Wind Farm Volt/VAR Control Using a Real-Time Automation Controller

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Abstract—**Wind generating facilities often require significant reactive power support to maintain voltage and power factor within operating limits prescribed by the transmission grid entity. Many installations include multiple stages of switched capacitor and reactor banks for this purpose. Coordinated control of these capacitor and reactor banks, which are often connected to the point of interconnection via multiple step-up transformers, requires a centralized control system.**

This paper discusses a reactive power control system that utilizes a central automation controller to regulate both power factor and voltage at the point of utility interconnection. This controller includes the capabilities of a complete communications processor to exchange voltage, power flow, and status information along with control commands to microprocessor-based relays throughout the system. It also includes a powerful IEC 61131-3-compliant soft programmable logic controller (PLC) logic engine to execute the control algorithms. The system is easily adaptable and scalable to nearly any configuration.

The challenge when controlling both power factor and voltage is to prevent hunting due to conflicts between the two control requirements. An adaptive algorithm is utilized to deal with this challenge. The controller also includes a sophisticated sequencing algorithm to ensure that both reactors and capacitors are not in service at the same time, to optimize power factor through multiple step-up transformers to reduce losses, and to even out switching operations between reactive banks.

I. INTRODUCTION

Wind generating facilities often require significant reactive power (VAR) support to maintain voltage and power factor within the operating limits prescribed by the transmission grid entity that supplies the tie to the grid. VAR support is often provided by multiple capacitor and reactor banks connected to wind farm collector buses that can be switched in and out.

This paper discusses an integrated control system that utilizes a central automation (CA) controller to regulate both power factor and voltage at the point of utility interconnection. The control system measures voltage, active (P) and reactive (Q) power flow, and power factor and controls the multiple reactive power devices (RPDs) of capacitor and reactor banks.

II. OVERVIEW OF THE CONTROL SYSTEM

Fig. 1 shows a simplified single-line diagram of the system. The metering device measures power flow at the point that the facility ties to the utility system. It measures three-phase voltage and power factor (ratio of apparent power, S, to active power, P) at the point of interconnection (POI), as well as active and reactive power flowing towards the utility system. The transformer relays measure active and reactive power flow through the transformers. These measurements are used to optimize power factor, thereby minimizing losses through

each transformer. The RPD relays monitor positive-sequence voltage on the collector bus. The collector bus sensing is used to determine the status of the collector bus and to determine the expected ΔQ per step for RPDs connected to it.
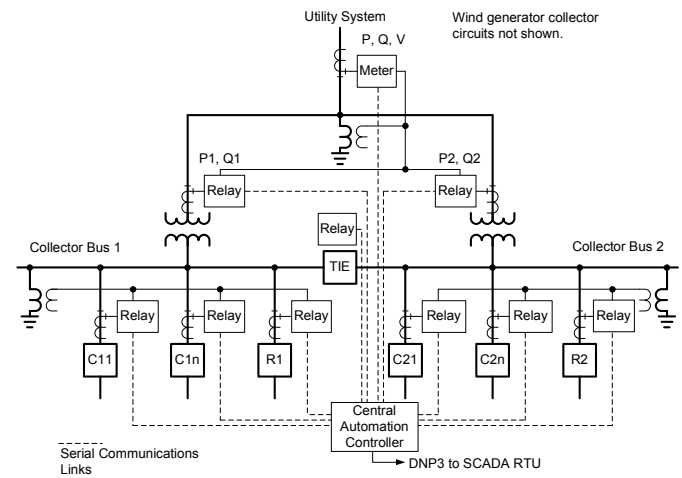

Fig. 1. Control system simplified one-line diagram

The functions of the CA controller and RPD relays are described in more detail in the following sections.

A. Central Automation Controller

The CA controller monitors and controls the relay for each RPD via a serial communications link. The CA controller analyzes the system status and sends control commands to each relay. The need to send control commands in order to add or remove RPDs is determined by a priority sequencing algorithm, which maintains the voltage between upper and lower limits and the power factor between leading and lagging limits. When either condition is out of band, the algorithm requests the addition or removal of an RPD. However, the control commands are supervised and reevaluated if the two measurements (voltage and power factor) are in conflict and it is predicted that a command to improve one will also adversely affect the other.

If the power factor and voltage criteria are in conflict, voltage control has priority. For example, if the facility is consuming too many VARs supplied by the utility, resulting in the power factor being out-of-band leading, the CA controller will want to add capacitors. But, if the voltage is out-of-band high, the controller will want to remove capacitors. Under this condition, the controller will remove capacitors to correct the voltage and let the power factor stay out of band.

