Experience and Use of FACTS

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Abstract: In the emerging competitive utility business environment, wholesale power wheeling has to be supported by the existing transmission systems. Flexible AC transmission system (FACTS) technologies offers much flexibility to the transmission operators for handling such new wheeling demands because FACTS systems can be installed in less than two years whereas a new line, if it can be built at all, sometimes takes 10 to 12 years for completion. Performance and cost information for the newly developed FACTS systems is however, lacking, which makes it difficult for planners to properly evaluate expansion alternatives. Therefore, a few systems have been installed in North America intended to provide such data. Also, several FACTS supported transmission systems are already in operation in the US. This paper will discuss the FACTS applications and the experience to date from the new system demonstrations.

Keywords: AC transmission, Power Electronics Applications, FACTS Technologies, Series Compensation, TCSC, Shunt Compensation, STATCOM, Voltage Source Converter, Unified Power Flow Controller, UPFC.

1. Origin of FACTS: The oil embargoes of 1974 and 1979 had a tremendous impact on the economies of the world. Prior to the first shock, the growth rate in the US for consumption of electric energy had been close to 6% per year. The increased energy cost wiped out about 5% of the US industrial asset base including a lot of the energy demanding steel production. Many of the electric utilities in the old “smoke stack” regions saw a negative growth rate. There were proposals for shifting power production from oil to coal with power plants located close to the coalmines, which are typically far from the load centers. There were also new demands for renewable energy sources. Tax and regulatory incentives were created to promote what now is referred to as “Green” power. However, also much higher efficiencies were sought for conventional power plants. The modern, high efficiency, combined cycle gas turbine power plants are largely a result of R&D initiated to meet this market need. It is the combination of the cheap natural gas and the efficient; low cost power plants that has made the deregulation of the electric power production possible.

In parallel with this, the environmental movement began to fight anything that looked or smelled like industrial facilities. This included transmission lines, which have become virtually impossible to build. At first it was the danger of electric fields and when this was proven to be a non-problem, it was the magnetic fields. Even this is probably a non-problem but it is still almost impossible to get permits for new high voltage transmission lines at least in the US. The permit process is so dragged out that it can take over 12 years to build a new line if it can be built at all. Although the new power plants are typically built in smaller sizes close to the loads, there is still a need to transfer more power over the existing lines. Power levels that often can be managed from the thermal line loading point of view but in the US, where the transmission distances are often quite long, can not be reliably transferred because of stability limits. This is the origin of FACTS.

The planning of what eventually became the EPRI FACTS initiative began in 1986. The need was known but how to address the needs with new technology was not quite as clear. The inspiration came from two publications. The first was a paper [1] authored by a team from GE. The paper showed that it might be possible to displace the oil generation in the Southern States by coal power from the States in the Midwest. The other was a comparison of HVdc with ac transmission [2]. The Department of Energy sponsored this study. However, the researchers working on the DOE study decided to look not just at what could be achieved by means of HVdc transmission but also at how far ac transmission could be pushed by heavy use of shunt and series compensation. In both of these studies, the conclusion was that existing ac transmission lines typically could carry much more power before they would be thermally limited. Although in both of the studies, it was assumed that existing compensation system technologies could be used to increase the loading of ac lines, it was clear that cost reductions of these systems would be desirable. It was also clear that the duty cycle limits for electromechanical systems could be a limiting factor, because the compensation would have to be adjusted fairly frequently to match line loads. Thus, power semiconductor based equipment would be preferable. Furthermore, to make the power flow through the desirable paths would require power flow control technology, which was not really available at the time. This is really what the FACTS initiative was supposed to accomplish and has accomplished today.

Line compensation in the past has primarily been for reactive power management. Switched or fixed shunt capacitors and reactors as well as series capacitors are typically applied. Synchronous condensers have also been used and continues to be used where dynamic voltage control is needed. In the 70's, the static-var compensators (SVC) began to be applied. The first of these was the EPRI-Minnesota Power & Light and Westinghouse project commissioned in 1978. Prior to this, SVC systems had been applied for voltage control or flicker control primarily at locations with heavy industrial loads but not for transmission system stabilization. The system installed by MP&L at the Shannon substation would enable an 80 MW increase (from 320 to 400 MW) in the power from Manitoba to Minnesota [3]. This installation consists of a 45 MVA thyristor controlled reactor (TCR), a 10 MVA filter and two switched 36 MVA shunt capacitor banks connected to the 230 kV bus. This was followed by a small number of other similar SVC installations in the US. The first installation of thyristor switched capacitors was an ABB built system for voltage control around Wichita, Kansas. This was the state of the art in the industry when the FACTS projects were being planned.

2. FACTS – The missing elements: Power flows in a transmission system can be very complex. In many systems the power overloads the weaker and thermally limited lines while other lines are operating far from their thermal limits. This can happen where a high voltage line is overbuilt (in parallel with) a lower voltage line. The power does not necessarily follow the contract path but is distributed on all lines in the system. Load balancing is often desirable and can most effectively be accomplished using phase angle and impedance control. However, in highly stressed systems, conventional electro-mechanically controlled systems would see severe duty cycles and also for stability reasons, fast acting controllers would be needed. Therefore, power flow controllers were identified for development.

