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Wide Area Reactive Power Control for Optimization of AEP's Static Var Compensation

Kyle Phillips Mark Ellis
American Electric Power
United States of America

SUMMARY

Voltage compensation on the transmission system is needed for several reasons. One such reason is that contingency situations like an unexpected line or generator outage can cause both steady state and dynamic emergency voltage situations. Shunt Capacitor Banks and Static Var Compensator (SVC) are two methods for improving system operation. Utilizing an intelligent system to simultaneously control both in coordinated manner improves the overall system operation. This paper discusses the requirements, challenges, and implementation of coordinated control between a SVC and existing capacitor banks in the greater Columbus (Ohio) metro area.

KEYWORDS

Static Var Compensation, Wide Area Control, Coordinated Control, Transmission, Capacitor Bank, Thyristor Switched, Economic Dispatch

K. Phillips (e-mail: kdphillips@aep.com)

I. NOMENCLATURE

CAP IED	Microprocessor Based Relay for protection and control of Shunt Capacitor Banks
MSC	Mechanically switched capacitor
MSR	Mechanically switched reactor
SCADA	Supervisory control and data acquisition
SVC	Static var compensator
TSC	Thyristor switched capacitor

II. INTRODUCTION

AsS the aging electric power transmission infrastructure is replaced, advances in telecommunications have made possible higher levels of coordination between otherwise unconnected pieces of equipment. AEP's 2012 installation of their static compensation system and wide area controller will be reviewed, and their coordinated control schemes will be discussed. Before justifying the need for coordinated schemes, the historical control of capacitor banks will be discussed.

A. Traditional Capacitor Bank Control

Capacitor banks have been used for many decades at transmission voltages (69kV to 765kV) on the power grid. These capacitors provide var support that counteracts the inductive nature of many types of electrical loads.

Historically there have been two basic methods of operating the relays. The first method is by time-delayed voltage (var) bandwidth control. A relay can be set for a voltage (var) level at which to connect the bank to the system and another voltage (var) level at which to disconnect the bank. In other words, when load increases and voltage decreases (reactive var increases), the capacitor bank is turned on. When load decreases and voltage increases (reactive var decreases), the capacitor bank is turned off. The advantage of this system is that it requires no human interaction. The disadvantage is that it is a blind system that cannot sense the voltage (var) conditions at other locations or know the status of neighboring capacitor banks.

Another method of control is by human operation. An operator can have remote control of these banks through the supervisory control and data acquisition (SCADA) system. The operator has voltage measurements at different substations throughout the system. The disadvantage of this approach is the requirement of continual labor resources, which results in continuous operational costs.

B. Static Var Compensation

Static var compensation (SVC) allows for reactive support by shunt connected capacitor banks that are switched by thyristors (TSC). TSC may be installed in parallel to achieve wider operating range. Using high speed microprocessor based systems the firing range can be varied for each cycle and each shunt connected capacitor bank. The system allows for a very quick response to abnormal system conditions, such as faults. For high voltage transmission systems, SVCs are typically connected utilizing a step down transformer. Two of the main benefits for this installation method are reductions in cost, mainly from the thyristor technology and for the isolation of harmonics. Since the TSC are switching devices, high levels of harmonics can be generated.

C. System Topology

The 250 Mvar SVC is connected to the transmission grid at a local AEP substation. The local substation also contains a mechanically switched reactor (MSR) and a mechanically switched capacitor (MSC). Fig. 1 shows a partial one line diagram for this local substation. The SVC is connected to the transmission system through a 138 to 11.5 kV transformer. The SVC consists of three TSCs, rated at 50, 100, and 100 Mvar. The MSR is rated at 100 Mvar and the MSC is rated at 72 Mvar. There is a potential transformer connected to the 138kV bus that transmits voltage readings to the SVC controller.

