Static Var Compensation Controlled via Synchrophasors

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Abstract—To date, synchronized phasor measurements have only been used to monitor and analyze power system operations. However, synchrophasors have a much greater potential than just monitoring and visualization. Near term applications of synchrophasors include Wide Area Control (WAC), Special Protection Schemes (SPS), and Remedial Action Schemes (RAS), which can offer much greater benefits.

Southern California Edison (SCE) is actively pursuing electric power system control applications using synchrophasors. SCE's Rector SVC project is considered the first application where synchronized phasor measurements are used in a closed-loop dynamic control scheme.

The Rector project consists of a complex system generation, a Static Var Compensation (SVC) system, PMUs, and a SCADA gateway. The project objective is to successfully maintain voltage stability through the use of the SVC without creating an over-voltage condition at the Big Creek Generation Station. A phasor measurement unit (PMU) currently monitors Big Creek and streams data back to SCE's central office for system operations. The goal is to integrate the synchrophasor voltage data from the PMU at Big Creek and write it to the SVC controller using traditional SCADA protocols with a total measurement and communications latency of less than 1 second.

This paper will also demonstrate how synchrophasors can be effectively integrated into traditional SCADA and Energy Management Systems/State Estimator systems.

I. EXISTING SYSTEM

The following is a description of the transmission corridor under investigation in this case study.

A. Existing Corridor Description

The corridor under consideration is a north-to-south 230 kV transmission corridor approximately 130 miles long. See Fig. 1 for a simplified single-line diagram of the corridor.

This corridor is connected in a radial fashion at the south end to an extensive 230 kV transmission network. From this southern location, the 230 kV corridor travels north in two "legs" routed in distinct right-of-ways. These two legs converge once again at the north end of the corridor at a network of hydroelectric generation facilities with approximately 1000 MW of installed generation capacity. Load is served out of three 230 kV transmission substations in the corridor, with one station located on the east leg and two on the west leg.

The transmission lines in the corridor are beginning to exhibit reliability problems consistent with very old age. The existing transmission lines have very limited emergency capability because of conductor sag limitations, particularly at high load levels. The lines in the corridor have a large number of splices, some of which are nearly as old as the conductor it-

self. Consequently, splice failure is becoming a greater operational concern every year. There is a notable absence of transposition towers, and the importance was not understood at the time the transmission lines were designed and constructed. As a result, imbalanced loading between phases is a daily reality for system operations. There is a significant amount of transmission losses in the corridor, particularly under peak load conditions (heavy summer) and conditions of maximum hydrogeneration.
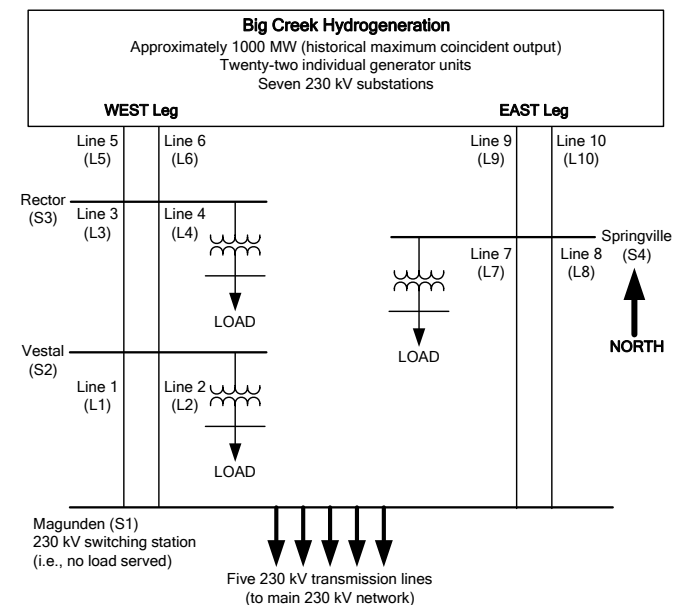

Fig. 1. Simplified single-line diagram of the existing 230 kV transmission corridor without planned system upgrades

