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Evaluation of Voltage Instability Countermeasures in Constrained Sub-transmission Power Networks

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Evaluation of Voltage Instability Countermeasures in Constrained Sub-transmission Power Networks

by

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Abstract

This paper investigates the various parameters that affect voltage stability in sub-transmission power networks. The paper first looks at contributions from equipment: generators, transmission lines, transformers, capacitors, SVCs and STATCOMs. The paper also looks at the effects of loads on voltage stability. Power flow solutions, PV and VQ curves are covered. The study models an existing voltage problem i.e., a long, radial, 115 kV sub-transmission network that serves a 65 MW load. The network model is simulated with the following voltage instability countermeasures: adding a capacitor, adding an SVC, adding a STATCOM, adding generation, tying to a neighboring transmission system and bringing in a new 230 kV source. Then, using the WECC heavy-winter 2012 power flow base case and Siemens PTI software, VQ and PV curves are created for each solution. Finally, the curves are analyzed to determine the best solution.

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1 Introduction

1.1 Strategy

The Intention of this study is to:

- Define voltage stability and describe its associated problems;
- Describe factors that influence voltage stability i.e., equipment and loads;
- Describe some techniques used to analyze a network's voltage stability;
- Use those techniques to evaluate solutions to an actual network with a voltage stability problem, and
- Compare the results to determine the best solution.

1.1.1 Methodology

The first part of the study looked at the effects of equipment and loads on voltage stability and defined the parameters necessary for modeling. A power flow computer model of a test network was then created using the WECC PTI heavy-winter 2012 base case. The individual solutions were simulated with the worst-case outage, where the voltage problem exists. These solutions (described in Chapters 2 and 5) were: adding a capacitor, adding an SVC, adding a STATCOM, tying the network to the end of a different radial line, adding generation and bringing a new 230 kV transmission source into the area.

The size of the equipment used in the solutions was determined by the following: 1) putting a fictitious synchronous condenser at the end of the long, radial line that serves the test network; 2) finding the output of the synchronous condenser to determine the reactive power deficit, and 3) choosing equipment with the next practical size larger than the deficit. V-Q and P-V curves were then created for each solution. The corresponding real and reactive power margins were used to determine the suitability of the solutions.

1.1.2 Applicability

The network simulated in Chapter 5 consists of primarily 115 kV and 69 kV elements. The results may not be applicable to networks outside of this voltage range. The tests were conducted on a voltage-constrained network; radially served by two 70-mile 115 kV lines with an outage on one of the lines near its source. An example would be a large, rural load.

1.2 Background

Interest in this topic came while doing transmission studies for a large western utility. In computer simulations of the transmission system, several areas had no apparent voltage or thermal loading problems, even using peak loads. But when faced with a contingency or slight load increase conditions quickly deteriorated approaching voltage collapse[1]. The concern is that many voltage conditions may go unnoticed if networks are not thoroughly scrutinized. The good news is, most utilities and regulatory agencies are aware of the potential for voltage problems and have guidelines

[1] Voltage collapse is the condition where voltage in a power system quickly decreases. This will be explained later in detail.

and standards to screen them. However, much of the attention has been given to main grid[2] systems and less attention is given to sub-transmission[3] voltage networks. Furthermore, sub-transmission networks have different characteristics and equipment and thus warranting their own studies.

It would not be economically feasible to make a transmission system 100% reliable for all circumstances. Ultimately, what gets built will be a trade-off of best design, financial restrictions and willingness of the owners to take on risk. These conflicting priorities change over the years, depending on regulation and the economy. One reason voltage problems arise stems from the fact that, when money gets allocated for system enhancements, it is usually organized by investment reason, e.g. new load connections, reliability, overloaded equipment, regulatory compliance, maintenance, etc. Voltage security improvements do not fit cleanly in those buckets and may get less attention, being harder to justify. This is particularly true with mature systems that may have had slow growth over the years. The cost of building new infrastructure (especially transmission lines) has also increased in recent history from higher copper and steel prices. [Chupka and Basheda, 2007] So the relative cost of installing capacitors to fix voltage problems (as opposed to building new transmission lines) is attractive, but problems can develop from over-reliance on shunt capacitors for voltage support.

> "Why the recent concern in mature power systems? One reason is intensive use of existing generation and transmission... A second reason is the increased use of shunt capacitor banks for reactive power compensation. Excessive use of shunt capacitor banks, while extending transfer limits,

[2] Main grid is loosely defined as the bulk electric system at 230 kV and above

[3] Sub-transmission is loosely defined as networks operating between 50-161 kV

> results in a voltage collapse-prone (brittle or fragile) network. Shunt capacitor bank reactive power decreases by the square of the voltage, hence the terms brittle or fragile... The combination of fast-acting fault clearing in protection and high performance excitation systems on generators has been effective in removing transient stability-imposed transfer limits. With transient stability imposed limits removed, either thermal capacity or voltage stability may dictate transfer limits." [Taylor, 1994]

Another consequence from the increased utilization of capacity, has been the hampering of ability to cope with disturbances. Transferring load between different sources may only be possible for a part of the year without overloading equipment or causing voltage issues. While this may not be a problem during spring or autumn, during a system peak the constrained network could start a cascading event. The power grid is designed with some redundancy and can normally handle single or even double contingencies when the loads are light. When lines are heavily loaded they tend to have bigger voltage drops. The extra heating from high current (I^2R losses) can cause the lines to sag and potentially trip off, exacerbating the situation.

The ultimate goal of electric utilities, aside from financial, is to meet customer demand with as few interruptions as possible and with consistent voltages. 'As few interruptions as possible' refers to reliability; 'as much power as demanded' refers to ensuring enough capacity in both generation and transmission is available for all load levels. The final part, 'with consistent voltage' refers to voltage security, or having enough reactive reserve in generation and transmission to deliver consistent voltage to the customer for all load levels.

1.3 Reliability Problems

Large-scale power blackouts and brownouts are the most dramatic examples of electric grid problems. They cost the US economy approximately $80 billion every year. [LaCommare and Eto, 2004] A brief survey of events over the last month identified with three significant power interruptions. On September 15, 2011 South Korea underwent wide-spread load shedding to maintain system stability.

> "South Korea effectively had no power reserves and was in danger of experiencing a total blackout last Thursday... from around 2 to 4 p.m., the country repeatedly had no emergency electricity reserves. The blackouts were caused by unseasonably high temperatures that pushed up power demand for air conditioning... compounded by many power plants going offline for regular maintenance, forced temporary power cuts that affected more than 2.1 million households and numerous businesses." [Yonhap, 2011]

One week later on September 22, a major outage affected Chile. The root cause of this outage was not known. There were no temperature extremes present, which tends to be a contributing factor. This could be attributed to a lack of infrastructure investment.

> "A massive power blackout paralyzed crucial copper mines in Chile Saturday and darkened vast swaths of the country including the capital Santiago.The outage acutely exposed the fragility of the energy grid in the world's top copper producer." [Avila and Gardner, 2011]

On September 8, 2011 there was yet another blackout; this time in northwest Mexico and the southwest US region, including the entire San Diego metro area.[Wolff, 2011]

While the newspapers may have attributed the fault to a single point of failure, such as an operator error in Arizona, the truth is that there were multiple points of failure. Many parts of the system actually worked as expected, such as under-frequency generator tripping and interchange disconnections. Though these events may have further contributed to a blackout, they were designed to prevent damaging equipment which would be much more costly.

Probably the most well-known US blackout in the last decade was on August 14, 2003. The outage affected much of the northeastern US and parts of eastern Ontario. A combination of events went wrong during a system peak; a key transformer out for maintenance, a generator trip, and then the subsequent tripping of interchange tie lines. This increased loading on the remaining lines caused further voltage deterioration across the region. This outage caused the loss of service to 50 million customers and took hours to restore. [U.S.-Canada Power System Outage Task Force, 2004]

Voltage instability incidents There are multiple processes that could contribute to the cascading outages described in section 1.3 such as under-frequency tripping, over current tripping, voltage instability, fractionalization and islanding. Sometimes one failure mode dominates, such as a partial voltage collapse. In Florida there were a series of voltage collapse incidents that caused blackouts between September and December of 1982. The problems all followed the same pattern, a generator trip, overloading lines, system islanding and progressive deterioration of voltage until under-voltage load shedding is engaged.

> All four disturbances were similar and were initiated by loss of a large generator unit in central or southern Florida. Because of the increased

> imports, voltages deteriorated and separations occurred after one to three minutes. The islandings were followed by underfrequency load shedding of about 2000 MW. [Taylor, 1994, p.263]

Many voltage instability incidents are recovered from with only minor loss of service. While they may remain unnoticed by the end customers, these incidents can be very alarming behind the scenes. The following is a dramatic summary from the Bonneville Power Administration (BPA) during a near-miss voltage collapse-induced blackout in Longview, WA in August of 1981.

> Temperature was very hot (41 °C). The Allston 500/230-kV autotransformer near the Trojan nuclear power plant was out for maintenance. The 1100 MW Trojan plant tripped, removing power and voltage support to the Longview area. Transmission lines (230 kV and 115 kV) were overloaded and a number of single line-to-ground faults occurred, probably because of sagging [lines] into trees (sagging due to temperature, and current overload due to high load and low voltage). The Longview aluminum reduction plant 13.8 kV voltage dropped as low as 12.4 kV [0.89 pu][4] and the Bonneville Power Administration dispatch permitted plant operators to change taps changers on the 230/13.8 kV transformers. This was the wrong thing to do; the voltage rose to 13.2 kV, but dropped again below 13 kV... At one point the 230 kV system voltage was down to 208 kV [0.90 pu] and voltage collapse in the Longview area was imminent. [Taylor, 1994, p. 266]

[4]The notation pu means the value is given in *per unit*.

The combination of the actions of protection and control devices; the quick reaction of the BPA dispatch; strategic load shedding and the restoration of the Allston 500-230 kV transformer was enough to narrowly avert voltage collapse and bring levels back to normal within 46 minutes. One of the main lessons of this event was not to schedule maintenance of critical equipment during system peak. The Trojan plant's lack of reliability and high maintenance costs, among other things, eventually led to the decommissioning of the plant.

1.4 Stability Definition

A Dynamic System Daily and seasonal fluctuations in voltage are normal. There are many changes the system has to respond to such as: large changes in load, loss of transmission equipment, loss of generation or outages. The grid as a whole has some elasticity. However, behind the scenes many shifts and adjustments are taking place to maintain acceptable operating conditions. Figure 1.1 shows a plot of the 115 kV voltage at a transmission substation over one week. The plot shows the voltage fluctuating $\pm$ 4% around the mean. As an example of how the system seeks equilibrium: when voltages are low generators can increase reactive output, transformers may change tap positions or capacitors could be turned on. When voltages are high, generation may back off, reactors[5] may be engaged or transformers can adjust to a higher tap to bring down the low side voltages.

> "The power system is a highly nonlinear system that operates in a constantly changing environment; loads, generator outputs and key operating

[5] The term *reactor* is used for devices that function like inductors for high voltage, high power applications

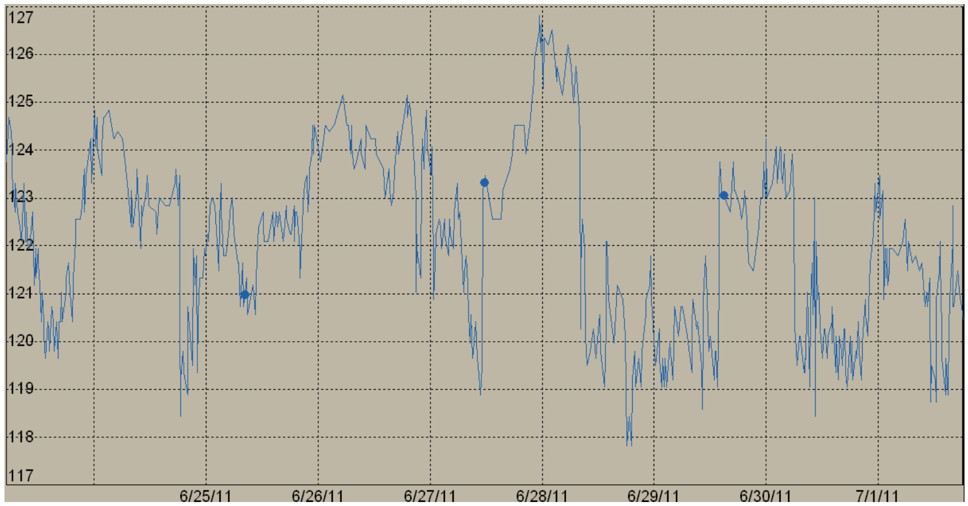

Figure 1.1: Historical Plot of Voltage at a 115 kV bus

> parameters change continually... Stability of an electric power system is thus a property of the system motion around an equilibrium set, i.e., the initial operating condition." [Kundur et al., 2004]

A general definition for stability for power systems was defined by a joint stability task force commissioned by the IEEE and GIGRE as:

> "Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact." [Kundur et al., 2004]

Time frame: short term vs. long term stability Within the timelines of the outages described in section 1.3, several forms of instability may have manifested. Different forms of instability are interrelated and sometimes hard to distinguish.

"The term stability implies a dynamic phenomenon. Indeed the power network is a dynamic system. However, the distinction between dynamic and static is made here as a matter of time." [Taylor, 1994] For simplicity, power systems stability is usually distinguished by either short term or long term time frames. The short term, or transient may last between a few cycles and a few seconds. These types of disturbances can be: switching area interchanges, the clearing of a line fault, or a sudden load increase such as from a large arc furnace. The long term, or steady state stability elements can last between one and 15 minutes. Examples of these elements could be: correction of time errors due to frequency excursions; the action of an under-load tap changer (LTC); the automatic switching of shunt capacitor banks or the stalling of a synchronous motor. Despite being a long term phenomenon, power system stability exhibits many of the same characteristics as the classical equilibrium-seeking step function stability analysis. There are three categories of power system stability: rotor angle stability, frequency stability and voltage stability.

Frequency Stability Frequency instability is a large scale, main grid phenomenon. This form of instability is less common due to modern under-frequency load shedding schemes. "Frequency stability refers to the ability of a power system to maintain steady frequency following a severe system upset, resulting in a significant imbalance between generation and load." [Kundur et al., 2004] Frequency instability can be a slow phenomenon such as in the case of boiler dynamics or a fast one such as in under-frequency load shedding. One common cause of frequency instability is separating of islands in a large interconnected system where one of the islands has insufficient generation and insufficient under-frequency load shedding. Such a scenario

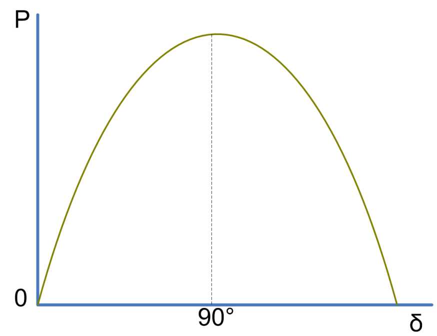

Figure 1.2: Graph showing power versus δ (from equation 1.1). The power transfered from the generator to the load is given by $P = \frac{E_G E_l}{X_T} \sin\delta$. [Kundur, 1994]

would quickly deteriorate causing a blackout. Frequency excursions can cause large voltage fluctuations if the phase angle gets out of sync and lead to generation/load shedding.

Rotor Angle Stability In rotor angle stability the term *rotor angle* refers to the angle by which a synchronous generator's rotor leads its stator field; plus the angular difference between the terminals of the generator and the load; plus (assuming a motor load) the angle a motor's rotor lags its stator field. That is:

$$\delta = \delta_{generator} + \delta_{line} + \delta_{motor} \tag{1.1}$$

The non-linear relationship between δ and the power a generator can transmit to its load is illustrated in figure 1.2. The maximum power transmitted occurs at 90°. As the load lags further it will be more difficult for the generator to support it.

Rotor angle stability is defined by the IEEE/CIGRE task force on stability terms and definitions as

> "the ability of synchronous machines in an interconnected system to remain in synchronism after being subjected to a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic

> torque and mechanical torque of each machine in the system. Instability that may result occurs in the form of increasing angular swings of some generators." [Kundur et al., 2004]

Rotor angle stability is a short-term phenomenon. It is categorized by how large a disturbance the system is subjected to. Small disturbances can either be local or global. In a small signal, local disturbance the instability is caused by a single machine with insufficient rotor damping torque. This causes rotor oscillations (accelerating and retarding) that increase in amplitude.

In a large region, small-signal disturbance two groups of generators many miles apart may act together. If group one accelerates it will take more load from group two causing group one to decelerate and group two to accelerate, then the process reverses. Normally the machines' torque would dampen this process. In rotor angle instability that angular difference increases. [Kundur, 1994] This scenario can be expanded to inter-area oscillations (e.g. pacific Northwest hydros and the Palo Verde Nuclear plants in California). In that case, the protection and control systems would trigger the temporary break-up of the WECC system.

In the case of a large disturbance rotor angle stability comes in the form of the first swing oscillation. This could originate with a fault or from the super-position of a slow inter-area mode and a local plant mode. [Kundur et al., 2004]

Voltage Stability Voltage instability, the focus of this paper, occurs when the system cannot supply enough reactive power to support voltages at a load bus. This can be caused by a disturbance such as a loss of generation, a line outage or a sudden load increase. Voltage stability can be a fast phenomenon such as when the system is affected by the action of induction motors, or a slow phenomenon when considering the effect of LTC adjustment or generator excitation current limiters. The reactive power deficit can arise from inadequate transfer paths for the demanded load or inadequate reactive reserves in generation. Instability is characterized by progressive decrease in voltages at the load bus.

High voltages are also a problem, though instability is usually associated with low voltages. they can cause damage to equipment such as capacitors or motors. Unusually low voltage conditions can lead to *voltage collapse*, a positive feedback phenomenon where the higher line losses due to the increased current, rob the network of needed reactive support, accelerating the runaway reduction in voltage.

"The driving force for voltage instability is usually loads." [Kundur et al., 2004] Normally, when voltage decreases at the load bus, power to distribution customers is restored via motor-slip adjustment, voltage regulators, LTCs or thermostats. In a strained scenario, however, this increase in power consumption would put more stress on the transmission network by increasing the reactive power demand. This type of stability is usually caused by the loss of equipment rather than the disturbance itself.

An example of a voltage stability problem is a large load served by a long radial transmission line with widely varying reactive requirements and limited ability to get reactive support from the grid. "Rotor angle stability is basically generator stability, while voltage stability is basically load stability." [Taylor, 1994]

2 Equipment Influences

The purpose of this chapter is to give a brief description of transmission system equipment elements and how they affect voltage stability. Detailed models of the various equipment can be found in [Kundur, 1994] and [Van Cutsem and Vournas, 1998].

2.1 Generators

There are several drivers influencing generators' outputs, depending on their purpose: the availability of fuel, base load, load followers[1], peakers[2] or based solely on the price of energy. Common sources of energy used in electrical generation are: coal, hydro, natural gas, nuclear, biomass, wind, geothermal and solar.

2.1.1 Generator description

Generators convert mechanical energy into electrical energy. They take advantage of Faraday's law which says a changing magnetic field causes an induced voltage and an electrical current in a perpendicular (closed) conduction path. Generators have a rotating part (rotor) and a stationary part (stator). Each side acts as a pole in a magnetic pole pair, one side controls the flux density (field), and the other side has the wire windings that carry the induced current (armature). Higher voltages are achieved by increasing the number of windings around the poles in the armature. Voltages can also be boosted to transmission levels via step-up transformers. The

[1] The term *load follower* refers to a generator that tailors its output to the load level present.

[2] Peaker plants are typically smaller gas plants located near load centers. Their function is to follow load through daily cycles.

Figure 2.1: Picture of a 21 MVA hydro-electric generator

rotor is directly coupled to a turbine which is driven by a kinetic energy source (prime mover).

There are two families of generator types, synchronous and induction. Most electric utility generators are synchronous. Synchronous generators are operated at a speed proportional to the system frequency. The rotational speed can be changed by using gears or changing the number of poles. The system is strong enough compared to the size of any single generator to hold the unit's relative speed in a locked state. Despite being synchronous, small speed variations do occur. The most common method of frequency regulation by turbine governors is called *droop control*. This method allows the speed to vary by 5% with load changes, recommended as a good operating practice [NERC, 2004]. Many times voltage or power factor control is required by the utility they connect to.

For most large synchronous machines, the field is on the rotor and the armature is on the stator. The field is usually composed of electromagnets powered by DC

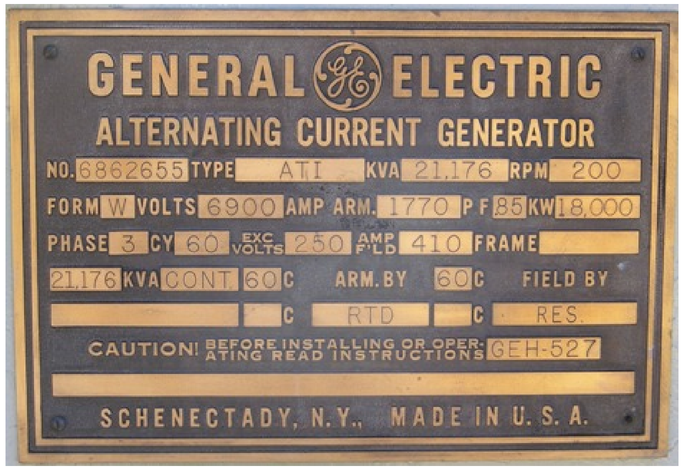

Figure 2.2: Nameplate of the same generator. It operates at 6.9 kV, has a minimum p.f. of 0.85 and rotates at 200 RPM or $3\frac{1}{3}$ rotations per second. This also means there are 36 poles (or 18 pairs).

rather than permanent magnets. The DC is usually provided by a device mounted on the rotor called an exciter. This allows the amount of flux between the poles to be varied. The exciters are usually electronic and can react very fast to the changing system conditions. Consider:

> "The generated voltage is a function of the flux created by the field windings on the rotor. By controlling the excitation of the machine it is possible to change the generated voltage without changing the terminal voltage [by increasing reactive output]. However, changing the excitation by itself cannot change the amount of real power from the machine. To deliver more power from the generator, more power must be delivered to the shaft of the generator by its prime mover." [Skvarenina and DeWitt, 2001]

The exciters will usually have a specified bus that they monitor and maintain voltage for. In some cases there will be a family of turbines for a wind farm or group of hydros that will all be set to maintain the voltage on the same bus so as not to fight each other.

Exciters have limitations on how much the excitation voltage can vary. Some electronically controlled generators such as wind turbines can ride through low voltage conditions, continuing to generate despite a VAr deficiency. This is helpful in the situation where a system is becoming voltage unstable since the loss of generation could cause further deterioration of conditions. [Skvarenina and DeWitt, 2001]

2.1.2 Operation

At any point in time the system's total generation must be equal to the sum of loads plus losses. Generation has to constantly adjust as load conditions change.

There are two types of controls used for synchronous generators, isochronous and droop control. Isochronous control follows load follows load variations and adjusts the output accordingly. Isochronous control would only be used in an islanded system since two or more isochronous-controlled generators would fight each other.

The normal mode of control for synchronous generators is droop control. With droop control, the controlled generator is connected to a network with many other generators; enough that the combined electromagnetic coupling is considered infinite. The droop control adjusts the machine's frequency. For example, when an operator wants to increase a machine's output the control is set to raise the frequency slightly higher than that of the system, only the system frequency is too strong. The additional torque applied to the turbine is converted into higher Watt output.

