Analysis of Indian Electricity Distribution Systems for the Integration of High Shares of Rooftop PV

Paper#1: PV Integration Manual

On behalf of:

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Project

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1. Introduction

This manual on the integration of large numbers of distributed PV generators into the distribution grid aims to identify the main issues that can be expected when undertaking such development, and the typical technical, economic and regulatory solutions that have to be considered.

The document is based on the results obtained and recommendations developed during the GIZ commissioned PV integration study, which included a desktop study on general issues in the Indian power system as well as modelling and simulation of distribution grids in Delhi and Bhopal.

Based on the study and general international experience with the integration of rooftop PV, this manual is intended to provide a brief, high-level overview of the main issues, technical and non-technical.

2. Legal and Regulatory Framework

2.1 Incentives

As of 2017, small scale PV power is still slightly more expensive than the wholesale market prices commanded by large conventional generation, requiring some type of incentive to draw investments. These can take the shape of investment subsidies by the government, a granted feed-in tariff over a certain period of time, a premium on the wholesale market price, or a net or gross metering scheme.

Investment subsidies were given by most countries with ambitious PV targets at some point, but have expired or been reduced in the meanwhile in some cases as prices for PV installations dropped. Typical early adopter strategies in Europe involved high feed-in tariffs granted for a period of 15 to 25 years, granting a return on interest for the owner of the unit, while net metering schemes were and are more common outside of Europe. The FIT model proved to be very successful, with large capacities of PV eventually being installed especially in Germany, Italy and Spain. This eventually brought down PV installation prices, which played a role in metering schemes picking up pace as well. Feed-in tariffs in most countries that use them have been reduced over time to reflect the dropping PV cost – a new PV unit in Germany would get around 0.50 €/kWh (ca. INR 34/kWh) in the early 2000s, while the tariff for one installed in 2016 is around 0.10 €/kWh (ca. INR 7/kWh.)

A net metering scheme will only be an incentive to install PV if grid parity is reached – it is then cheaper to produce the electricity with PV panels than to draw it from the grid.[1] Until about 2012, this was not the case in any major country[2], resulting in very slow development in countries with only a metering scheme. Some countries tried to compensate this with investment subsidies, but usually with limited success. However, as of 2016, where rooftop PV has either reached grid parity or is close to it, investment subsidies turn out to be a good incentive. California currently offers the choice between a granted feed-in tariff (the European model)[3] or an investment subsidy and a net metering scheme[4] (which is what is currently offered in India as well), with the latter

2.2 Tariffing and Financing

As indicated in the previous sections, in India, large customers have to pay higher electricity charges than small customers. This is a typical structure for developing countries where electricity retailers cross-subsidize potentially poor residential customers through financially stable commercial and industrial customers.

This is fundamentally different from the tariff structures found in wealthy, heavily industrialized countries. In most cases, commercial and industrial customers pay lower rates than residential. In Germany, a large percentage of industrial customers is also exempt from the renewable energy charge which is used to pay the feed-in tariff for wind and PV. There are several reasons for this type of structure, the primary one is that large customers with a steady baseload demand are able to negotiate better deals for their electricity supply. Lower tariffs for industry are often also state supported – for example through the exemption from the renewable energy charge – to stay competitive in a globalized economy.

Especially if a net metering scheme is used to support PV, different tariffing philosophies will have an impact on PV development. Typically, those customer groups paying the highest rates will reach

1 It must be noted that a net metering scheme will still be an implicit subsidy, as PV generation does not have to compete with wholesale prices which are much lower, but with retail prices, which include the grid fees etc.
2 Grid parity may have been reached earlier in small island systems with extremely high power prices caused by a dependence on imported petroleum.
3 http://fit.powerauthority.on.ca/
4 http://www.gosolarcalifornia.ca.gov/solar_basics/net_metering.php

grid parity for PV first and start investing. In California, this was the residential sector, while rooftop PV development in India was primarily focused on commercial and industrial customers paying high electricity rates in the last years. This is currently being offset by the 30 % capital subsidy for PV granted to residential customers, possibly shifting PV development towards that sector.

The Indian structure may in the long run lead to economic issues with PV integration. The DISCOMS draw most of their revenue from large customers, and industry and commerce implicitly subsidize resident customers that pay lower prices. The high tariffs incentivize industrial and commercial customers to connect PV systems under net metering schemes, as power from such units will be cheaper than the power bought from the grid. Development is picking up quickly, as these types of customers typically have the cash available for the upfront investment needed to install a PV unit. This is favorable for India's PV targets, but may turn out to be very challenging for the DISCOMS, as demand from highly charged customers shrinks while demand from residents paying low tariffs is expected to grow. A restructuring and rationalization of tariffing regimes may be necessary to accommodate the changes in the system. Especially with DISCOMs often purchasing power via long term contracts with time frames up to 20 years, this may be a significant barrier to PV integration and the improvement of supply quality in general.