The amount of compensation is easily determined for steady state operation. However, when the dynamics of the system is considered, the speed of response, the behavior of the system during over and undervoltage, during and after short circuit events is important. Other performance characteristics such as the dynamic behavior of the loads have a big impact on the required compensation, too. Also, the performance of the control systems used for the compensation equipment itself is a factor to consider. In addition, when several FACTS controllers, power system stabilizers and voltage control systems on generators have to be coordinated, possibilities for undesirable interactions are numerous. There was and still is today not much experience with optimizing the system performance when many high speed controllable devices or systems are distributed throughout the transmission system. This was identified as an area in need of further work.

Before high levels of compensation were applied to transmission systems, the voltage would droop noticeable with increased power flows. However, in heavily compensated systems. The voltage profile is much flatter and therefore there is almost no warning prior to reaching the point of voltage collapse. Thus voltage stability has to be continuously monitored to ensure that the system is kept at an operating point which remains stable after a disturbance. Some of these aspects have been treated in [4].

Finally, power electronic equipment is relatively costly and has lower efficiency than conventional electro-mechanically controlled equipment. Cost reduction and efficiency improvements were therefore identified as desirable technology enhancements.

3. FACTS Controlled Systems: The premise for application of FACTS systems is that at an increased load level, the transmission system is operating with the same level of reliability and security as before the FACTS systems were installed and the system was stressed at a lower load level. Basically this implies that the joint probability for failure of the transmission system and a FACTS controller is negligibly small [5]. However, design and operation of transmission systems operating under contingency conditions up to the thermal limit is without precedence. The EPRI program addressed this in many different ways [6]. The program addresses thermal modeling of transmission corridors [7] and a number of FACTS studies [8] have been conducted, some of which are summarized in [5]. New study tools had to be developed to model FACTS systems before interactions between FACTS controllers and other components of the power system could be studied [8]. These developments can be described as enabling technologies, which are needed before FACTS controllers can be applied with confidence.

The design of the control system for a FACTS controller can have a significant impact on the cost of the system. There is a trade-off between how well the controls work and the size of the main circuit equipment. [10]. A new control concept was first implemented on the Chester SVC system installed in a 345 kV line between the Boston area and New Brunswick, Canada [11]. This system consists of a 163 MVA TCR, three 121 MVA TSC and two filter banks for 5th and 7th harmonics. The filters account for 31 MVA. The system was needed to keep the 345 kV line and the generators connected to this line in operation if the 2000 MW HVdc link from Canada to Boston was lost. The addition of a fast response Supplemental Modulation Control function made it possible to handle first swing stability with a smaller SVC system at some considerable cost saving. Another control function was also added to prevent undesirable subsynchronous interactions (SSI) between the SVC and nearby generators. (SSI is a normally of special concern where series capacitors are installed but can also be a problem where there is a high gain control loop operating close to the subsynchronous frequencies.) The control systems know-how is advancing through research and from experience with actual installations. However, each installation is unique and requires individual tuning of the control system for best overall performance of the power system. Although the knowledge about how to tune the controllers is spreading, it is still an area where experience is limited with a few, highly qualified experts doing most of the design work. More work to simplify the control system design is needed.

4. **New FACTS Controllers**: Consider that. $\Delta P = -\frac{\Delta X}{X}P + \frac{\Delta \phi}{tg\phi}P + \frac{\Delta V}{V}P$

From this it is obvious that at high power levels, a small change in impedance produces a proportional change in power. For low transmission angles (normally associated with low power levels) the change in power from a small angle change can be substantial. Voltage changes can also produce significant power changes but voltages normally have to be kept within narrow boundaries (5 to 10 % depending on load levels is what equipment standards typically allow) and is therefore in general not a practical tool for power flow control. Therefore, it is obvious that two different types of power flow control equipment should be used. One that works on controlling the line impedance and the other controlling the angle. However, as will be discussed later, the unified power flow controller (UPFC) can be used to control all of the variables and is therefore the most versatile of the FACTS controllers.

4.1 Series compensation: Series capacitors have been used since the 1940's for compensation of long distance transmission lines. Most of the installations in the US are found in the Western States because this is a region with long distances between the generating plants and the load centers. However, a result of the subsynchronous resonance (SSR) in the early 1970's between a generator and series compensated lines in the Southwestern US, aggressive use of series capacitors have not been applied in regions with large steam turbine power plants. Also no series capacitor installations were used outside the Western States in the US until AEP installed a bank at Kawana River in West Virginia in the early 90's. A precursor to FACTS was in fact a thyristor controlled SSR-damping system, which was installed in the early 80's for trial operation at Victorville in Southern California Edison's system. This was the so-called NGH SSR damping system invented by Dr. Hingorani. In spite of this, impedance control using series capacitors is a powerful method for controlling power flows in a heavily loaded system. There are two thyristor controlled and one thyristor switched series compensation system demonstrations in the US.

4.1.1 Kawana River: The first to be put into operation in 1991 was the ABB built thyristor bypass switch of one phase and one segment of AEP's Kawana River series capacitor banks. The Kawana River system is rated 788 MVA, 2500 A comprising three banks 7, 14 and 21 Ω. The 110-mile long 345 kV line can be compensated from 0 to 60 % in steps of 10% [12]. The series capacitor bank is needed to prevent overloading of the line and a parallel 138 kV line in case of the loss of a major 765 kV line. The site provided a good demonstration bed for the thyristor switched series capacitor technology.