Small changes in the system load, such as someone turning on a motor are offset by someone else turning off a similar load. On an aggregate scale system load changes

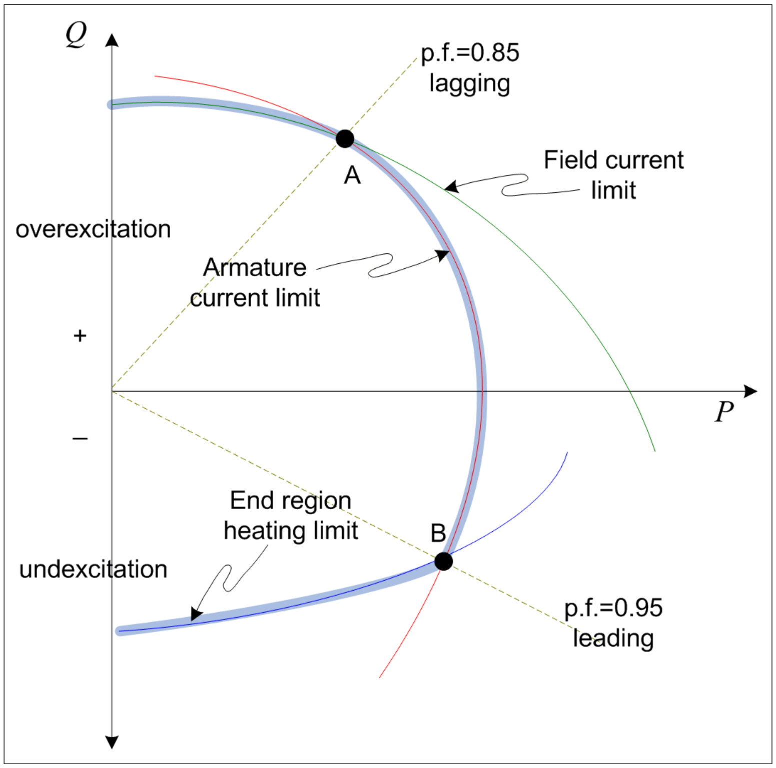

Figure 2.3: Capability curve showing the limit of a machine's operating range

are smoother and more predictable, which is what grid operators and load-following generators adjust to.

It is possible, indeed normal, for the frequency of the entire grid to change slightly ($< \frac{1}{2}\%$). This is monitored and controlled by coordinating entities (like WECC) that can use large plants to make frequency corrections via remote control. This is called Automatic Generator Control (AGC). In this case the coordinating entity will adjust the generators' droop controls as the loads change. Since the aggregate load levels are more predictable dispatchers can preemptively schedule generation. If the frequency deviates throughout part of the day it must be corrected for, e.g. speed the frequency up at night to correct clocks. [Hubert, 2002]

2.1.3 Generator limits

The main concern in generator operation is damage from overheating the field and armature windings. These limits are illustrated in a curve called *the capability curve* as in Figure 2.3. The right-facing part of the curve between points A and B represents the armature's capacity, simply the thermal limit based on complex current. The upper and lower bounds are the field over- and under-excitation limits respectively. These bounds represent the minimum and maximum power factors. The upper limit is based on the maximum current in the field windings. The lower limit (under-excitation case) occurs when there is overheating at the end of the stator from flux eddy currents due to lack of saturation. [Kundur, 1994]

If the exciter detects low voltage at the generator's terminal it will increase the reactive output which should normally restore it to acceptable levels. This works until the generator reaches its reactive limit. Most modern generators have static exciters which prevent the unit from exceeding its thermal limit, while keeping the machine in service. At low voltages, synchronizing torque can be lost, which can lead to rotor angle instability.

It is important to note that reactive power output can only be increased at the sacrifice of the real power's maximum output. As such, generators are normally operated below their maximum output in order to reserve some reactive power for when it's needed. WECC specifies minimum reactive reserve requirements for utilities.

In addition to reactive reserves WECC has generation reserve requirements. When a large load is added to the system (e.g., an area interchange) or a large generator trips off, the system uses its elasticity (the sum of the generators' inertia) to absorb the change. However, this can only accommodate a small percentage

(¡3%)of the load. To prevent a major system problem when this happens, some machines are left online, spinning but producing no power. They are ready to quickly ramp up their output when needed. This capacity is called the spinning reserve. Generating plants are not individually bound to operating reserve requirements, this is the duty of a regional balancing authority[3]. This reserve must be large enough to handle daily regulation with load variations, the sum of energy lost during the worst single contingency and any obligations to reserve sharing groups[4]. Up to 50% of the contingency reserve can be non-spinning, in the form of interruptible load or exports.

2.2 Lines

2.2.1 Line parameters

The three biggest influences on a transmission line's behavior are the conductor's resistance, the line's inductance between itself and the other phases and the capacitance between the phases. All of these are influenced by the geometry, the line current and a the conductor's metallic fundamental properties. The resistance (R) is defined as

$$R = \frac{\rho L}{A} \Omega, \tag{2.1}$$

where ρ is the conductor's resistivity, A is the cross-sectional area of the conductor and L is the length of the conductor. The resistivity is dependent on the conductor's temperature and the system frequency, which is normally 60 Hz (in the US).

[3]A balancing authority is responsible for making sure there is enough generation to meet demand and maintains frequency.

[4]Reserve sharing groups such as the Northwest Power Pool share the responsibility of maintaining generation reserves. This is needed because some smaller utilities may not have enough generation to supply their load. This allows the reserve to be shared, sold or traded among the members.

[Glover and Sarma, 2002]

Inductance for overhead lines is dependent on the spacing between the phases. In long lines, unequal spacing leads to unequal inductances (and capacitances) between the phases. This can be corrected by transposing the lines (swapping their position) at select intervals. [Kundur, 1994] The inductance of a single phase in a transmission line can be approximated using equation 2.2.1. This equation generalizes L_a and results in $L_a = L_b = L_c$, i.e. it imparts an equilateral approximation a non-equilateral arrangement.

$$L_a = \frac{\lambda_a}{I_a} = 2 \times 10^{-7} \ln \frac{\sqrt[3]{D_{ab} D_{bc} D_{ca}}}{D_s} \text{ H/m} \tag{2.2}$$

[Glover and Sarma, 2002] Here, λ is the flux linkage[5], D_s is the geometric mean radius of the conductor and the values: D_{ab}, D_{bc}, and D_{ca} are the distances between phases a, b and c respectively. This equation uses the natural log of the ratio of the conductor's geometric mean radius to the geometric mean of the distances between the phases.

Since the flux linkage is itself a product of the current, the primary contribution to inductance is simply the geometry of the layout of the phases in the transmission line. This will vary by conductor sizes and voltages, since voltages determine the minimum phase spacing requirements.

Capacitance is defined by equation 2.2.1 In the case of two long cylindrical

[5] Flux linkage for a long cylindrical conductor is simply the integral of the flux times the differential length (dx) along the conductor.

Impedance values for 10 miles per unit 100 MVA				
conductor	R	X_l	$1/X_c$	angle
1557 ACSS	0.00516	0.05311	0.00804	84.0
795 ACSR	0.00988	0.05470	0.00777	79.9
397.5 ACSR	0.01967	0.05787	0.00732	71.2
4/0 CuHD	0.02291	0.06256	0.00686	68.9
4/0 ACSR	0.04032	0.06649	0.00695	57.1

Table 2.1: Table showing R, X_c and X_i for various conductor sizes using typical phase spacing for 115 kV

conductors with a conductor radius of a and distance between the conductors b:

$$V_{ab} = \int_a^b E_x \, dx = \int_a^b \frac{q_m}{2\pi\epsilon} \, dx = \frac{q}{2\pi\epsilon} \ln \frac{D_a}{D_b} \; volts \tag{2.3}$$

The ϵ term is the permitivity of free air, defined as 2×10^{-7}. Since the voltage depends on the charge, the capacitance between the conductors becomes:

$$C_{ab} = \frac{q}{V} = \frac{2\pi\epsilon}{\ln(\frac{distance}{radius})} \tag{2.4}$$

[Glover and Sarma, 2002]

Similar to the inductance calculation, the primary influence on the capacitance is the geometry of the transmission line. This means that transmission lines with different conductor types operated at the same voltage (and thus the same phase spacing) will have similar per-distance values for L and C. Table 2.1 shows some sample X_c and X_l per unit values for 10 miles of 115 kV conductor, assuming a typical 10 foot spacing.

The transmission line's conductance (G) is also a line parameter. It is the combined real losses from either corona (typical in coastal environments) or from

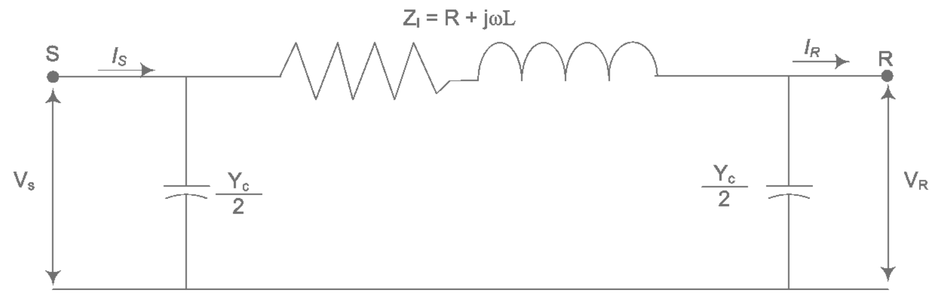

Figure 2.4: Equivalent pi model

insulator leakage. Conductance is normally neglected since its influence is very small.

2.2.2 Equivalent π circuit

Rigorous mathematical modeling of transmission lines requires use of the telegrapher's equations, which impart a distributed model. For simplicity, it is common practice to lump the transmission line parameters into three parts: two shunt admittances at either end and the series impedances so that the model is lumped rather than distributed. This is known as the equivalent π model. The addition of factors for leakage reactance and conductance only yield a small gain in modeling accuracy. Figure 2.4 shows the lumped-element equivalent π model.

From figure 2.4 it can be seen that the source voltage V_s is:

$$V_s = V_R + Z_l\left(I_R + \frac{V_R Y_c}{2}\right) \tag{2.5}$$

$$= \left(1 + \frac{Y_c Z_l}{2}\right) V_R + Z_l I_R \tag{2.6}$$

[Glover and Sarma, 2002] The charging current due to the line's capacitance would then be: $I_R = \frac{Y_c V_R}{2}$.

2.2.3 Ferranti effect

When the loads are light or disconnected, the voltage at the end of the line can be higher than the sending end. This is caused by the capacitance between the lines and the line charging current flowing across the line's inductance causing a voltage rise. This phenomenon is called the *Ferranti effect*. This is a nonlinear function of voltage, $Q_c = \frac{V^2}{X_c}$. This is how transmission lines can be producers of reactive power.

2.2.4 Surge Impedance Loading

To find the voltage and current at any point along the line consider the differential equations: $dV/dx = -Zi$ and $di/dx = -Yv$. The solutions to these equations at any distance x are:

$$v(x) = \frac{v(0) - Z_s i(0)}{2} e^{\gamma x} + \frac{v(0) - Z_s i(0)}{2} e^{-\gamma x} \tag{2.7}$$

$$i(x) = \frac{v(0) - Z_s i(0)}{2Z_s} e^{\gamma x} + \frac{v(0) - Z_s i(0)}{2Z_s} e^{-\gamma x} \tag{2.8}$$

where

$$\gamma = \sqrt{ZY} \left[\frac{\Omega}{m}\right] \tag{2.9}$$

and

$$Z_s = \sqrt{\frac{Z}{Y}} [\Omega] \tag{2.10}$$

[Siemens, 2011]

The γ and $\sqrt{\frac{Z}{Y}}$ elements are fundamental properties of the transmission line. γ is the propagation constant and $\sqrt{\frac{Z}{Y}}$ is the characteristic or surge impedance.

When the impedance of the network load is equal to the surge impedance, called

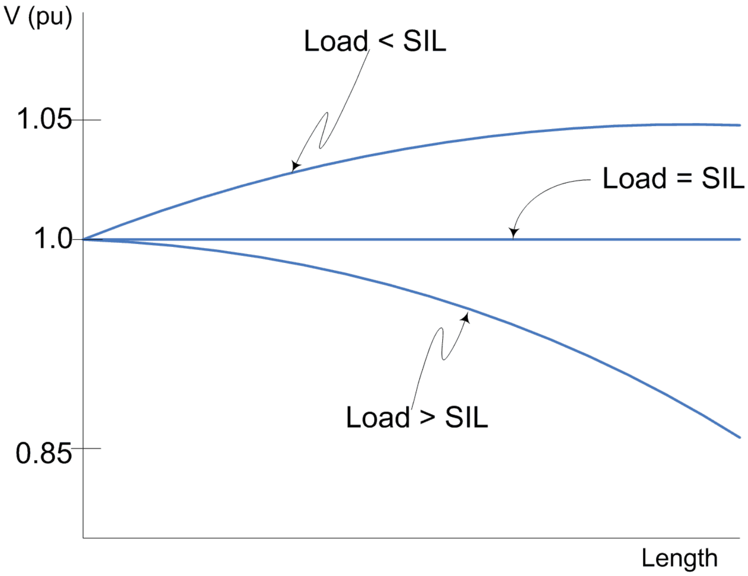

Figure 2.5: This plot shows the voltage profile of a line over its length operated at different load levels

the surge impedance load (SIL), there will be zero net reactive power produced or consumed by the line. It is similar to the way communications circuits use impedance matching to eliminate the reflected (surge) wave. In power networks however, the load impedance is constantly changing and the network can not easily be designed for it. The surge impedance load marks the point where the transmission line is neither a producer nor a consumer of reactive power. Also noteworthy, is that the voltage and current are in phase at all points along the line and the voltages at the source and receiving ends are equal. [Kundur, 1994]

Figure 2.5 shows the plots of three different load levels. The top plot represents the voltage profile of a transmission line with a light load or an open circuit at the end. The middle plot shows the voltage profile for a line operated at its SIL. The third plot is a heavy load scenario.

2.3 Transformers

2.3.1 Transformer description

Transformers couple two or more electric circuits using a magnetic circuit. Their main purpose in the electric power context is to change voltage, though they can also be for isolation, measurement or changing voltage phase angle. Transformers allow for the conversion to the most economical voltage for the application. Subtransmission transformers consist of two (or sometimes three) conductor windings, usually made of copper or aluminum conductors with a thin varnish coating wound around an iron core. The transformer windings are separated by a polymer paper and the entire structure is enclosed in a steel housing filled with mineral oil which insulates and helps with heat dissipation.

To reduce exposure to failure, transformers are often installed as three single phase units as opposed to a single three-phase unit. The advantage being it's cheaper to get redundancy with a fourth. The voltage regulating part of the transformer has the highest mode of failure, so it is also common to see transformers with separate regulator banks at lower voltages.

Auto-transformers are a separate category that use a single winding tapped at some point in the middle. They connect the two networks both magnetically and electrically. The simple design of auto-transformers has the advantages of having lower losses, having a lower voltage drop and being less expensive. There are two common applications for auto-transformers. One application is when a small voltage change is needed. Regulators are normally auto-transformers, with a variable tap on the load side. An other application is at very high voltages, where losses and voltage

Figure 2.6: Author inspecting a 125 MVA 230-115 kV Load tap changing autotransformer

drop must be kept to a minimum. One problem with auto-transformers is the lack of isolation, which can be a protection issue.

Some sub-transmission transformers have three windings. In three winding transformers, the tertiary is usually used for station service or for balancing zero sequence currents. It typically would have a lower fault duty rating because it's a smaller winding on the outside of the winding assembly. In order to make the tertiary more robust, the manufacturer would need to use larger wire and make the core bigger, which would increase the transformer's size, cost and footprint in the substation.

The core in transformers acts as a flux channel. "The current that establishes the flux [in a transformer's core] is called the exciting current it is usually about 1%-5% of the rated current in the primary... [and it] is proportional to the size of the core." [Skvarenina and DeWitt, 2001]

There is some hysteresis in the relationship of the flux density to magnetic field intensity (B-H) in the transformer's core material, which causes the exciting current to be non-sinusoidal. The hysteresis occurs because it takes energy to align the magnetic poles, and they tend to hold their own magnetic field once created.

To demagnetize the material a reverse field must be applied, a measure called coercivity. Materials with a high coercivity are considered magnetically hard, e.g. materials used for permanent magnets. Magnetically soft materials such as amorphous steel are used in transformer cores and motors as a flux channel.
[Skvarenina and DeWitt, 2001]

2.3.2 Losses and Limitations

A transformer is rated by its apparent power in VA. This rating is based on its ability to continuously dissipate heat from the losses during heavy loads. It's not uncommon to exceed a transformer's rating for a short duration during an extreme peak load. The risk in overloads is the breakdown of the transformer's insulation by extreme heat; this is known as loss of life.

Transformers have a rated impedance given as a percentage which would be stamped on its nameplate. This impedance is defined, "the percentage of the normal terminal voltage required to circulate full-load current under short circuit conditions." [Brand, 2005] As the definition implies, the measurement test is done with one side shorted (usually the primary). The percentage voltage drop is the Z%. This comes into play when determining fault duty and when two or more transformers are operated in parallel (to share the load equally). When transformers of different impedances are run in parallel there is a possibility of circulating VArs, without a proper paralleling scheme in place.

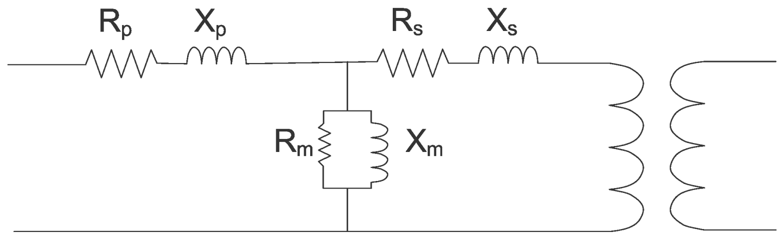

Figure 2.7: This model shows the main points of transformer power loss.

The two main losses for transformers are from the resistance of the copper windings and the reactive losses from the core's magnetizing current. A short circuit test is used for determining the real losses (full-load); open circuit tests are used for finding the magnetizing current losses (no-load). "Copper loss varies with the square of the transformer current or the square of the apparent power if voltage is constant... Core losses do not change very much from no load to full load." [Skvarenina and DeWitt, 2001]

In figure 2.7 R_p and R_s are the core winding resistance in the primary and secondaries respectively. Not all the flux is contained in the core. The flux that escapes, called leakage flux, will not contribute to induction of voltage in the windings. X_p and X_s are the inductive winding (leakage flux) losses in the primary and secondary. R_m is the real loss associated with the core losses and X_m is the loss associated with the magnetizing current.

There are two types of core losses: hysteresis loss and eddy current loss. Hysteresis is the energy used aligning the magnetic poles in the core. Eddy current losses are from the currents induced in the iron core material.

Transformers have a specific voltage they are designed for. Below the rated voltage the transformer will be under-excited. In this scenario flux coupling in the core takes place, but the transformer can not utilize its full rated capacity. Conversely, "if the magnitude of the voltage applied to a transformer is too large, the core will saturate and a high magnetic current will flow." [Skvarenina and DeWitt, 2001]

2.3.3 Regulation

Under-load tap changing

Voltage regulation is achieved either when a transformer has its own built-in tap changer, called an under-Load Tap Changing Transformer (LTC) or by use of a separate downstream transformer used exclusively for voltage regulation. Typical sub-transmission transformers will regulate voltage for $\pm$ 10% variation on the load side, with 16 boost (raised) positions, 16 buck (lowered) positions and a neutral. The advantage of regulation is that the distribution customers will experience consistent voltages while the main grid fluctuates throughout the day. The disadvantage comes during low-voltage grid events when loads' higher voltages maintain high consumption and thus higher currents. This will be discussed further in chapter three.

Line drop compensators

Line drop compensators (LDCs) are usually included in modern regulators. These devices adjust the voltage target of the regulator based on the current. If the regulated circuit is long and has a large load at the end there could be a big difference in the voltage drop between light and heavy loads.

As the measured current increases, the tap changer's voltage set point is also increased. The rate of increase is determined by R and X settings. These are normally between 0-15 volts. Both the R and X compensation have the same effect, to adjust the voltage. They are supposed to represent the relative R and X of the line. In effect, the LDC simulates the impedance out to a point on the line, such that the voltage regulating equipment will try to hold a steady voltage at that location rather than at the source.

Most LDCs have both forward and reverse compensation. The forward compensation is used when a load is connected on a long line. Reverse compensation is used when there is a power source connected to the circuit downstream of the transformer. The power source can be a generator without voltage control or Ferranti effect at light loading, both of which would boost the voltage at the transformer. In that example it would be desirable to have the LDC lower (buck) the regulator's voltage set point.

It is less common that a single load is connected at the end of a long line. Usually there are many loads at varying distances along the distribution line. The LDC must then be set to compromise, giving the closer loads slightly higher voltage and the remote loads slightly lower voltage.

Sometimes the mix of loads on the feeder makes it impossible to get correct voltage to all customers with just the LDC. In this case other voltage correction equipment can be installed at points further down the line. The two most common types of distribution voltage support are in-line regulators (usually pole-mounted) or capacitors. [Waters, 2008]

Timing

There are many places throughout the grid where voltage regulation is taking place. Transformer regulators have delays set based on their voltage level. This is to allow short spikes to pass and only change when necessary. Distribution circuits will have the shortest delays, maybe 15-20 seconds; sub-transmission could be in the range of 30-45 seconds; transmission regulation may wait near a minute before changing taps. This means a 33 step sub-transmission regulator could potentially take 17.5 minutes to switch from the lowest tap to the highest tap during a disturbance.

2.4 Capacitors

Capacitors are one of the simplest and most effective ways of generating and managing reactive power. They can be placed virtually anywhere in the power system where needed.

2.4.1 Structure

Capacitance happens when two conducting objects of different charge are separated by an insulating region, creating an electric field. Section 2.2 showed that transmission lines can behave like capacitors. In the context of electric power equipment, a capacitor is typically a sheet of aluminum foil separated by a thin film of insulation (e.g. Mylar), rolled and placed in a polyurethane-filled container (called a can). Capacitors are always designed with a specific voltage in mind. This is necessary to establish the thickness of the insulation as well as for the bushing and fuse dimensions.

Typically shunt capacitors are composed of multiple units arranged in parallel on a rack. Each unit would be connected to the grounded rack on one side and connected to the system by a fuse on the other side. On some larger capacitors a reactor will be placed in series to limit the in-rush current when the capacitor is

Figure 2.8: Example rack installation of a 50.4 MVAr, 230 kV capacitor with 84 cans per phase. Note the reactor on the left for limiting inrush current.

engaged.

Each capacitor will have a rated voltage for which it has a guaranteed output. If the operating voltage is lower, the output will be less. For example, a 20 MVA distribution substation may have a three-phase wye-connected shunt capacitor with 18 cans each rated 200 kVAr, for a total of 3600 kVAr. If the capacitor's rated voltage is 13.09 kV the output onto a 12.47 kV nominal voltage system is $(\frac{V_{base}}{V_{rated}})^2 \times Q_{rated} =$ 3260 kVAr$_{effective}$. If the voltage exceeds the rated level, damage may occur.

Capacitor banks are either connected shunt to ground or in series with the transmission. Series capacitors are used more often for main grid transmission applications to increase a line's capacity. They have the effect of reducing the line's reactance.

Series capacitors participate as an active component since they generate reactive power proportionally to the current. As the load increases the line's I^2X_l

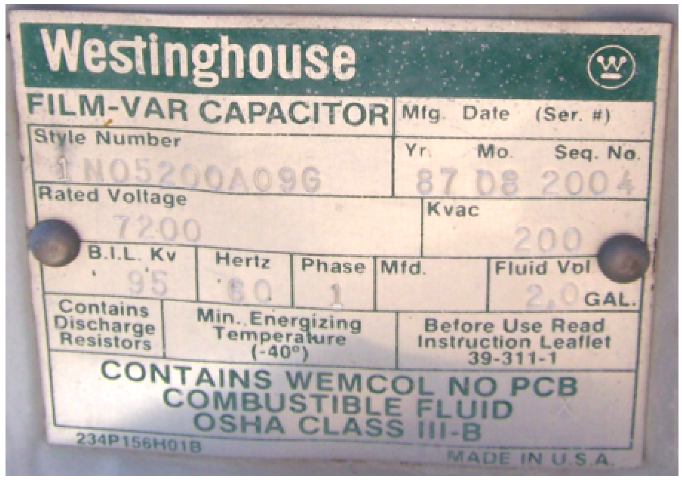

Figure 2.9: Nameplate of individual capacitor can.

reactive losses increase, but so does the generated I^2X_C reactive power from the capacitor. As such, they do not usually need switching control. Since series capacitors' outputs increase with the square of the current, they generate reactive power when most needed. [Taylor, 1994]

Shunt capacitors are ubiquitous in sub-transmission and distribution networks. "They are typically used at lower voltages where line capacitance does not generate enough reactive power to supply line losses and near loads that dissipate reactive power." [PTI, 2009] Since transporting reactive power long distances causes increased losses, it is economical to install the capacitors where the reactive power is needed.