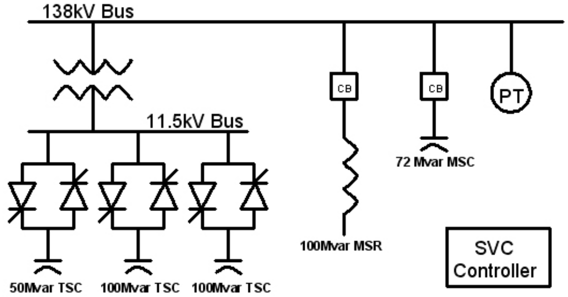

Fig. 1. One Line Diagram of SVC, MSC, and MSR at Local Substation on AEP system

The area wide transmission grid contains several other capacitor banks at other remote substations. These capacitor banks are connected to the 138kV grid through circuit breakers and therefore are also referred to as MSC. Five of these remote MSCs are associated with the coordinated control scheme. The capacitor banks are rated at various capacitive loads from 62 to 86 Mvar. The remote MSCs have been upgraded with digital protection and control relays (CAP IED) that operate the circuit breaker when called upon.

D. Wide Area Reactive Power and Coordinated Control System

The goal of the Wide Area Reactive Power and Coordinated Control System implemented on the AEP system is to align the advantages of both traditional capacitor bank control methods without human operator interaction. This is accomplished by using a central real time automation controller (RPC). The RPC communicates with each CAP IED through either an Ethernet connection or a direct fiber optic path. The CAP IED sends the capacitor status and remote station voltage. The RPC can send requests to the CAP IED to close or open capacitor bank circuit breakers. The RPC can be programmed with the control algorithms to coordinate the efforts of the remote capacitor banks.

The coordinated control system must also work in conjunction with a static var compensator (SVC) installed on the AEP 138 kV transmission system. The static var compensator utilizes a voltage control scheme that will allow the thyristor switched capacitors (TSC) to provide dynamic support during system disturbances as well as reactive power support.

III. Implementation of SVC and Coordinated Control on AEP Transmission Grid

A. Communication Overview

Fig. 2 shows the communication block diagram for the overall coordinated control scheme. The RTU, RPC, and the SVC reside at same substation. The RTU acts as a communication bridge between SCADA, RPC, and the SVC via DNP protocol. The SVC communicates to the RTU and the TSC utilizing DNP over Serial. Communications from the RTU to the MSC and MSR also occur over serial. The RPC communicates over the SCADA LAN to CAP IEDs 1-3, and directly to 4 & 5 via a serial to fiber system. The connection to #4 & #5 provides a proof of concept for future installations of wide area control systems when considering control of 3rd party equipment and/or NERC critical cyber asset restrictions. Each device has the ability to communicate analog values and operational status to SCADA and the RPC. SCADA has the ability to collectively or independently remove control authority from the RPC, SVC, and CAP IEDs. The RTU acts as a communications bridge between the SVC and the RPC, and the SVC and the MSR and MSC due to the lack of the ability to host multiple DNP sessions and act as a DNP Master (Server). This communications restriction provided not only a challenge to overcome by employing non-traditional communications techniques but also introduces a single point of failure for coordinated control. In addition the ability for station to station communications utilizing AEP SCADA LAN required special network configurations, namely changes to the network access control list (ACL).

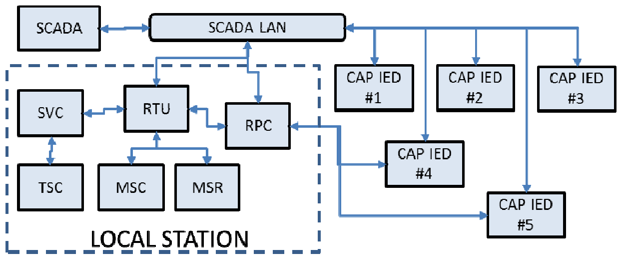

Fig. 2. Communication Diagram for SVC Controller at Local Substation and Coordinated Control of Remote Capacitor Banks

B. SVC Control Theory

Before the coordination effort can be discussed, the voltage control scheme of the SVC controller must be reviewed. The SVC controller receives the input of the 138kV bus voltage from the potential transformer at the local substation. The SVC controller has two main modes of voltage correction: a ***reference voltage with slope mode***, and a ***voltage bandwidth mode***.