Finally, the transmission corridor is rapidly evolving into a corridor that exhibits bidirectional power flows. Originally, the corridor was the exclusive means to deliver hydropower generated in the north to the main 230 kV network south of the corridor. Power flow was primarily north-to-south and was essentially balanced between the east and west legs of the corridor. In recent years, however, the phenomenon of "urban sprawl" load growth has extended into this transmission corridor. Significant load growth has taken place in the corridor, and the summer peak load in the corridor is now in excess of the hydrogeneration-installed capacity. Therefore, during heavy summer load conditions, generation resources outside of the corridor serve the balance of local area load not served by the local hydro resource (i.e., south-to-north power flow). In addition, because of geographic constraints, the vast majority of this load growth has taken place at Rector substation,

located on the western leg of the corridor. This has resulted in operating conditions where the west leg overloads well before the east leg reaches full capacity, reflecting an under-utilization of the full transmission capacity of the corridor.

II. CORRIDOR CONSTRAINTS TO BE RESOLVED

A. Existing System Power Flow Limitations

From a transmission planning perspective, the corridor as described above has two critical power flow limitations.

The first critical power flow limitation takes place under heavy summer load conditions with maximum hydrogenera-tion. Under such conditions, north-to-south overloads occur on transmission Line L5 and Line L6 because of unbalanced loading between the east and west legs of the corridor. The second critical power flow limitation takes place under mod-erate-to-high summer load levels and reduced hydro genera-tion in the north. Under such conditions, south-to-north over-loads occur on transmission Line L1 and Line L2 because of a combination of insufficient local area generation and unbal-anced loading between the east and west legs of the corridor.

To address these two critical transmission limitations, a single transmission project (the "loop") was identified as a solution. This project involves the looping in of transmission Line L9 into Rector Substation as shown in Fig. 2. The loop involves a minimum amount of new 230 kV construction compared to all other upgrade alternatives, better balances the loading between the east and west legs, and increases the transmission capacity for both north-to-south and south-to-north flow into Rector Substation as required.
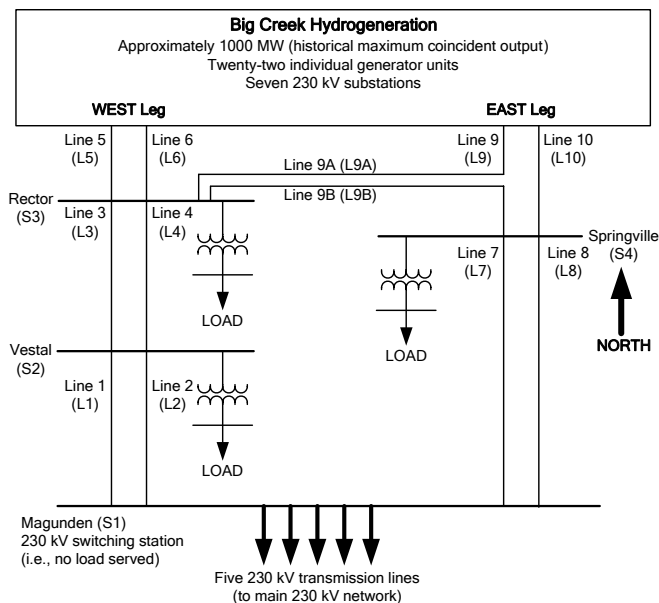

Fig. 2. Simplified single-line diagram of the future 230 kV transmission corridor showing the planned transmission Line L9 loop project upgrade

B. Existing System Transient Voltage Stability Limitations

From a transmission planning perspective, the existing cor-ridor as described above also has a critical transient voltage stability limitation.

This critical condition takes place under heavy summer load conditions with maximum hydrogeneration. Under such conditions, single-line outage conditions on Line L5 or Line L6 can cause low transient voltage conditions at Rector Sub-station. These low transient voltages are caused by the per-centage of induction motor load present in the aggregate total load served out of Rector Substation. Without mitigation, these low-voltage conditions would result in large first swing transient voltage drops (measured in percent) as well as long first swing voltage drop duration (measured in cycles).

The transmission line upgrade described above diminishes the severity of these problems but does not completely miti-gate them. To address these limitations, a 200 MVAR SVC was recommended for installation at Rector Substation. This dynamic reactive device was intended to provide voltage sup-port during the first swing transient voltage time frame upon completion of the loop-in.