It is common to find capacitor installations for transmission improvement connected to the tertiary of a three-winding transformer. This is because in the past, capacitors were cheaper to build for lower voltages. Now most capacitor manufacturers offer internally-fused models that can be produced for higher voltages, meaning they can be connected directly on the high side bus. This will also reduce transformer losses.

In most electrical engineering disciplines capacitors are defined in terms of Farads. Since the capacitors are designed to operate at 60 Hz (in the US) and at a fixed rated voltage, the Q output is known. In fact, power system capacitors are almost always defined in terms of VArs and never in Farads.

Capacitive reactance is defined by $X_c = \frac{1}{j\omega C}$ and the reactive power generated by a capacitor is $Q = \frac{V^2}{X_c} = j2\pi(60Hz)CV^2$ VAr. For example a 200 kVAr capacitor rated at 12470 kV line-to-line (a common size can) would have a capacitance of $\frac{200\text{ kVAr}}{12470^2\text{V}\times 2\pi \times 60\text{Hz}} = 3.41\mu$F. To get a three-phase bank of 5400 kVAr one would need nine of these cans per phase.

While the capacitor is designed for a specific voltage, theoretically it could be used at lower voltages. Below the rated voltage the output will be reduced by a factor of V^2. At higher voltages there is a risk of arcing across the insulation inside the capacitor.

2.4.2 Control

When planning a capacitor installation the first thing to consider is, what is the problem this capacitor is going to correct? Examples of such problems include: low voltage during certain load conditions, power factor correction or to improve transmission. Capacitors are also used to keep fully-loaded transformers under their ratings.

Manual Control

For some situations it is sufficient to switch a capacitor seasonally, e.g. for agricultural pumping load. In cases where transmission voltage is the concern, the preferred method would be manual switching, but remotely by SCADA[6] so that dispatchers can decide when it is appropriate to switch.

Automatic Control

The most common type of automatic control in sub-transmission is based on VAr flow. The controller measures the current and voltage on the controlled bus and determines the reactive power flow. For example, a 9.375 MVA transformer may serve a peak load of 8 MW and 2 MVAr and have a 1800 kVAr capacitor on its regulated bus. The controller could be set to turn on at 800 kVAr lagging and turn off at 1800 kVAr leading. When the reactive flow increases to 800 kVAr the control closes the capacitor switch, stepping Q up to 1000 kVAr (leading). The flow will continue to increase to its a peak of 2 MVAr (at the load) with a transformer flow of Q = 1000 kVAr (lagging). At night when the load decreases, Q climbs up to 1800 kVAR leading and the capacitor switch opens. This scenario will favor the 'on' state, and in doing so, will also compensate for transformer losses.

The control band must be greater than the capacitor's impact if the measurement transformer is located upstream of the capacitor bank: a VAr controller must leave a range greater than the capacitor's VAr size and the voltage switch range must be greater than the expected voltage rise. Large capacitors are usually manually con-

[6]SCADA is System Control And Data Acquisition, a communication network to remotely monitor and control the power system.

trolled, and switched less frequently. Consideration should be given to decrease the frequency of switch operations both to reduce putting transient voltage spikes on the system and to reduce the risk of equipment failure. Duty cycles can range from daily to seasonally switching. Some controllers can also use simple clock timers when the load is predictable.

Voltage override is used when the VAr flow is not past the control's switch threshold, but the voltage is going out of bounds. Voltage control is also used when there are particular voltage concerns, such as the potential for a contingency that would require reactive support. Current control is used less frequently, but it could be desirable for places with predictable power factors or when a voltage problem may exist downstream.

Capacitor controllers are designed with a delay to allow for reclosing when there is a temporary voltage deviation due to a fault (by some estimates 70-80% of faults are temporary). This is to keep the bank from responding to short term variations which would cause unnecessary wear and tear. On the other hand, capacitors can be set to react very quickly if conditions require it. Here is a description of a capacitor installation where a fast response is appropriate.

> "In 1975 four 70 MVAr banks were installed in a 115 kV system in Minnesota. These banks are energized by Basler solid state inverse time-undervoltage relays. These relays pick up in less than 0.5 seconds following the loss of a large local generator, which leaves the local industrial load served by a weak 115 and 230 kV system from remote generation. The capacitor switches are closed within about 0.75 seconds and the capacitors are large enough to re-accelerate the area induction motor load

> from the modest slip that accumulates during the 0.75 seconds of low voltage." [PTI, 2009]

2.4.3 Operation and Planning

To a large degree, a capacitor's influence on the voltage will depend on how strong the system is at that location. On a long radial system with a utilization of 2.5 surge impedance load, the voltage will be more elastic than one that is connected to the main grid where the voltage may not vary at all. Many remote areas served by long transmission lines have problems of both under and over voltages.

Shunt capacitors are relatively inexpensive, but they lack the ability to specifically control voltage; their effect is more of a bump than a smooth transition. WECC has a requirement that post-transient[7] voltage deviations should not exceed 5%.

> "Much has been written about optimum size and location of distribution feeder capacitor banks... Most studies find that $\frac{1}{3}$ of the capacitance should be located about $\frac{1}{3}$ of the distance from the substation to the end of the line, and $\frac{2}{3}$ should be located about $\frac{2}{3}$ of the distance from the substation to the end of the line." [PTI, 2009]

Switching on large capacitor banks during a voltage decay event could cause over-voltage problems. This is because all the voltage regulators will be at full-boost settings. An alternative approach could be to disconnect load where there is the voltage problem, engage the capacitors then reconnect the load.

[7] Post-transient refers to the period immediately following the capacitor state change, but before the network adjusts(approximately 10 seconds).

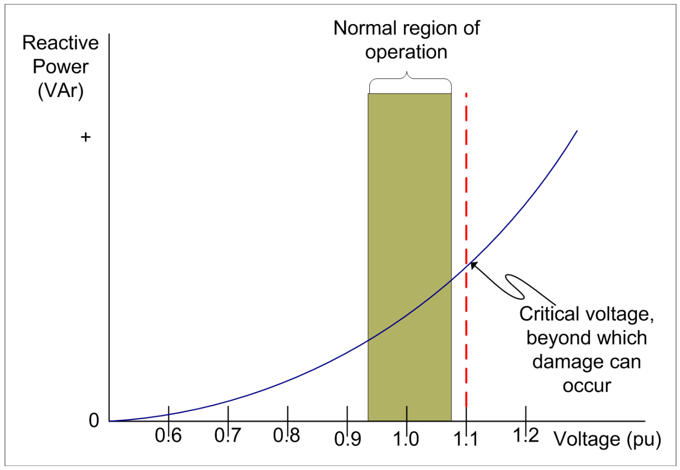

Figure 2.10: Plot showing the reactive generation of a capacitor as the voltage is varied.

2.4.4 Analysis considerations

As mentioned above, the output of capacitors is voltage dependent. As the voltage rises so does the output; the converse is also true. This means that during low voltage scenarios, when shunt capacitors are needed most for voltage support, their output is reduced. Figure 2.10 shows a plot of Reactive power output of a capacitor versus voltage.

While capacitors are a cost-effective way to manage reactive power, over-reliance, particularly on long radial circuits can lead to voltage stability problems.

2.5 FACTS devices

The term Flexible AC Transmission System (FACTS) refers to a family of equipment systems created to make the power grid more reliable and efficient. There are many new designs for FACTS devices. Some of them control impedance, some control voltage and some incorporate energy storage or a backup power source. Two of the more common devices, the Static VAr Compensator (SVC) and the Synchronous Static Compensator (STATCOM) will be examined here since they would both be potential solutions to the problem network in Chapter 5. Note, these are only considered to the extent necessary to understand operating principles. For further investigation into FACTS [Hingorani and Gyugyi, 2000] is excellent reference.

2.5.1 SVCs

The oldest and most common FACTS device is the SVC. It has been in use since the 1970s [Hingorani and Gyugyi, 2000]. SVCs combine several pieces of reactive compensation equipment in parallel with electronic controls in an effort to closely match the network impedance. The electronics increase the price of the SVCs several times that of stand-alone capacitors so they are only used in networks with voltage problems.

An SVC comprises a group of large reactors and capacitors, a step-up transformer and harmonic filters (see figure 2.11). The reactors in an SVC are thyristor-controlled (TCRs). Thyristors are essentially transistors made for high power, high voltage operation. The thyristor acts as a voltage-controlled switch. The voltage reference is applied to the gate, based on the system or other signal. Assuming the thyristors do not have turn off capability (the standard type), they would turn off at the half-cycle zero crossing. They turn on at an adjustable phase angle, which changes the output RMS voltage. This controls the current into the reactor.

The capacitor control can either be thyristor or fast-acting mechanical switch. SVCs that use MSCs are termed Static VAr Systems (SVS). Thyristor-switched capacitors (TSC) work in a similar fashion to the TCRs. One advantage of TSCs is

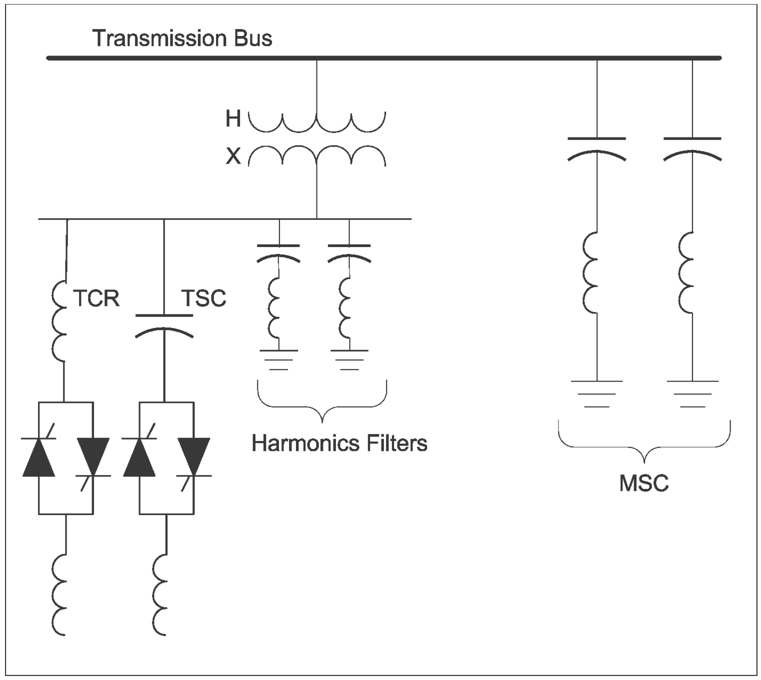

Figure 2.11: Schematic for a general SVC

the capacitor is kept at its full voltage, using the thyristor as a valve to control the reactive current. Keeping the capacitor at full voltage avoids switching transients. For many applications, fast-acting, mechanically switched capacitors (MSCs) are sufficient. The MSC by itself would affect the system voltage in steps, but the TCR is operated to make the transitions smooth. [Hingorani and Gyugyi, 2000]

The combination of the reactor and capacitor in the SVC creates a resonant circuit, the frequency of which will vary depending on the SVC's state (L and C values). As such, the SVC must also have an adjustable harmonic filter to follow the circuit.

Figure 2.12 shows an installation of an SVC in southern Utah. The SVC combines a TCR and Mechanically Switched Capacitors (MSCs) with harmonic filters at 180 Hz (3rd), 300 Hz (5th) and 420 Hz (7th). The system voltage is 138 kV and

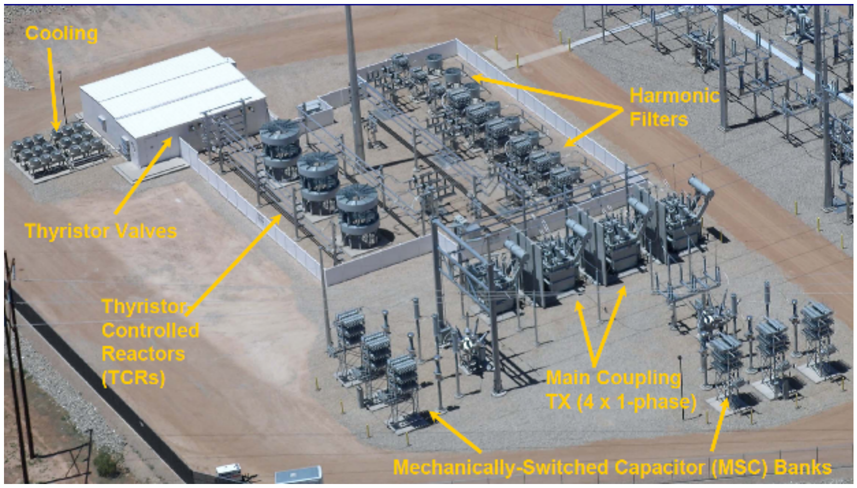

Figure 2.12: This SVC installation was in 2006 at St George Substation in Utah. The system voltage is 138 kV and the operating range is -35 to +100 MVAr. [Sullivan and Hall, 2006]

the operating range is -35 to +100 MVAr. [Sullivan and Hall, 2006]

One disadvantage of the SVC is that it depends on the outputs of the capacitor and reactor. As was shown in section 2.4.4 a capacitor's reactive power generation is dependent on the network voltage. When the voltage is critically low, the SVC's support will be lower.

2.5.2 STATCOMs

The FACTS device that addresses the short comings of the SVC is the synchronous static condenser (STATCOM). The STATCOM can provide inductive or capacitive power regardless of the system voltage. They perform as ideal synchronous condensers[8], but with no moving parts outside of the switching.

The STATCOM has no reactive energy storage. The primary component of

[8]Synchronous condensers are essentially a synchronous machine with no load and no prime mover, able to supply reactive power though excitation control.

the STATCOM is the power converter, which acts similar to a DC-to-AC inverter except that it can transfer power in either direction. The magnitude of the generated AC voltage has no external dependency. It creates reactive compensation by pushing VArs onto the system when the system voltage is lower than the STATCOM terminal voltage or absorbing them when the system voltage is higher. Because of their symmetrical structure, STATCOMs have the same inductive and capacitive outputs, though they can be complemented by adding capacitors.

Figure 2.13 (a) shows the basic structure of the STATCOM. The power converter is connected to a small DC capacitor on one side and a transformer to step up to transmission voltage on the other side.

The capacitor used in the circuit is DC. Its purpose is not to provide reactive power. It is kept charged by the DC created by the circuit. The reactive power is provided by "... circulating alternating current from among the phases of the ac system... The [DC] capacitor must be large enough to handle the charge/discharge current that accompanies the switching sequence of the converter valves." [Noroozian, 2003]

The power converter is built so the wave is chopped by the diode bridge to rectify for a portion of the cycle and invert for a portion of the cycle. As one phase (wire) gets inverted the power becomes a DC source. This is then rectified as AC for another phase (obviously this requires three-phases). "The magnitude of the source voltage is controlled through the DC voltage across the capacitor." [Noroozian, 2003] Since reactive power flows from higher to lower voltage, the reactive current direction will be dependent on the difference between the system and terminal voltages.

An important part of the design is that the thyristors can be controlled to turn off. By controlling the point at which the thyristor conducts, the generated phase

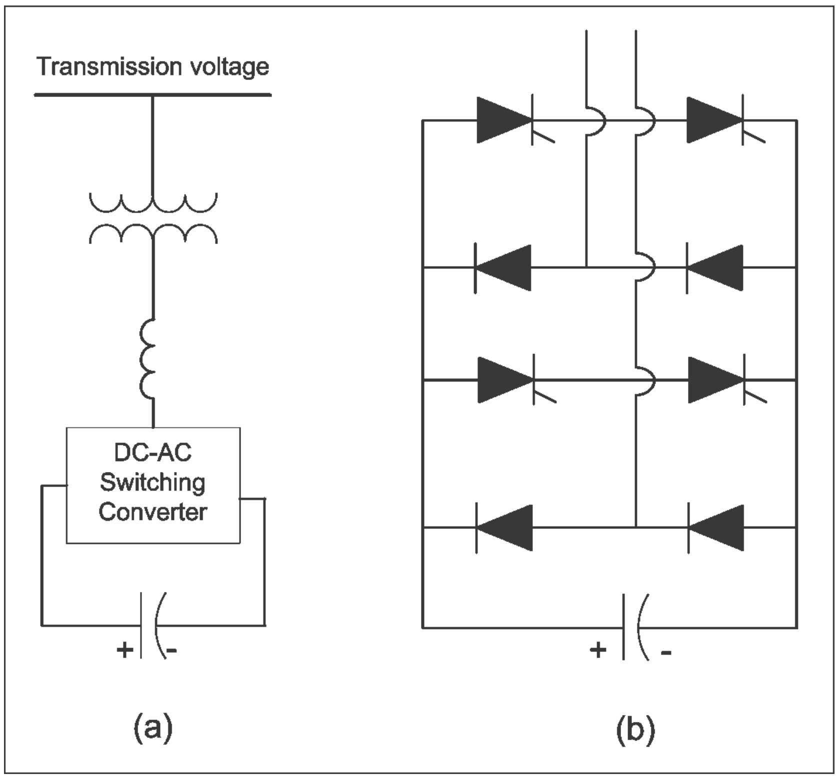

Figure 2.13: (a) Schematic of a typical STATCOM and (b) the detail of the DC-AC converter. Only one phase shown [Hingorani and Gyugyi, 2000]

angle, and thus the power factor can be controlled. [Hingorani and Gyugyi, 2000]

Comparison The STATCOM is more expensive because it requires the use of Gate turn-off (GTO) thyristors. "The investment cost of SVCs is today substantially lower than that of comparable STATCOMs." [Noroozian, 2003] This is due to the high cost of the turn-off semiconductors. They also have higher losses and require significant cooling. Both SVCs and STATCOMs generate harmonics and need harmonic filters.

Because of the SVC's capacitor voltage dependency, the SVC will have voltage limitations, the STATCOM will have output limited by current. "With the same reactive power rating STATCOMs contribute to voltage regulation more effectively than SVCs during under-voltage situations, while SVCs contribute to voltage regulation more effectively than STATCOMs during overvoltage situations." [Noroozian, 2003] For the problem network outlined in Chapter 5, and in most subtransmission networks, undervoltage is a greater concern.

3 Load Influences

3.1 Introduction

The final and most important element influencing voltage stability is loads. As was mentioned in Chapter 1, the driving force behind voltage instability is usually the loads. Voltage instability is most likely to occur at peak seasonal loads during temperature extremes. On hot summer afternoons people use more air conditioning and on cold winter mornings electric heat is at a maximum. Figures 3.1 and 3.2 show the strong correlation of temperature (heating/cooling degree days) to load. Winter heating load has a relatively high power factor (approximately 0.98) because most electric heaters use resistive heating elements. Summer peak loads are due to air conditioning which has a much lower power factor (0.8 to 0.9 pu), meaning heavy summer loads will have a higher reactive requirement in addition to the already high I^2X line losses.

3.2 Load Classes

Loads are an aggregate of many different types of devices, including the loads themselves, wiring, transformer and line losses and distribution (feeder) capacitors. Loads are categorized into four classes based on their behavior and device makeup: residential, industrial, commercial and agricultural.

Residential loads are characterized by higher demand early in the morning and late in the evening. They have low levels during the middle of the night and mid-day. Typical household loads include: refrigerators, air conditioners, heaters,

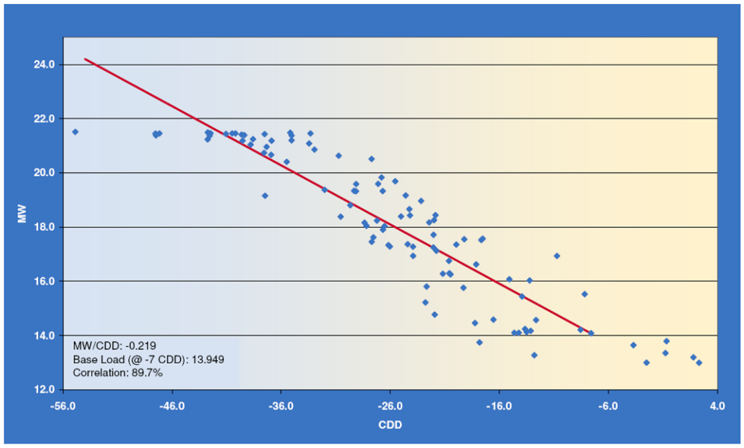

Figure 3.1: This chart shows the correlation of heating degree days to winter loads

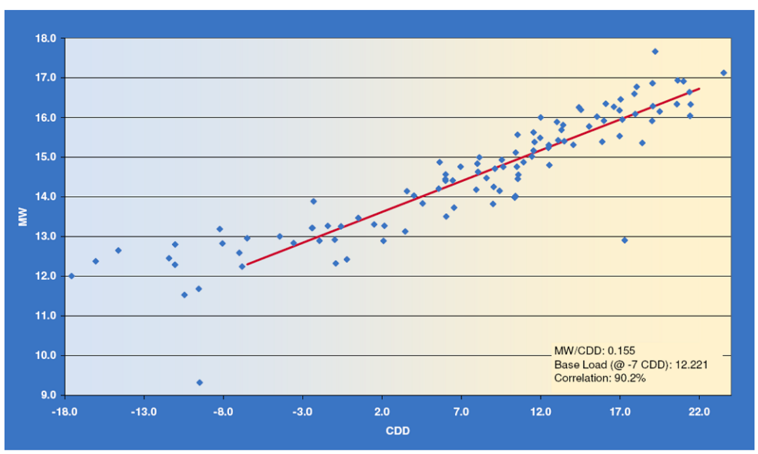

Figure 3.2: This chart shows even stronger correlation of cooling degree days to summer loads

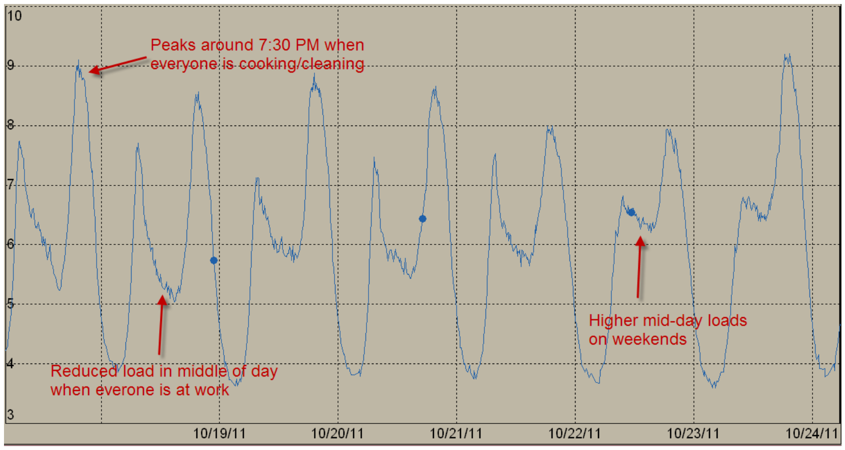

Figure 3.3: SCADA reads showing a weekly profile of residential load

electronics and household appliances. Figure 3.3 shows an example of a residential weekly profile.

Industrial loads have a signature of a distinct on and off time. Examples of industrial load devices are: conveyors, pumps, compressors, furnaces and motors. Figure 3.4 shows an example of a weekly profile for an industrial load.

Commercial loads have traits of both residential and industrial loads. They have the distinct hours associated with a business, but are influenced more by heating and cooling like residential. Figure 3.5 shows an example of a weekly profile for a commercial load.

Agricultural loads have distinctive summer and winter load levels. Summer is the heavily loaded season due to irrigation (pump load), harvesting and processing of the produce (conveyors and canning equipment). Figure 3.6 shows an example of a semi-annual profile for a agricultural load.