3. Technical Requirements

3.1 The Grid Code

Technical requirements for generating units are specified in the grid code, which is typically developed by the grid operator, but also involves other stakeholders such as generator operators and manufacturers. The necessity for grid codes arose with the unbundling of power systems in Europe in the 1990s, but vertically integrated systems may also need grid codes if privately owned generation is allowed. Grid codes introduce a set of rules and requirements generators must fulfil, often combined with legal frameworks that oblige the grid operator to connect generators compliant with those rules. Grid codes should not be considered to be fixed sets of rules, but must be updated and revised as grids, policy and technology change. National renewable energy policy should be reflected in the grid code in a way that the requirements set are adequate for the planned expansion of renewable generation. The operator and/or the legislator must be able to verify grid code compliance, which is typically done by requiring type certification by an independent third party.

3.2 Local requirements

During the early years of rooftop PV integration, reverse power flows were expected to become a major problem at rising capacities. As distribution grids were designed as load-only grid with unidirectional power flow, a reversal of power flow in case PV generation on a feeder exceeded load was widely regarded as a hazard. In the case of California, in 1999, this led to the restriction of PV installed capacity on a feeder to 15 % of its peak load to avoid reversed power flows in any situation. The reasoning was that minimum load of a distribution feeder typically amounts to around 30 % of its peak load, and with a safety margin of 100 %, 15 % was the value accepted to be safe under any circumstances.

This rule has been widely used in other countries as well and is still applied in several Indian states, sometimes expanded to 30 % of peak load, or 15 % of transformer rating. Meanwhile, this rule has been dropped altogether in California, as international experience especially from Germany has shown that reversed power flows in distribution grids are not inherently dangerous. Neither Germany nor Australia employ any type of general limit on feeder PV penetration.

In Germany and Australia, where most PV was connected to rural grids, voltage rises through PV feed-in quickly became one of the most pressing issues. With Germany being the first to react, all high-PV study case countries – Germany, California and Australia – have introduced requirements for PV inverters to be able to operate at offset power factors to mitigate the impact on the voltage. In Germany, for example, units above 3.68 kW_p must be able to realize power factors between 0.95 capacitive and 0.95 inductive and adhere to a Q(U) characteristic which is set by the grid operator based on the grid characteristic[5].

Other grid operators worldwide have set similar requirements. The impact of PV on the voltage in highly loaded, primarily urban Indian distribution grids is still to be determined, but it would be very advisable to revise the Indian grid codes to include voltage control requirements for PV inverters similar to those in Germany, California and Australia, which it currently does not have.

Overloading of cables, lines and transformers has also been a widespread issue encountered by German distribution grid operators at rising PV shares, especially in areas with low load, but much roof space. In principle, installed PV capacity on a feeder is limited by the rating of the assets connecting it to the higher voltage level. If PV capacity on a low voltage feeder is limited to the transformer rating, the

5 Smaller units must be able to realize the same power factors, but this is a provision for the future – no Q(U) characteristic is set by the operator yet.

amount of power that is actually fed in is potentially overestimated – especially in northern countries like Germany, PV almost never reaches its peak output. It may be sensible to curtail peak power during the few hours in a year where it is actually reached. Little energy is lost, while the amount of PV that can be integrated is raised significantly. German energy legislation thus requires all PV above 30 kW_p to be able to be curtailed remotely, and PV below that threshold to be either remotely curtailable or capped at 70 % of its peak power.

3.3 Global Requirements

The most notable example of a failure to anticipate the increase in PV generation is the 50.2 Hz issue that was created by an inadequate grid code requirement. Distributed PV units were initially required to disconnect if the grid frequency exceeded 50.2 Hz. In 2007, German PV capacity exceeded 3 GW, which is the amount of primary reserve provided in the European interconnected system. This meant that from this point on, if the frequency rose above 50.2 Hz on a sunny day – indicating excess generation, meaning a balancing failure already existed – the sudden loss of more than 3 GW of generation would occur, leading to a potential blackout. By the time the requirement was changed, capacity had exceeded 20 GW, and a costly retrofitting scheme implementing a gradual power reduction at high frequency had to be executed. As the European grid has a high amount of inertia and very stable frequency, the 50.2 Hz threshold was never actually exceeded.

The Indian grid code currently requires PV units to disconnect at 50.5 Hz, possibly creating a very similar problem at quickly rising PV shares. Learning from the German case and considering the ambitious Indian targets, this should be revised as quickly as possible to include gradual power reduction or staggered disconnection. IEEE 1547, which sets the connection standards in California, suffers from a similar issue, while the Australian grid code already includes the same requirement as the updated German codes.

This issue also serves as an example for the necessity for communication between distribution and transmission system operators (DSO and TSO.) Frequency control is taken care of exclusively by the TSO, however, generation connected to the distribution grid is relevant for that task. This means that the grid code requirements for distributed generation – typically set and enforced by the DSO – also have to address issues relevant to the TSO, requiring a communication link between the two in grid code development.

California currently considers requiring remote control from PV inverters for reasons concerning power system impact – if the PV share keeps increasing, conventional generators may at some point no longer be able to cope with the daily ramps requiredthe California Independent System Operator published the \u201cduck chart,\u201d which shows a significant drop in mid-day net load on a spring day as solar photovoltaics (PV. This serves as another example for the necessity of communication between DSOs, TSOs and regulators. Considering the significant amount of distributed PV power, it is recommended that India should look into this issue as well.