III. SYSTEM REQUIREMENTS

A. Rector SVC Rating and Design

Fig. 3 shows the key SVC equipment components of the Rector SVC and its connection to the 230 kV bus at the Rector substation. The SVC is a TCR/TSC/FC (thyristor-controlled reactor/thyristor-switched capacitor/fixed capacitor) configu-ration.

The 200 MVA coupling transformer is made up of three 66.7 MVA single-phase transformers (with one single-phase-spare) that steps down the voltage from 230 kV system volt-age to 9.5 kV low voltage for efficient operation and eco-nomic design of the thyristor valves associated with the TCR and TSC branches. The reactive power branches connected to the 9.5 kV bus are listed below:

- three 0 to –70 MVAR TCR branches
- three +40 MVAR TSC branches
- two +40 MVAR total fixed harmonic filter banks

Each of the harmonic filter banks consist of a 13 MVAR filter tuned to the third harmonic, a 14 MVAR filter tuned to the fifth harmonic, and a 13 MVAR filter tuned to the seventh harmonic. The third-harmonic filter branch is needed to re-duce pre-existing system harmonic voltage distortion levels.

The SVC has three TCR branches, each having a continu-ous rating of 0 to –70 MVAR inductive, so that the loss of one TCR branch does not reduce the SVC inductive MVAR output by more than 50 percent (i.e., –60 MVAR), as required by SCE's design/configuration criteria. For example, if one of the TCR branches is out of service, the remaining two TCRs (2 x –70 MVAR) can provide 60 MVAR of inductive output with two-harmonic filter branches (2 x 40 MVAR).

In the event of a failure in one of the reactive power branches, the SVC can continue to operate in a degraded mode/reduced capacity (after a controlled shutdown) with the loss of one TSC branch, the loss of one TCR branch, and the loss of one filter branch.
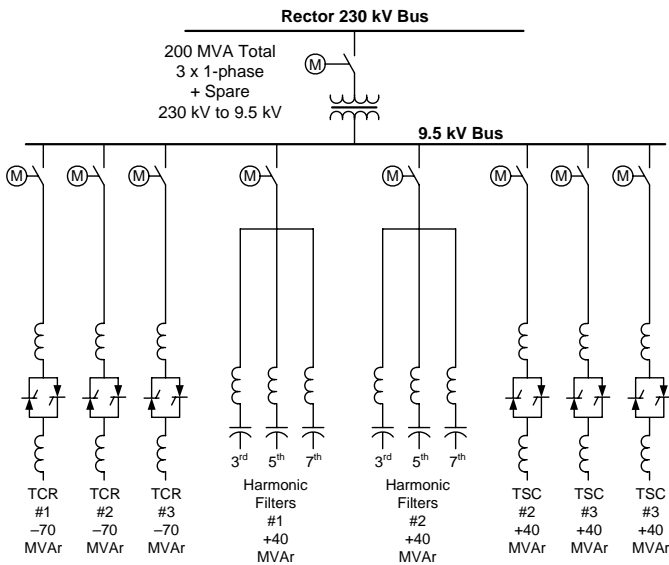

Fig. 3.   One-line diagram of the Rector SVC

B. Overview of Coordinated Voltage/Var Control Scheme

Fig. 4 illustrates the coordinated control system for the Rector SVC control system.

The SVC mainly controls the dynamic voltage change at the Rector 230 kV bus (REC-AVR). The SVC steady-state control includes the following functions:

- control of SVC steady-state reactive power output (SVC-AQR)
- supplementary regulation of the 230 kV Big Creek #3 bus voltage via phasor measurement unit (PMU) (BC-AVR)
- control of a 79 MVAR, 230 kV shunt capacitor in the Rector substation (SC-Control)
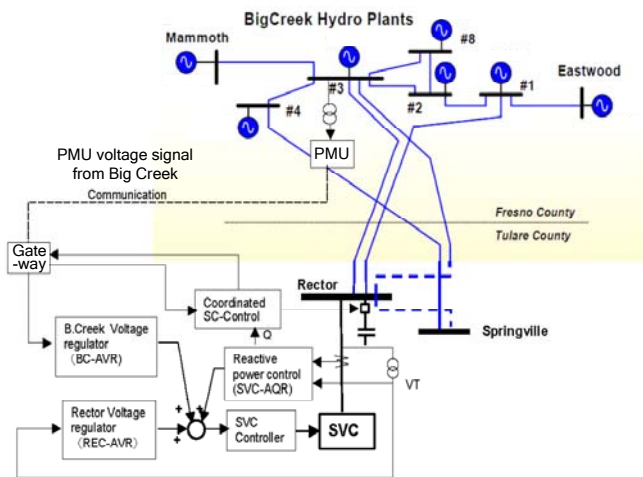