A previous volt/VAR control system included logic to allow the voltage versus power factor priority to be user settable [1]. However, it was discovered that users always selected voltage priority, so that logic was not carried forward in this new control system.

Alarms are provided to indicate if the regulated parameters are outside of band limits. The alarms also assert if the regulated parameters are out of band but the CA controller cannot add or remove RPDs because there are none available to switch. The alarms are provided to the utility supervisory control and data acquisition (SCADA) system.

The controller also includes loss-of-voltage detection for each bank. When a relay senses dead bus voltage, the controller removes that bank from operation in the system.

B. RPD Relays

In addition to providing primary protection for the RPD or banks of RPDs, each RPD relay informs the CA controller of the status of its corresponding RPD(s). This information is used in the controller sequencing algorithm. If a relay receives a command to add or remove an RPD, it opens and closes its respective RPD breaker or RPD vacuum switch.

An RPD breaker must be in automatic mode before it can be available for automated addition or removal. The RPD breaker control mode is set to automatic or manual via pushbuttons on the relay front panel.

The CA controller monitors a timer in each capacitor RPD relay, which prevents a capacitor RPD from being available to add for a user-settable dead time (configured in the relay) after being removed to allow the capacitors to discharge.

III. OVERVIEW OF RPD CONTROL FUNCTIONS

A. Control of Reactive Power Supply

The reactive power supply at a facility is important to the reliable and economical operation of the power system. In many cases, utility system operators charge power factor penalties if a facility is consuming too much reactive power. Reactive power support helps control the voltage on the interconnected power grid. Increasing the VAR supply raises the local bus voltage, while decreasing the VAR supply lowers the local bus voltage. Voltage support is necessary for power transfer.

The VAR supply can come from dynamic sources, such as rotating machine excitation systems and static compensators (STATCOMs), or from static sources, such as switched capacitor banks. Often, there is a combination of these sources. External sources of reactive power are commonly required for wind generation—the primary application for which this system was developed.

The CA controller monitors voltage and power factor at the POI and regulates both parameters. As long as the two control parameters are not in conflict, either control function can add or remove RPDs.

B. Regulation Challenges

In the PQ plane, active power (P) and reactive power (Q) are quadrature components. The hypotenuse of the power triangle is the apparent power (S). For this application, one of the regulated quantities is the power factor (PF). PF is the ratio of P/S. However, the controlled quantity is discrete steps of Q. The step size is based upon the size of each switched RPD and the voltage on the collector bus. PF is a ratio, so at low active power flow, the ΔQ from one step can overshoot the opposite band limit, which would result in hunting. So, the power factor regulation limits must be modified as active power flow approaches zero.

Another complicating matter in designing the regulation characteristics is that the expected ΔQ from a switching operation varies by the square of the bus voltage. For this reason, it is desirable to measure the voltage on each collector bus so the controller can adjust its regulation characteristics based upon the actual expected ΔQ, instead of using the nominal VAR rating of the RPD.

For voltage regulation, the change in voltage (ΔV) associated with a step change in local VAR support is a function of the equivalent source impedance to that bus. High source impedance will magnify the rise associated with a step addition in reactive power.

Other devices, such as wind generator control systems or a load tap changer (LTC) on the step-up transformer, may also make control responses to regulate the voltage on a bus. The ΔV resulting from an RPD switching operation may cause a converse reaction in these other voltage control systems. For this reason, it is necessary to consider other control systems at the wind farm facility that may respond to power factor and voltage. Hunting may result if various control systems interact [1].

IV. ADD/REMOVE RPD LOGIC

A. Voltage Regulation

The CA controller uses the voltage read from the POI revenue meter and operator-configurable upper and lower voltage limits to regulate the system.

The upper and lower voltage limits are set by the user via SCADA. These values are in turn sent to the CA controller for use in selecting and blocking control requests. When voltage and PF are not in conflict and the voltage is out-of-band high, the controller removes capacitor RPDs or inserts reactor RPDs. If the voltage is out-of-band low, the controller will perform the opposite of the aforementioned operation.