4. Operational Issues and Solutions

Operational issues should not occur during actual power system operation, but be identified beforehand through simulations and calculations. However, it has happened in the pioneering countries that PV development went ahead faster than expected because the incentives were successful, and grid operators found themselves actually facing operational issues. In any way, to each operational issue there are technical solutions available. The main issues and their solutions will be shortly described in this section.

4.1 Reversed Power Flows

Typically, distribution grids are designed for a uni-directional power flow, transporting electricity from the transmission grid to the end customer. In most countries, distributed generation connected to the distribution grid was not an issue until the late 1990s.

Introducing distributed generation will, at first, only reduce the vertical grid load, the amount of power that is fed from the transmission grid into the distribution grid. With further development, at some point there will be times where generation on a distribution feeder exceeds local demand, leading to a reversal of power flow. Depending on the voltage level and the distribution of generation, the power flow may be reversed back to the next substation, or all the way to the transmission grid. Although many countries set limits on distributed generation to avoid reversed power flows, these are not inherently harmful. High reversed power flows may lead to a number of issues discussed in the following subsections, but these only appear at very high reversed power flows, meaning the power flows have to be in the same order of magnitude as load flows without generation, just in the opposed direction (generation exceeds momentary load by a factor of more than 2.)

The only direct impact of a reversal of power flow with a moderate flow that can be observed concerns the protection settings. Especially with the overcurrent protection typically used at medium and low voltage levels, the short circuit current contribution of the units feeding in between the protection relay and the location of the fault have to be considered. For PV, the short circuit current is no larger than the rated current of the inverter, leading to a moderate contribution that should nevertheless be considered in the calculation of protection settings, see section 5.2.3.

4.2 Violation of Operational Parameters

The main issues arising with very high PV feed-in and subsequently high reversed power flows are overloading of assets such as lines, cables and transformers, and voltage rises on the feeders that may lead to a violation of the allowed voltage range. Both issues are not independent from each other, as both are caused by the active power feed-in. It depends on the grid characteristic which issue becomes more relevant. Typically, grid with short lines will experience overloading before voltage ever becomes an issue. Grids with long lines, for example in rural areas, may on the other hand experience critical voltage rises long before any asset is overloaded. Often, overloading and overvoltage appear at similar PV penetration levels. In any case, any measure that is used to alleviate loading problems will also resolve voltage problems:

- Capping PV inverters at a certain percentage of installed panel or inverter power – for example, capping at 70 to 75 % of maximum output will lead to a very light loss of energy (<3 % of annual production) but significantly increase hosting capacity.
- Curtailing PV by remote control if the grid is overloaded.
- Demand side management to increase demand during PV peak (example: Agricultural pumps in rural grids.)
- Topology changes (modifying the switching states during normal operation.)

- Deployment of battery storage (for self-consumption or grid optimized, this may include a demonstration of the impact of different storage charging/discharging regimes.)
- "Copper in the ground," meaning line and transformer reinforcements, as a last resort.

  In grids that still have some headroom in asset loading but experience voltage problems due to long feeders, low load and high PV feed-in, the following solutions are available to alleviate only the overvoltage with no grid reinforcement or active power management:
- Introduction of automatic voltage regulation of on-load tap changing transformers at 66, 33 or 11 kV.
- Refining the automatic voltage regulation by the transformer by adding a wide area monitoring system, which measures the voltage at different points in the grid and switches the transformer's tap changer accordingly.
- Using shunt compensators which usually operate in power factor control mode to control the voltage directly.
- Operating PV inverters at a fixed non-unity power factor to reduce the voltage.
- Introducing active voltage control by PV inverters based on a Q(U) characteristic. (It should be noted that PV inverters could also be used for voltage control if there is no active power feed-in from the PV panels – this option may be useful to boost voltage during high-load, low-PV hours. This has however not been used in other countries so far and may lead to regulatory issues, but could be an option worth investigating anyway.)

The most effective and cost-efficient solution has to be obtained by simulation and economic analysis. Generally, a capping of active power or voltage control through provision of reactive power can be required by the grid code at no cost to the operator. Challenging grid code requirements will increase the cost of PV inverters, but the capabilities for basic active and reactive power management are standard in many markets worldwide and thus commercially available at no drastic price increase.

4.3 Controllability of Generators

Controllability of generators (and keeping track of installed units in the first place) is a grid code issue as well. The grid operator does not want to end up with a large number of completely uncontrollable distributed generation on the one hand, on the other hand, making small generators controllable requires some degree of communications infrastructure and thus investments. Additionally, generator owners may not be comfortable with giving the grid operator control over their facilities, especially if the operator also acts as a retailer and may thus have economic interest in curtailing as much distributed generation as possible.

This can be resolved by giving the operator the authority to control distributed generation while specifying clearly the conditions under which he may actually do so and curtail active power. Usually, the grid operator may curtail as much as necessary during emergencies in the grid. If no emergency is present, he may curtail as well, but has to remunerate the owner of the curtailed generator. In recent years, some countries such as Germany have allowed grid operators to curtail a small amount of power (< 3 %) outside of emergencies, to increase the hosting capacity of the grids (akin to the 70 % cap mentioned in the previous subsection.)