Figure 3.4: SCADA reads showing a weekly profile of industrial load

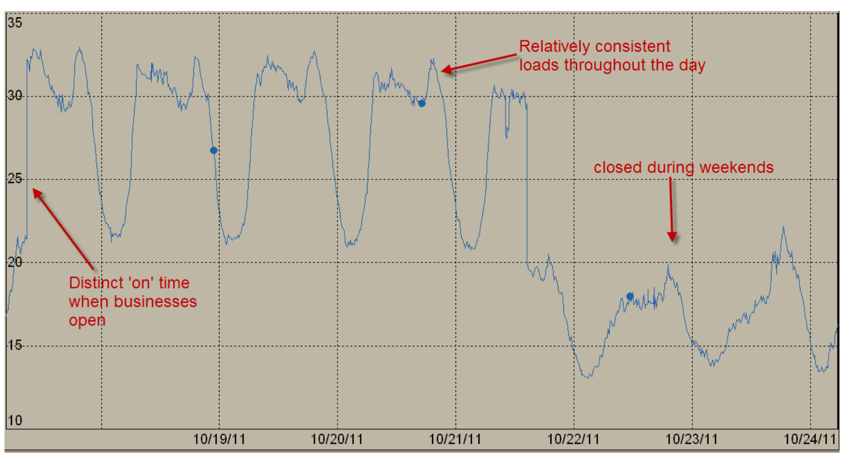

Figure 3.5: SCADA reads showing a weekly profile of commercial load

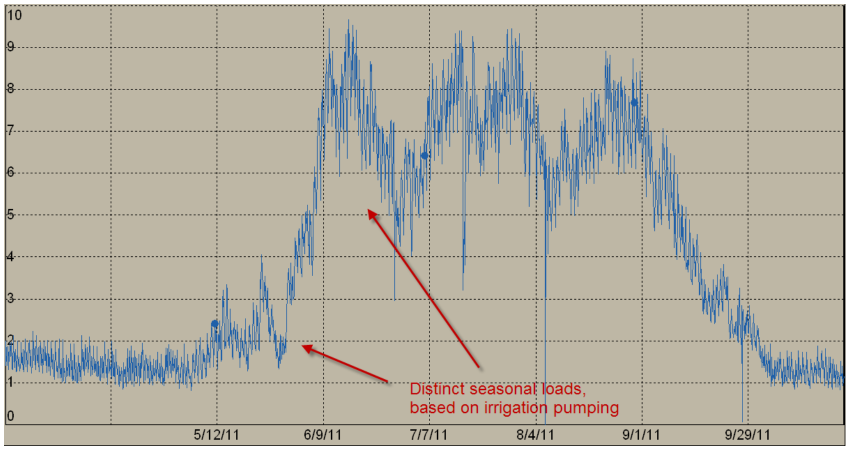

Figure 3.6: SCADA reads showing a semi-annual profile of agricultural load

3.3 Model

3.3.1 Exponential approximation

The most important consideration with loads is their voltage sensitivity. Both the real and reactive power will change for loads as the voltage varies. The general form of the equations is shown in equations 3.1 and 3.2.

$$P = P_0 \left(\frac{V}{V_0}\right)^{\alpha} \tag{3.1}$$

$$Q = Q_0 \left(\frac{V}{V_0}\right)^{\beta} \tag{3.2}$$

For ideal load types $\alpha = \beta$ and the exponents would be: 0 for constant power, 1 for constant current and 2 for constant impedance. Table 3.1 shows the exponential responses of a sample group of devices to voltage change. The α and β values are the exponential influences of voltage for real and reactive power respectively. As an example, an incandescent light has a nearly constant resistance so $\alpha = 2$ and $\beta = 0$.

Fractional Load Exponents		
Device	α	β
Incandescent lights	2.0	–
Air conditioner	0.5	2.5
Furnace fan	0.08	1.6
Battery charger	2.6	4.1
Compact fluorescent light	1.0	0.4
Conventional fluorescent	2.1	3.2

Table 3.1: Table comparing the sensitivity of various devices to voltage [Van Cutsem and Vournas, 1998]

The general method for load modeling will be to break the loads down into three groups based on their reaction to voltage fluctuations: those that have a constant impedance, those that draw a constant current and those whose power does not change. An example of a constant impedance load would be resistive heating. Most modern fluorescent lighting has power factor-corrected ballasts, making the load act like a constant impedance load. Motors are pretty much constant power. Constant current devices are not common; the model is used as a compromise between constant impedance and constant power loads.

$$\text{Constant MVA: } P = P_0 \left(\frac{V}{V_0}\right)^0 \tag{3.3}$$

$$\text{Constant Current: } P = P_0 \left(\frac{V}{V_0}\right)^1 \tag{3.4}$$

$$\text{Constant Admittance: } P = P_0 \left(\frac{V}{V_0}\right)^2 \tag{3.5}$$

Polynomial load class coefficients			
Load Class	Constant current	Constant MVA	Constant impedance
Agricultural	6%	90%	4%
Commercial	30%	50%	20%
Industrial	3%	90%	7%
Residential	30%	50 %	20%

Table 3.2: Table outlining voltage dependency of the load classes.

3.3.2 Polynomial Model

All three types can be combined into a polynomial model to account for the mixture of classes within a given load. For example a load that had 40% constant MVA, 40% constant current and 20% constant admittance would have a load function:

$$P = (0.4)P_0 \left(\frac{V}{V_0}\right)^0 + (0.4)P_0 \left(\frac{V}{V_0}\right)^1 + (0.2)P_0 \left(\frac{V}{V_0}\right)^2 \tag{3.6}$$

This type of mixture of components can then be applied to the classes. Table 3.2 outlines how the classes are applied; for this study loads will be modeled at the substation level as aggregate approximations. These values were only estimated; they could be refined by further research. Fractional load exponents are most applicable when modeling specific loads, whereas the polynomial model is better suited for groups of loads such as distribution feeders, etc.

3.4 Load behavior at low voltage

As mentioned earlier, summertime peak loads are dominated by air conditioning. Air conditioning acts like a constant MVA load with a poor power factor (0.8 to 0.9). As temperatures increase further, the air conditioning duty cycle (time on vs. time off) increases and the aggregate load diversity[1] decreases. As diversity goes down the total system load goes up.

The relatively small inertia of an air conditioner motor contributes to its tendency to stall[2] rapidly. Some new air conditioners have electronic controls that disconnect the unit when voltage gets too low. Tests conducted by [N Lu, 2008] showed a sample group of modern air conditioners with average low voltage stall at 0.62 pu. Five of the 13 tested tripped off at 0.76 pu (average) and eight restarted at 0.78 pu (average). Both the trip and restart settings were well below a safe system recovery voltage (0.9 pu), meaning they will probably be on as the system enters voltage collapse.

Motors are an important factor in load estimation. Most motors are of the induction type. Synchronous motors are less common, but actually have a positive effect on voltage stability by the action of their exciters.

> "About 57% of the US electricity consumption goes to power motors... About 78% of industrial sector energy use is for motors; the corresponding values for residential and commercial sectors are 37% and 43%. Induction motors consume 90% of total motor energy... at sustained voltages of 0.7 to 0.9 pu many motors will stall and draw large amounts of reactive power. Stalling of one motor may cause nearby motors to stall." [Taylor, 1994]

Many induction motors have a contactor drop out that will disconnect the motor if

[1] Aggregate load diversity refers to the sum total of of loads turned on. At any instant on a hot day some air conditioners will be off and some will be on. If the power goes off for 20 minutes most, if not all the air conditioners would be on for some period. During this period the diversity would be close to zero.

[2] Stalling is when the voltage (and thus electromagnetic torque) is too low to move the machine's rotor. During this condition the machine will draw large amounts of reactive power and deliver no real power.

the voltage drops too low; this point varies between 40-70%. Detailed motor models are important for transient voltage studies. For the steady state analysis in this paper, motors will be considered a constant MVA load; motor slip adjusts as voltage goes down.

Adjustable speed drives (ASD) are a modern genre of highly efficient and accurate motors with electronic speed controllers. They are the exception to the growing trend towards more constant MVA loads. As the terminal voltage decreases the power factor actually improves (the firing advances, improving the displacement power factor). [PTI, 2009]

With constant impedance loads, the power they consume will decrease during low voltages. For example, incandescent lights will dim. New fluorescent lights act like constant MVA loads with power factor correction. "About $\frac{1}{3}$ of commercial load is lighting, largely fluorescent... below 80% [of nominal voltage] they will extinguish." [Taylor, 1994]

3.5 Summary

Assuming regulators and transformer tap changers are being used, the loads would see consistent voltage and thus, the particular load model would not matter much. Most customers being downstream would not experience a change in voltage unless the regulator had reached the limit of its range. If the system voltage is low and the tap changers had reached their maximum boost value, the voltage at the load would follow the system variations and would more closely resemble the voltage dependent load models. While the load would be reduced when the voltage is low (based on the previous analysis), the current and I^2X line losses would be higher. The LTCs and regulators mask the transmission problem from the loads, which could keep them higher than they would have been, contributing to voltage instability.

It is possible to take advantage of the voltage dependency of loads and deliberately lower a regulator when the system is in trouble. Similarly, deliberate load shedding can be implemented in such a situation. Care must be taken however, to exclude hospitals, prisons, sewage treatment plants, public safety facilities or customers with voltage sensitive manufacturing processes.

4 Analysis Techniques

This chapter covers the power flow, PV, VQ analysis techniques. Other techniques not used in this study include bifurcation and eigenvalue analysis. Description of these methods can be found in [Kundur, 1994] and [Van Cutsem and Vournas, 1998].

4.1 Power flow modeling

4.1.1 Impetus

Power system planners are interested in seeing how the system behaves when it is most stressed, during peak demand and during extreme light loads. Peak demand is important because it reveals what equipment will be overloaded and where there might be low voltages. Light load is also important since it can result in high voltage problems. One way the system can be analyzed is through power flow models. Power flow models show the entire connected system (60 kV and above) as a contiguous circuit, including generation, loads, transmission lines and other equipment. It attempts to show a snapshot of the system at an instant for a given load and generation level.

The reason large bus networks must be modeled is to achieve more accurate models for various load conditions, to prevent the possibility that changing the network in one area will have some unforeseen consequence someplace far off and to capture dynamic effects such as oscillations from disturbances.

Loads are modeled as bulk items attached to the high voltage system. Data is collected from every utility in a region by a coordinating entity. The data is then compiled into a base case against which all other scenarios will be compared. The common goal among the member utilities is system stability and reliability through better planning. As an example, information of the entire western United States and Canadian grid is gathered together by the Western Electricity Coordinating Council (WECC). The WECC area operates independently from the rest of the continent, connected only through a few weak HVDC connections. WECC provides a case to its members who can then use it to model their own networks as part of the grid. The current WECC Heavy Summer case has near 18,000 network nodes or buses [WECC, 2011]. This model includes roughly 28,800 network branches, 9,000 bulk loads, and 3,600 generating units. The simulation model of such a system requires approximately:

- 18,000 Simultaneous complex algebraic equations for the network modeling.
- 9,000 Nonlinear load boundary condition equations.
- 3,600 Equivalent network sources (Norton) to represent generator internal voltages.
- 14,000 Coupled, simultaneous, nonlinear differential equations governing the variations of 14,000 state variables, to model the generating units and their controls.

To handle such large computing requirements, special power flow modeling software has been developed. WECC provides heavy summer, heavy winter, light spring and light autumn cases to its members. The primary providers of the software for modeling are GE, Seimens (PTI) and PowerWorld. While there is presently no

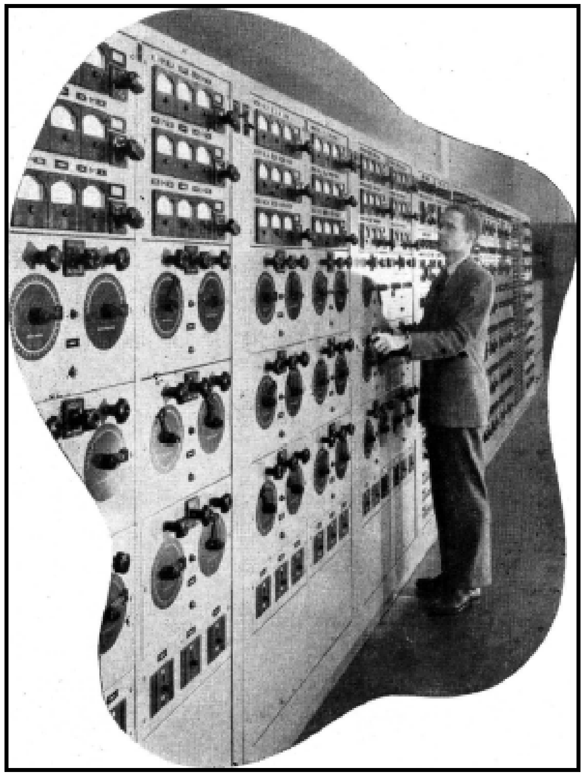

Figure 4.1: The 'Electric brain' power flow model [Westinghouse, 1944]

standard, WECC favors the GE software, though it also publishes cases in the PTI format, which is used for this study.

4.1.2 Evolution

The evolution of power flow modeling closely follows the computational capabilities available at the time. Before computer models were available, actual small-scale circuits were assembled on modeling boards. Obviously the complexity of the network was limited to what could be practically built. Figures 4.1 and 4.2 are examples of early efforts in network modeling. This type of board used a DC circuit with variable resistors to help solve voltage regulation problems in the 1930-1950s.

Figure 4.2: Early example of physical power flow modeling [Goettling, 2009]

With such a limited number of network elements, only small portions of the system could be modeled at a time. Early computer models were also limited in the number of buses available. Today, production power flow software programs can handle 100k+ buses. This means much greater detail can be added to the model, increasing its accuracy. Along with better software algorithms, computer speeds have allowed very large networks to be modeled very rapidly. Previously, the device models and algorithms were based around computing limitations.

> "The selection of equipment models was strongly biased by computing equipment limitations during the early development of power system simulation. Many simulation programs used equipment models that were characterized more by their ability to fit within specific computer constraints or their compatibility with given mathematical techniques than by their engineering accuracy. Modern computer developments have virtually eliminated the predominance of computational considerations in selecting equipment models." [Siemens, 2011]

Power flow programs attempt to represent the system in steady state, where an equilibrium point has been reached between the power generated and power demanded (plus losses). The basic parts of the model are the buses or nodes, the branches connecting the buses, power sources and sinks. The nodal network is compiled with admittance values for each branch. The values are complex, and based on the equivalent π model of a transmission line (see section 2.2). These values are known and specified by the user. While the circuit model contains many elements, the data is condensed into four values, either specified or computed, for each bus. Those values are: real power, reactive power, voltage magnitude and voltage phase angle.

4.1.3 Mathematical Background

The focus of this section is to illustrate the most common methods used in solving power flow problems. The results from the power flows are used to make sure: there are no overloading transmission lines or transformers; voltage is maintained within acceptable limits at all buses; and generator reactive output stays within the operating limits.

The following are the known input data for power flow calculations:

- Transmission line impedances and charging admittances.
- Transformer impedances and tap ratios.
- Admittances of shunt-connected devices such as static capacitors and reactors.
- Load-power consumption at each bus of the system.
- Real power output of each generator or generating plant.

- Either voltage magnitude at each generator bus or reactive power output of each generating plant.
- Maximum and minimum reactive power output capability of each generating plant.

The quantities to be determined are:

- The magnitude of the voltage at every bus where this is not specified in the input data.
- The phase angle of the voltage at every bus except the reference (swing) bus.
- The reactive power output of each plant for which it is not specified.
- The real power, reactive power, and current flow in each transmission line and transformer.

[Siemens, 2011]

The admittance matrix is derived from the general statement, $\hat{I} = \hat{Y}\hat{V}$ where $\hat{\mathrm{V}}$ and $\hat{\mathrm{I}}$ are vectors of the the phasor form of voltage and current respectively into any bus *1 to n*. The expanded form would be (using the tilde to indicate phasor form):

$$\begin{bmatrix} \tilde{I}_1 \\ \tilde{I}_2 \\ \vdots \\ \tilde{I}_n \end{bmatrix} = \begin{bmatrix} \tilde{Y}_{11} & \tilde{Y}_{12} & ... & \tilde{Y}_{1n} \\ \tilde{Y}_{21} & \tilde{Y}_{22} & ... & \tilde{Y}_{2n} \\ \vdots & \vdots & \ddots & \vdots \\ \tilde{Y}_{n1} & \tilde{Y}_{n2} & ... & \tilde{Y}_{nn} \end{bmatrix} \begin{bmatrix} \tilde{V}_1 \\ \tilde{V}_2 \\ \vdots \\ \tilde{V}_n \end{bmatrix} \tag{4.1}$$

This is the basis for the differential equations that will be derived to calculate the unknowns at each bus. The diagonal elements of the matrix are the self admittance, i.e., the sum of admittances terminating at the bus. The off-diagonal values are the individual admittances between buses i and j. The case will have a square matrix of size n, where n is the number of buses. Most buses will have only a few lines connecting to them; the larger the matrix, the more sparse. Further simplifications can be made from the upper and lower off-diagonal parts of the matrix based on the loose coupling between real power and voltage, and reactive power and phase angle. This topic will be discussed later in this chapter.

Buses Each bus has an associated type which describes whether it will be connected to a load (PQ) where P and Q are specified, generation (PV) where P and V are specified or a swing bus (the initializing or reference bus), or if the bus will be disconnected. Non-load, connecting buses are considered PQ the type. The swing bus is usually connected to a very large generation source. This bus has voltage magnitude and phase angle specified and calculates the necessary P and Q to meet the system needs. The initial guess of voltage magnitude and angle are also specified for each bus prior to computing a solution. [Taylor, 1994]

Loads Loads are entered with both real and reactive power. The power can be specified as constant MVA, constant current, or constant impedance (see Chapter 3). For constant MVA and constant current load buses, P and Q are specified, then voltage magnitude and phase are calculated. Constant impedance loads are included in the admittance matrix. [Kundur, 1994]

Generators Generators have a specified P and V. They will try to maintain the voltage at an associated bus. The values entered are: real power generated, initial reactive power, maximum and minimum reactive power limits and the voltage setpoint. If, when trying to maintain the voltage setpoint, the generator reaches its maximum or minimum reactive power limit, the generator is treated as a negative load (PQ bus) with the generator's specified P, and the reactive power at the Q-limit value. At that point, the voltage magnitude and phase angle would be calculated for the bus.

Branches (non-transformer) For branches, the program uses the π equivalent transmission line model (see section 2.2). The values entered are the reactive impedance, the charging suceptance between the conductor phases and to ground, the resistance, the conductance (sometimes) and the lines' thermal rating (for checking thermal overloads).

Transformers Transformers are the most complicated equipment in the model. The values specified are: the magnetizing suceptance and conductance, the resistance in p.u., the leakage reactance as a percentage, the turns ratio in terms of voltage and the MVA rating. If the transformer is a load tap changing transformer (LTC) the control mode, off-nominal turns ratio (the maximum possible range for the taps), the target voltage range which the LTC will try to hold the number of tap positions available as well as any real or reactive compensation (see section 2.3). Transformers are treated similar to a branch in the admittance matrix.

Switched Shunts Switched shunt information is also entered. The program treats a switched shunt device as a voltage-dependent reactive power source. Shunt capacitors are a positive Q source and reactors a negative source. The values specified are the control method, setpoints, an initial value and maximum/minimum outputs.

FACTS devices The genre of FACTS devices includes STATCOMs and Static VAr Compensators (SVCs). These two items work in a similar manner from the powerflow standpoint. They both produce zero real power and have a range of reactive power output (positive and negative). Both rely on solid-state electronics to optimize their output for network conditions. The SVC is more discrete in operation with distinct levels of capacitor or reactor engagement. Both have nearly instantaneous adjustments to meet the reactive demand. The primary difference between the models is the SVC will be a group of capacitors and reactors that can switch with almost no delay. The STATCOM can be modeled as either a generator or a FACTS device. The output is the same for both elements, but as a generator the STATCOM can control the voltage on a non-adjacent bus: As a FACTS device it controls the voltage only on the adjacent bus.

Swing bus In addition to the elements described above, each power flow case must have one swing (slack) bus. The purpose of this bus is to be a reference point with a voltage of $1\angle 0°$. From this bus, all the other angles are referenced. The swing bus has no real or reactive power limits. It produces or absorbs whatever is necessary to make the case converge.

The programs have several other elements which can be specified such as area interchanges, series capacitors and reactors, or HVDC line information. In addition, new features are being added routinely.

The boundary conditions required by the multiple bus types and their unknowns make the problem nonlinear, and iterative techniques are required to solve the equations. [Kundur, 1994] The concept behind iterative techniques is to:

1. Assign an initial guess for values of variables;
2. Solve the equations using those guesses;
3. Adjust the values based on the outcomes;
4. Repeat by solving again; and
5. Compare the calculated variable against a defined tolerance for the termination condition. [Glover and Sarma, 2002]

If starting from a previously saved case, the previous values for voltage magnitude and phase are used. If solving from a *flat start*, all the angles are solved first starting from the swing bus at 0° and the initial guesses for the voltage magnitudes are set to the buses nominal values.

4.1.4 Gauss-Seidel method to solve a system of equations

The earliest iterative method used in power flows was the Gauss-Seidel method. The method uses the above steps and in step three, adjusts the values by adding the difference between the old and new values while utilizing the values already calculated.

The Gauss Seidel method works as follows, consider the matrix equation **Y=AX**, or

$$y_k = A_{k1}x_1 + A_{k2}x_2 + \cdots + \underline{A_{kk}x_k} + \cdots + A_{kn}x_n. \tag{4.2}$$

Solving for x_k the equation becomes

$$x_k = \frac{1}{A_{kk}}[y_k - (A_{k1}x_1 + \cdots + A_{k-1,1}x_{k-1} + A_{k+1,1}x_{k+1} + ...A_{kn}x_n)] \quad (4.3)$$

$$= \frac{1}{A_{kk}}\left[y_k - \sum_{n=1}^{k-1} A_{kn}x_n - \sum_{n=k+1}^{N} A_{kn}x_n\right] \quad (4.4)$$

$$x_k(i+1) = \frac{1}{A_{kk}}\left[y_k - \sum_{n=1}^{k-1} A_{kn}x_n(i+1) - \sum_{n=k+1}^{N} A_{kn}x_n(i)\right]. \quad (4.5)$$

[Glover and Sarma, 2002]

Here $(i + 1)$ denotes the next interation and (i) denotes the last iteration solved. "Since power-flow bus data consist of P_k and Q_k for load buses and P_k and V_k for voltage controlled buses, nodal equations do not directly fit the linear equation format" [Glover and Sarma, 2002] The current into the bus can be related to the other values by:

$$\tilde{I}_k = \frac{P_k - jQ_k}{\tilde{V}_k^*} \quad (4.6)$$

Where $\tilde{V}_k^*$ is the complex conjugate of voltage at bus k.