Fig. 4.   Rector SVC coordinated control

Since three different control loops (REC-AVR, SVC-AQR, and BC-AVR) function together in the steady-state coordinated control, the steady-state SVC output should be controlled based on the V-Q characteristics in Fig. 5 and in the following order of priority:

Priority #1
- Maintain Big Creek #3 230 kV bus voltage within its upper (VH2) and lower (VL2) limits as shown in Fig. 5 (BC-AVR).
- Maintain SVC steady-state output within QCmax and QLmax (SVC-AQR).

Priority #2
- Maintain Rector 230 kV bus voltage within its upper (VH1) and lower (VL1) limits with Priority #1 maintained (REC-AVR).

Priority #3
- If Big Creek #3 230 kV bus voltage is below VL2, the SVC should control it within VL2 with Priority #1 and Priority #2 maintained.
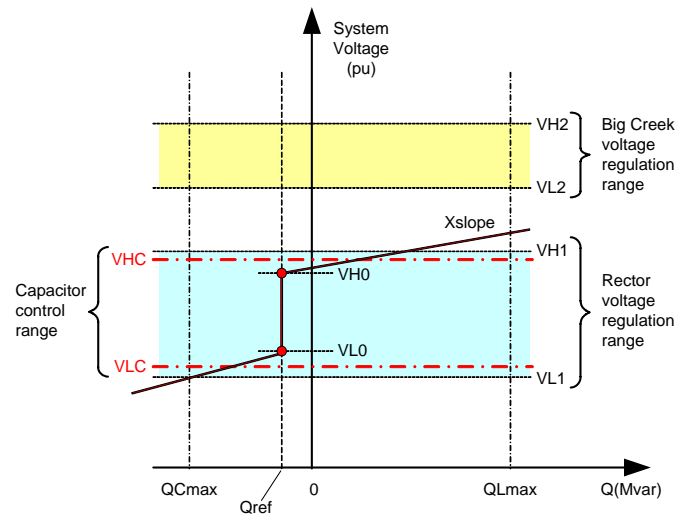

Fig. 5.   V-Q characteristics of the Rector SVC coordinated control

IV. BIG CREEK VOLTAGE REFERENCE SOLUTION

The Big Creek voltage reference is critical to the use of the SVC to provide coordinated steady-state voltage regulation. This voltage input requirement was included in the device specifications, but the manner of providing this input was left open. In all, three different options were considered.

1. Use SCE's EMS system to rebroadcast the voltage input to the SVC.
2. Use a stand-alone transducer to provide the data via a traditional RTU master to the SVC controller.
3. Use the available synchronized phasor measurement to provide the data to the SVC utilizing the C37.118 phasor data protocol.

Upon investigation we discovered that SCE's EMS system is not configured to easily retransmit the required information to the SVC. Also, SCE is in the middle of an EMS upgrade so any major development to provide this input would have to be performed twice—once on the old system to meet the operating date of the SVC and again on the new system that is

scheduled to be in service by the end of the year. Given these restrictions, this option was shelved as not practical unless no other solution could be found.

The second option, while using a more traditional approach, also had some limitations. First, the project had not identified significant work to be performed at Big Creek #3. Therefore, project funds would have to be allocated for this work. Second, the installation of transducers and an RTU would require using engineering and construction labor that had not been scheduled as part of the project, and this labor may not be available. Thus this option was placed on the "not preferred but doable" shelf.

The last option, utilization of phasor data also had its issues. First, at the time the project was being discussed, the SVC manufacturer was on a very tight schedule to meet the operating date. Adding significant software development to the schedule could put that date in jeopardy. Second, the phasor monitoring unit at the station uses a proprietary protocol, not the latest IEEE C37.118 format, so a manner of upgrading this unit would need to be investigated. So this option also had some development risks to be considered. In addition, the SVC controller is not IEEE C37.118 compliant, so some method of protocol conversion is necessary.