The amount of control the operator has is subject to grid code requirements. For small units, it may be sufficient to only require them to be switched off upon signal by the operator, while large units may be required to control active power in steps or continually. Reactive power in larger units may also be remotely controlled.

The legitimate legal reasons for active power curtailment are subject to energy legislation.

4.4 Impact on Dispatch and Power System Operation

PV connected to the distribution grid may be small in individual unit size, but by sheer number, have a significant impact on operation not only of the distribution grid, but also the entire power system. Distribution grid operators will thus have to communicate with the system or transmission grid operator, the electricity market operator and other stakeholders more than before. Issues include technical requirements for generators as described in 3.3 as well as forecasting and scheduling. The exact scope of communication and agreements required should be determined in regular stakeholder meetings involving all parties involved in power system operation.

5. Integration Studies

5.1 General objectives

The general objectives of conducting a PV study at distribution grid level are the same as those of any renewable energy integration study:

- Get familiar with the impact of new technologies installed in the grid and the sensitivity of grid parameters;
- Assess how much generating capacity can be added to an otherwise unchanged system before operational issues (such as voltage range violations or thermal overloads) appear;
- Analyze the possible solutions for appearing problems and compare their cost and adequacy;
- Assess how much additional generating capacity can be added to the system if these solutions are implemented;
- Develop a strategy involving the most promising solutions.

The result can be, as a first step and in its simplest form, something like the California Public Utilities Commission's 1999 rule that PV penetration levels of less than 15 % of peak load on a distribution feeder are most likely to be integrated without any problems, but that further studies have to be conducted for higher levels. Such simple assessments can be made based on examples of operational data without allocating too many resources to more time consuming work.

If the expected penetration levels are high and/or the budget for a study is adequate, much more detailed studies can and should be conducted. Grid models, load flow calculations and optimization tools may be used. A full integration study will typically deliver a step-by-step approach to find the optimal solution that can be used for the relevant grid areas.

5.2 Analysis without simulations

A large part of the general analysis of the impact of PV on a distribution grid can be done without any additional software or complex calculations. With some basic understanding of grid parameters and knowledge of the assets that are actually installed in the grid as well as some operational data, the following questions can be answered:

- How much installed capacity can be expected in the area in question? The potential for rooftop PV is limited by the available roof space, which can be estimated quickly.
- What is the minimum daytime load? If installed PV capacity exceeds the minimum daytime load on a feeder, reversed power flows will occur.
- What is the current rating of the grid assets? In case reversed power flows are considered generally acceptable, their magnitude (and thus installed PV capacity) will be limited by transformer ratings and line/cable ampacity. The maximum reversed flow across a line or transformer that can be expected is the difference of downstream PV capacity and minimum daily downstream load.
- Is the voltage quality on the feeder sufficient? Already high voltage levels may reduce the headroom left for PV induced voltage rises, while too low voltages may indicate either high load – in which case PV will be beneficial – or a weak grid, in which case PV may lead to excessive voltage rises. (For a simple formula see section 5.2.1.)
- Will the protection be able to cope with reversed power flows or reduced short circuit currents? (See section 5.2.2.)

5.2.1 Simple estimation of feeder voltage fluctuations

The difference between the voltage at a busbar and the voltage at the end of a feeder connected to that busbar is dependent on the active and reactive power balance and distribution on the feeder, as well as the impendance of the lines and cables used on the feeder.

If all load and all generation is attached only to the end of the feeder, representing a worst case, the voltage at the end of a radial feeder can be calculated with the following formula, involving the busbar voltage U_j, the end of feeder voltage U_k, the feeder resistance R, reactance X and susceptance B as well as the active power flow P and the reactive power flow Q:

$$U_k^2 = -\frac{a_4}{2a_3} \pm \sqrt{\left(\frac{a_4}{2a_3}\right)^2 - \frac{1}{a_3}(a_1^2 + a_2^2)}$$

$$a_1 = -RP_{kj} - XQ_{kj}$$

$$a_2 = -RX - RQ_{kj}$$

$$a_3 = (1 - XB)^2 - R^2B^2$$

$$a_4 = 2a_1(1 - XB) - U_j^2 + 2a_2RB$$

For a quick estimation for distribution grid feeders with a dominating resistive component, B can be neglected to 0, simplifying the calculation.

5.2.2 Simple estimation of grid loading

The maximum reversed flow on a feeder can simply be estimated by subtracting the minimum feeder load from the maximum of PV feed-in:

$$P_{reversed,max} = P_{PV,max} - P_{load,min}$$

This can be calculated for any point on the feeder, considering only the load and PV units between the relevant point and the end of the feeder. The maximum phase current flowing can be calculated as follows:

$$I_{phase} = \frac{P_{reversed,max}}{\sqrt{3} \cdot U_r}$$

If this phase current exceeds the ampacity of a line or transformer, overloading issues can appear.

5.2.3 Simple estimation of short circuit current and protection adequacy

There are two different issues when it comes to short circuit currents from inverter fed generators such as PV. On a power system level, it is important to recognize that synchronous generators automatically provide high transient short circuit currents of up to eight times their rated current, while inverters are typically limited to their rated current. This means that short circuit currents will decrease as penetration of inverter fed generation rises, forcing adjustments in protection regimes in the long run.

