Volt/VAR Control Options and How to Leverage AMI Data

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Energy efficiency and operational optimization remain strong drivers for utilities implementing advanced metering infrastructure (AMI). Utilities looking to leverage their AMI technology for operational improvements are increasingly interested in voltage conservation programs. Such programs have the potential to achieve 1-to-3 percent in energy savings without requiring customers to change their energy consumption behavior. This “killer app” provides utilities the opportunity to bolster “green” goals and improve financial performance without impacting customer life styles.

While voltage regulation has always been a core function of utility operations, the widespread deployment of AMI programs has created a new technology enabler that can provide significant improvements in the effectiveness of volt/VAR controls. Smart grid and AMI systems have laid the foundation for improved voltage management by providing reliable, two-way communications between numerous field devices. Intelligent electronic devices (IEDs), in combination with new distribution system control centers with distribution management systems (DMS), can measure voltage from every grid endpoint and provide improved voltage controls.

APPROACHES FOR VOLTAGE CONSERVATION

There are three competing approaches to implementing voltage conservation:

- Power system model based centralized volt/VAR optimization (VVO)
- Substation based Coordinated voltage/VAR control (CVVC)
- Point solution for conservation voltage reduction (CVR)

All three approaches require the same level of investments in power system infrastructure. These include investments in controllable load tap changers (LTCs) for their power transformers, controllable capacitor banks, controllable voltage regulators and circuit bellwether meters. However, there is a substantial difference in information technology (IT) systems and field level data change management commitment between these approaches (See Table 1 for comparison of approaches).

Table 1. Deployment Options for Voltage Conservation

<table>
<thead>
<tr>
<th>APPROACH</th>
<th>1–DMS BASED VVO</th>
<th>2–SUBSTATION BASED CVVC</th>
<th>3–CVR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Systems Infrastructure Investment</td>
<td>All components required</td>
<td>All components required, but could be implemented at a subset of substations</td>
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</tr>
<tr>
<td></td>
<td>Target deployments are between 35% – 50% of substations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IT Systems Infrastructure Investment</td>
<td>Full DMS implementation is a prerequisite for this approach. Good data in both GIS and Asset Management</td>
<td>Pure Power Systems Automation implementation</td>
<td>Integration with SCADA, AMI and Distribution Planning</td>
</tr>
<tr>
<td>APPROACH</td>
<td>1–DMS BASED VVO</td>
<td>2–SUBSTATION BASED CVVC</td>
<td>3–CVR</td>
</tr>
<tr>
<td>-----------------</td>
<td>-------------------------------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Maintenance Cost</td>
<td>Requires full lifecycle maintenance of a major software system</td>
<td>Requires diligence to maintain connectivity model in IEDs</td>
<td>Lifecycle maintenance for a small software system</td>
</tr>
<tr>
<td>Smallest Deployment Unit</td>
<td>Single Substation, but not leveraging investment of a DMS. Typically seeing 35% to 50% of substations set of feeders being upgraded to support VVO</td>
<td>Single Substation</td>
<td>Single Substation</td>
</tr>
<tr>
<td>Time to First Deployment</td>
<td>18 – 24 months</td>
<td>4 – 6 months</td>
<td>4 – 6 months (after AMI deployed in that area)</td>
</tr>
<tr>
<td>Benefit</td>
<td>1% – 3% of implemented substation energy</td>
<td>1% – 3% of implemented substation energy</td>
<td>1% – 3% of implemented substation energy</td>
</tr>
<tr>
<td>Maximizes Investment in AMI</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Adapts to changes in power system</td>
<td>Immediately – Zero Latency</td>
<td>No</td>
<td>Yes; but at course level of readings at substation in inner loop, and then slower at outer AMI loop</td>
</tr>
<tr>
<td>Ready for DER deployments</td>
<td>Yes</td>
<td>No</td>
<td>CVR still works, just not ready to control/ manage DERs</td>
</tr>
<tr>
<td>Effect on existing business processes</td>
<td>Substantial</td>
<td>Minimal</td>
<td>Minimal</td>
</tr>
</tbody>
</table>
**Approach 1: Centralized DMS with VVO**

Utilities that implement a centralized DMS (that is driven from a network model based on the daily changes to the power system network) can take advantage of their DMS vendor’s voltage/VAR optimization (VVO) functionality. The effort to turn on the core DMS functionality represents a substantial scope of work that may take between 18 and 24 months to complete. The magnitude of this effort depends on the selected vendor solution and the quality of the utility’s power system network connectivity information residing in its geographic information system (GIS) and enterprise asset management (EAM) systems. The additional effort to enable VVO once the core DMS is running is typically a six-to-nine month effort. This involves tuning the DMS vendor’s VVO algorithm to meet the specific needs of the utility. Some of the available VVO solutions on the market actually allow the utility to set multiple parameters (goals) for the VVO module to optimize. These may include one or more of the following operating objectives:

1) Reduce electric demand  
2) Reduce energy consumption  
3) Improve feeder voltage profile  
4) Maximize revenue  
5) Minimize energy loss/improve power factor

Other available VVO solutions allow the utility to minimize device operations to conserve set point changes and avoid wear on voltage regulators and LTCs.

**Required System Components**

DMS core functionality is required to implement this approach. The following modules will need to be implemented to effect this solution as shown in Figure 1:

- Distribution SCADA  
- On line power flow  
- Switch order management

**Change Management for DMS with VVO**

Implementation of a DMS requires significant organizational change in how a utility maintains its power system network model. Most utilities feed their outage management system (OMS) with daily “as-built” information from their GIS. This daily model build process is not sufficient to support a DMS that will be running VVO.