The thyristor switch uses a total of 24 thyristors and is rated for 3750 A and 26.25 kV for 10 minutes, which for semiconductor devices from the thermal point of view is the same as continuos operation. The thyristors were tested for peak currents up to 34 kA, which is roughly equal to a fully offset 12 kA_{RMS} fault current. However, the thyristors could see a peak current of up to 70 kA for faults close to the installation. The system, which now has been decommissioned as planned because the tests are complete, has operated well. Critical design issues for this system has been:

a) The thyristor housing is freestanding and can be removed from service for access by opening a two-pole disconnect switch between the capacitor bank and the switch. When closing the disconnect switch with the capacitor bank in operation, a transient with a rise time in the 100 to 200 ns range will be seen by the thyristors. The switch has been designed and tested to handle such surges without problems.

b) Discharging the capacitor by firing the switch when the MOVs are conducting will lead to high di/dt stresses in the thyristors. For this reason a small reactor (about 0.4 mH) is used to limit the current rate of rise in the thyristors.

If all three phases of the bank had been equipped with thyristor switches, the bank could have been used for damping of power system swings by means of a bang-bang control concept. In theory, one phase could also have been switched for this effect but with a smaller gain.

4.1.2. Kayenta: The second installation, WAPA's Kayenta system, was the first thyristor controlled series capacitor (TCSC) system. This was supplied by Siemens and commissioned in 1992. This is a part of a 330 MVA series capacitor bank installed at approximately the mid-point of a 320-km long 230 kV line. The purpose of this installation is to improve the loading of the line and to provide voltage support to the Kayenta 230 kV bus. The thyristor controlled series compensation system is shown in Figure1. The 15 Ω segment of this installation is nominally rated 45 MVA but the thyristor valve has a one minute rating of 1890 A_{RMS} at 36 kV_{PEAK}, which is equal to 48 MVA per valve [13]. This determines the steady state thermal and voltage rating of the thyristor valves. The short circuit current rating is 12 $kA_{CREST,}$ which actually determines the current rating of the thyristors themselves. The maximum short circuit current is 6.9 kA and is expected to increase to 7.6 kA_{RMS} in the future. It is of interest to note that the one minute rating of the TCSC portion of the bank is 1700 A, whereas the rest of the system is rated 1500 A. That is, the added duty of the capacitors from the continuous thyristor switching is considered in the rating.

The Kayenta system is also built for modulation as a series reactor. The reactance at 90-degree firing angle is about 3.1 Ω inductive. The equivalent reactance can be increased by delaying the firing beyond 90 degree up to a limit set by the voltage limits of the capacitors and the switch. In this operation mode, the TCSC can be used to buck power flows and as a fault current limiter.

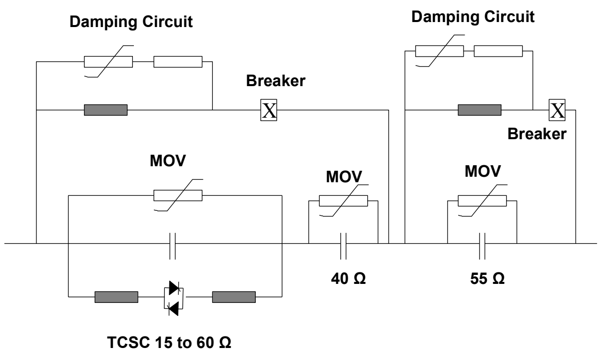


Figure 1. Kayenta TCSC

The operation of the Kayenta series compensation system is coordinated with the setting of a phase angle regulator (PAR) at one end of the line. The TCSC portion can be controlled to increase the power flows on the line by up to 40 MW continuously or 60 MW for 10 minutes. It will be able to reduce or remove the inadvertent flows on parallel lines. Initially the TCSC will be controlled either in a constant impedance or a constant current control mode. In the constant current mode, the power flow will be relatively constant because the voltages are relatively unchanged during power swings. This means that the power flow in theory can be scheduled to match a contractual obligation. Note that a constant power mode may destabilize the ac system because if will reduce the synchronizing power transmitted through the line during disturbances. However, supplemental control signals for system damping have been anticipated in the design so the undesirable feature of a constant current mode may be avoided trough the supplementary controls.

Of particular interest is the performance of the TCSC in the subsynchronous frequency regime. It is noteworthy that the TCSC while appearing as a capacitor for 60 Hz frequencies looks like an inductor with a firing angle less than about 160 degrees. Thus, the TCSC can not by itself cause SSR and can help alleviate the risk for SSR from the conventional series capacitor banks, too. This assumes that the control system is designed properly so that it does not cause SSI.

The operating experience has been good [14]. The TCSC system is typically operating in the vernier mode with an impedance setting of about 18 to 20 ohms. During an outage of the PAR some of the control functions for which the PAR was used, were handled by the TCSC. That is, to some degree, the TCSC serves as a back up for the PAR. The site has no auxiliary power supply from the outside. Experience has shown that a local source of auxiliary power such as a diesel or UPS system, would be desirable to keep the system operating under low current conditions because the auxiliary power at the valve levels is derived from the line current. Therefore, under low current operation of the line there is insufficient power for control of the thyristors. Complete loss of auxiliary power to the Kayenta station has also occurred due to faults on the line. Loss of cooling to the thyristors resulted from this event. However, this is not an uncommon problem in very remote areas without any access to local generation and where low current operation is required, voltage transformers can be used to provide auxiliary power.