Given that any of these options required some effort, we investigated further. A computing system platform was identified as an option for use as a protocol gateway for the SVC system that, with some programming effort, could translate the C37.118 protocol to DNP3, which the SVC controller already understood. At the same time the existing PMU manufacturer indicated that they were developing the C37.118 protocol. This made Option 3 have the least impact to the overall schedule and provided several fallback options in case any single effort was delayed.

V. PROTOCOL GATEWAY SOLUTION

The Protocol Gateway acts as a data concentrator and protocol converter for the SVC controller and the SCE SCADA system. The primary functions of the gateway are to receive status information from a number of devices integrated into the overall SVC system and Rector 230 kV yard, process the data, and provide data and potential operation information back to the SVC controller and the SCADA RTU. Fig. 6 provides a block diagram of the protocol gateway and communications to various system equipment. Devices providing input into the gateway include a circuit breaker connecting the SVC to a 230 kV shunt capacitor, a latch set/reset switch used to toggle operation of the SVC controller from automatic to manual mode depending on other data available, and the Rector master RTU. Integrating the synchrophasor data into the gateway would require adding a software module that could receive and parse the synchrophasor protocol, and then provide it to the main SCADA interface in an accepted protocol.

The IEEE C37.118-2005 Standard for Synchrophasors for Power Systems defines a method for measuring, formatting, and communicating synchronized phasor measurement data. Because of the nature of the synchrophasor measurements, converting the C37.118 standard to a more traditional SCADA protocol such as DNP3 poses some challenges. First, synchrophasor data, by definition, are time synchronized and intended primarily for real-time applications and are deterministic in communications. DNP3, in contrast, is a serially scanned, asynchronous protocol with no specific time reference. In addition, synchrophasor data is typically sampled at much higher rates. The U.S. de facto standard for synchrophasor measurement for real-time applications is 30 messages per second. DNP3 scans can range from twice per second to as slow as once over 10 seconds. As a result, the translation must be carefully engineered.

DNP3 is a very encompassing protocol designed to manage many different data types and applications. It is not a trivial task to develop a quality translation mechanism in a short time frame. Because of the schedule for the SVC implementation and testing, development of the protocol conversion software prototype was limited to five weeks. Because of this schedule and the complexities of the DNP implementation, other solutions were reviewed.