More important for a distribution grid is the fact that short circuit current contributions may appear there with the introduction of distributed generation. In a traditional distribution grid with unidirectional load flow, the fault current in case of a short circuit is drawn from the transmission grid (and subsequently from large generators). The large fault current is often used for easy fault detection, triggering overcurrent protection devices (time delayed or not).

If generators are installed at any place between protection gear (overcurrent protection) and the fault location, any fault contribution from these units will not only not be "seen" by the protection, but will also reduce the actual short circuit current detected. This can lead to a delayed reaction of the protection, or in the extreme case, to the loss of protection functionality.

The easy way around this problem would be to require the units on a feeder protected by an overcurrent relay to immediately disconnect at detection of a voltage drop (which indicates a short circuit nearby), or stay connected but not provide any short circuit current. If this requirement collides with low voltage ride through that may be required for other reasons, the short circuit current of all units on a feeder should be limited to

$$\sum I_{sc,unit} \leq I_{sc,max} - I_{sc,trigger}$$

5.3 Simulations and required software capabilities

The most important type of simulation used for PV integration studies in distribution grids is the AC[6] load flow calculation. Based on a grid model – which must not be a graphic representation of the grid, but can merely be a table of grid objects and their parameters – the active and reactive currents and the voltage levels are calculated based on the distribution of load and generation, using an iterative approach such as the Newton-Raphson algorithm. For a meshed grid at transmission or sub-transmission level, the way the power flows split up between parallel lines may be the most important output of such a calculation.

- As distribution grids are mostly operated as radial grids, especially at medium and low voltage level (< 50 kV), there are no parallel paths, and the general behavior of active power flows will be obvious – each feeder will draw the difference of its load and generation from the upstream network, or feed a certain amount of power back. In this case, the reactive power flows (which may not be as obvious as they depend on grid asset characteristics as well as their loading) and the sensitivity of the voltage on a feeder to active and reactive power flows will be of interest. Specific to PV integration, this will usually yield the following results:
- Sensitivity of voltage on a feeder, especially at the end of the feeder, to changes in load and generation;
- Reactive power consumption of a feeder due to changes in loading of lines, cables and transformers;
- Loading (including possible overloading) of assets by active and reactive power currents – simple analysis of loading may be conducted without simulations, however, especially in larger grids, the impact of reactive currents may not be so obvious, requiring a simulative approach.

  For very small networks, load flow calculations can be done manually or using simple calculation tools like Excel, or by setting up a simple algorithm in a convenient programming language. However, specialized power system or grid simulation software tools may be much more convenient in most cases:
- Graphic representation of networks as SLD, as well as a projection of the SLD onto a geomap;
- Graphical user interface (GUI) is easier to use;
- Direct graphical display of results;
- Grid simulation software tools often include generic models for many different grid assets;
- Sensitivity analysis and cost optimization of solutions may be easier.

There are many widely used tools available, both commercial and open source. For grid operators, there are specialized grid planning software suites which also include load flow calculation tools.

6 In this case, the AC stands for the full load flow calculation considering both active and reactive power. DC calculations are used at transmission grid level, especially for market simulations, and use linearized load flow calculations (i.e. a DC representation of an AC network.) These are mostly useless at distribution grid level.

5.4 Grid modelling

Power flow calculations and the graphical representation of results using a power system simulation software require the setup of a grid model based on the available data. It would obviously require very much time and budget to set up a model of an entire synchronous power system, if it is even possible at all. For any system size that goes beyond a small island grid with a few 10 MW of load, a representation of the entire system including transmission and distribution system is typically not feasible. In this case, simplified models have to be used. This will usually be a transmission grid model with all high and extra high voltage line and transformers (> 100 kV) and centralized generation, while everything below is aggregated and represented with their load/generation equivalents for transmission grid studies, and sets of independent distribution grids models. In the following, the structure and role of distribution grid models will be described.

The role of a distribution grid model is to correctly reflect the properties at the relevant area and voltage level and allow for evaluations of the reaction of the grid to changes in parameters such as an increase in distributed generation. Transmission system issues and the impact on the entire power system are of minor interest for such studies. For this reason, the transmission grid is mostly modelled as a slack bus, also called an external grid, which keeps the voltage fixed at a certain point and can absorb or deliver infinite amounts of active and reactive power. Comparing the size of a distribution feeder with a few MW of peak demand at max, and a multi-GW power system, this is a permissible simplification. Of course a large scale roll-out of distributed generation will also impact the transmission grid and power system level, but the analysis thereof will require separate studies.

The point in the grid where the model is "cut," meaning the point from which on the upstream grid is modelled as a slack, depends on the focus of the studies to be conducted. If the lower distribution levels – secondary and last mile distribution, typically low voltage and low medium voltage grids below 33 kV – are expected to be impacted the most, it makes sense to place the slack node at the last instance of active voltage control. In many instances, this will be the power transformer that connects the transmission or subtransmission grid to the distribution grid. This is usually an on-load tap changing transformer which controls the voltage at its secondary side, either manually or automatically operated. In this case, the slack node will be connected to the primary side of the transformer, representing the transmission grid.