B. Power Factor Regulation

Fig. 2 illustrates the power factor control characteristics in the P/Q plane.
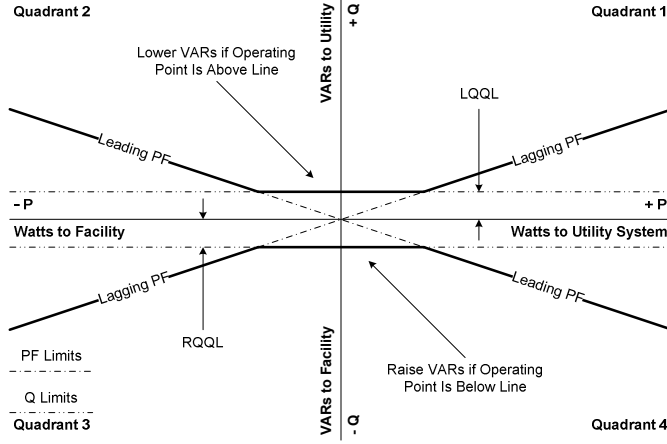

Fig. 2.   Power factor regulation characteristic

The CA controller has separate leading and lagging power factor limits. The limit in effect depends upon the quadrant where the power system is operating. Because power factor is a ratio of P/S (active power over apparent power) and the controlled quantity is Q, the power factor band limits are cut off when the expected ΔQ overshoots the opposite power factor band limit. Equations (1) and (2) describe the limits.

$$LQQL = \frac{MAX\Delta QNextAdd\_Rmv * Margin}{2} \quad (1)$$

$$RQQL = \frac{MAX\Delta QNextAdd\_Rmv * Margin}{2} \quad (2)$$

where:

LQQL is the lower VAR reactive power limit.
RQQL is the raise VAR reactive power limit.
$MAX\Delta QNextAdd\_Rmv$ is the maximum ΔQ expected between the next RPD to be removed or added, per (3).
Margin is the ΔQ margin setting.

C. ΔQ Next RPD Step Function

The VARs supplied by an RPD vary by the square of the voltage at its terminals. The CA controller adjusts the nominal Q rating of the RPD based upon the measured voltage, as shown in (3) and (4). This is the value used to determine the expected ΔQ for the next RPD to operate. This value, shown in (5), is used in (1) and (2).

$$\Delta QNextRmv = VNR_{PU}{}^2 * Q_{NOM} \quad (3)$$

$$\Delta QNextAdd = VNA_{PU}{}^2 * Q_{NOM} \quad (4)$$

$$\begin{aligned} MAX&\Delta QNextAdd\_Rmv \\ &= \max(\Delta QNextAdd, \Delta QNextRmv) \end{aligned} \quad (5)$$

where:

$\Delta QNextRmv$ is the delta Q expected from the next RPD to be switched to lower VAR supply.

VNR_{PU} is the per-unit voltage associated with the next RPD to be switched to lower VAR supply.

$\Delta QNextAdd$ is the delta Q expected from the next RPD to be switched to raise VAR supply.

VNA_{PU} is the per-unit voltage associated with the next RPD bank to be switched to raise VAR supply.

Q_{NOM} is the nominal three-phase MVAR rating setting for each RPD.

The sequencing logic function determines which RPD will be the next to be added or removed and from which bus. This function is described in Section V.

The CA controller receives the bus voltage measurement from each relay and converts it to per unit based upon the nominal RPD voltage rating. The nominal RPD voltage is the voltage at which the nominal VAR rating will be supplied by the RPD. If the capacitor bank nominal voltage rating differs from the reactor bank nominal voltage rating, it is necessary to convert the VAR and voltage ratings to a common voltage base when setting up the control.

D. V Priority Logic

If voltage and power factor regulation criteria are in conflict, voltage has priority. The controller uses logic, described in Table I, to mediate conflicts between the two control parameters. See Fig. 3 and Fig. 4 for the blocking limit characteristics. The control action of the power factor control parameter is blocked when performing that action would cause voltage to be out of band.