4.1.3 Slatt: Figure 2 shows the second TCSC system to be commissioned. It is the EPRI/BPA/GE system that was installed at BPA's Slatt substation in Oregon and put into operation in 1993. The major differences between Slatt and Kayenta are found in the short circuit current duty, modularity and voltage ratings. Slatt is installed in a high short circuit capacity (20.3 kA_{RMS}; maximum crest fault current equal to 60 kA) 500 kV system. It is an 8 Ω bank, rated 2900 A, divided into six modules of 1.33 Ω. However, the continuos rating with the thyristors operating is 9.2 Ω or 1.53 Ω per module. The 30-minute current rating is 1.5 p.u. and the 10-second current rating is 2 p.u. That is, the 202 MVA bank can deliver over 800 MVA for 10 s. The 30-minute impedance rating at 1.0 p.u. current is 12 Ω and the 10-s rating also at 1 p.u. current is 16 Ω. A protective by-pass of the capacitors are ordered if the current reaches 10.7 kA. The reasoning behind this specification is that maximum compensation of the line is needed for maintaining transient stability of two systems during the first swing in a disturbed system. This is when the current will be the highest. Also, by dividing the TCSC in several series segment, the control range approximates a continuos function from a small inductive impedance to full capacitive compensation when all modules are inserted with maximum vernier control. This minimized the installed capacitance of the system.

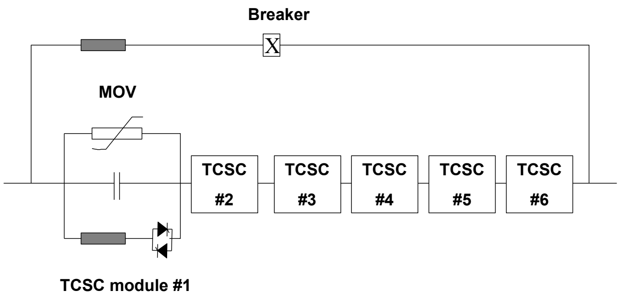


Figure 2. Slatt TCSC

Slatt is equipped with control features for damping and transient stability improvements as well as for SSR damping. All of the functions were tested in staged tests to the degree this was possible before putting the system into commercial operation early 1995. Staged fault tests were probably the most severe for the TCSC equipment itself because faults on the line side of the TCSC puts the 500 kV bus voltage across the bank. Very steep front surges will be impressed upon the thyristors. Although a few thyristors are reported to have failed in these tests, the performance was remarkably good.

The operating experience from Slatt is skewed because the system is not absolutely needed for operation of the transmission system of the Northwest [15]. Thus, the priority for maintenance, troubleshooting and repair of the TCSC has been low and extended outages have therefore been experienced. The need for quick maintenance has been reduced because the modularity of the Slatt system has enabled partial system operation. In the same situation a single module system would have been bypassed and completely out of service. The TCSC has not been connected to the SCADA system and can therefore not be operated as intended in the design. Some teething problems have been noted, too. As for most other systems, leaks in the cooling system has been experienced. Also, some corrosion because of the water-glycol mixture, have been corrected. Corrosion of coaxial cable connectors has also been seen. Also, fiberoptic cable connectors became submerged in water and this lead to weak signals between the platform and ground that caused some thyristors failures. However, these problems, which are the result of having outdoor installations instead of an indoor valve hall, are relatively minor most have been corrected. The lessons learnt form the demonstrations can readily be incorporated into any future system.

Because the auxiliary power for the thyristor control on the platform is derived from current transformers, poor firing of the thyristors was seen below about 400 A. This is similar to the experience of Kayenta. Power from ground level may be required for low current operation.

In the Slatt system, there is no other series capacitor bank in the circuit. It was discovered that a small unbalance in the firing of the two halves of a cycle will lead to a dc offset, which caused some problems with adjacent transformers. This is similar to what will be seen from geomagnetically induced currents. The other demonstration systems had all other series capacitor banks which effectively blocks any dc flow. The solution to this problem could be simply to have one of the capacitor segments inserted continuously. That is, with the thyristor switch in the non-conducting state.

4.1.4 TCSC Modularity: The question often arises as to how many modules that is the optimum. The answer depends on the application. Consider that the capacitor required for the lowest compensation impedance is as follows:

$C_{module} = \frac{N}{\omega X_{min}}$ Where N is the number of modules used in the bank. But the maximum voltage per module limits the current as is shown in Figure 3. The voltage at the highest current for the maximum compensation (high vernier angle) as follows:

$V_{C,\max} = I_{\max} f(angle) \frac{N}{\omega C_{module}}$ Therefore, the rating of the total installed capacitor will be:

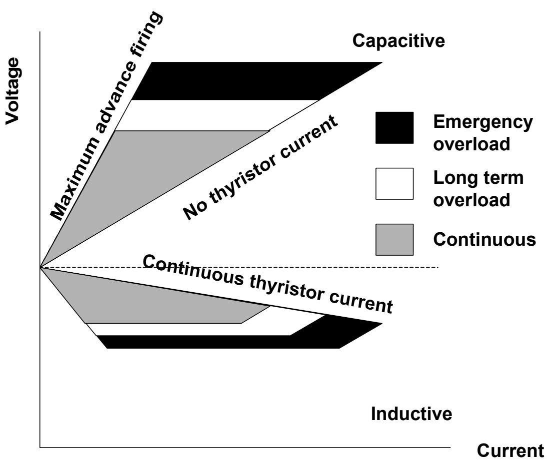


Figure 3. Typical TCSC V-I Characterisitc

$$S_{Capacitor} = I_{\max} V_{\max} = \frac{\omega C_{module} (V_{C,\max})^2}{N \bullet f(angle)}$$ Per phase.