Modbus® is a communications protocol developed by Modicon Corporation (now known as Telemecanique, a brand of Schneider Electric) in the late 1970s for use in data collection in programmable logic controllers. Now, nearly 30 years later, Modbus has become a de facto standard for data collection and exchange in the industrial sector. Modbus offers some advantages over DNP3 from a development perspective; Modbus is a relatively simple protocol, so product implementation is much easier and takes less time, typically only a couple of weeks instead of several months. Because Modbus is royalty-free and there are no licensing costs, overall development and product costs are reduced. Modbus transmits the raw form of the data (binary data or analog quantities) so there is less likelihood that the data can be corrupt during translation between protocols. This also assists in testing to confirm that what is measured is what is communicated. Finally, Modbus is a relatively efficient protocol. Because of its simplicity, there is very little overhead in the packets, again reducing the overall effort in testing. One disadvantage to using Modbus was that the SVC controller was not compliant. However, the Protocol Gateway, which is at the heart of the entire SVC system communications, is capable of translating Modbus to DNP3. This feature would allow us to receive the phasor measurement, qualify its integrity based on status data included with the measurement, then format the measurement data for the DNP3 protocol, and write it to the SVC DACs.
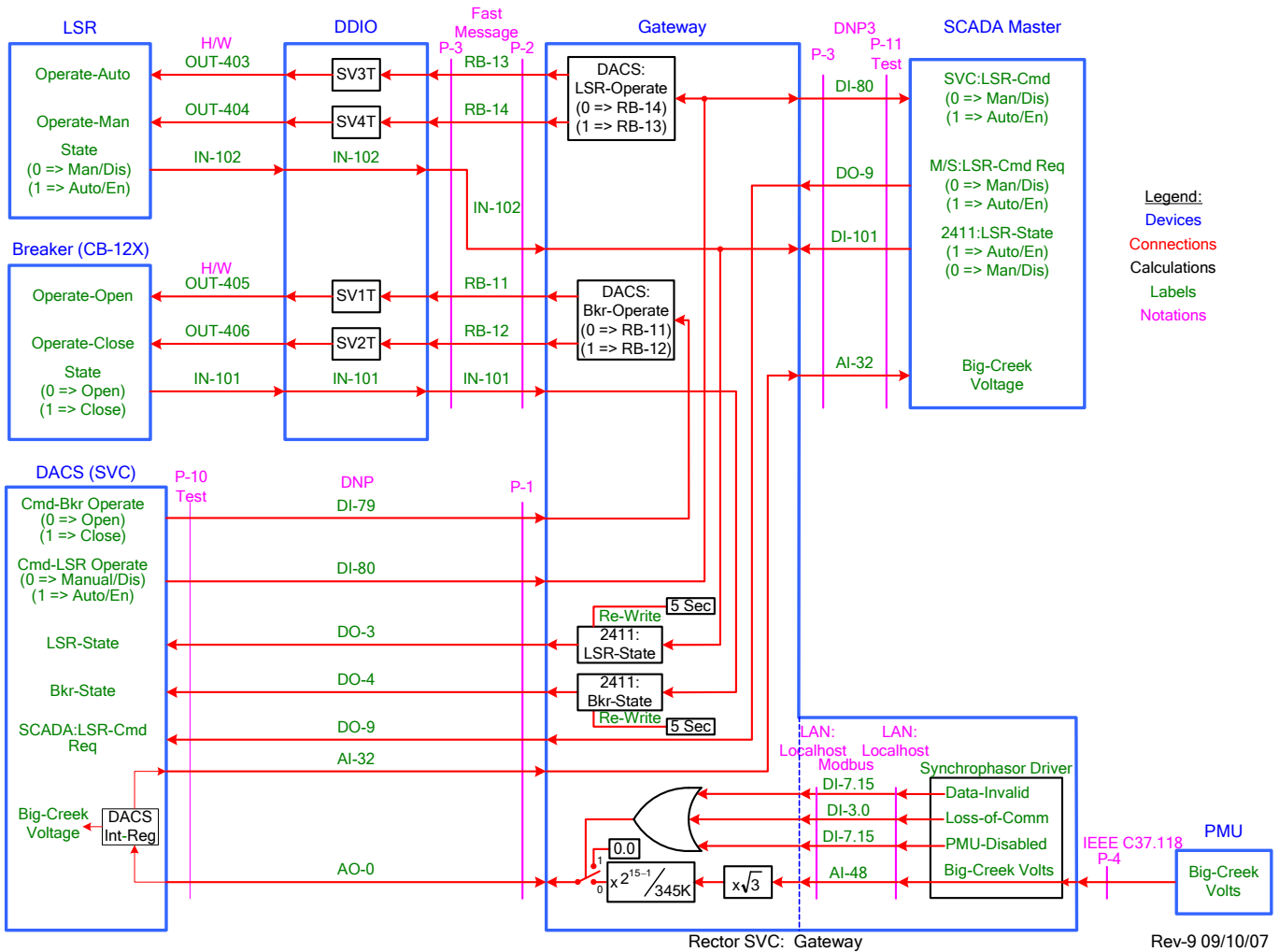
Fig. 6.   Protocol gateway synchrophasor translation and logic

Modbus, like DNP, is a polled protocol, so it shares the same issue noted earlier regarding differences in polling rates vs. the high-speed data delivery of PMUs. One concern this poses is that incoming data delivered at 30 messages per second may overwrite a one-half second poll response that is in process. Careful design was implemented to lock each data set that was included in a poll response. This was fairly simple for a single PMU response, since the data map was small. However in future applications, such as integrating synchrophasor data into EMS/SCADA, the data maps must be carefully constructed to maintain contemporaneous data sets. Modbus has limits on the size of each poll response; so large data sets from many PMUs must be mapped in order to capture similar data from a given instant in time from all included devices.

Another issue that required careful engineering was the potential that a transient voltage sag or swell, such as could occur during a system disturbance, might be captured and transmitted to the SVC controller. This transient data could misrepresent the state of the Big Creek 3 voltage and cause the SVC controller to take inappropriate action that could eventually lead to instability in the system. For this application, an Olympic filter was applied to remove noise and provide an average across the filtering window.