As the name suggests, in the *reference voltage with slope mode*, the controller tries to maintain the system voltage around a reference voltage, using a voltage-droop type control based on a slope setpoint. The slope defines how much capacitance should be used to correct for a certain amount of voltage drop. The slope value should be calculated based on the system impedances and an estimate or measurement of voltage change due to reactive compensation. The controller uses a feedback loop to slow the voltage correction based on how fast the measured system voltage is changing. The controller will respond quickly for dynamic disturbances and more slowly for steady state voltage drops. The controller also employs a small dead band around the operating point to eliminate any "hunting" operation of the SVC. Hunting is defined as successive, back-and-forth, operation of the SVC as it turns its compensation on and off to try and satisfy its controller.

The second control mode of the SVC controller, the *voltage bandwidth mode*, utilizes setpoints for V_H and V_L which define a bandwidth where the controller will not operate. When the measured bus voltage at the local substation is within this bandwidth, the controller is satisfied with system conditions. When the measured bus voltage creeps outside of the bandwidth, the controller will operate based on the same slope value used in the previous control mode. The SVC controller will add capacitance or inductance to the system until the measured voltage is back within the bandwidth, or the available compensation is exhausted. Just like the *reference voltage with slope mode*, this control mode uses a small deadband to prevent hunting and a feedback loop to control the speed of compensation depending on the speed of the measured voltage change.

Regardless of control mode, the output of the controller is a susceptance value, B_{SVC}. The TSC branches and the MSR at the local substation will operate based on this susceptance value. The SVC can output anywhere from 100 Mvar inductive to 250 Mvar capacitive, in 50 Mvar steps. It should be noted that each individual TSC branch conducts the entire rating of its connected capacitor bank, and does not have the ability to continuously vary output less than the full rating. Fig. 3 shows the allowable output levels of the SVC.

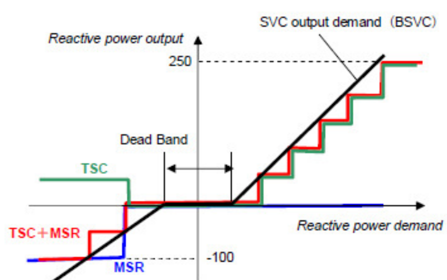

Fig. 3. Allowable step change output of the SVC, including TSC branches and MSR [2]

C. RPC Remote Station Voltage Control

As previously seen in Fig. 2, the RPC has the ability to communicate with and control the remote capacitor banks. 138kV voltage measurements from the remote substations are sent via DNP to the RPC. Each remote MSC has a time-delayed voltage bandwidth control scheme programmed in the RPC. When a remote bus voltage is outside the bandwidth for a particular bus, the RPC will issue a command to the CAP IED to operate the associated MSC. The intent of the voltage bandwidth settings is to allow each remote capacitor bank to regulate its bus voltage. This scheme can be selectively enabled in RPC by a SCADA operator.

The time-delayed voltage bandwidth control scheme is duplicated in the CAP IED for its associated MSC. In the event of either communications or equipment/software related failure of the RPC, each individual CAP IED automatically assumes control of its associated MSC. This key feature is the main contingency plan for a failure of the RPC and eliminates the need for a SCADA operator to immediately take action to address the failure. Additionally the SCADA operator has overriding control capabilities that can supersede the time-delayed voltage control scheme at each CAP IED.

D. SVC-RPC Coordinated Control

Coordination is necessary to provide for a healthy voltage level across every bus in an area-wide system while minimizing operations and eliminating human interaction. The operation of the TSC branches and the MSR at the local substation is coordinated with the operation of the MSC at the local substation as well as the operation of each MSC at the remote substations in the neighboring transmission grid. This coordinated control scheme is realized by the interaction between the SVC controller and the RPC in two ways.

The first is based upon the output status of the SVC and is coordinated with remote cap banks via settings in the SVC controller. The intent of this coordinated control function is to allow for the SVC system to reserve the full capacity of the SVC for dynamic disturbances and contingency voltage situations. When SVC provides 20 Mvar ($Q > QCON$) support continuously for duration greater then 10 seconds for var support, the SVC controller will send a signal to the RPC to close a remote station cap bank. The SVC controller will continue to send this signal as long as $Q > QCON$. The RPC will close the remote station MSRs based upon a predefined switching sequence when this signal is received. If no remote banks are available, the SVC will continue to provide support. The condition where all banks are in service and the SVC is providing var support is only expected for extreme contingencies.