Thus, if the control range is large as shown in Figure 4, a modularity of the type used in the Slatt system should lead to the lowest cost. If the control range is small or if the current is reduced at higher levels of compensation, a single module as is used for Keyenta would have the lowest cost. Also, if a system is used for improvement of the transient stability only, in which case the duty is short bursts of high compensation, a single module will also lead to the lowest cost. This will be the case in radial transmission system where there is no need to balance the load between parallel paths. From this it should be clear that the system performance requirements ultimately determines the optimum modularity for any give application.

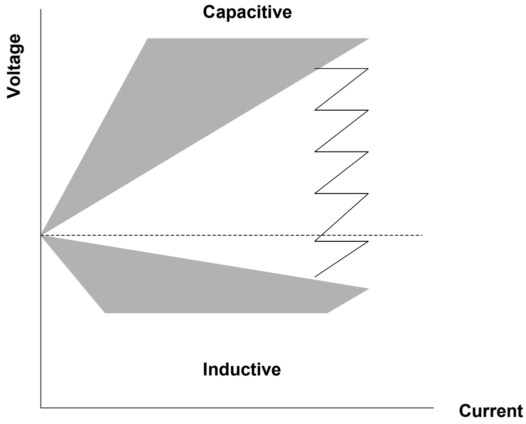


Figure 4. Six Module TCSC V-I Characterisitc

4.1.5 Other Design Aspects: The coordination of the mechanical by-pass breaker with the thyristors is a critical design problem. If the mechanical bypass breaker is closed at the peak of a fault current circulating in the thyristor/reactor leg of the circuit, the current will continue with very little attenuation for a long time through the short circuit created through the bypass breaker. This can be the worst case operating point for the thyristors from the thermal point of view. Where there is a capacitor segment in the bypass branch, the current will die down quickly but in Slatt, it can take a very long time for this circulating current to die out.

Trapped charge in the capacitors when transferring from a thyristor bypass mode to insertion of the capacitor segment has been dealt with in the design of all three systems by using controlled firing of the thyristors to eliminate the offset. If this were not done, it could lead to high voltage stresses on the thyristors.

The general conclusion to be drawn from the operating experience of all three prototype installations is that trial operation in a realistic but possible not overly critical application pays off for any new technology. The problems, which have been found, have for the most part been associated with conventional equipment. However, a few design problems related to the new power electronic system application have also been uncovered. Most of these are not critical in the test systems and can easily be changed in any future system. It is also noteworthy that none of the installations required any harmonic filters. The harmonics are relatively well confined to the TCSC system itself. The demonstrations have lead to proven technology from three different suppliers.

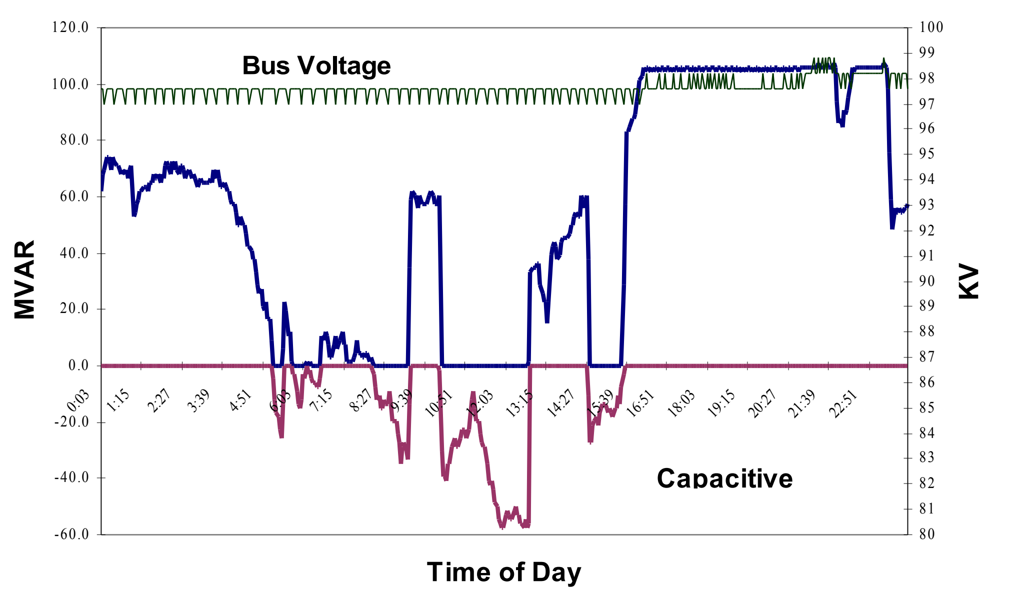
4.2 New Shunt Compensation System: Voltage source inverters (VSI) has generated a lot of interest for power system applications. This spans from power conditioning for new energy sources or storage systems to reactive power compensation and active filters. Such systems would overcome the limitations of shunt capacitors and reactors, which are basically constant impedances when operating at full capacity. The VSI based systems behave like constant current sources at the limits. Cost and losses seemed to be insurmountable barriers to commercialization. However, some breakthroughs in circuit topology[1] and a better understanding of the performance differences between "conventional" SVC systems and the

[1] Bill McMurray, retired from GE, first proposed the new topology that enabled the use of relatively standard transformers of the type typically used for conventional SVC equipment.

new VSI based systems, hereinafter referred to as STATCOM for static compensator, have brought the costs down to a level where they can be competitive [16].

