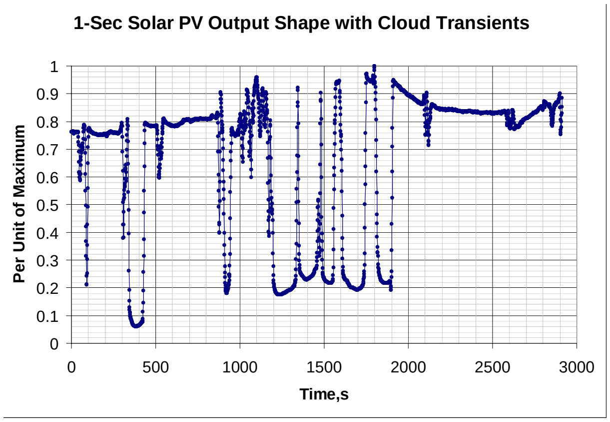

Figure 2. Measured Solar PV Power Output Characteristic

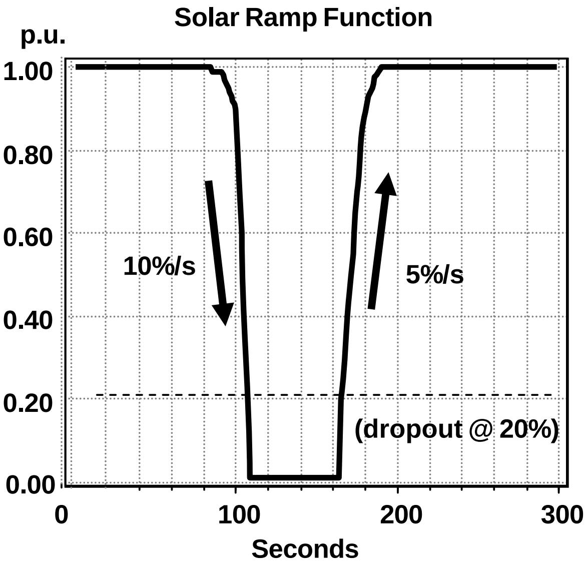

Figure 3. Prototype Solar Ramping Characteristic

A similar characteristic has been observed in other locations. Therefore, we have developed a prototype solar ramping function (Figure 3) to use to test the ability of a distribution system to accept large solar PV generation installations. The generator output is assumed to follow this shape and the resulting system voltage is computed. The ramp starts down at a rate of 10% power per second until it reaches 20% where it is assumed the inverter drops out. The recovery is slower at 5% per second, assuming the inverter can moderate the ramping rate. The duration of the dead time at the bottom can be adjusted as required. It should be longer than the regulator control delay time.

Example of Solar Ramping Analysis

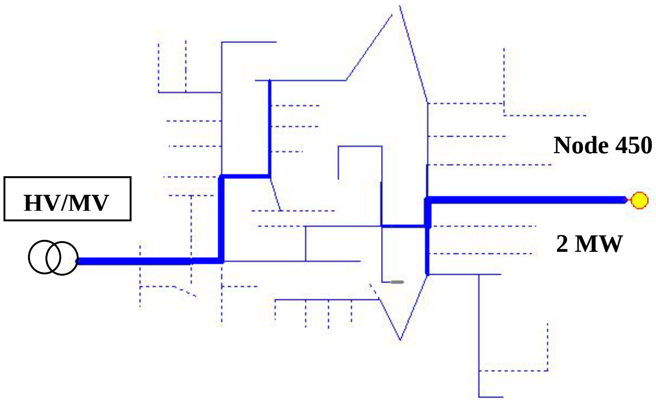

Figure 4. IEEE 123-bus Test Feeder with 2 MW Generator at Node 450

Figure 5 illustrates the results of applying the prototype ramping function to a hypothetical 2 MW generator on Node 450 of the IEEE 123-Bus Test Feeder [7] (see Figure 4). This feeder has several voltage regulator banks. As the ramp starts down, the voltage at the POC drops, taking the voltage regulators out of band. This causes the voltage regulators to tap up to compensate after a time delay. Thus, when the cloud passes, the regulator taps are too high and there is a voltage overshoot above 105%.

This is a common problem being experienced, or anticipated, by utilities hosting multi-MW solar PV installations. The basic reason is that many distribution feeders are operated with voltage regulation schemes that assume the voltage would always drop as one moves away from the HV/MV substation. The voltage is generally regulated near the top of the band (105% in North America). This leaves insufficient "headroom" for the voltage rise that could occur from DG power output.

The voltage profiles in Figure 6 and Figure 7, computed by the OpenDSS program, demonstrate the problem for the IEEE 123-bus Test Feeder. The regulators are set so that without the 2MW DG there is only 1-2% voltage headroom near the POC (Figure 6). The Test Feeder is umbalanced and each phase is slightly different. The same loading case with the DG is shown in Figure 7.