Applying the Gauss-Seidel method, the voltage magnitude and phase can be determined by:

$$V_k(i+1) = \frac{1}{Y_k}\left(\frac{P_k - jQ_k}{V_k^*(i)} - \sum_{n=1}^{k-1} Y_{kn}V_n(i+1) - \sum_{n=k+1}^{N} Y_{kn}V_n(i)\right). \quad (4.7)$$

Similarly, $(i{+}1)$ is the next value and (i) is the previous value or initial guess. To get the reactive power for voltage controlled (generator) buses the equation would be rearranged to:

$$Q_k = -\mathrm{Im}\left[\frac{P_k - jQ_k}{V_k^*(i)} - \sum_{n=1}^{k-1} Y_{kn}V_n - \sum_{n=k+1}^{N} Y_{kn}V_n(i)\right]. \tag{4.8}$$

[Kundur, 1994]

4.1.5 Newton-Raphson method

The main method used today is the Newton-Raphson method. The Newton-Raphson method is similar to the Gauss-Seidel method except in step three it adds the *derivative* of the function times the *change* in calculated value to the new value. Newton-Raphson in general terms is determined by starting from the set of equations:

$$\begin{aligned} f_1(x_1, x_2, ..., x_n) &= b_1 \\ f_2(x_1, x_2, ..., x_n) &= b_2 \\ ... \quad ... \quad ... \quad & ... \\ f_n(x_1, x_2, ..., x_n) &= b_n \end{aligned} \tag{4.9}$$

Where $f\ (x)$ is the function with the initial guesses, $\mathbf{b}$ is the desired result. The goal is to determine the x values to satisfy the equation $f(x) = \mathbf{b}$. To do this, correction factors Δx can be added to the x values: [1]

$$\begin{aligned}
f_1(x_1^0 + \Delta x_1, x_2^0 + \Delta x_2,\ \ldots\ x_n^0 + \Delta x_n) &= b_1 \\
f_2(x_1^0 + \Delta x_1, x_2^0 + \Delta x_2,\ \ldots\ x_n^0 + \Delta x_n) &= b_2 \\
\ldots \quad \ldots \quad \ldots \quad \ldots & \\
f_n(x_1^0 + \Delta x_1, x_2^0 + \Delta x_2,\ \ldots\ x_n^0 + \Delta x_n) &= b_n
\end{aligned} \tag{4.10}$$

These terms can then be expanded by Taylors theorem:

$$b_i = f_i(x_1^0 + \Delta x_1, x_2^0 + \Delta x_2,\ \ldots\ x_n^0 + \Delta x_n) \tag{4.11}$$

$$= \underbrace{f_i(x_1^0, x_2^0,\ \ldots,\ x_n^0)}_{Previous\ results} \left[\left(\frac{\partial f_i}{\partial x_1}\right) \Delta x_1 + \left(\frac{\partial f_i}{\partial x_2}\right) \Delta x_2 +\ \ldots\ \left(\frac{\partial f_i}{\partial x_n}\right) \Delta x_n \right] \tag{4.12}$$

Note, only the first term of the Taylor series is used. Put into matrix form, the equation becomes:

$$\underbrace{\begin{bmatrix} b_1 - f_1(x_1^0, x_2^0,\ \ldots\ x_n^0) \\ b_2 - f_2(x_1^0, x_2^0,\ \ldots\ x_n^0) \\ \vdots \\ b_n - f_n(x_1^0, x_2^0,\ \ldots\ x_n^0) \end{bmatrix}}_{errors\ \Delta f} = \underbrace{\begin{bmatrix} \left(\frac{\partial f_1}{\partial x_1}\right)_0 & \left(\frac{\partial f_1}{\partial x_2}\right)_0 & \cdots & \left(\frac{\partial f_1}{\partial x_n}\right)_0 \\ \left(\frac{\partial f_2}{\partial x_1}\right)_0 & \left(\frac{\partial f_2}{\partial x_2}\right)_0 & \cdots & \left(\frac{\partial f_2}{\partial x_n}\right)_0 \\ \vdots & \vdots & \ddots & \vdots \\ \left(\frac{\partial f_n}{\partial x_1}\right)_0 & \left(\frac{\partial f_n}{\partial x_2}\right)_0 & \cdots & \left(\frac{\partial f_n}{\partial x_n}\right)_0 \end{bmatrix}}_{Jacobian} \underbrace{\begin{bmatrix} \Delta x_1 \\ \Delta x_2 \\ \vdots \\ \Delta x_n \end{bmatrix}}_{corrections \Delta x} \tag{4.13}$$

Applying the Newton-Raphson method to the power flow problem starts with the equation

$$\tilde{S} = P_k + jQ_k = \tilde{Y_k} \tilde{I_k^*} \tag{4.14}$$

[1] The notations (i) and $(i{+}1)$ have been used to indicate the previous and next iterations respectively. To simplify the longer equations the superscript 0 will be used to indicate the previous iteration.

Recall from (4.2) the current into a given bus k is

$$\tilde{I}_k = \sum_{m=1}^{n} \tilde{Y}_{km} \tilde{V}_m \tag{4.15}$$

Substitution of I_k yields:

$$P_k + jQ_k = \tilde{V}_k \sum_{m=1}^{n} (G_{km} - jB_{km}) V_m^* \tag{4.16}$$

The product of phasers V_k and V_m^* are then be expressed as:

$$\tilde{V}_k \tilde{V}_m = (V_k e^{j\delta_k})(V_m e^{-j\delta_m}) = V_k V_m (\cos\theta_{km} + j\sin\theta_{km}) \tag{4.17}$$

Where δ_k and δ_n are the voltage angles of the current bus being calculated and the connected buses respectively, and θ_{km} is the phaser angle of the complex admittance between the current bus and the connected buses. The corresponding equations for real and reactive power are:

$$P_k = V_k \sum_{m=1}^{n} (G_{km} V_m \cos\theta_{km} + B_{km} V_m \sin\theta_{km}) \tag{4.18}$$

$$Q_k = V_k \sum_{m=1}^{n} (G_{km} V_m \sin\theta_{km} - B_{km} V_m \cos\theta_{km}) \text{[Kundur, 1994]} \tag{4.19}$$

Comparing the specified values of real and reactive power to the calculated values

$$
\begin{aligned}
P_1(\theta_1,\ \cdots\ \theta_n,\ V_1,\ \cdots\ V_n) &= P_1^{sp} \\
P_n(\theta_1,\ \cdots\ \theta_n,\ V_1,\ \cdots\ V_n) &= P_n^{sp} \\
...\quad \cdots \quad \cdots \quad & \cdots \\
Q_1(\theta_1,\ \cdots\ \theta_n,\ V_1,\ \cdots\ V_n) &= Q_1^{sp} \\
\cdots \quad \cdots \quad \cdots \quad & \cdots \\
Q_n(\theta_1,\ \cdots\ \theta_n,\ V_1,\ \cdots\ V_n) &= Q_n^{sp}
\end{aligned}
\tag{4.20}
$$

Equation 4.21 shows the full matrix format of the power equation:

$$
\underbrace{\begin{bmatrix}
P_1^{sp} - P_1(\theta_n^0, \cdots \theta_n^0, V_1^0, \cdots V_n^0) \\
\vdots \\
P_1^{sp} - P_n(\theta_1^0, \cdots \theta_n^0, V_1^0, \cdots V_n^0) \\
Q_1^{sp} - Q_1(\theta_1^0, \cdots \theta_n^0, V_1^0, \cdots V_n^0 \\
\vdots \\
Q_1^{sp} - Q_1(\theta_1^0, \cdots \theta_n^0, V_1^0, \cdots V_n^0)
\end{bmatrix}}_{errors\ \Delta P,\ \Delta Q}
$$

$$
= \underbrace{\begin{bmatrix}
\left(\frac{\partial P_1}{\partial \theta_1}\right) & \cdots & \left(\frac{\partial P_1}{\partial \theta_n}\right) & \left(\frac{\partial P_1}{\partial V_1}\right) & \cdots & \left(\frac{\partial P_1}{\partial V_n}\right) \\
\vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\
\left(\frac{\partial P_n}{\partial \theta_1}\right) & \cdots & \left(\frac{\partial P_n}{\partial \theta_n}\right) & \left(\frac{\partial P_n}{\partial V_1}\right) & \cdots & \left(\frac{\partial P_n}{\partial V_n}\right) \\
\left(\frac{\partial Q_1}{\partial \theta_1}\right) & \cdots & \left(\frac{\partial Q_1}{\partial \theta_n}\right) & \left(\frac{\partial Q_1}{\partial V_1}\right) & \cdots & \left(\frac{\partial Q_1}{\partial V_n}\right) \\
\vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\
\left(\frac{\partial Q_n}{\partial \theta_1}\right) & \cdots & \left(\frac{\partial Q_n}{\partial \theta_n}\right) & \left(\frac{\partial Q_n}{\partial V_1}\right) & \cdots & \left(\frac{\partial Q_n}{\partial V_n}\right)
\end{bmatrix}}_{Jacobian}
\underbrace{\begin{bmatrix}
\Delta\theta_1 \\ \vdots \\ \Delta\theta_n \\ \vdots \\ \Delta V_1 \\ \vdots \\ \Delta V_n
\end{bmatrix}}_{corrections \Delta\theta,\ \Delta V}
\tag{4.21}
$$

In abbreviated form:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \theta} & \frac{\partial Q}{\partial V} \end{bmatrix} \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} \tag{4.22}$$

[Kundur, 1994]

In equation (4.21) the left term is the difference between the specified P and Q values for the bus. The center term, Jacobian matrix is the power matrix and the right term is the correction vector matrices of voltage phase and magnitude. It should be noted that the Jacobian matrix is partitioned with the top-left quadrant the partial derivatives of real power with respect to voltage phase angle; the top-right quadrant with respect to voltage magnitude; the bottom-left quadrant the partial derivative of reactive power with respect to phase angle and the bottom-right quadrant with respect to voltage magnitude. Note, the upper-left and lower-right terms are more significant because real power flow is a strong function of $\Delta\theta$ and reactive power flow is a strong function of ΔV.

Comparison

The Gauss-Seidel method will diverge for some scenarios and is unable to accommodate series capacitors, as such it is not used as frequently. A modified version of the Gauss-Seidel equation is still a better option where no initial estimates are available (flat starts). The Newton-Raphson method solves more readily and is faster.

4.2 P-V modeling

Along with Powerflow modeling, transmission planners commonly use P-V and V-Q models to help understand a system's voltage stability. These models relate voltage to real and reactive power at the load.

The maximum power transfer of a circuit occurs when the load impedance matches the source impedance. In the case where the load is served off a long transmission line, the Thevenin equivalent of the source impedance would be roughly the line's impedance plus the step-down transformer's impedance. Loads are a combination of time-varying resistive and inductive impedances. The maximum power transfer point is that point at which the load impedance most closely matches the complex conjugate of the sum of impedances from the transformers and transmission lines. The resistance is relatively small for transmission lines so the more significant influence will be the inductive portion of the load. $P_{maximum} = \frac{VE}{2X}$ $V_{Pmax} = \frac{E}{\sqrt{2}}$ approximately 0.71 pu. In practice, this value varies (usually higher). Beyond this point voltage will rapidly decrease with increasing demand. An illustration of this can be seen in Figure 5.2

The maximum power point can be increased by several ways. First by adding series capacitors in the transmission line or adding shunt capacitors at the load end. The maximum power transfer point on the P-V curve is called the *critical point.* [Taylor, 1994] Before the critical point, incremental additions of load will correspond to an equal addition of generation. After the critical point more generation will be needed to offset line losses for each increase in load.

This leads to the question: what happens after the maximum power transfer point? The answer is illustrated in the P-V curve. As the power demanded increases, the higher current will cause further drop in the voltage at the load end by $V = IX$. This in turn will force the generator to increase the source-end voltage to push more VArs down the line to support the load voltage. The process results in decay of voltage at the load end due to this positive feedback.

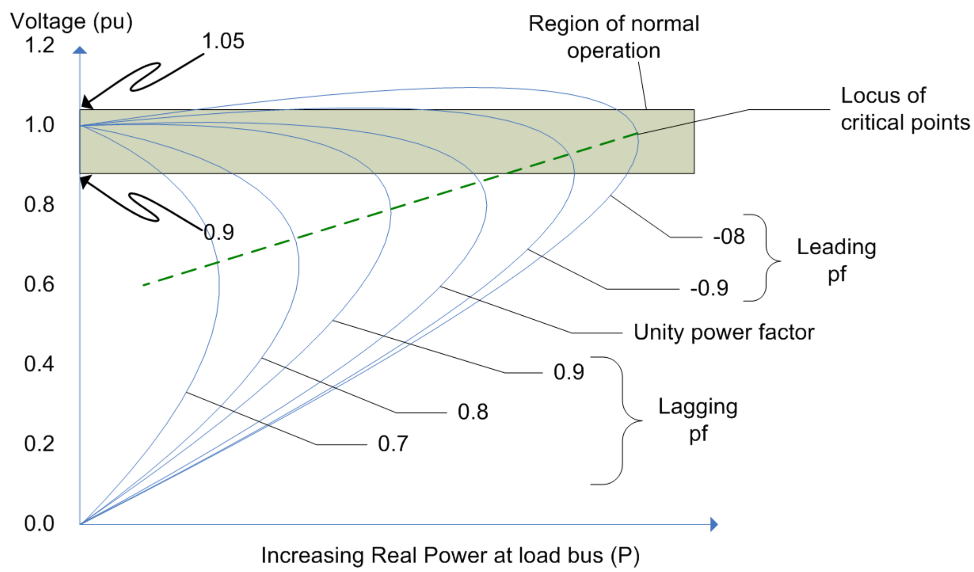

Figure 4.3: Normalized P-V Curve.

Figure 4.3 shows a theoretical P-V curve normalized to the source voltage. All points on and inside the curve would be possible convergence points where the system could find an equilibrium state. In reality, the normal points of operation are between 0.9 and 1.05 pu. Note, it has been shown mathematically by Van Cutsem, and there is at least one documented case demonstrating a system can converge at an abnormally low voltage in a partial voltage collapse event. [Taylor, 1994] [Van Cutsem and Vournas, 1998]

The voltage at the load end can be described by: $\bar{V} = \bar{E} - jX\bar{I}$. The real power into the bus would then be:

$$
\begin{aligned}
S &= P + jQ = \bar{V} I^* \\
&= \bar{V}\left(\frac{\bar{E}^* - \bar{V}^*}{-jX}\right) \\
&= \frac{j}{X}(EV\cos\theta + jEV\sin\theta - V^2) \\
&= \underbrace{-\left(\frac{EV\sin\theta}{X}\right)}_{P} - j\underbrace{\left(\frac{V^2 + EV\cos\theta}{X}\right)}_{Q}
\end{aligned}
$$

$$Q = -\frac{V^2}{X} + \frac{EV}{X}\cos\theta \tag{4.23}$$

$$P = \frac{-EV}{X}\sin\theta \tag{4.24}$$

[Van Cutsem and Vournas, 1998]

When creating a P-V curve from power flow simulations, the lower limit will be much higher than the theoretical curve because the case will not converge when the voltage gets too low ($\approx$ 3.5 MW in figure 4.4). In real situations, protection and control relays would intervene (or something would break) before the voltage got that low.

4.3 V-Q Modeling

V-Q curves compare the voltage and reactive power at a specified test bus. They are often referred to as Q-V curves, but the terminology of V-Q emphasizes that Voltage is the independent variable on the abscissa which is being associated with the reactive power required to maintain that voltage. The most common method for finding a VQ curve is by using powerflow analysis. This method incorporates a fictitious generator with zero real and infinite reactive power output, similar to an ideal synchronous condenser. This generator is placed at the studied bus. In the case where the network is radial, the generator could equivalently be placed at the source; either case would capture the characteristics of the network. For radial networks, the studied bus is usually at or near the end of the circuit since that is where the voltage would be most variable.

The ordinate of a VQ graph is the reactive power required or flowing into the studied bus. The positive values represent a deficiency. The negative values below the zero axis represent reactive power excess. If the synchronous condenser is at the studied bus, the positive values are the reactive power flowing into the bus, while the negative values are reactive power flowing out of the bus. The inflection point, also called the critical point, is where $\frac{\delta Q}{\delta V} = 0$, which represents the beginning of voltage collapse.

Similar to P-V curves, V-Q curves have limits beyond practical operating limits, but are helpful to illustrate theoretical behavior. On the right side of the critical point the curve has an exponential, concave, positive slope. As the required voltage setpoint is raised, the reactive power required to hold that voltage becomes exponentially more difficult due to the V^2 relationship. In this region adding capacitors will raise the voltage at the studied bus. On the left side of the critical point the curve has an exponential, negative, concave shape. This is applicable to loads represented as constant MVA. As the voltage decreases, the current increases, causing higher I^2X losses, thus requiring greater reactive support. Constant impedance loads would have a flatter shape.

Reactive Power Margin or VAr Margin, is an important concept in studying voltage stability. It is the vertical distance from the critical point to the zero axis crossing. It represents the amount of reactive reserve a system has. It is also a quantifiable value that can be directly influenced by the insertion of shunt capacitors. WECC has reactive margin requirements for utilities. The following is the RPM operating requirement as defined by WECC.

> "The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worse: (i) a 5% increase beyond maximum forecasted loads or (ii) a 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin." [WECC, 2006]

The operating point occurs where the curve crosses the zero axis, representing zero additional reactive support needed. In some weak circuits the operating point will be above the zero axis, implying the network will be unstable if that load level is reached without additional reactive compensation.

Note that the critical point shifts right or left with different load levels. As the load increases the critical point will be at a higher voltage, potentially even above 1.0 pu. It is expected that as the voltage gets very low the system would become less stable, but for these cases even normal operating voltages are too low.

Figure 4.5 shows curves for the same network with different real power loads. Curve A represents the system operating at a light load; curve D represents the same system at peak loading and curve E represents the system operating at peak load and with a contingency. As the network's capacity is more heavily utilized the ability to transfer reactive power diminishes. Besides shifts from altering the real power at the load, the curves can shift from addition of reactive compensation, e.g. shunt capacitors or by altering the network either strengthening e.g. tie to an adjacent network or weakening e.g. an outage changing the network configuration and thus the impedance.

While the theoretical VQ curve is helpful, practical operating voltages are limited to 0.9 to 1.1 pu. The VQ curve in Figure 4.6 was accomplished by reducing the load enough to get the lower voltage range, otherwise the case would not have converged.

Note that the compensated curve is shifted lower, increasing the available capacity, but that it is also steeper in its shape. This is because capacitors' effectiveness is dependent on square of the the operating voltage. Conveniently, capacitors can be plotted directly onto a V-Q curve so as to easily find the operating point.

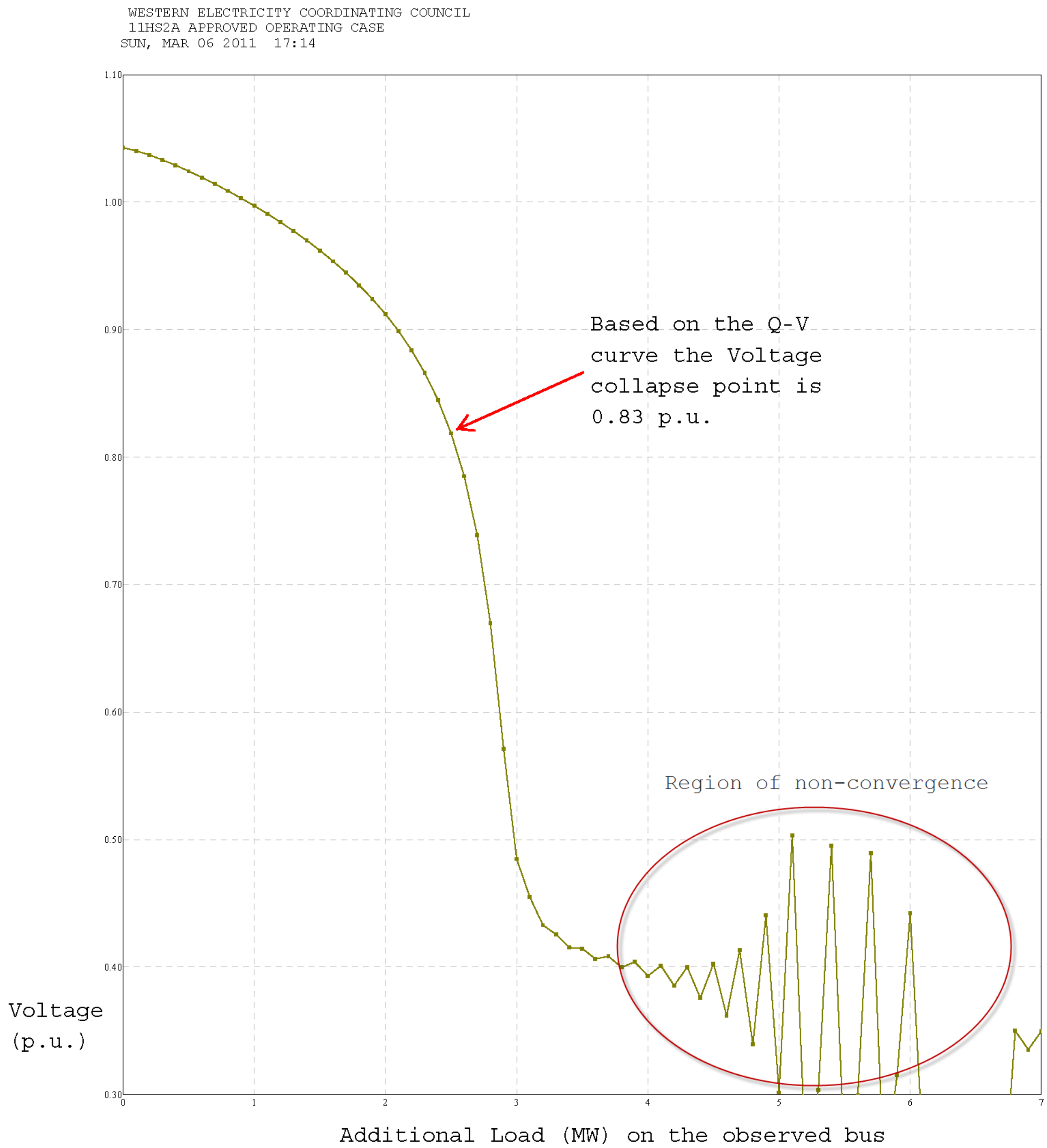

Figure 4.4: Example P-V Curve from a weak bus, obtained from power flow model.