Even so, the underlying distribution grid structure may be too large and complex to be modelled in its entirety. However, as most distribution grids are not operated as meshed grids, but are mostly radial structures from medium voltage level downwards, some further aggregations and simplifications can be used without severely impacting result quality. If no meshing exists in a grid section, power flows are strictly bidirectional. Voltage on each point along the feeder is dependent only on the voltage drop between the last point of active voltage control and the local active and reactive power balance. Parallel feeders branching off the same busbar can thus be represented by their load/generation equivalent without changing the voltage at the busbar itself. Thus, a structure like the one given in Figure 1 can be used to conduct analysis on an individual feeder without neglecting the impact of other load and generation connected to the same grid.

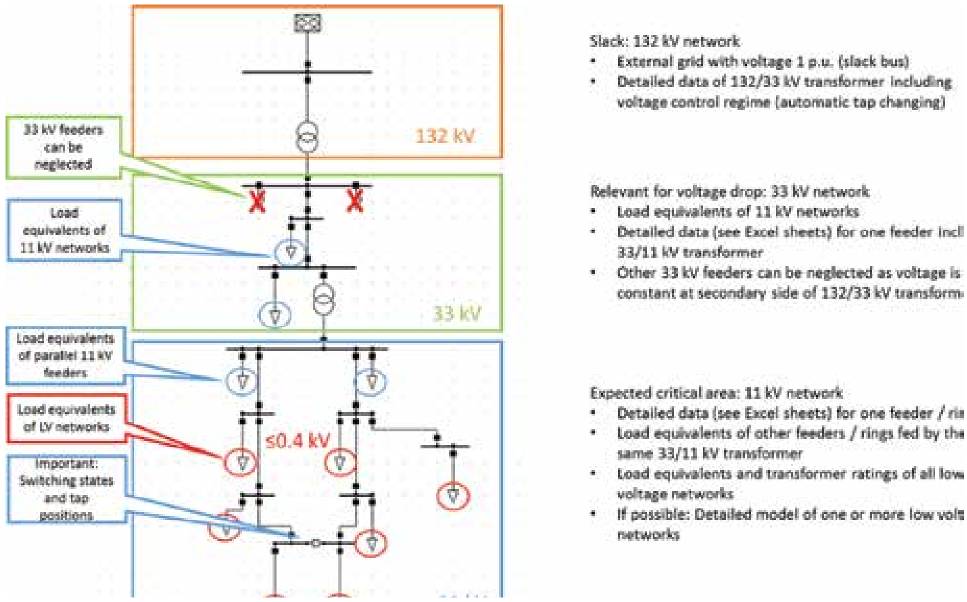

Figure 1: Grid model structure, example of a 132/33/11 kV structure like it can be found in Bhopal.

The point from which on the upstream network is neglected can of course be chosen differently – if for example the transformer connecting 33 and 11 kV automatically controls the voltage, the slack can be attached to the 33 kV busbar.

If there is no means of automatic voltage control whatsoever – for example, the 132/33 kV transformer may not control the voltage on its secondary side – this does not mean that the entire system has to be modelled. In this case, voltage fluctuations at the point from which on the grid is modelled have to be considered, resulting in a higher number of total simulation runs.

In many cases, the detailed grid data of low voltage (below 1 kV) last mile distribution grids are not available. Low voltage grids, including the distribution transformers feeding them, will then be represented by their load equivalents. For detailed assessments of low voltage grid issues, more detailed models will of course be necessary.

In the following, the modelling issues of each voltage level encountered in Indian distribution grids will be addressed briefly.

5.4.1 Transmission / subtransmission level

As mentioned before, the transmission and subtransmission system will usually be modelled as a slack node or external grid. With this simplification, it can deliver and absorb infinite power at a constant voltage. In India, the distribution level starts at 66 or 33 kV, and the highest distribution voltage level is supplied from either 220 or 132 kV (in some cases also 400 or 765 kV) by an on-load tap changing transformer. If this transformer actively controls the voltage at its secondary side, transmission system operations have little to no impact on the distribution grid.

If the connection between transmission and distribution grid is fixed, it will still be sensible to model the transmission grid as a slack. However, voltage measurements at the relevant 132 or 220 kV busbar are necessary to determine the typical voltage deviations. Because of the fixed connection, these will also affect the distribution grid, and simulations have to be conducted either with different transmission voltage deviations, or according to an expected daily/monthly/seasonal pattern.

5.4.2 Insert: Load equivalents

The use of load equivalents or load/generation equivalents has already been mentioned. Such equivalents can be used at any voltage level. A load or load/generation equivalent is basically a PQ node reflecting the active and reactive power that flows into a distribution feeder. This includes active and reactive power demand of attached loads, reactive power demand of the lines, cables and transformers, active power demand through grid losses, and active and reactive power fed in by generation connected to the feeder.

Load/generation equivalents can only be used for feeders or grid areas supplied by a single connection, otherwise grid properties will be distorted, yielding incorrect results.

5.4.3 66 and 33 kV grids

66 and 33 kV grids – either voltage level may be used, or both – will have to be modelled if the last instance of voltage control is the transformer supplying them, or if the impact of distributed generation on the 33 and 66 kV grid itself is of interest. Otherwise, they may be considered to be part of the upstream network modelled as a slack node.