The second method of coordinated control is voltage based. The RPC and the SVC both monitor the local station voltage. The SVC will conduct immediately with no delay in the event of a dynamic disturbance or severely depressed voltages. The RPC applies the classical time-delayed voltage bandwidth control to voltage at the local substation to operate remote station capacitor banks. The voltage set points between the RPC and SVC are coordinated for controlled achieving controlled voltage step changes. This method uses the same predefined switching order as the var support scheme.

The SVC manufacturer performed a voltage study [3] of the area transmission system to help determine voltage settings for the coordinated control scheme. The study used actual system parameters to model the voltage at remote busses during steady state and dynamic voltage changes. Fig 4. shows the results of one case study that simulated the SVC operating in response to a decrease in voltage step change. Fig. 4(b) shows the TSC branches being reduced in response to the remote MSC banks being requested on in Fig. 4(d). Several test cases such as this were simulated. The voltage study also showed the change in system voltages due to compensation at the local substation. This provided data for a calculation of the slope value used in the SVC's voltage control scheme.

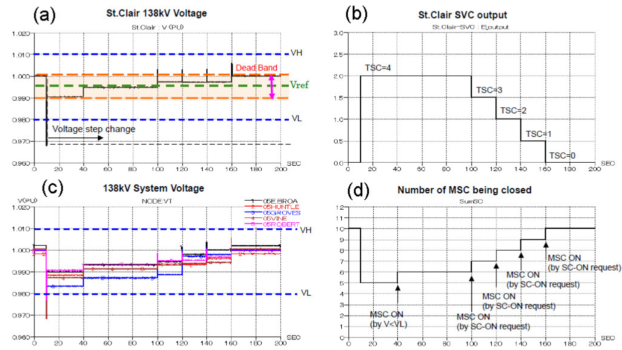

Fig. 4. Results of one simulation in a study for coordinated voltage control. Test case shows the ability for remote MSC banks to switch onto the system and allow SVC to reduce output [3]

IV. Coordination Concerns and Possibilities for Improvement

A. *Need for Coordination with Extended Set of Equipment*

The SVC installations on the AEP transmission systems highlight some of the coordination issues that have been documented and planned for, as well as coordination issues which remain unaccounted for. In both cases, the issue of voltage stability was the driving force behind the installation of an SVC system. Care has been taken to coordinate the operation of the SVC with other existing transmission level capacitor banks in the area. On any interconnected system where voltage regulation is a crucial component to system stability, there are often many other sources of voltage regulation. For instance, utilities use capacitor banks, tap changing transformers, and stand-alone voltage regulators at the distribution level to control the magnitude of voltage supplied to the customer. While the distribution bus voltage is somewhat isolated from the transmission bus voltage through the relatively high impedance of the transformer, immediate step changes in transmission bus voltage will still produce a corresponding step change in distribution bus voltage.

During testing of the SVC on the AEP system, one test case produced results that provide evidence of this condition. During the test case the voltage reference setpoint of the SVC controller was manipulated so that the SVC was forced to operate in capacitive mode, and therefore raised the system voltage. It was found that 30 seconds after this occurred, the system voltage started to rise slightly (the voltage rise did not match the steady state voltage condition previous to the beginning of the test), and this was enough voltage rise for the SVC to back off its output. Due to the fact that most distribution voltage regulators in the vicinity of the SVC are set with a 30 second delay before operating, it is plausible that every affected distribution voltage regulator in the area simultaneously lowered their distribution feeder voltage to compensate for the higher voltage supplied to them. Of course the instantaneous lowered voltage at the distribution level would slightly lower the power flow through the transformer, and therefore allow the transmission bus voltage to rise. Regardless of causality, this event shows that there are many factors in system voltage that should be accounted for.