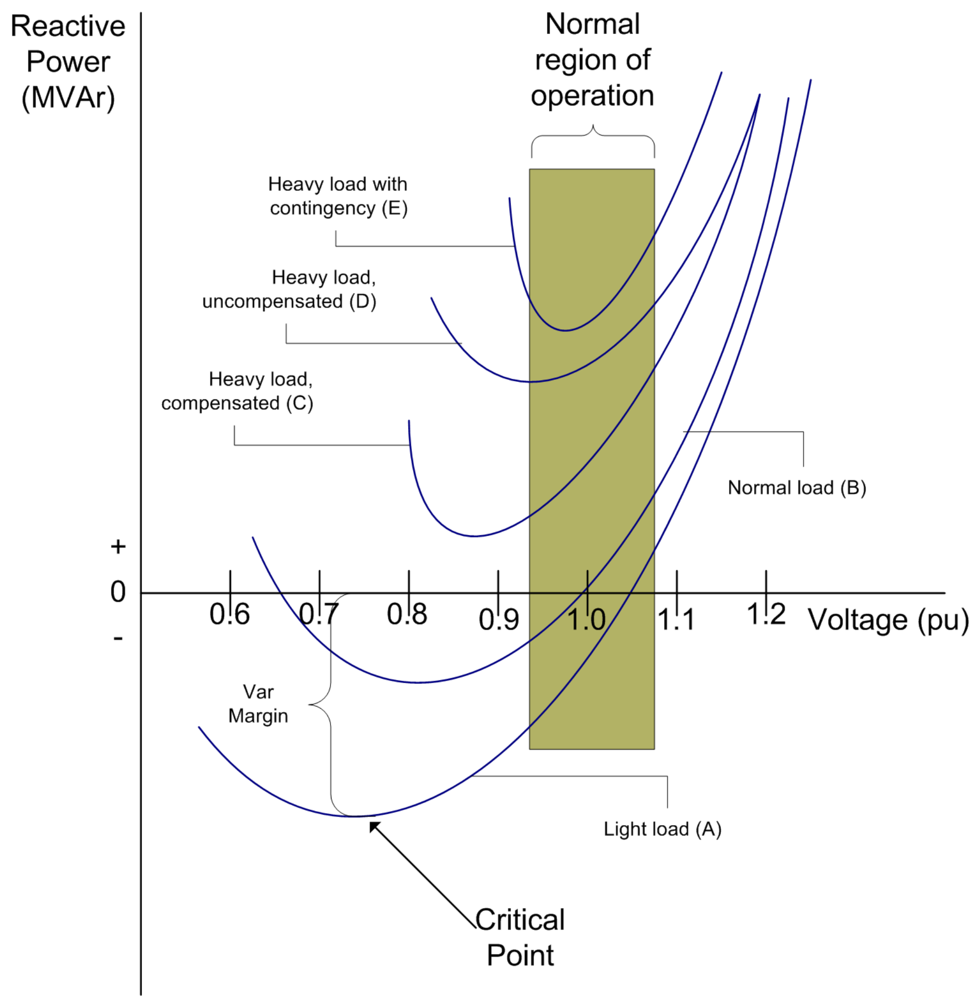

Figure 4.5: Normalized V-Q Curves

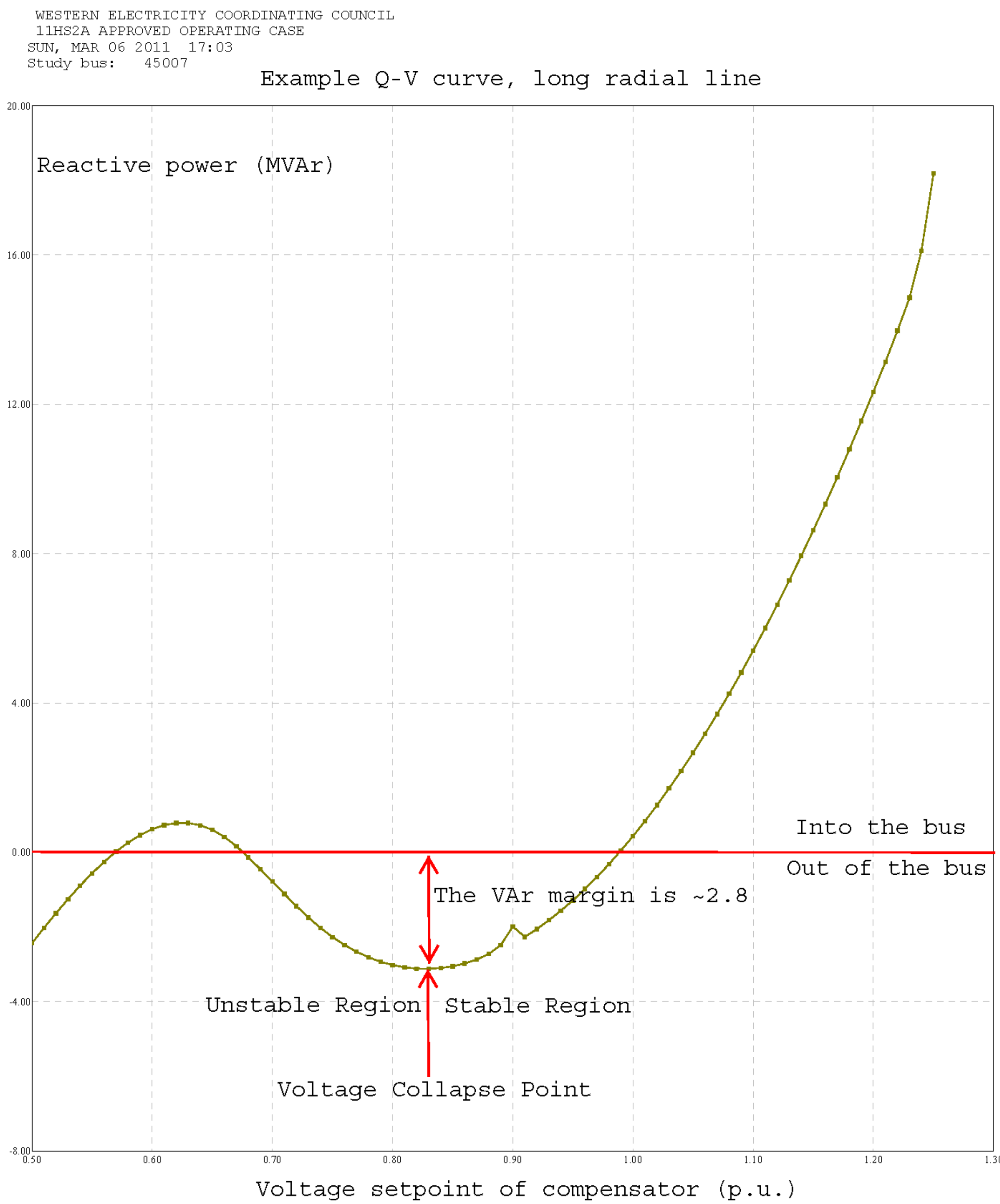

Figure 4.6: V-Q Curve obtained from power flow model

5 Tests and Results

5.1 Example sub-transmission network

In this chapter data from an actual sub-transmission network with a voltage problem is used to simulate seven different solutions based on equipment properties described in Chapter 2. The system studied in this section is radially-served by two 115 kV lines that tie to the 230 kV system 70 miles away (Figure 5.1). The 230 kV system ties to the rest of the WECC network and can be considered solid voltage-wise. The total load of the test region is about 45 MW in summer and 65 MW in the winter. Both lines are primarily 397.5 kcmil ACSR conductor. Under normal conditions there is ample thermal capacity to serve the city's demand with adequate voltage. There can be problems however, when one of the lines is out of service; the voltage drop becomes severe. For an outage near the source, simulations show voltage collapsing during winter peak. The goal of this chapter is to take the worst-case outage and apply countermeasures to stabilize the voltage.
The first step was to get an idea of how large of compensation equipment would be needed. To do this, a fictitious synchronous condenser (with infinite reactive power and no real power output) was attached to the 115 kV bus D. When the worst-case outage was applied to the network the output of the synchronous condenser was 18.2 MVAr. This would imply a minimum size reactive compensation device would be in the range of 20 to 30 MVAr.

Figure 5.2 shows a plot of additional load demanded beyond the winter peak in comparison with the actual flow on the line. What is evident is the linear relationship

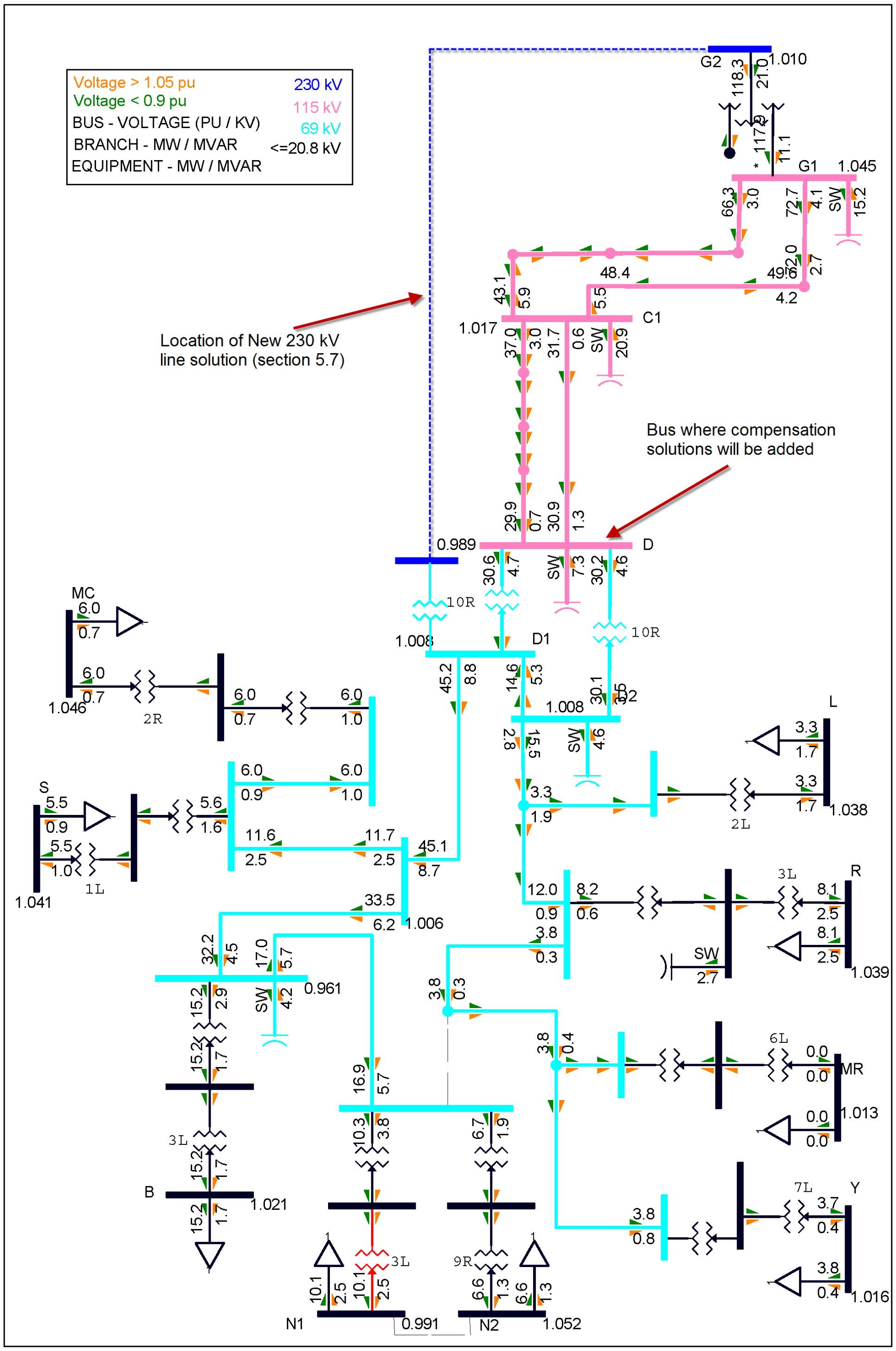

Figure 5.1: Schematic showing the test network in system normal state. The entire WECC system is also connected via the 230 kV bus G2 at the top.

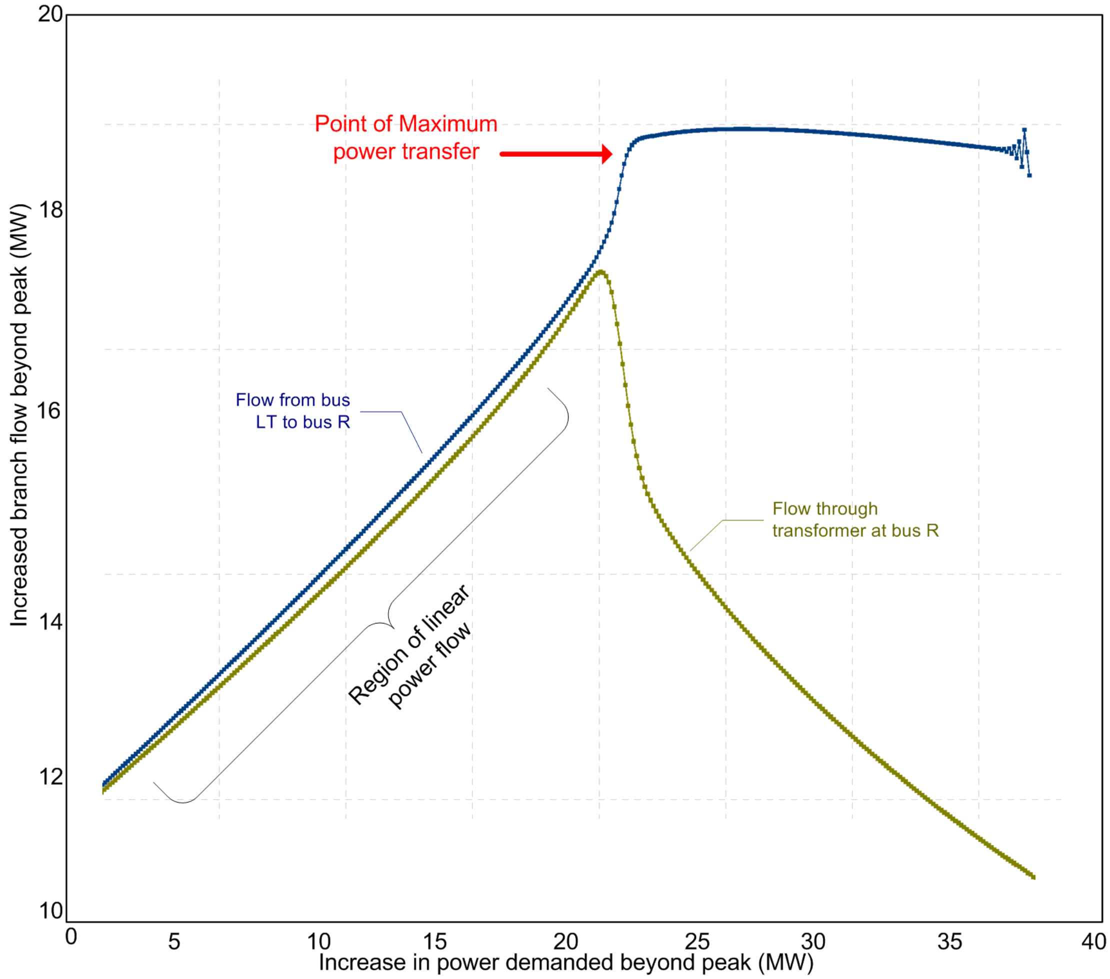

Figure 5.2: Branch flow as power demand increases with no lines out of service.

of power demanded to power delivered. That is, until the maximum power transfer point has been reached. At that point, only a slight amount of increase in delivered power is possible for the increase in demand. This point correlates to the critical voltage point in Figure 5.3.

Figure 5.5 shows a one-line diagram of the stressed network during the worst-case outage described earlier. In this scenario the voltage collapses and the base case cannot converge. As such, V-Q and P-V curves could not be compiled.

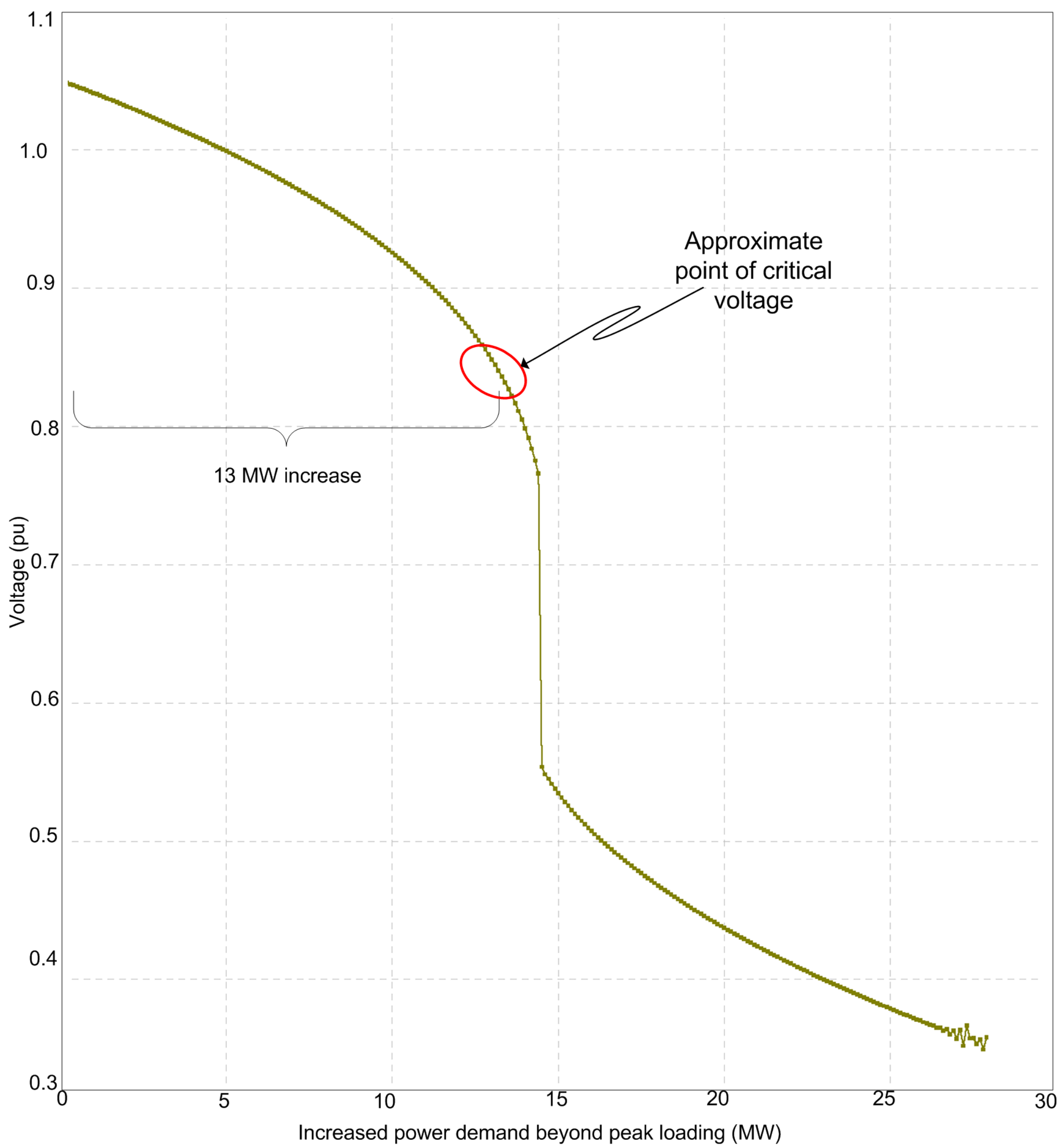

Figure 5.3: P-V curve of the studied network with no lines out of service, showing the relationship of voltage to power demanded beyond the normal peak load. Note the sharp drop off of voltage at 13 MW.

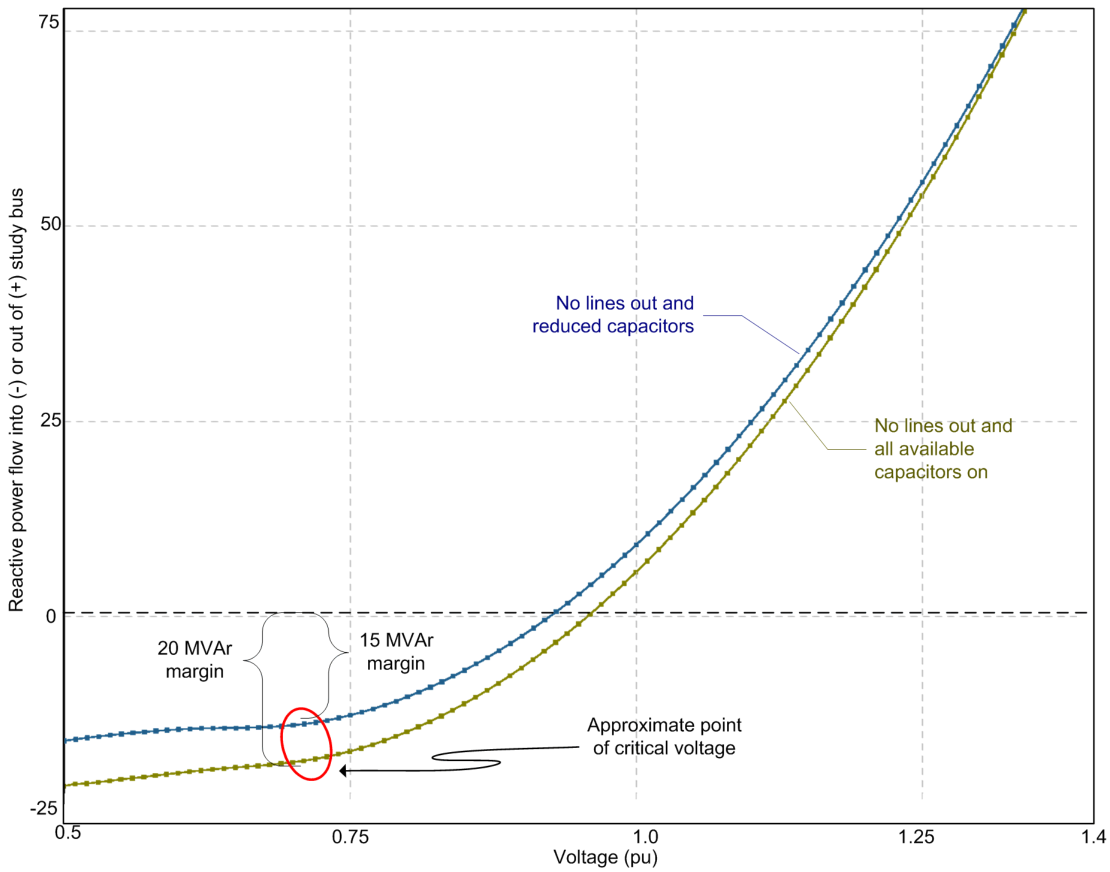

Figure 5.4: V-Q curve of the studied network with no lines out. The two curves show the normal configuration and then with all available capacitors on.

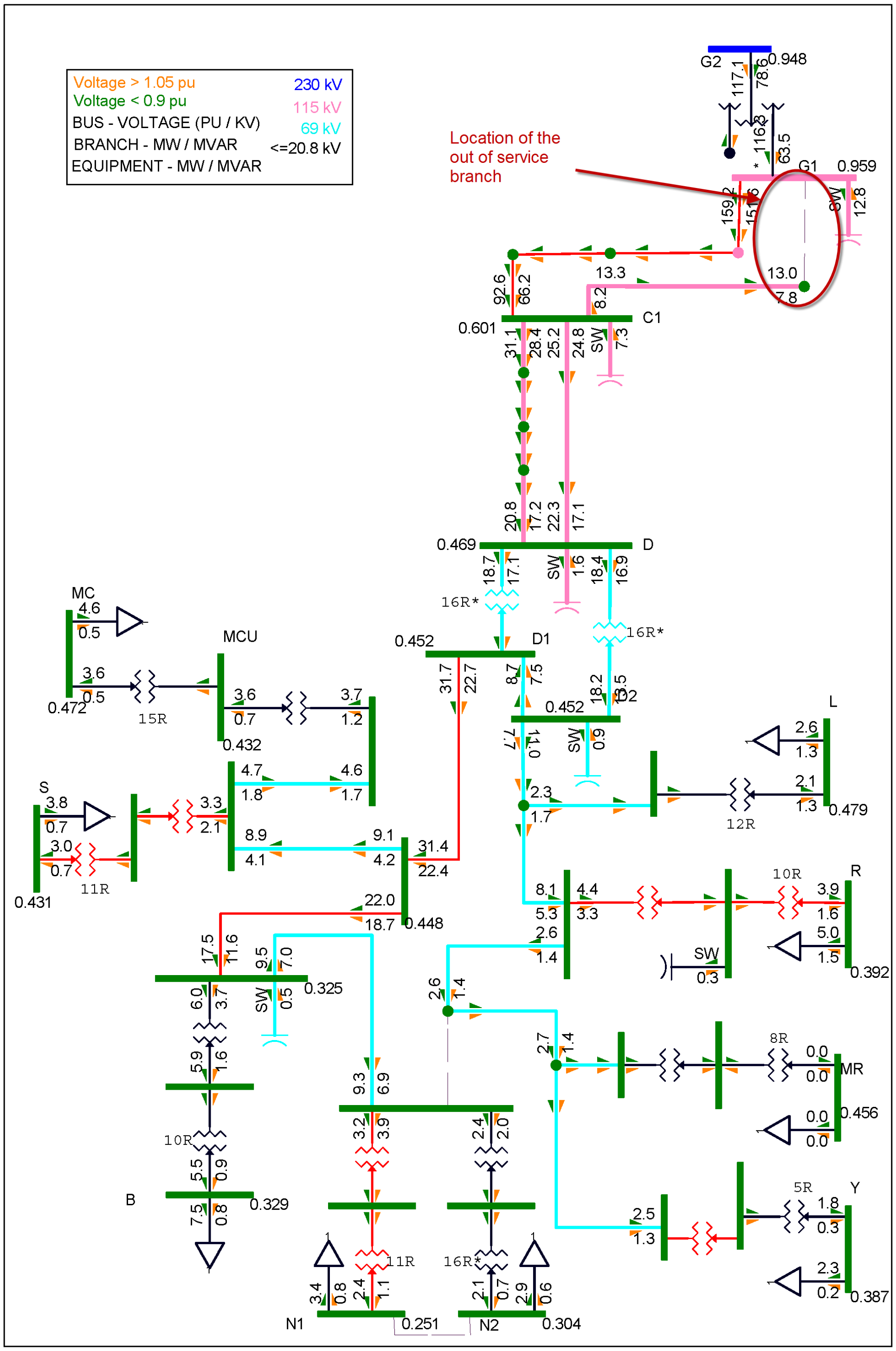

Figure 5.5: Diagram showing the network topology under a stressed case (N-1). Here the voltage has collapsed. Note the low voltages at all buses indicated by the green color.