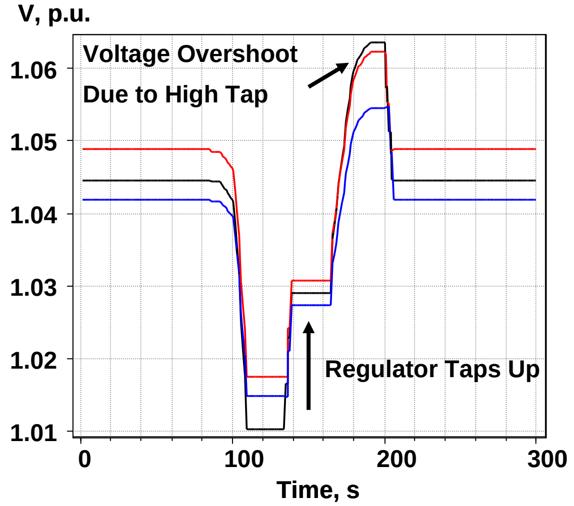

Figure 5. Node 450 Voltage Response to Solar Ramp

Note that the regulator tap values in Figure 7 are settled out after going through the excursion depicted in Figure 5. The voltages at the nodes near Node 450 are bumping up against the upper limit. This would suggest that 2 MW is the limit for DG in this part of the feeder based solely on voltage rise.

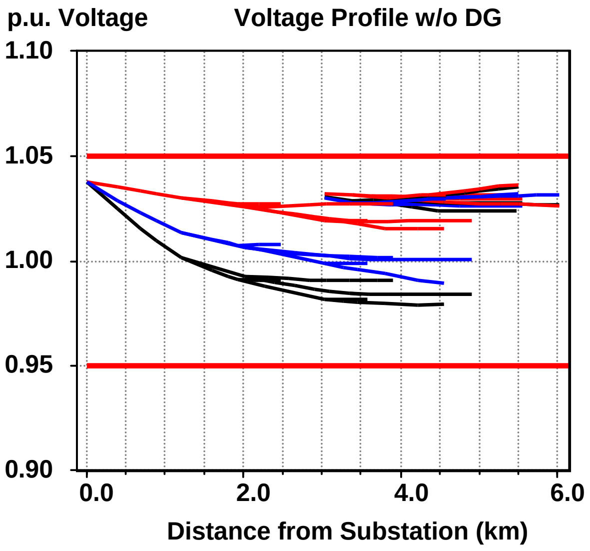

Figure 6. Voltage Profile of IEEE 123-Bus Test Feeder

Actually, the limit would apply to all parts of the feeder downline from the regulators. However, this is only part of the story. In order for regulators to reach the final tap position, several customers on the feeder would be subjected to an overvoltage. Remedial action of some sort would be necessary to accommodate even 2 MW because this event could happen several times per day as suggested by the cloud transient characteristic in Figure 2.

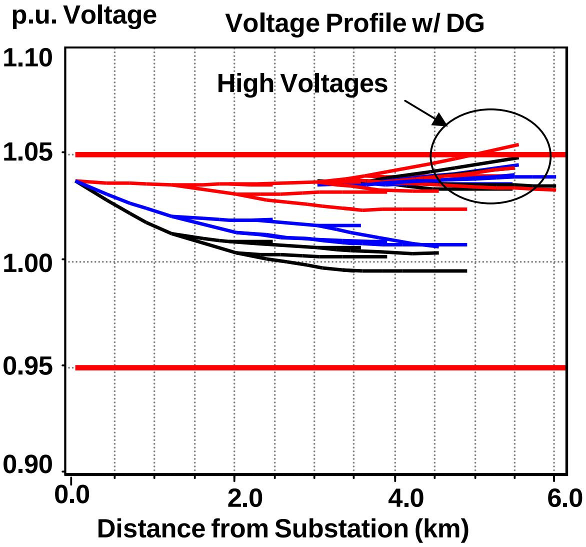

Figure 7. Voltage Profile of IEEE 123-Bus Test Feeder with 2 MW Generator at Node 450

If planners wish to provide more headroom for voltage rise one solution would be to reduce the voltage regulation target voltage. Another might be to require DG to absorb reactive power to suppress voltage rise. For the IEEE 123-bus Test Feeder, there is adequate room to drop the voltage profile approximately 2%, which would avoid the overvoltages for the case shown. For other systems, the line drop compensators, which are often unused, would have to be employed in a coordinated manner to flatten the voltage profile while making use of the full 105-95% range at heavy load.

Table 1.
Planning Limits for DG

Criteria	Limit
Voltage Change (Infrequent)	< 5%
Voltage Change for fluctuating generation such as solar PV or wind generation	< 1%
Voltage Regulation (Voltage Rise)	±5% of nominal
Generation Ratio (% of min load kVA)	< 20% - rotating machine < 33% - inverters
Feeder Design Capacity (% of feeder design kVA)	<15%
System Stiffness (DG current in % of short circuit current at POC)	< 2% (wind and PV) <4% (continuous generation)
% Short Circuit Current Contribution by DG	< 5% (rotating machines) N/A for inverters
& of Ground Source Contribution by DG	< 5%

OTHER PLANNING LIMITS

Table 1 lists several planning limits identified through our research. Many of the limits correspond to the "high penetration" values in Barker's classification. [8] Others reflect the experience of the authors. The basic idea is that when these limits are exceeded, further planning studies are warranted to determine remedial actions. There is generally a margin of safety in these numbers from the perspective of utility distribution planners, but conflicts with either voltage regulation and/or overcurrent protection are more common when these values are exceeded.

DISTRIBUTION SYSTEM ANALYSIS TOOLS

The chief capability of distribution system analysis tools featured in the evaluations demonstrated in this paper is the ability to perform sequential-time power flow simulations of multi-phase distribution models. This is particularly important for capturing the response of voltage regulating equipment on North American 4-wire multi-grounded neutral distribution system to DG output variations. Detailed regulator and capacitor control models are required.

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