TABLE I
V PRIORITY LOGIC

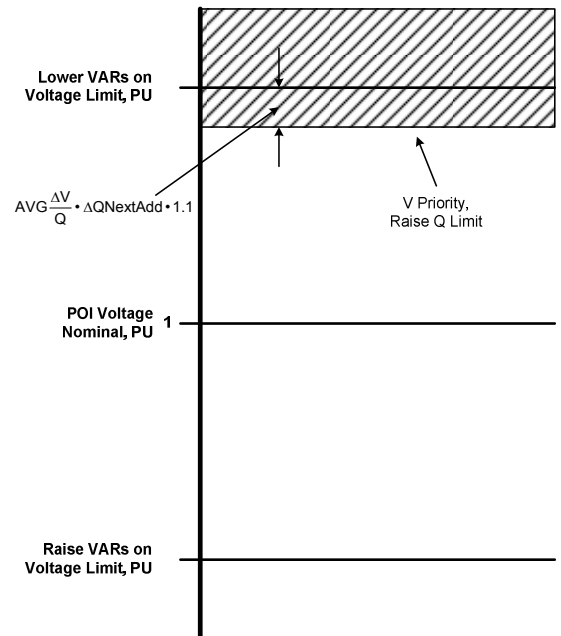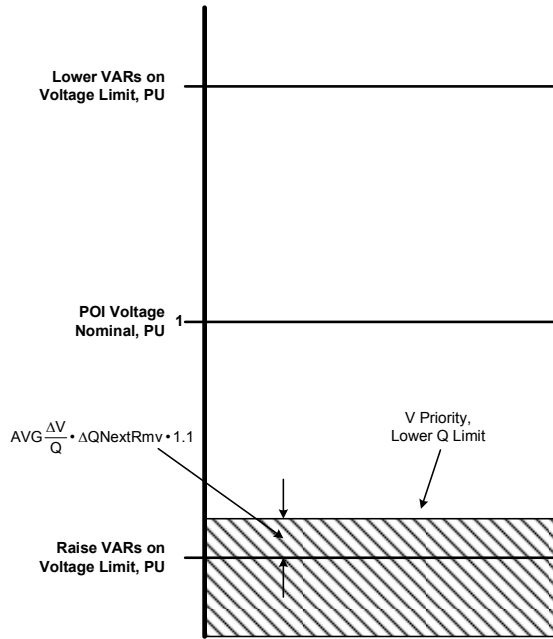| Control Function	Supervision Logic	Figure
Add capacitor or remove reactor on PF	But not if V > V priority raise Q limit	Fig. 3
Remove capacitor or add reactor on PF	But not if V < V priority lower Q limit	Fig. 4

Fig. 3.   V priority, raise VARs on Q blocking characteristic

Fig. 4. V priority, lower VARs on Q blocking characteristic

The regulation limit is offset by the average ΔV/Q from the most recent six switching operations multiplied by ΔQ next raise or ΔQ next lower multiplied by a margin of 1.1. The averaging function uses the previous six samples or, in cases where the CA controller has yet to issue six operations, the actual number of operations the controller has issued. See the average ΔV/ΔQ function discussion in the next subsection.

E. Average ΔV/ΔQ Function

Because the ΔV associated with each step is expected to vary based upon system conditions, the CA controller performs a learning function by recording the observed ΔV and ΔQ associated with each switching operation in two six-register first in, first out (FIFO) memory buffers and averages the ΔV/ΔQ for use by the V/Q priority logic. The memory buffers are reset to zero upon initial enable of automatic control. See Fig. 5 and Fig. 6.