B. *Need for Accurate Measurement and Communication*

Another concern in the coordination of voltage control schemes is the reliability of incoming voltage measurements. Utilities can make a business case for keeping as much existing equipment as possible when upgrading their system. Due to the aging electric grid, this means that some voltage readings may come from coupling capacitor voltage transformers (CCVT) that have been in service for decades. A quick review of one manufacturer's specification sheet shows that the accuracy of a brand new CCVT output is between 90-95% of input voltage during transient response. This could be a problem when trying to regulate system voltages to within 1%. The SVC installed on the AEP system takes care of this by using a wire wound potential transformer with much higher accuracy, but the existing capacitor banks still utilize original CCVT equipment. Using telemetered data in a coordinated control scheme can compound the problem. Different communication protocols can allow for a differing accuracy when sending analog values (DNP scaling and deadband settings), and time delays in data transmission can create inconsistencies in voltage readings. Fig. 5 shows the voltage difference measured at two points of the *same phase of the same 138kv bus* over a four hour period. Both readings rise and fall together, but there is roughly a 2% difference in the readings that can be attributed to errors in measurement and data transmission. Because the same measurement type and data transmission protocols are being used for the coordination of voltage control, it is likely that it will be difficult to control the voltage to within 2% of a desired value without manipulating the values.

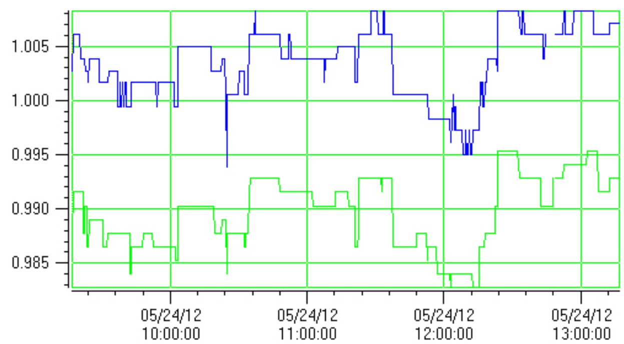

Fig. 5. Differences in voltage measurements (in per unit) on the same phase of the same bus over a four hour period

C. Coordination Based on the Theory of Economic Dispatch

Economic dispatch is defined as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities" [4]. The central theme of economic dispatch is to minimize the cost of total power generation while supplying power to all demanding loads. It is a mathematical problem that involves the optimization of a set of equations given a set of constraints. For instance, constraints may be system conditions such as transmission line outages and generating unit outages. Minimum and maximum bus voltages, as well as maximum generator power output would also be constraints. Computer software using power algorithms are used to find the minimum cost generating configuration that will meet all the constraints.

The same theory could be applied to the coordination of capacitor banks, SVC, and other voltage regulating devices. The goal of such a system would be to optimize power flow and capacity across the entire system, including both transmission and distribution from the point of generation to the point of consumption. Application of this theory would help to delay or mitigate capital investments in the T&D system, due to capacity restrictions on system. A main drawback to application of this theory is the engineering investment and maintenance required to implement a successful system.

V. Conclusion

Voltage compensation on the transmission system is needed for several reasons. Normal daily loading patterns cause the voltage to swing out of an acceptable range due to line losses and reactive power flow. Regulations that slow the building of transmission lines and shut down the operation of fossil fuel burning power plants can cause a gap in the constantly growing load and the available sources to feed that load. Contingency situations such as unexpected line or generator outages can cause both steady state and dynamic emergency voltage situations.

SVC installation is one method to help alleviate the concerns noted above. The inclusion of a coordinated control scheme greatly improves the robustness of the SVC. The justification of such a system easily recognizable based on operation of capacitor banks residing at or near the SVC allows for the SVC to retain capacity for dynamic system events. Utilizing an intelligent automation controller to achieve optimal control is strongly recommended to perform this action to alleviate the burden of the system operators. This paper explores AEP's most recent approach to coordinated control, the identified challenges, and the result of their application.

Some of the identified challenges are error in measuring equipment, communication challenges, and the interaction with non-coordinated equipment; such as tap changers and distribution equipment.

These issues were discussed and possible implementations of extended and more advanced coordinated control were reviewed. A coordinated control scheme based on the theory of economic dispatch would allow the system to be reconfigured on a timed basis, based on an optimization algorithm that minimized voltage differences from nominal and number of switching operations.

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