5.2 Adding shunt capacitance

The first solution was to add capacitive compensation at Bus D (see figure 5.1). As was discussed in section 2.4, shunt capacitors are a simple and cost-effective solution when voltage needs to be propped up. For this solution, three different sizes of capacitors were applied to the network: 20, 25 and 30 MVAr. The size of capacitor is limited to what can be reasonably switched without causing unacceptable post-transient voltage deviations. On a network like this, even 20 MVAr is too high: It would need to be broken down into smaller stages. Ideally, they would have voltage control with the ability to remotely override the controls.

The P-V curve in Figure 5.6 shows the 30 MVAr capacitor increasing the amount of available power, but only by about 1 MW. The V-Q curve shows all three capacitor sizes resulting in the same 9 MVAr reactive power margin.

5.3 Adding an SVC

As described in Section 2.5.1, SVCs take the concept of reactive power compensation and smooth out the changes in capacitance. This means higher values of capacitance can be applied. For this solution three sizes of SVCs were tested: 30, 40 and 50 MVAr. The P-V curves in figure 5.8 show incremental increases of approximately 2 MW in real power margin for each size. The V-Q curves in Figure 5.9 however, show all three sizes of SVC converging on the same values. For comparison, the 30 MVAr capacitor curve was included. The interesting observation is that reactive power margin is approximately the same, while the critical voltage is lowered with the SVCs, an indicator that the uniform change in reactive compensation a SVC

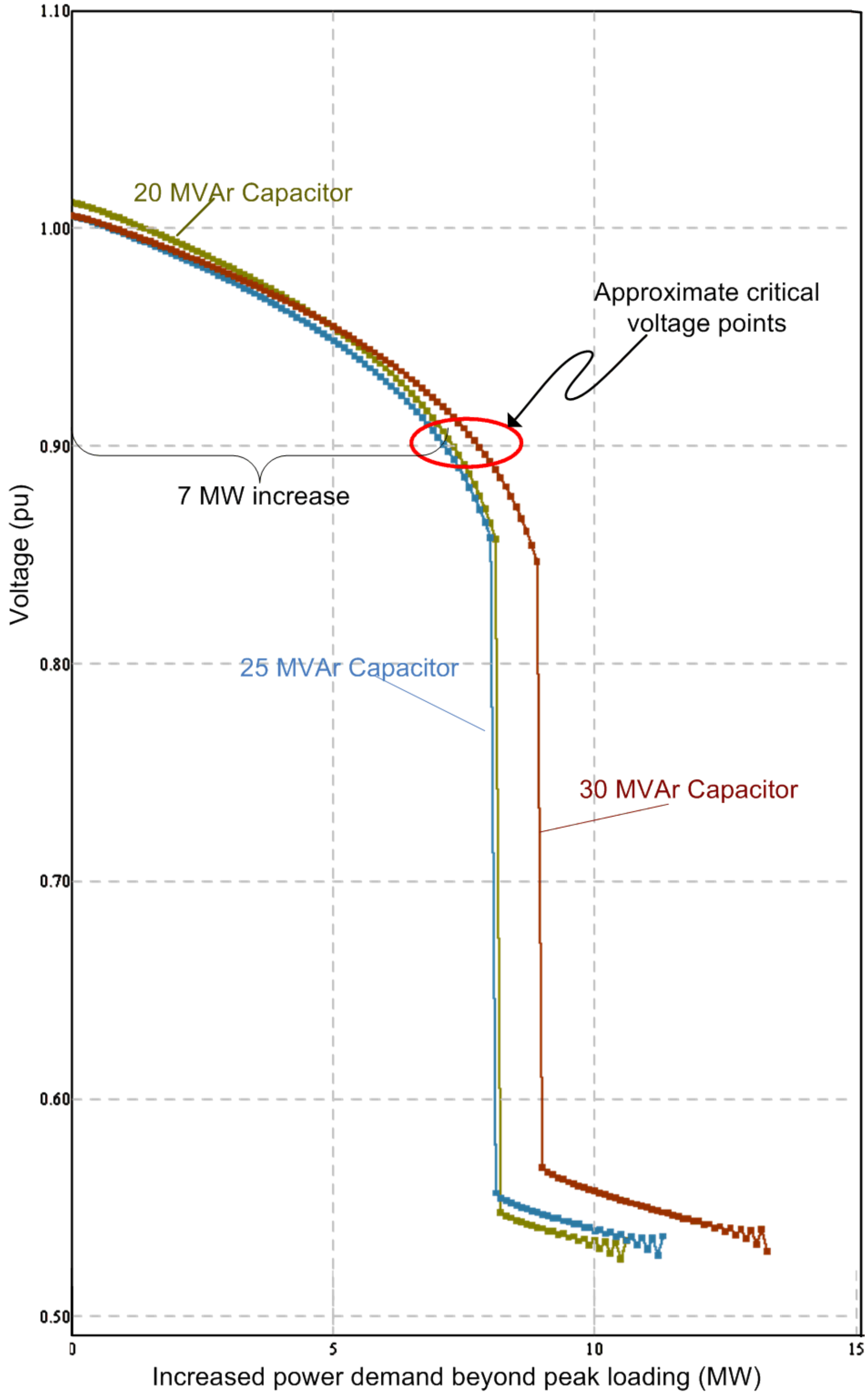

Figure 5.6: P-V curve showing the system in the N-1 state, using 20, 25 and 30 MVAr capacitors to compensate for the reactive power deficit.

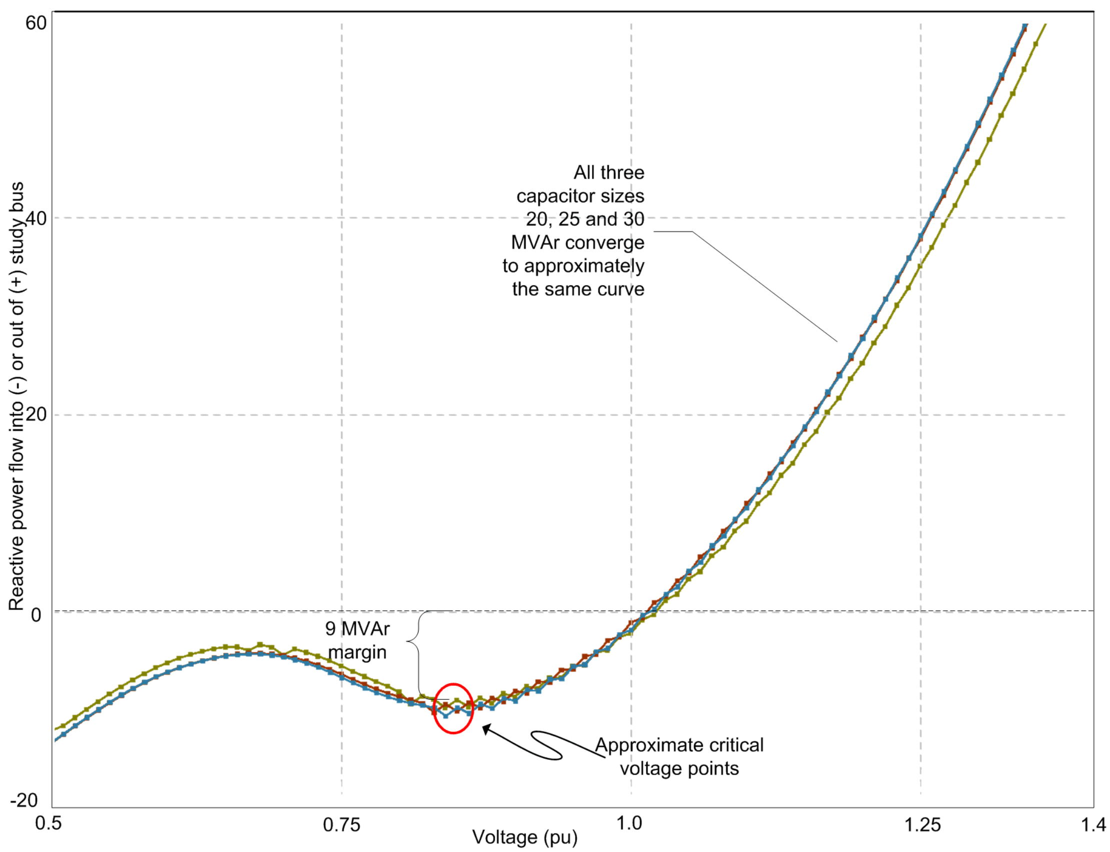

Figure 5.7: V-Q curves of the capacitor solution. Note, all capacitor sizes have approximately the same result.

provides helps the system to stay stable in deteriorating conditions.

5.4 Adding a STATCOM

Section 2.5.2 described the operation of STATCOMs; primarily that they do not rely on capacitance to provide voltage support. This solution compared installations of three different sizes of STACOMs: 30, 40 and 50 MVAr. Their impact on system stability was promising. Looking at Figure 5.10 the notable increases in available real power margin were: 17, 23 and 30 MW respectively. The STATCOMs also hold the system voltage right at 1.0 pu. Comparing the P-V curves for the different STATCOM sizes, one can see the increasing sharpness with additional compensation. The limit as the compensation increases is a step function where the system is held at perfect voltage and then completely collapses.

Figure 5.11 shows the corresponding V-Q curves. What is immediately apparent is that the curves have a nearly vertical section at V=1.0 pu. This indicates the STACOM would be able to maintain consistent voltage over a wide range of reactive power conditions. Also noteworthy, is the increase from the 40 to 50 MVAr size does not effect the reactive margin, but does lower the critical voltage point.

5.5 Adding Generation

The studied network lies in a scenic and remote region. One prerequisite for adding generation is that the energy source (fuel) must be available. Section 2.1 described some of the different energy sources. While adding generation to the studied network may be a good solution, there are limitations in what kind of generation could reasonably be installed. This area has no available gas or coal. A biomass plant is a

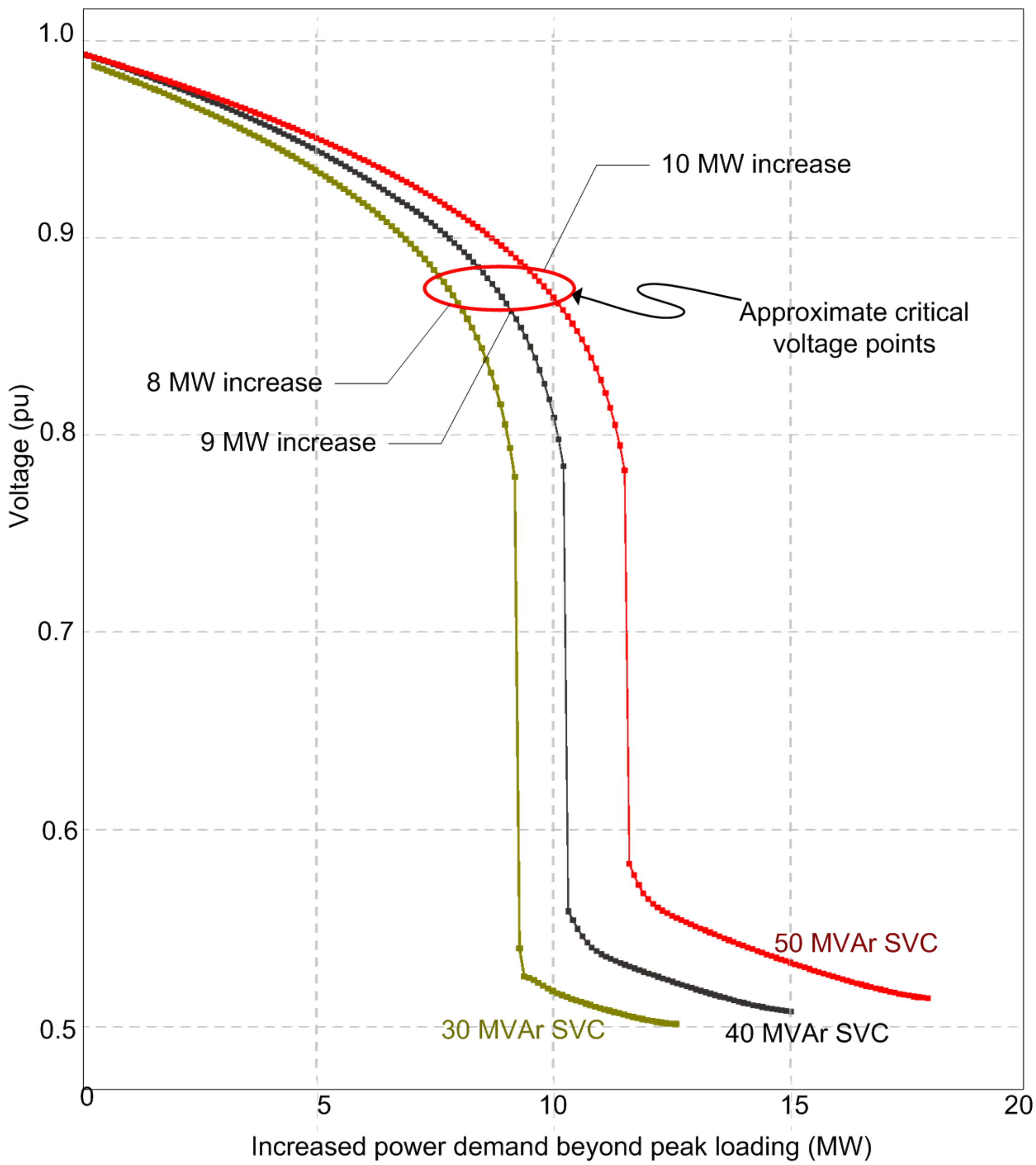

Figure 5.8: P-V curves of the SVC solution, showing the system in the N-1 state using 30, 40 and 50 MVAr SVCs to correct the reactive power deficiency. The profiles for the the different sizes are similar, each with a voltage collapse point near 0.85 pu.

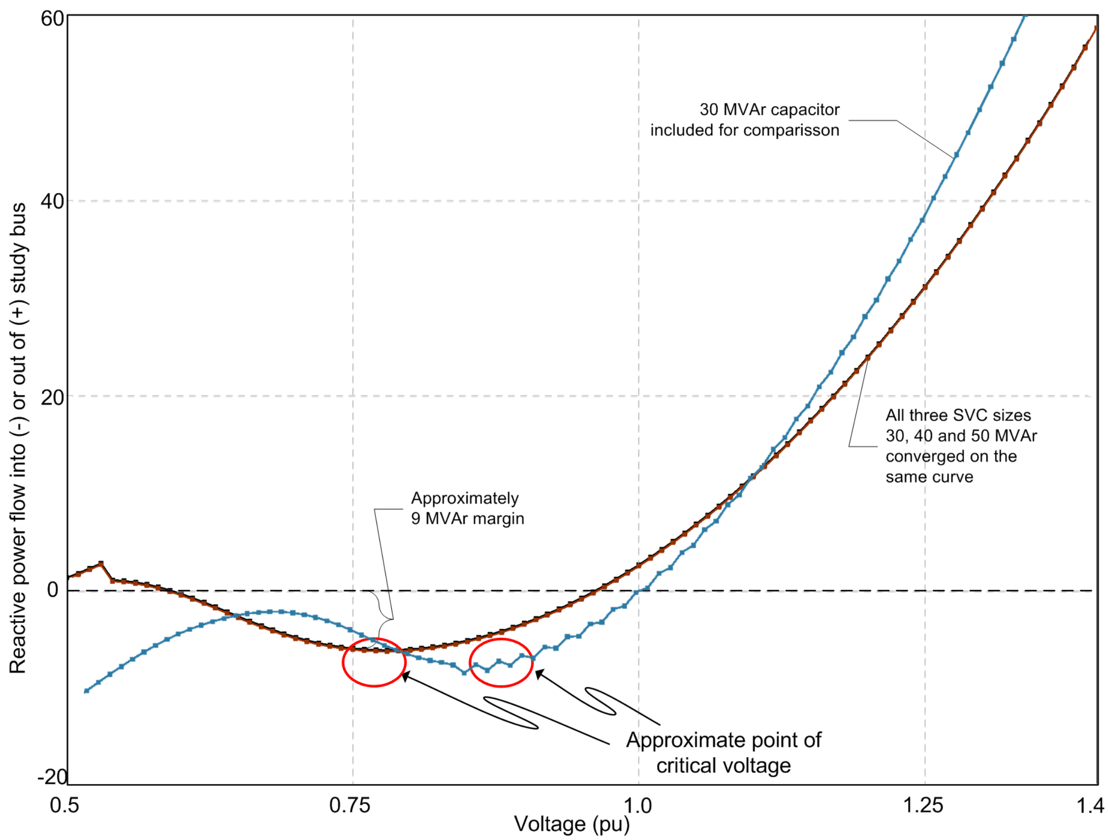

Figure 5.9: V-Q curves with the SVC solution applied. All three SVC sizes result the same profile. The 30 MVAr capacitor was included to show the same reactive margin is acheived, but the voltage collapse point is slightly lower for the SVC.

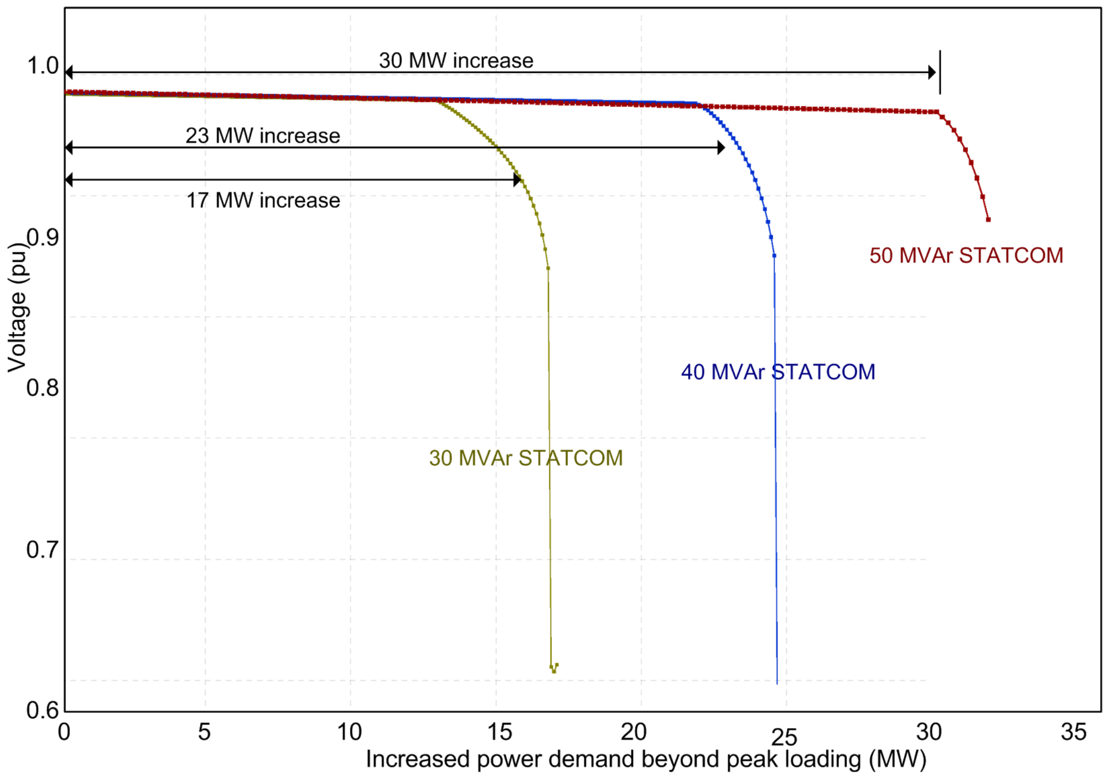

Figure 5.10: P-V curve of the STATCOM solution, showing the significant gains in achievable real power. Note, the curves getting sharper with the increased compensation.

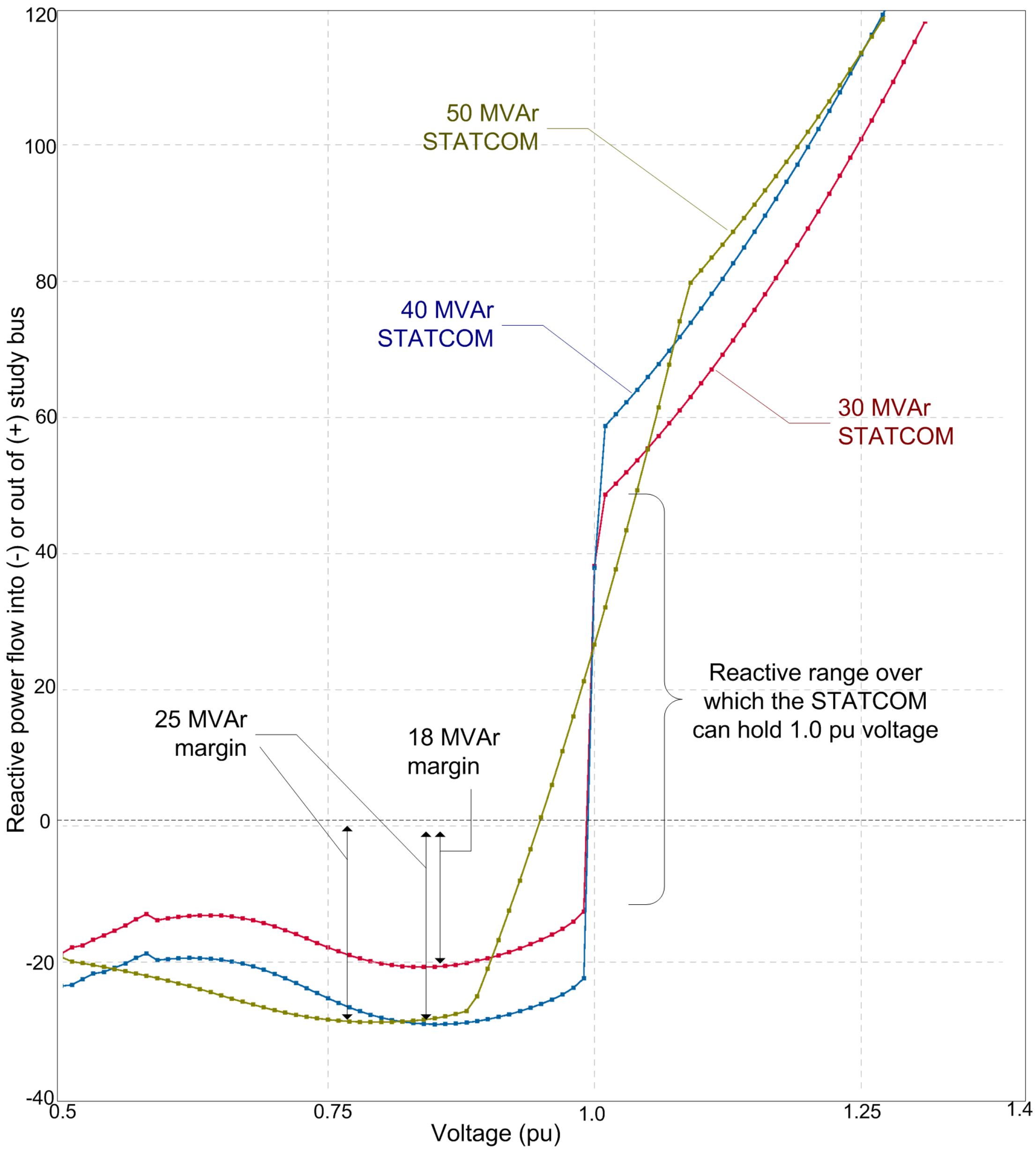

Figure 5.11: V-Q curve of the STATCOM solution. The vertical segment at V=1.0 pu shows the range of reactive power over which the STATCOM is capable of maintaining voltage.

possibility since the area has some forestry activity, though those are normally built and operated by third parties (e.g., timber companies) rather than utilities. The area does have consistent strong winds, so a large wind plant may also be conceivable. One problem with wind is that it is non-dispatchable. Often the coldest winter peak occurs when there is no wind at all (the same is true for the summer peak). Nevertheless, the wind plant option would be electrically beneficial.