Some meshed structures may be existent especially at the 66 kV level, but these are not always be operated as a meshed grid. Switches are often left open, forming several radial feeders that can be connected to each other if the necessity arises. This means that information about the switching states during normal operation have to be obtained to set up the model correctly, as well as conditions for switching and possible alternate configurations. The result will be a model of a 66 and/or 33 kV grid fed by the same transformer, with all lines and substations modelled in detail. Lower voltage grids – typically 11 kV – may be represented with their load equivalents. Depending on the focus of the study, 66 or 33 kV feeders branching off the main area of interest may be modelled in the same way. However, great care has to be taken not to neglect possible alternate switching configurations (like a feeder that can be supplied from both sides.)

5.4.4 11 kV grids

As a large share of roof mounted PV in India is expected to be installed by commercial, institutional and industrial customers connected to the 11 kV grid, 11 kV structures may be of considerable interest. In most cases, a 33/11 kV or 66/11 kV substation transformer feeds multiple 11 kV feeders connected to the same 11 kV busbar. These may or may not exhibit similar characteristics. In any case, the number of 11 kV feeders supplied by a given 66 or 33 kV structure may be too high to model all of them in detail. In these case, one or more feeders have to be selected based on their characteristics and expected development (examples: Feeder from a wealthy area that can be expected to invest in PV soon, feeder from a rural area with especially weak lines, industrial feeder.)

These should be modelled with all their characteristics, as well as the 11 kV substation, which may for example be equipped with reactive compensation units. All other feeders can be modelled as load/generation equivalents as to not neglect their impact on the voltage at the 11 kV busbar.

5.4.5 240 and 415 V grids

Low voltage grids can have different voltages from 1 kV downwards, in India mostly 415 V (three phase) or 240 V (single phase.) For simulations intending to analyze the impact of distributed generation on the upper voltage levels, low voltage grids will be replaced with their load/generation equivalent.

As for the 11 kV grids, detailed simulation and modelling of all low voltage grids connected to the same feeder may be as time consuming as it is unnecessary. Detailed models of a few selected grids can be used to assess the direct impact of distributed generation on the low voltage grid. If single phase customer connections are used in the relevant area, some attention may have to be paid to asymmetric loading both by load and PV.

5.5 Development of scenarios

5.5.1 Worst case analysis

The traditional way of assessing the impact of distributed generation is to look at the worst possible cases and make sure that the grid can withstand those situations without any violations of security constraints. This approach does not work as well for transmission systems where extreme situations will occur very rarely due to distribution effects, but in a smaller distribution system, critical operational scenarios, if they occur, occur much more often. Especially as load and PV curves in India are expected to be very similar each day – especially due to the usually cloudless sky during the summer – it can be expected that a worst case situation identified will appear regularly.

When looking at PV integration, the critical scenarios will usually be the ones with high PV feed-in and low load. Reversed power flows may cause voltage range violations and protection issues. At very high PV penetration levels, grid assets may even be overloaded by reversed power flows.

In some cases, high load situations may also be interesting, as PV may help to mitigate previously existing grid overloading issues.

5.5.2 Basic scenarios

Due to the daily characteristic of load in the respective grid areas and the usually clear sky during summer, the critical situations to be analyzed will typically be around noon, when load is lowest and PV generation is highest (see Figure 2.) Depending on demand development and PV penetration, different instantaneous penetration levels may be simulated, but with this daily characteristic, an investigation of different times of the day is not necessary in the first iteration. Time sweeps across an entire day may later be introduced to assess the impact of storage and curtailment regimes.

For the first round of simulations, sweeps of the following parameters may be conducted to assess the amount of PV that can be integrated without further investments under the given circumstances:

- Load and PV level at noon, possibly both during summer and monsoon season to account for different transformer tap settings;
- Amount of installed PV;
- Connection points of PV, even distribution across the feeder as opposed to a concentration at the beginning or end.