Each ΔV that is recorded is divided by its corresponding ΔQ. The resulting ratio indicates the expected change in voltage per VAR to be added or removed from the system. These values are used in conjunction with the logic, as described in Section IV, Subsection D, to determine the upper and lower limits for switching operations based upon the expected ΔV resulting from a switching operation.
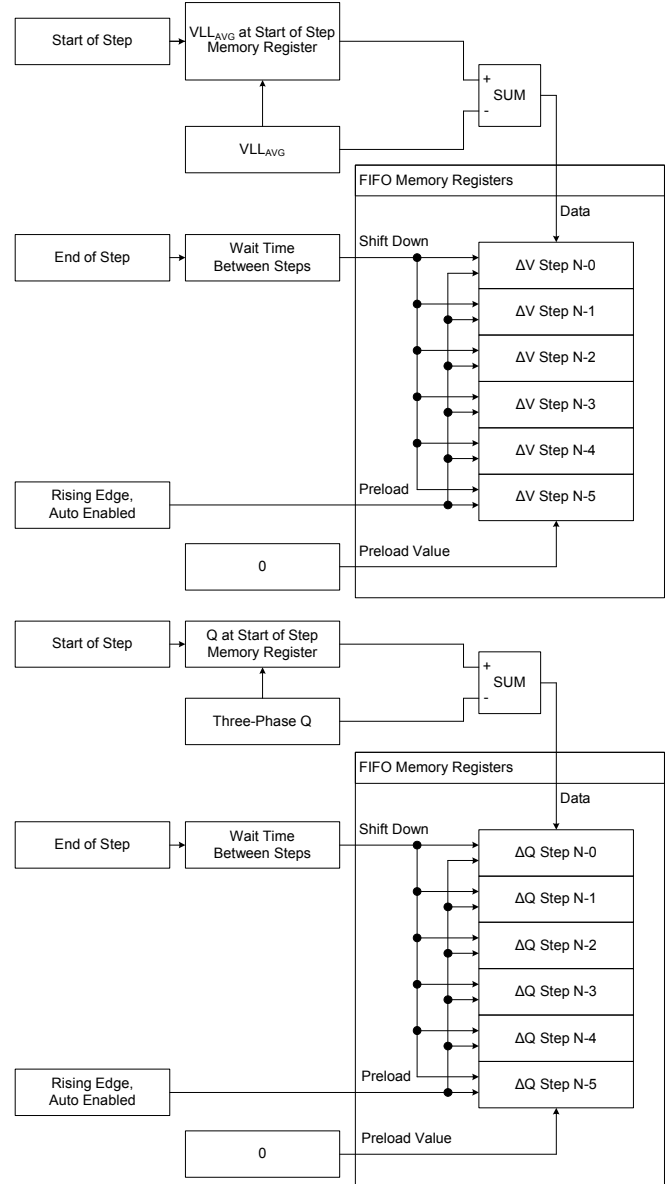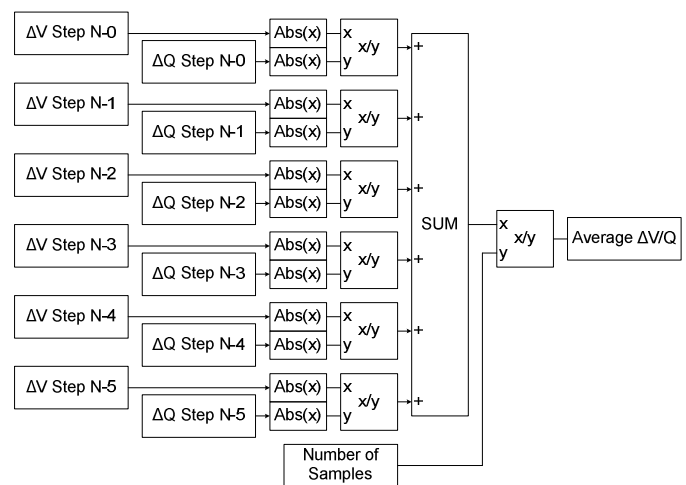

Fig. 5. FIFO memory

Fig. 6. Average ΔV/Q function

V. Automatic Switching Logic

The automatic switching logic handles routing of switching commands to the appropriate RPD relay and monitoring for alarm conditions. It includes logic to prevent both reactors and capacitors from being in service, to reduce losses in the step-up transformers, and to even out operations between RPD switching devices. The following subsections describe these functions in more detail.

A. Insert and Remove Process Logic

Fig. 7 shows the flow chart for the automatic switching logic. When the control parameters call for switching an RPD, the CA controller sends an add or remove command to the designated relay. The relay starts a timer to wait for the feedback input from the RPD breaker (the 52A contact). If the timer expires before the feedback input is detected, the relay sets a fail-to-open/close alarm for that RPD. The CA controller sees this input and proceeds on to the next RPD in the sequence.

When a single switching process ends (either by fail to open/close or successful operation), the time-between-steps timer delays the next step for a user-settable time. When the time-between-steps timer expires, the logic updates the ΔV and ΔQ registers and then checks to see if the condition that caused the switching operation has been satisfied.

The time-between-steps timer allows the LTC to adjust the bus voltage back inside its regulation band before measuring the ΔV and ΔQ from that switching operation. For example, if the switching operation raises the reactive power supply from that collector bus, the collector bus voltage will rise and the VAR supply will be temporarily higher (and therefore the POI voltage will be higher) compared with after the LTC lowers the collector bus voltage back down to its regulated level. If time is not allowed for the LTC to settle before measuring ΔV and ΔQ and the control parameter is still out of band, it is possible for the control interaction to cause hunting.