The EPRI/TVA/Westinghouse STATCOM demonstration is the first application of this new topology [17]. The development of this system was begun early 1992 with the objective of

Figure 5. STATCOM Data for 9/10/97



producing a ±60 Mvar STATCOM but was shortly thereafter increased to ±100 Mvar. It was commissioned in 1995. The VSI used for the system is a two level, 48-pulse design equivalent to eight 6-pulse converters.

The Sullivan substation in TVA’s system is a relatively weak station on the fringes of TVA’s system. It has a 1200 MVA transformer feeding a 161 kV bus. The 100 MVA STATCOM postpones the need for installing another transformer or construction on an additional 161 kV line. Another benefit is that it will allow for control of the 161 kV bus voltage with fewer operations of the LTC on the transformers. LTC failure is a leading cause of failure of large transformers so it is expected that the STATCOM installation will reduce the risk of failure in the transformer bank. A typical operating profile is shown in Figure 5.

The STATCOM controls the operation of a 84 MVA shunt capacitor bank also connected to the161 kV bus. This explains the steps in the reactive power output. During light loads at night, the STATCOM is operating at full inductive output. The system has been tested for contingency conditions. One of these is an outage of the 1200 MVA transformer. The system has passed all of the tests.

The system has met the expectations on performance. Some nuisance trips from the control logic have been reported but such “bugs” are not unusual in any new design.. This points to the need for incorporating good audit trail functions in digital control and protection equipment so that “bugs” can be quickly identified and corrected.

4.3 Combined series and shunt compensation: A concept for combining VSI converters into a unified power flow controller (UPFC) was studied by Westinghouse with WAPA and EPRI funding [18]. The system, shown in Figure 6, uses one shunt connected VSI and one connected in series with the line for control of active and reactive power flows through the line. The two converters are connected to a common dc bus. However, for the UPFC to have independent control of active and reactive power flows, at least one of the two converters must be a multilevel or pulse width modulated converter with the ability to synthesize an ac voltage with any desirable magnitude and phase. Such a system rated 2x160 MVA at 138 kV has been procured by AEP. The UPFC is a part of a 32-mile high capacity 138 kV double circuit (950 MVA) transmission system reinforcement [20]. The UPFC portion was developed by Westinghouse with AEP/EPRI sponsorship. Three level converters operating as one 48-pulse system have been used in the system installed at Inez in Kentucky. The UPFC has been built so that the two inverters can operate independent of each other as two shunt connected 160 MVA STATCOM systems. The spare 138 kV shunt transformer will then be used instead of the series transformer. The series transformer is rated for 16% of the phase to neutral voltage. The system was commissioned in June 1998 [19]. The system has not been in operation sufficiently long for any meaningful operating information to be available.

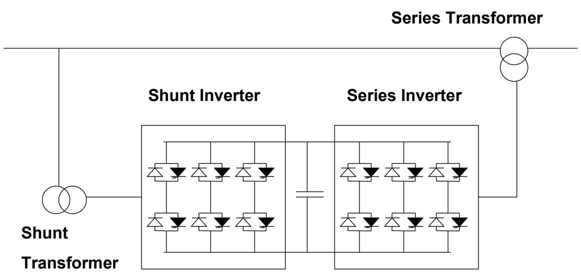


Figure 6. Unified Power Flow Controller

A stretch application of the UPFC technology has been announced by Westinghouse and NYPA [21]. The application, as shown in Figure 7, is for balancing of the loading on two parallel lines using two VSI converters. One is connected in series in one line and the other in the second, parallel line with the dc link in common. This makes it possible to load each line to the optimum operating point. That is, the loading does not have to be equal but could be a desirable ratio with consideration of efficiency and thermal limits of each line. This concept could be used also for routing power from one incoming and one outgoing line through a substation. That is, it could make it possible to schedule power to follow a contract path if this were a requirement.

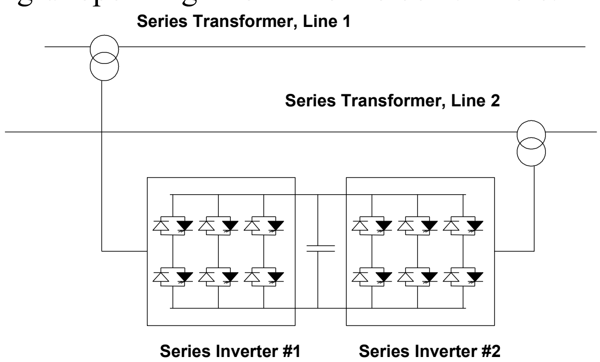


Figure 7. In-Line Power Flow Controller

5. Other FACTS supported transmissions systems: In addition to the Chester system described above, there are three significant FACTS supported ac systems in the US.

5.1 Pacific Northwest: The Pacific Northwest (Seattle, Washington and Portland, Oregon areas) has low voltage stability margins. To alleviate this, two large SVC systems were installed. Each of these consists of 2x175 MVA TCR, 2x150 MVA TSC and 50 MVA in harmonic filters. They are installed in key 230 kV substations (Keeler and Maple Valley).