In addition to the filtered voltage magnitude, a few binary data points were mapped to the SVC controller to assist with qualifying the integrity of the data from Big Creek 3. These points included diagnostics status of the PMU, GPS synchronism, and loss of communications. Assertion of any of these elements would switch logic within the Gateway, and zero-fill the Big Creek 3 voltage data delivered to the DACS. Fig. 7 shows the protocol translation and logic in the protocol gateway for processing and transmitting the synchrophasor data to the SVC controller.
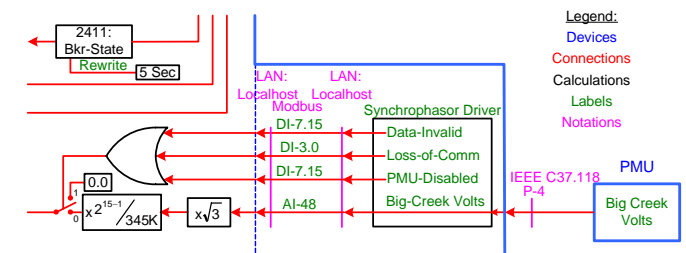

Fig. 7.   Protocol gateway synchrophasor translation and logic

VI. VC Operations and Performance

A. Effect of SVC Operation on Big Creek Voltage

The SVC has had a positive effect on the voltage profile in the corridor. The overall average voltage at Big Creek #3 appears to have been reduced from 242 kV prior to the SVC being in service to 238 kV after the SVC was in service. However, this voltage reduction, in part, could be because when the SVC was commissioned, it was found that the transducers at Big Creek needed to be calibrated. The range of the voltage varied 9 kV prior to the SVC and 4 kV after the SVC. Although the average voltage at Rector stayed approximately the same, 231.3 kV vs. 230.4 kV respectively, however, the range of the voltage variation decreased from a 12 kV range to a 7 kV range. The implementation of this control scheme has allowed operations to maintain a stable voltage for the utility customer.
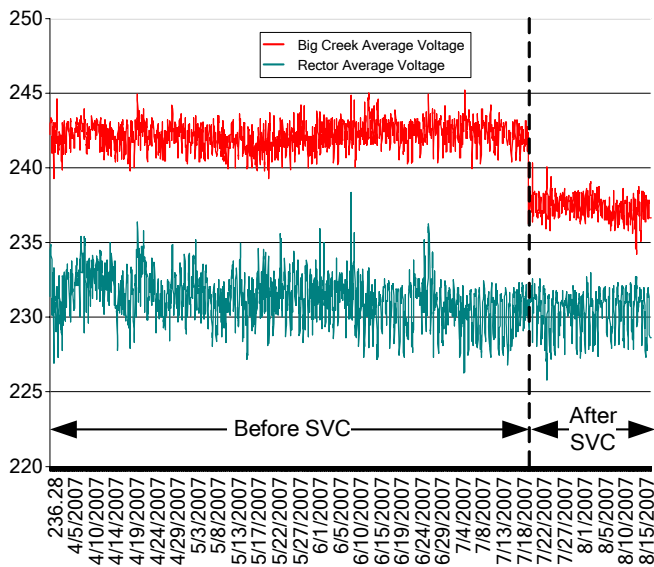

Fig. 8.   The hourly peak voltage of Rector and Big Creek #3 bus voltages

Fig. 8 illustrates the impact of the coordinated control utilizing the Big Creek #3 voltage provided by the PMU at Big Creek #3.