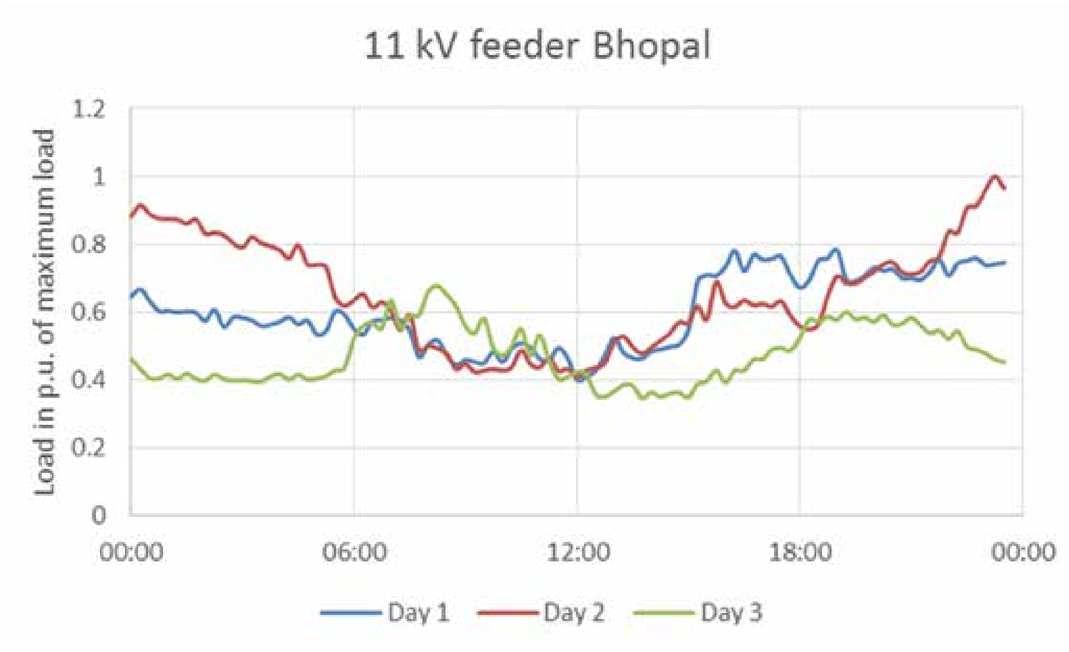

Figure 2: Measured 15 minute time series across three random days in 2016 of a typical urban 11 kV feeder in Bhopal.

5.5.3 Technology options

Depending on the structure of the investigated distribution grid area and the technical issues arising with high shares of PV, different technology types can be used to mitigate the effects. In rural grids, voltage problems are expected to occur at some point due to the longer lines and cables. These could be mitigated with the following measures:

- Introduction of automatic voltage regulation of on-load tap changing transformers at 66, 33 or 11 kV.
- Refining the automatic voltage regulation by the transformer by adding a wide area monitoring system, which measures the voltage at different points in the grid and switches the transformer's tap changer accordingly.
- Using shunt compensators which usually operate in power factor control mode to control the voltage directly.
- Operating PV inverters at a fixed non-unity power factor to reduce the voltage.
- Introducing active voltage control by PV inverters based on a Q(U) characteristic. (It should be noted that PV inverters could also be used for voltage control if there is no active power feed-in from the PV panels – this option may be useful to boost voltage during high-load, low-PV hours. This has however not been used in other countries so far and may lead to regulatory issues, but could be an option worth investigating anyway.)

  Measures should be ranked based on cost and effort as well as for their ability to resolve the occurring problems.

  While the urban grids are expected to experience no severe voltage rises at 11 kV level, voltages may rise along 415 V feeders. Besides the measures mentioned above, this can be addressed by the following:

- Introduction of on-load tap changing distribution transformers which have already been successfully used in some areas in Germany and California.

All grids, urban and rural, may also face transformer and/or line overloading issues at high PV shares, especially if voltage is controlled using reactive power from PV inverters (which increases asset loading through reactive currents.) These may be addressed by the following (unranked) solution approaches:

- Capping PV inverters at a certain percentage of installed panel power (for example 70 %.)
- Curtailing PV by remote control if the grid is overloaded.
- Demand side management to increase demand during PV peak (example: Agricultural pumps in rural grids.)
- Topology changes (modifying the switching states during normal operation.)
- Deployment of battery storage (for self-consumption or grid optimized, this may include a demonstration of the impact of different storage charging/discharging regimes.)
- "Copper in the ground," meaning line and transformer reinforcements, as a last resort.

All solutions for active power issues will also impact the voltage, so a combined approach may have to be used. A list of technology options with their strong and weak points is given in Table

Table 1: List of technology options.

Measure	Pro (+)	Contra (-)
OLTC with automatic voltage regulation at MV level (66/33/11 kV)	Inexpensive and easy to implement if transformer is already of OLTC type	Expensive if transformer has no OLTC capability yet, only regulates voltage at busbar without accounting for feeder voltage drop/rise
Wide area control	Technically easy to implement if OLTC is already automated, voltage control accounts for feeder voltage drop/rise	Requires extensive communications and control infrastructure
Shunt compensators for voltage control	Usually already there, simple change in control strategy	Typically only capacitive, so changed strategy would not really solve problems, only avoid additional ones
PV inverters with fixed non-unity power factor	Can be required via grid code, easy to implement, effective	Increased grid loading through reactive currents, even during situations where it is not really necessary Increases cost of PV inverters
Active voltage control by PV inverters (Q(U) characteristic)	Can be required via grid code, effective means, no unnecessary Q contributions, when dead band is applied	Increases cost of PV inverters
On-load tap changing DT	Active means of voltage control very close to generation, effective	Expensive and complex
PV cap at certain percentage of installed panel capacity	Can be required via grid code, easy to implement, little cost	Loses some percentage of potentially generated PV energy
Active PV curtailment	Can be required via grid code, loses less energy than cap option	Requires extensive communication infrastructure
Reinforcements of lines, cables transformers	Effective	Expensive
PV storage battery deployment	Effectively relieves the grid if smart charging strategies are used, also reduces total power system impact of PV	Relatively costly, may not relieve the grid at all if optimized for self-consumption only
Demand side management	Easy to implement for some selected customers (cooling houses etc.)	Residential customers: No business case, hard to incentivize, little potential
Alternative switching topologies	Cheap and easy if available	Only applicable if an alternative structure is already there

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