5.2 Minnesota-Manitoba: The 500 kV lines from the Minneapolis St. Paul area in Minnesota to Winnipeg Canada are used for excahnge of power from the Manitoba Hydro system to the US. A new 500 kV line was under consideration to increase the transfer capability of the line but instead a lower cost FACTS-type system, as shown in Figure 8, was chosen. This included series compensation of the 500 kV ac line and installation of a SVC in the Forbes substation, about a third of the distance from Minneapolis to Winnipeg. The system increased the transfer capability from about 1500 MW to 1975 MW from Manitoba to Minneapolis. This is close to 500 MW. It also increased the transfer limit northward by about 300 MW. This power is carried on the shown 500 kV line with two 230 kV lines in parallel. He system uses independent pole operation for fault clearing of single phase faults, which improves the availability of the system.

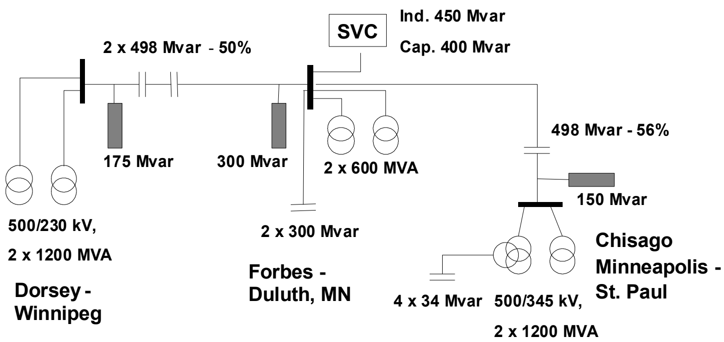


Figure 8. Winnipeg - Twin Cities FACTS Application

The compensation systems were installed to exploit seasonal power diversity between the two regions. The total cost of the project was close to $100M or about $200/kW. Although a new 500 kV line would have increased the power transfer capability above the 1975 MW limit, the extra capacity would not have been used and the cost would have been closer to $250M for the line alternative. That is, the cost saving was about 60% when compared with the line alternative.

The ABB supplied Forbes SVC system is unique because the steady state capability is from 110 MVA capacitive to 190 MVA inductive. However, as is shown in Figure 9, the inductive compensation is switched and not controlled. Thus, the adjustment of the inductive compensation is accomplished by switching of capacitor banks. As can be seen in Figure 10,

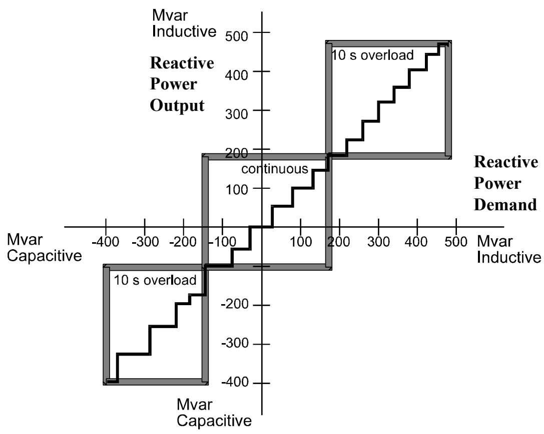


Figure 9. Switching Steps of Forbes SVC System

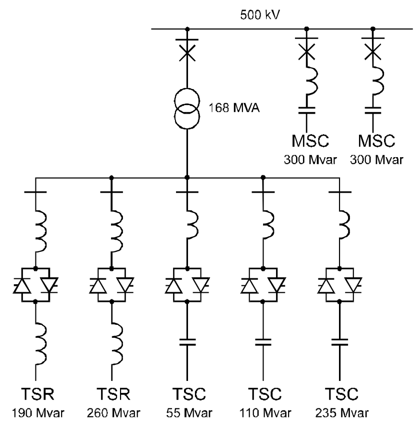


Figure 10 Forbes SVC System - One Line Diagram

there are also a 260 MVA reactor and a 235 MVA TSC with a 10-second rating. For transient stability purposes, the SVC has a controlled range between 400 MVA capacitive to 450 MVA inductive stepwise adjustable.

5.3 Phoenix – Los Angeles: The third FACTS line, shown in Figure 11, is a 500 kV line from Phoenix, Arizona, via Lake Mead to Adelanto, one of the major receiving stations for

Los Angeles. The 260 mile line from Phoenix to Mead has 70% series compensation (2x276 MVA), an183 MVA shunt reactor at each end of the line and two 500 kV, 650 MVA PARs in parallel at the Phoenix end of the line. The PARs are built to advance the angle for the line by up to 16 degrees. Without these, the power would flow on other existing parallel lines. The 202-mile line to Adelanto from Mead has 45 % series compensation, a 175 MVA shunt reactor at each end of the line, and a 375 MVA SVC at the Adelanto bus. A 375 MVA SVC is also located at the Marketplace station, which is close to Mead. The SVC systems, which were supplied by Siemens-GE are each comprised of two 155 MVA and one 78 MVA TSC modules. When this project was planned, none of the newer FACTS controllers were available.