B. Impact of SVC on Capacitor Switching

As shown in Fig. 9, switching the Rector 230 kV capacitor that can be placed under the control of the SVC has a minimal impact on voltage at Rector and the adjacent stations. Previously this switching event could cause a significant voltage event on the system, which had to be mitigated by utility operations.
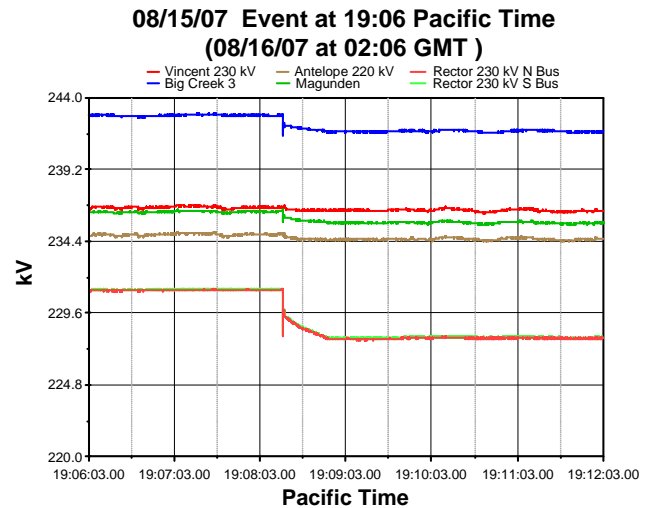

Fig. 9.   Switching of the 230 kV Rector Capacitor with SVC active

VII. Lessons Learned

Several issues would have helped ease the commissioning of the SVC remote voltage. The first is that all equipment should have been tested off-line prior to deployment in the field. We were not able to do this because of the project schedule. We were able to overcome this restriction with a lot of support by personnel at remote locations to identify and resolve any issues. The second issue is that the communication channel should be tested using a high-speed digital communication channel. It is a standard procedure to test these channels using a voice handset. The problem with this procedure is that a loose connection that can cause trouble with high-speed digital signals will not present itself to a voice test.

VIII. Conclusion

When coupled with the information available from Wide-Area Monitoring utilizing Phasor Technology, an SVC can be a very cost effective solution to maintain voltage stability of the high-voltage transmission network.

IX. BIOGRAPHIES

Anthony Johnson is a Senior Engineer at Southern California Edison. He received a Bachelor of Science in Electrical Engineering and a Masters of Science in Electrical Engineering from Montana State University. He is a licensed Professional Engineer in the state of California. He is also a member of IEEE.

Robert Tucker is a Power System Planner at Southern California Edison. He received a Bachelor of Science degree in Engineering from Harvey Mudd College and a Master of Science degree in Mathematics from Claremont Graduate School in Claremont, California, in June 1997 and December 2001, respectively.

Thuan Tran is a Senior Engineer at Southern California Edison. He is a licensed Professional Engineer in the state of California.

John Paserba earned his B.E.E. ('87) from Gannon University, Erie, Pennsylvania, and his M.E. ('88) from Rensselaer Polytechnic Institute, Troy, New York. Mr. Paserba joined Mitsubishi Electric Power Products, Inc. (MEPPI) in 1998 after 10 years with GE's Power Systems Energy Consulting Department. He is a Fellow of the IEEE and is presently the Chair for the IEEE PES Power System Dynamic Performance Committee.

Dan Sullivan is a Senior Engineer at Mitsubishi Electric Power Products Inc, (MEPPI) in Pittsburgh, Pennsylvania. Mr. Sullivan earned his BSEET degree from the Pennsylvania State University in 1995, MSEE from the University of Pittsburgh in 2006, and is a licensed Professional Engineer in the Commonwealth of Pennsylvania. He has been an IEEE member since 1992, and is the current Secretary of Substation Committee Working Group I4 on Static VAR Compensators.

Chris Anderson has an A.A.S in Electronics Engineering Technology from I.T.T. Technical Institute, and is currently working on his B.S. in Electrical Engineering through Warren National University. He joined SEL in July 1999. In the first three years at SEL, he worked in product development for transmission protection products. From August 2002 to August 2005, he was an associate product engineer supporting transmission protection in R&D. Since August 2005, he has been the product engineer supporting Synchrophasor Measurement Technology development in R&D.

David Whitehead, P.E., is the vice president of Research and Development at Schweitzer Engineering Laboratories, Inc. (SEL). Prior to joining SEL, he worked for General Dynamics, Electric Boat Division as a combat systems engineer. He received his BSEE from Washington State University in 1989, his MSEE from Rensselaer Polytechnic Institute in 1994, and is pursuing his Ph.D. at the University of Idaho. He is a registered professional engineer in Washington State and Senior Member of the IEEE. Mr. Whitehead holds seven patents with several others pending. He has worked at SEL since 1994 and has been responsible for the design of advanced hardware, embedded firmware, and PC software as a hardware engineer, research engineer, and chief engineer/assistant director.