If the out-of-band condition still exists, then the sequencing process starts from the beginning without additional delay and a new RPD is added or removed. Otherwise, the CA controller stays active and waits for the voltage or power factor to go out of band to initiate another switching operation.
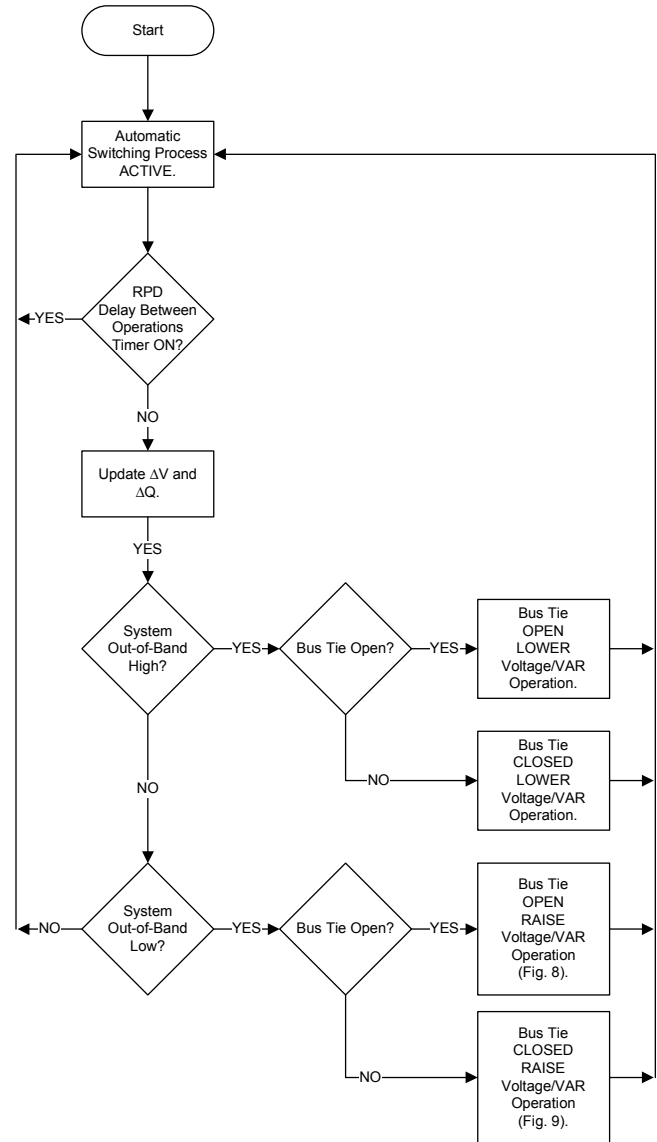

Fig. 7.   Automatic switching process flow chart

B. Sequencing Logic

The sequencing logic is an important feature of the controller. This function determines which RPD has the highest priority when multiple RPDs are available to switch. The reactor switching portions of the raise voltage/VAR flow charts are detailed in Fig. 8 and Fig. 9 to illustrate the concepts. The other flow charts are similar.

The controller considers the number of RPDs available on each bus and the operations counter value for each available RPD when selecting the next RPD to operate in an attempt to equalize the operations between switching devices. The sequencing algorithm also includes logic to optimize the VAR flow in each transformer when the collector system bus tie is open to reduce I^2R losses. To do this, the controller calculates the expected total apparent power (S) in the two banks if it sends the next switching command to an RPD on each bus. The scenario that results in the lowest total expected apparent power has priority. This reduces losses because S is directly proportional to I when the two transformers are bused together (V is equal) at the high side. To simplify the logic, it is assumed that any difference in R between the two transformers is relatively insignificant.

As seen in Fig. 7, the bus tie status determines which flow chart to use to select the RPD with the highest priority for switching. The sequencing algorithm includes logic to optimize the load flow power factor in each transformer when the collector system bus tie is open to reduce I^2R losses. If the bus tie is closed, active and reactive power flow divides evenly between the two transformers (assuming the impedances are similar), so there is no need to choose between RPDs on different collector buses.