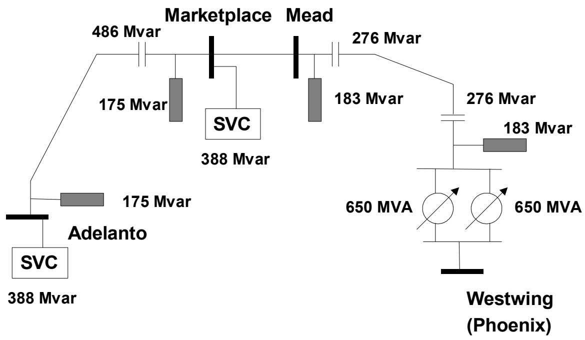


Figure 11. Phoenix-MeadAdelanto FACTS Application

The system would go out of step on the second swing for the worst case fault in the system. The critical damping for the pre-project system was 1.3% under heavy winter load conditions. With the SVCs and an increased loading from 5,700 to 7,000 MW into Southern California, the damping was expected to be 2.7%. However, with the addition of a supplemental damping control (similar to Chester), the damping was increased to over 10%. This is another example of benefits from the use of powerful control systems.

These systems are examples of what can be accomplished by using conventional and FACTS technologies in combination. Similar applications are found in the Hydro Quebec system in Canada. It is of interest to note that the first commercial application of TCSC will be in Brazil, where they are going to be used in combination with conventional series capacitor equipment on a new, long (1017 km) 500 kV transmission system. This application appears to be one where the TCSC systems are used for damping and transient stability enhancements.

6. Future FACTS Systems: Most of the FACTS controllers envisioned in the early stages of the developments have been built and demonstrated except the thyristor controlled phase angle regulator (TCPAR). The TCPAR appears to be cost effective in systems where the angle across a line section is small [22]. It could also be suitable where there is a need to buck power under normal conditions but for transient stability, a quick boost could save the system. The concept is in fact being developed and applied for voltage control in distribution systems but has not yet found application in a transmission application.

7. Concerns about FACTS: The FACTS concept is often misunderstood. The cost of FACTS systems, losses and reliability are areas of concern and it is easy to understand the reasons for such concerns..

Most likely, conventional reactive power compensation technologies are going to be the lowest cost solution for moderately compensated lines. That is, where the power flow increase is moderate and where there are no dynamic or duty cycle concerns. As is seen from the examples above and as is shown in Figure 12,

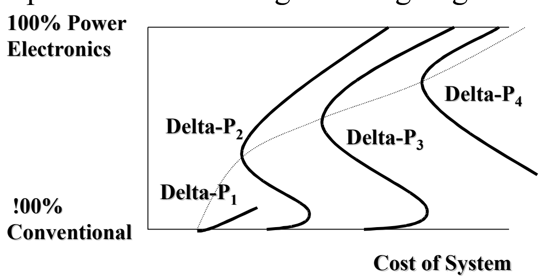


Figure 12. Economics of Power Electronics

sometimes a mix of conventional and FACTS systems has the lowest cost. This is probably because a FACTS solution will allow a line to be operated at larger angles than if only conventional compensation systems are used because the FACTS system can be overloaded for transient stability enhancement and can be controlled to improve the system damping. Sometimes, as is shown in the figure, there is no solution using conventional compensation technology for the increased power transfers. In that case, one or more new lines may be needed. This makes it hard for planners because the number of options has increased dramatically and it may be difficult to find the optimum (minimum cost) solution. However, in the deregulated environment of today, short term planning horizons and quick payback on investments will probably make new lines less attractive and FACTS and other similar options most attractive. Therefore, it is important to understand the cost and performance attributes of all of the available options so that the most competitive solution can be applied.

Losses will increase with higher line loading and FACTS equipment is more lossy than conventional compensation systems. The increased losses are a cost to consider but the annual cost of losses is typically much lower than the annual capital carrying charge for a new line. Since the transmission system owners are no longer in control of power plant siting decisions, there is no guarantee that a new line will be useful for the time it takes to make the investment pay off. Thus, it can be better use of capital to install compensation equipment, including the more costly FACTS systems than to build a new line. Such systems can be installed in about two years whereas construction of a new line can take a long time. The FACTS solution can bring in revenues much earlier that what would be possible if a new line were to be constructed. This should also be included in the equation.

Reliability and security issues are of concern when the system is loaded beyond the limits where our experience base stops. Consider then that there have been several noticeable power system disturbances in the US in the last several years. Some of these have been the result of unusual loading conditions and possibly some deferred system maintenance. Communication problems may also have been a contributing factor. Incorrect operation of relays has also been mentioned as a contributing factor in some of the outages but FACTS systems have not been reported to have been the cause of any of the problems. It is important to remember that a transmission expansion decision is really about different solutions to a problem. All of the choices entail some risk. However, our ability to deal with complex designs is remarkably good and relatively accurate risk assessments can be made. The HVdc technology has broken new ground in reliability based designs beginning in the mid-60s with the Pacific HVdc Intertie Project. The experience from HVdc systems has taught us how to build reliable transmission systems and the lessons learnt have been applied to ac systems in many areas with good results. Although it is an area of concern it should not prevent rational decision making in the presence of risks. The demonstration projects have shown that the risks are manageable because the demonstrations have been using a one-time-through design strategy with success.

8. Conclusions: There are quite a number of commercially operating, FACTS based transmission systems in the US. Where FACTS type transmission lines have been put into service, the experience is good. Also, several new FACTS systems have gone through many years of trial operation in the US. These systems have met the expectations and the demonstrations, as expected, have proven to be valuable in identifying some relatively minor design problems. Since the systems are not critical to the operation of the transmission system, the speed with which problems have been corrected have not been up to the requirements for commercially operating systems. However, that is the nature of prototype demonstrations. The real result is that systems can now be specified with confidence because the lessons from the demonstrations can be applied in any new system specification. Procurements can be made knowing that there will be no major problems with future commercial deliveries.

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