Implementation of a DMS requires that the utility post their daily as-builts to both the DMS and OMS. Additionally, they must post all proposed work to both the DMS and mobile workforce management (MWM) system.

The DMS must manage two states of the power system network: proposed and energized. By sending all scheduled work to both DMS and MWM, field crews can notify the DMS as specific portions of work assignments have been energized. This allows the DMS to update that portion of the power system network from proposed to energized. The field crew still must update all as-builts back to the GIS to ensure that the DMS reflects the new nominal state of the power system network. Since both the OMS and DMS have the same nominal state of the network, the DMS should manage abnormal changes to the network and synchronize these device changes and line cuts with the OMS. Some DMS vendors actually run their OMS against a single power system network model, so synchronizing between the OMS and DMS is not required.
- Short-term load forecasting
- State estimation
- Circuit bellwether meters—Leverages investments in AMI infrastructure
- Circuit level wireless telecommunications—Could leverage investment in AMI infrastructure
- GIS—Both proposed/scheduled work and all as-built changes
- EAM—Power system characteristic information
- Mobile work management (MWM)—Both proposed/scheduled work and as-built field changes
- Outage management system (OMS)—Abnormal conditions: device operations, line cuts, jumpers

Figure 1. DMS based VVO Conceptual Components
Benefits
The DMS with VVO approach is a large smart grid investment. However, experience has demonstrated that a utility often only has to implement VVO at 15 to 25 percent of their substations to justify the DMS investment.

Utilities that have investigated a substation-by-substation approach find that a centralized DMS allows them to deploy VVO on three-to-five more substations per year because of the enhanced visibility into operations that the DMS provides.

This approach provides many benefits in addition to VVO itself. These are enabled through the implementation of a DMS suite of advanced applications:

- Improved visibility/safety to manage the utility's smart grid investments in IEDs
- Improved reliability/customer service—Automated switching, automated fault location prediction, automated fault detection, automated isolation, automated restoration
- Improved asset management—Optimal network reconfiguration (ONR), historical peak usage durations
- Improved serviceability—Takes into account weather forecasting, load forecasting and distributed energy resources (DER) forecasting to maximize usage of heterogeneous DER resources (including distributed generation, electric vehicles and storage). This includes handling dispatching of resources, initiating demand response programs, verification and validation of active demand response programs and managing a networked power system grid (bi-direction flows).
- Enhanced Sustainability—This approach with integration to GIS, EAM and MWM means that VVO is making its decisions based on the most up-to-date version of the power system network.

Approach 2—Substation Based Coordinated Voltage/VAR Control (CVVC)
Many IED manufacturers have offerings that support coordinated Voltage/VAR control at the substation level. This approach to CVVC leverages the current state of the network for each substation.

Required System Components
Beyond the power system components themselves, this approach only requires an intelligent controller in the substation and wireless communications for the circuit in-line devices that will receive the set point commands. The required components, depicted in Figure 2, are as follows:

- Substation CVVC IEDs
- Controllable LTCs
- Controllable capacitor banks
- Controllable voltage regulators
- Circuit level wireless telecommunications—Could leverage investment in AMI infrastructure
Benefits
This CVVC approach allows the utility to achieve conservation voltage reduction benefits soon after making investments in power system infrastructure (LTCs, capacitor banks, voltage regulators). Because this approach can be implemented one substation at a time, it is relatively easy to initiate and allows the utility to realize the potential injected energy savings incrementally.

The drawback to this approach is that as the system changes significantly with time or is operated in abnormal configurations for long periods, the logic at the substation IED will be making decisions based on a stale network model configuration. In certain instances, control center operators have turned off CVVC at the substation because of the large number of power quality related issues that may be generated when CVVC is working within an old or stale network model. To attempt to alleviate this problem, some IED providers have offered a model build update process to try to keep the model at the substation up to date. However, this requires a utility to implement business processes to ensure the model update is reliable.

Approach 3 — Conservation Voltage Reduction (CVR)
Another commercially available approach to improve system voltage management is CVR. This approach takes advantage of data that is being collected by AMI meters in a closed loop control of system voltages. This approach requires all of the power system investments of the previous two approaches, but simplifies the IT infrastructure requirements by taking more of a power system engineering approach. This scheme controls voltage through the use of two, closed control loops. One utilizes substation values and in-line values and the other utilizes AMI metering information to provide a supervisory set point adjustment to the LTCs, capacitor banks, and voltage regulators.

Required System Components
The following components are required to support Closed Loop CVR and are depicted in Figure 3:

- DSCADA
- Controllable LTCs
- Controllable capacitor banks
- Controllable voltage regulators
- AMI network communications and voltage equipped smart meters
- Centralized CVR master integrated with distribution planning, DSCADA and AMI
Benefits

The CVR approach can be deployed substation by substation. One of the major benefits is that since it is utilizing AMI information, it is adaptable over time as smart meters are deployed and as circuits may be operating in abnormal configurations. This approach does not require a network power system model that is maintained with “zero” latency as the centralized DMS approach does. In fact, no model is needed since there is direct feedback of endpoint voltage via the smart meters. The connectivity model from the utility’s system planning tool is needed for predicting voltage at an endpoint when direct measurement is not available.

Figure 3. CVR Components
JUST DO IT!
Voltage conservation allows the utility to become as efficient as possible without requiring its customers to change their energy usage behavior. Two of the approaches described here can be implemented one substation at a time and allow the utility to incrementally validate the value of voltage conservation. The VVO approach is a much larger smart grid investment, but allows a utility to take advantage of all the other extended benefits that a DMS can offer. Whichever approach is taken, the results will improve system reliability, reduce the cost of power and potentially delay the need to procure power at peak prices.

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