Fig. 8 shows the flow chart for selecting which RPD to switch to raise voltage/VARs. When the tie is open, the controller first checks to see if there are reactors available to remove. If there are no reactors available, it looks to add a capacitor. If there is only one reactor available to remove, the controller removes it.
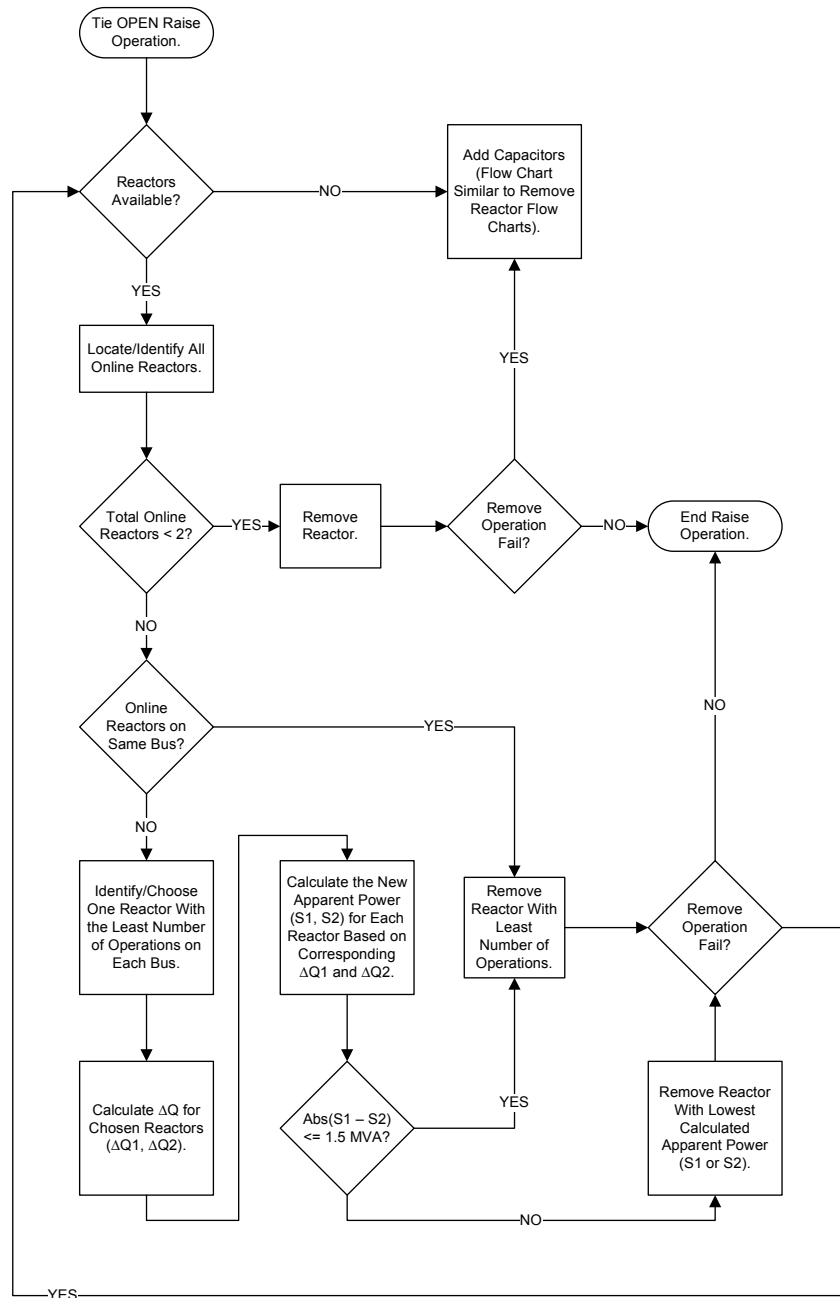

Fig. 8.   Bus tie open, raise voltage/VAR reactor switching flow chart

If there are multiple reactors available to remove, the controller checks to see if the reactors are on the same bus. If they are, it selects the reactor with the fewest operations to remove. This helps to even out the number of operations on the reactor breakers. If the reactors are on different buses, the controller calculates the expected ΔQ from removing a reactor on Bus 1 versus removing a reactor on Bus 2. From that, it can determine the expected apparent power flow in each transformer. If the apparent power flow difference between the two scenarios is insignificant (less than 1.5 MVA), the controller selects the reactor with the fewest operations. If the difference in apparent power flow is significant, the controller selects the reactor that will result in the optimal power factor through each transformer.

Fig. 9 shows the flow chart for selecting a reactor to remove when the bus tie is closed. In this case, the controller simply has to remove the reactor with the fewest operations.
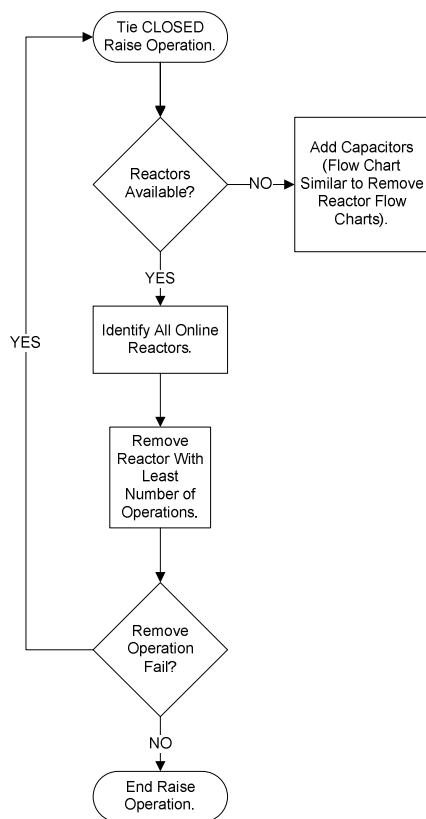

Fig. 9.   Bus tie closed, raise voltage/VAR reactor switching flow chart

VI. Static VAR Control With Dynamic VAR Control

While the majority of wind farms use a dynamic VAR control solution throughout normal operation, the static VAR control solution can complement the dynamic control solution by acting as a backup. In cases that the dynamic VAR control system should fail or be offline, the static control system takes over by automatically switching the capacitor and reactor banks according to the logic presented previously.

The dynamic VAR controls associated with doubly fed induction generators (Type 3 machines) and full converter generators (Type 4 machines) are able to control the VAR production or consumption of each generator in the wind farm dynamically and temporarily boost VAR supply up to 1.5 to 2 times the current limits of the power electronics during short circuits to aid ride-through capability. These systems can be centrally controlled or controlled on an individual basis. Static compensators also have the ability to dynamically boost VAR output to aid ride-through capability.

The total available VAR output from the wind farm is the collective contribution from each active static compensator and generator with dynamic capability within the system. As the wind farm nears its collective VAR limits, the dynamic VAR system can insert or remove capacitor or reactor banks as required, allowing each machine to back off of its respective limit and operate more comfortably within its VAR limits.

While the dynamic VAR controller is in operation, the static VAR controller can remain aware and continue to monitor the capacitor and reactor bank switching activity. As the dynamic VAR controller switches capacitor and reactor banks, the static system can continue to monitor and calculate the ΔV/VAR as well as the number of switching operations to which each capacitor and reactor bank has been subjected. The static controller uses the ΔV/VAR calculation and switching operations performed during dynamic operation to populate its learning algorithm. As the dynamic VAR controller becomes unavailable, the static VAR system can shift from standby to active and operate optimally immediately upon taking control.

The authors have encountered some dynamic VAR controllers that have a limitation. The dynamic VAR controller disables VAR production and consumption when the wind slows to a speed where the wind farm is unable to produce active power. The underground cable lines connected to the collector bus add a capacitive load, which affects the voltage at the collector bus. The static VAR controller was modified to include simple logic to identify when the wind farm was not producing power because of low wind speed and subsequently entering a mode of operation where it tried to maintain zero VAR flow at the POI. The resolution of control of the VAR flow in such cases is limited to the size of the capacitor and reactor banks. Large capacitor and reactor banks will produce large shifts in reactive power. As such, maintaining zero VAR flow at the intertie is often not achievable. However, such operation may be desired, or even required, by the transmission operator.

Coordinating dynamic VAR control with static VAR control presents many challenges. Dual control, if not coordinated properly, can result in the two control systems fighting each other as each controller tries to drive the system to potentially different set points. As such, in the absence of detailed investigation into the operational philosophy of the dynamic control system, it is best to leave the static control system in standby while the dynamic controller is in service. The static VAR controller is best suited as a low-cost backup controller in a system where a dynamic VAR control system can perform higher-resolution VAR control.

VII. Summary

Reactive power support for wind farms is critical to the successful integration of wind generation to the grid. The system this paper describes demonstrates a simple, centralized, and integrated system that can control a very large number of capacitor and reactor banks.

The system for this project is unique in that it can handle simultaneous regulation of both power factor and voltage at the point of utility interconnection. The system is in service on several wind farms and has been field proven to be a practical and useful solution using a central automation controller that manages communications and centralized logic processing all in one rugged device.

VIII. Reference

[1] M. Thompson and D. Kopf, "Reactive Power Control System for Wind Farm Application Using IEC 61850," proceedings of the 11th Annual Western Power Delivery Automation Conference, Spokane, WA, April 2009.

IX. Biographies

Michael J. Thompson received his BS, magna cum laude, from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in the SEL engineering services division, a senior member of the IEEE, a main committee member of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

Tony Martini received his BS from the University of Cincinnati in 1995. He has automation and control experience in manufacturing and power system operations. He joined Schweitzer Engineering Laboratories, Inc. in 2009 as an automation engineer in the engineering services division. He is a member of IEEE and IEEE PES.

Nicholas Seeley graduated from the University of Akron in 2002 with a BS in electrical engineering. After graduation, he began working at American Electric Power in Columbus, Ohio, for the station projects engineering group, where he focused on substation design work. In June 2004, he was hired at Schweitzer Engineering Laboratories, Inc. in the engineering services division as an automation engineer involved in the development, design, implementation, and commissioning of numerous control-based projects specifically geared towards power management solutions. He currently works as a lead power engineer in research and development, focusing on development of power system control solutions. He is a member of IEEE and IEEE IAS.