For this solution, two sizes generation plants were considered, 20 MW and 40 MW. They would probably be operated at 85% of nameplate capacity, i.e. 16 MW and 32 MW respectively, with a capability of ± 0.9 power factor.

Figure 5.12 shows the substantial increase in available power, almost the size of the generator output. The P-V curves show a smooth drop off of voltage compared to the STACOM.

5.6 Tie to neighboring system

This solution was included because the studied region happens to be only ten miles from the terminus of a completely separate, long, radial network. The question is, by tying two weak networks together is the combined system actually improved? In this case it appears so. The nearby network is operated at 115 kV so this solution would require rebuilding part of the 69 kV system from the end of the 115 kV supply line (bus D, Figure 5.1); then building ten miles of new 115 kV line. If the system was operated normally closed, there would still be two available sources during an outage of one of the lines.

The P-V curve in Figure 5.14 is very shallow, an indicator of the increased voltage stability. The voltage would only slowly degrade over the range of increased

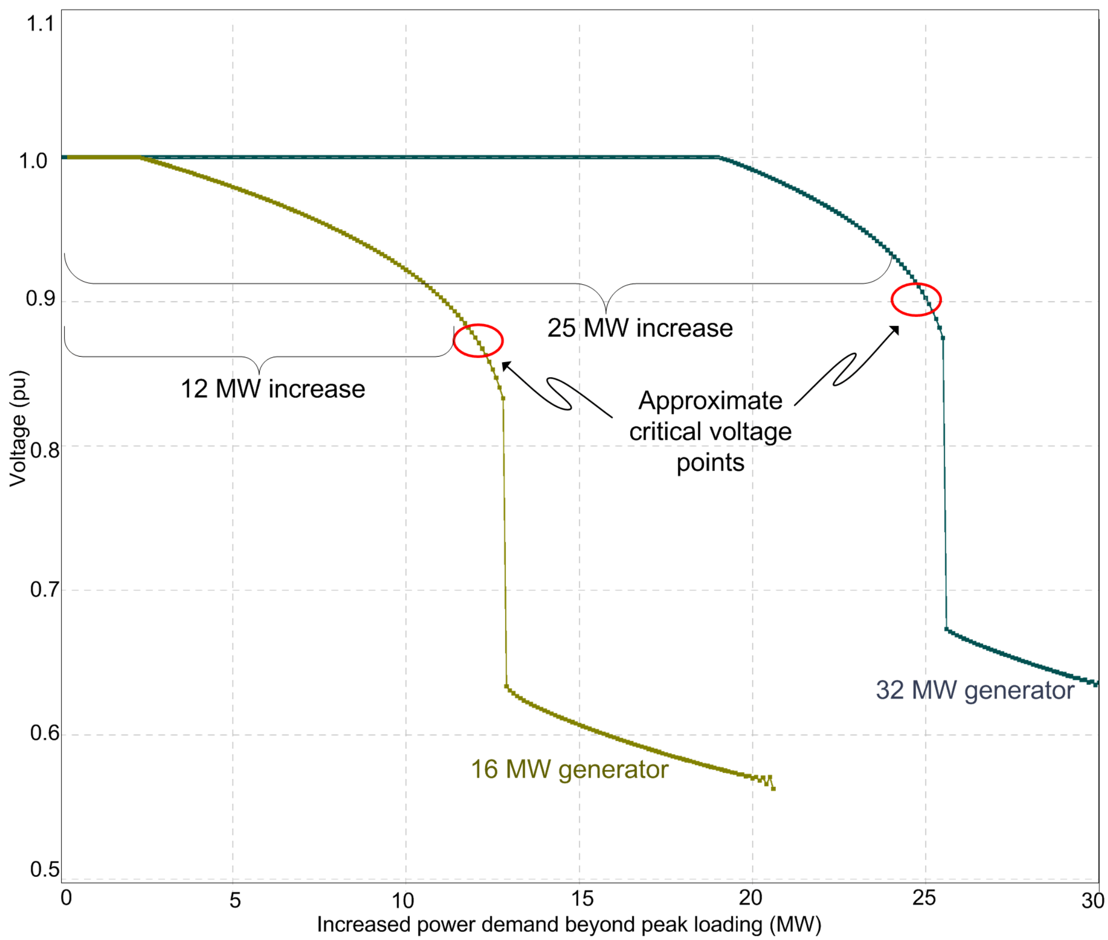

Figure 5.12: P-V curves showing the addition of 16 and 32 MW generators to the system. Note, the generators are able to maintain 1.0 pu for a wide range of increased power demand. Otherwise the curves look similar to the N-0 case.

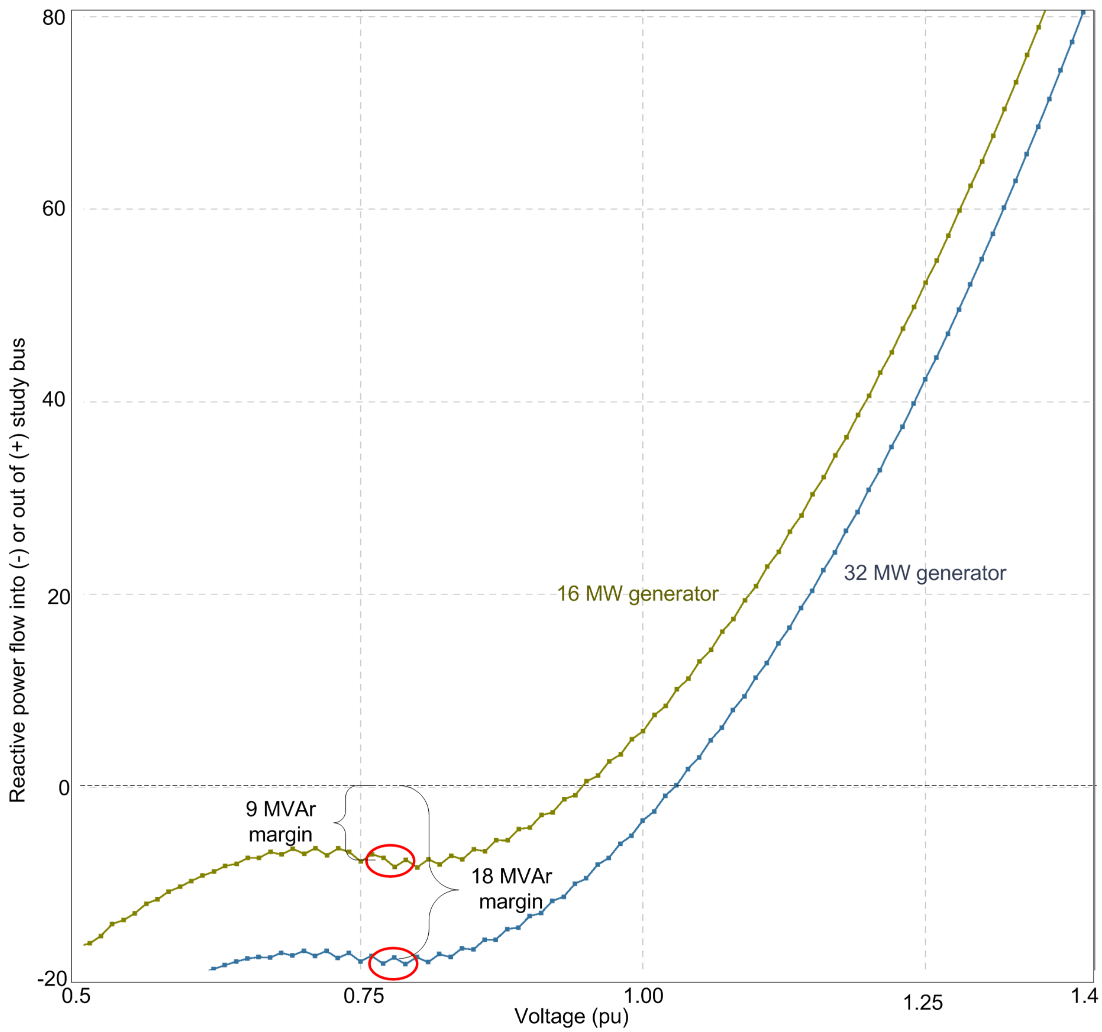

Figure 5.13: V-Q curves of the generator solution.

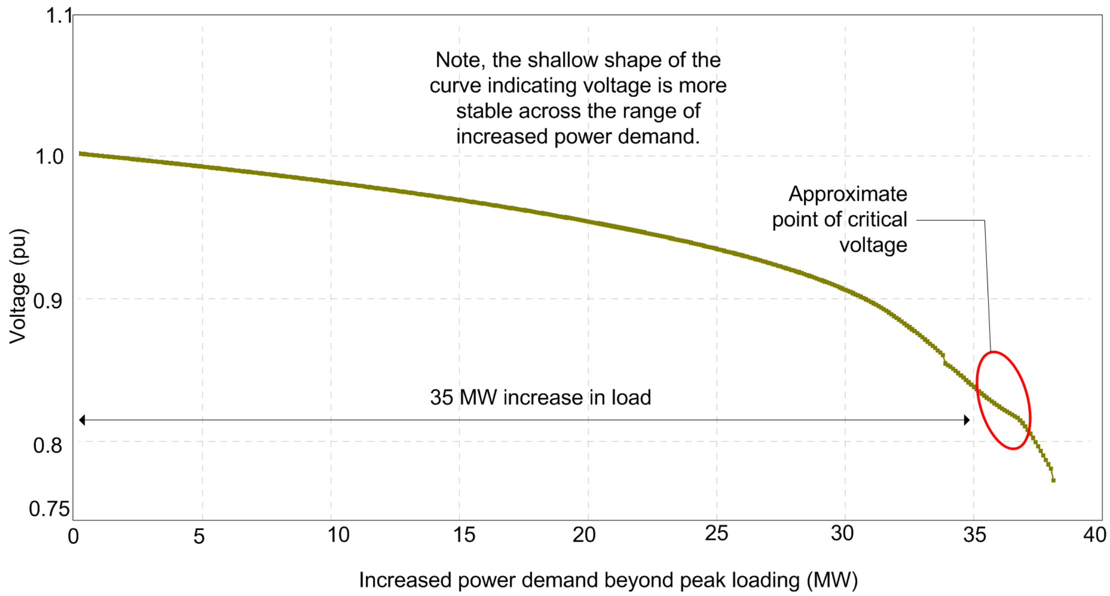

Figure 5.14: P-V curve showing the N-1 state when tied to an outside 115 kV source.

power demanded. The V-Q curve in Figure 5.15 show a new reactive margin of 30 MVAr.

5.7 New 230 kV transmission

The next solution proposes building a new 230 kV line from the source at bus G2 in Figure 5.1 to a new 230-115 kV substation adjacent to bus D. The new line would probably built along the same right-of-way for most of distance since this area has strict development rules. The line would be approximately 70 miles of 1272 ACSR conductor.

It is apparent from the curves in Figures 5.16 and 5.17 this is by far the best solution in terms of voltage stability. As with the previous solution in Section 5.7, the P-V curve is very shallow indicating the voltage would not collapse absolutely as in other cases. Using a practical operating limit of 0.9 pu, the system can safely

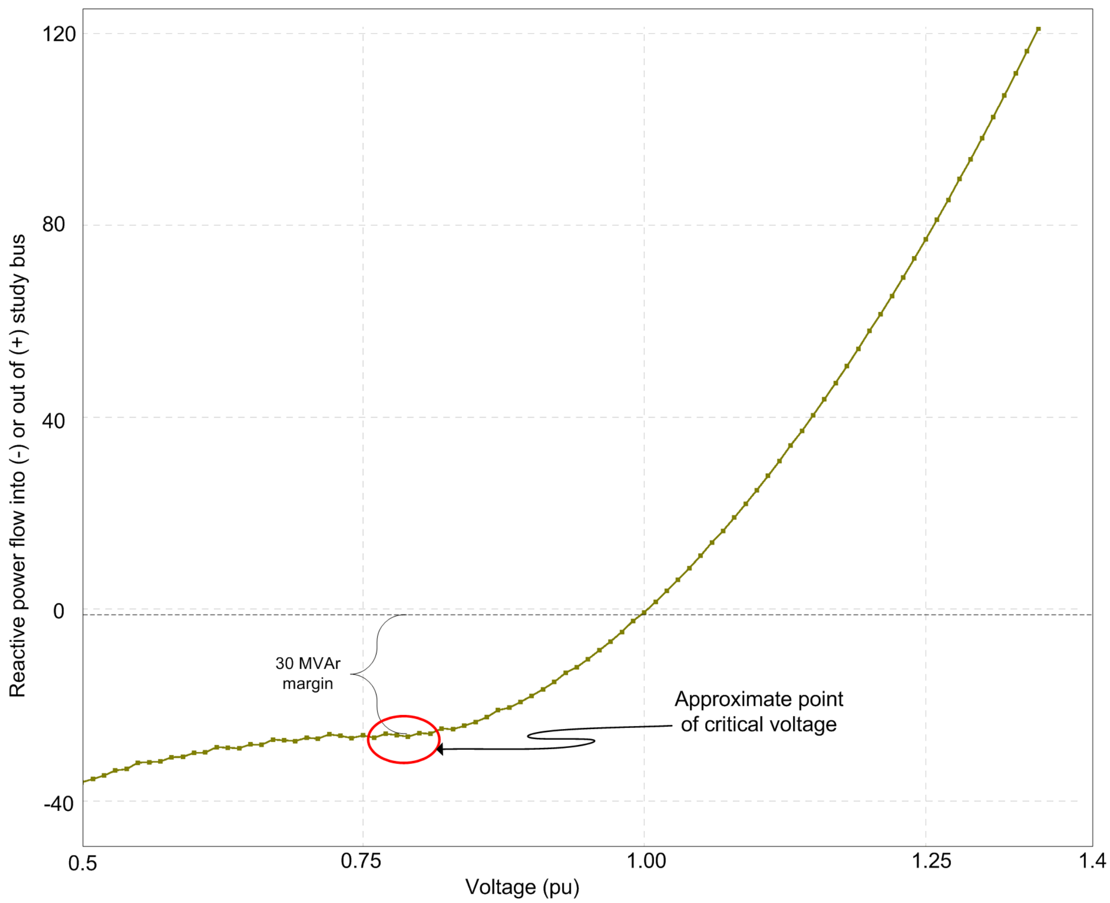

Figure 5.15: V-Q curve showing the system tied to an outside 115 kV network

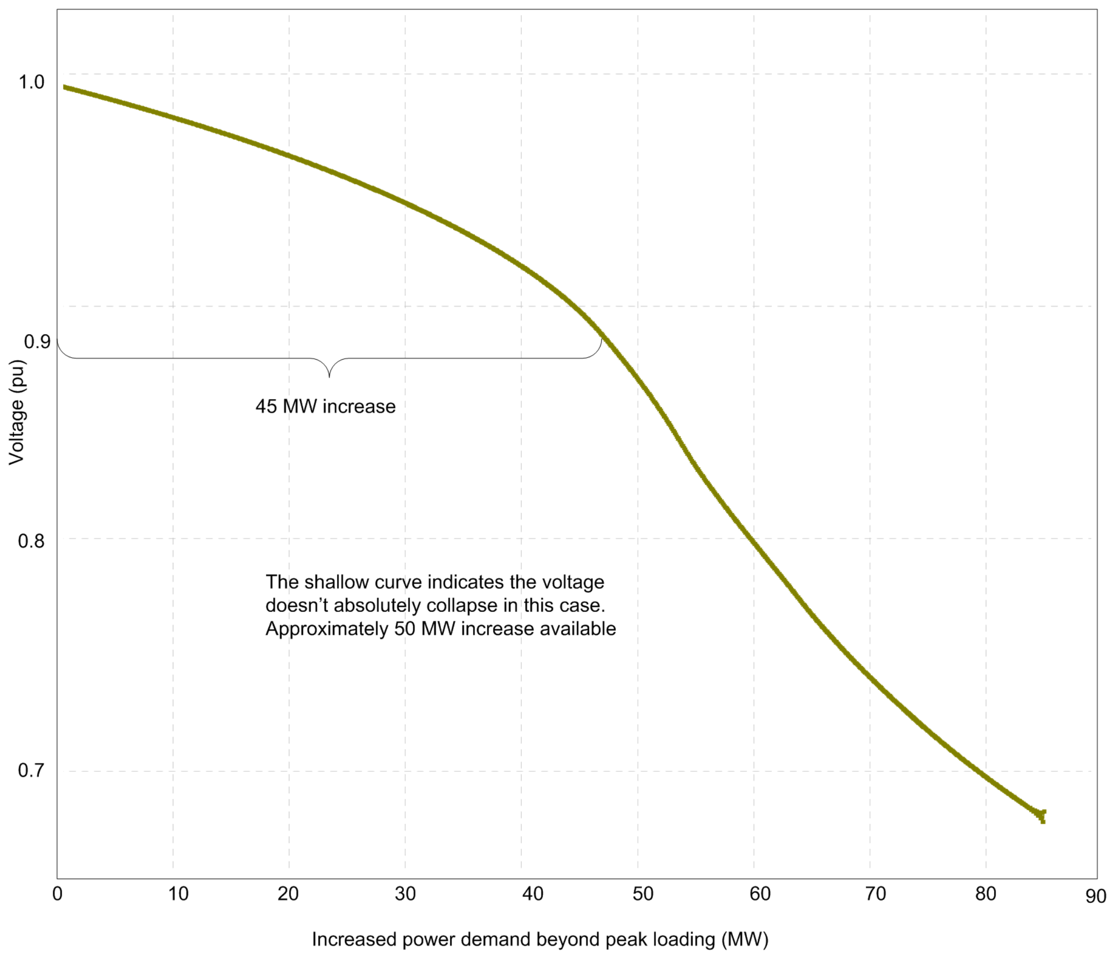

Figure 5.16: P-V curve of the network with a new 230 kV line. The shallow curve indicates the voltage would not absolutely collapse as in other cases, however a practical limit of 0.9 pu would indicate the safe addition of 45 MW.

handle an increase of 45 MW. The V-Q curve in Figure 5.17 shows a reactive margin of over 120 MVAr.

5.8 Comparison

All the solutions are shown in Figures 5.18 and 5.19. As mentioned earlier, it is immediately obvious the best solution from a stability point of view (as opposed to an economic point of view) for this problem network would be to build a new 230 kV transmission line into the area. It was also clear that while normally voltage can be supported by capacitors, in this case both the capacitor and SVC solutions (even large banks) do very little to reinforce the system. What this network needs to prevent voltage instability is real power, as was evident by the direct impact the generation had.

It would be incomplete to omit costs from the discussion since all projects are evaluated by their costs vs. benefits. Table 5.1 shows cost estimates and electrical benefits for the various projects. Note, this table is only provided as a rough estimate; construction costs are very fluid based on commodities (e.g. steel and copper) and labor prices. Neither analysis, economic or electrical by itself would be sufficient for infrastructure investment; they must be done in conjunction.

Project	Cost (Low)	Cost (high)	Margin		$/Margin Watt	$/Margin VAr
30 MVAr Capacitor	$0.5M	$1.5M	7 MW	9 MVAr	0.14	0.11
30 MVAr SVC	$8M	$15M	8 MW	9 MVAr	1.44	1.28
30 MVAr STATCOM	$11M	$20M	17 MW	18 MVAr	0.91	0.86
40 MW Generator	$50M	$100M	25 MW	18 MVAr	3.00	4.17
Tie to neighbor system	$28M	$35M	35 MW	30 MVAr	0.90	1.05
New 230 kV line	$70M	$120M	45 MW	120 MVAr	2.11	0.79

Table 5.1: Comparison of project costs and margin benefits. Note, the cost per margin column on the far right uses the median cost estimates.

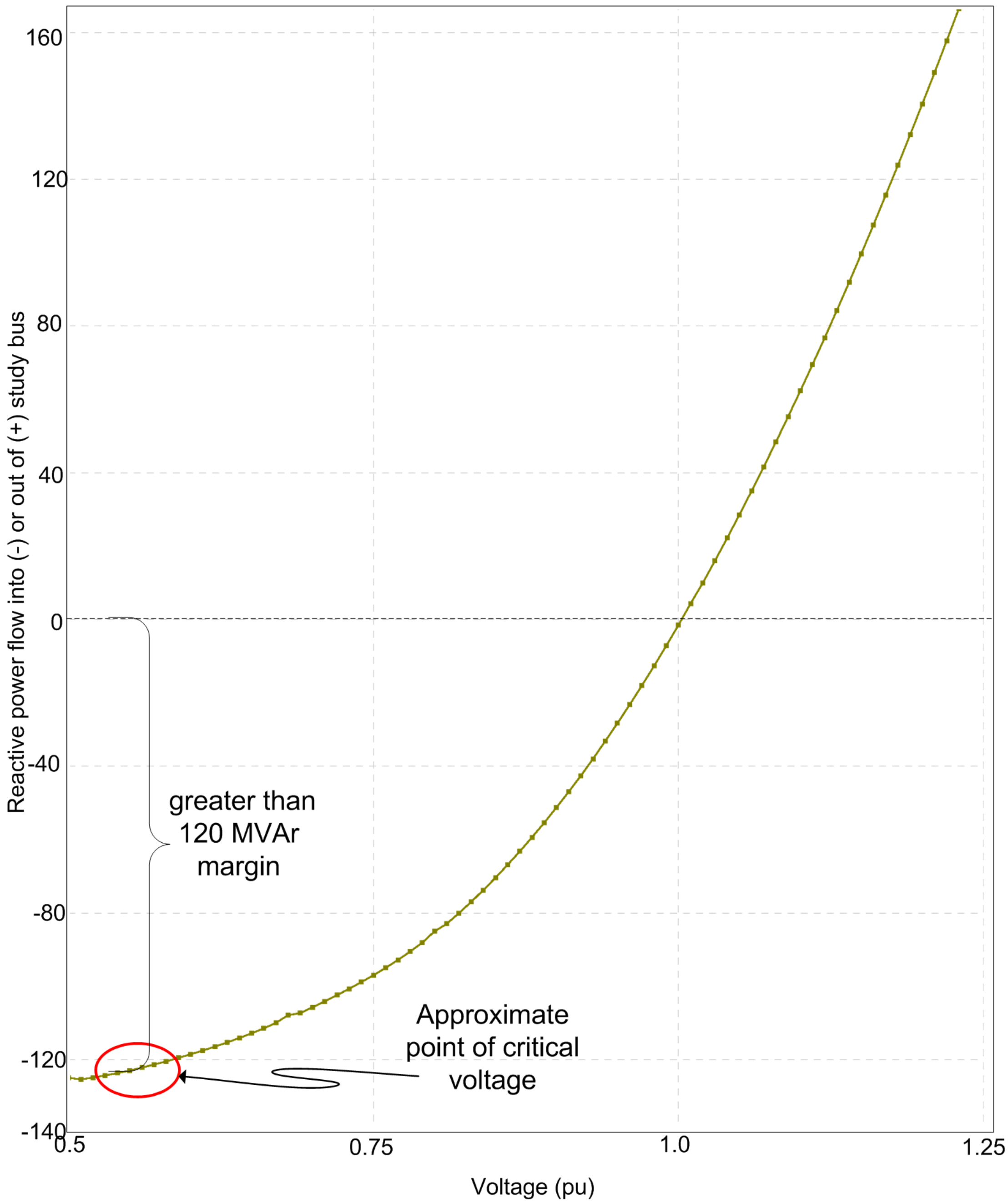

Figure 5.17: V-Q curve of the new 230 kV line solution. This solid solution is able to provide over 120 MVAr of reactive compensation.

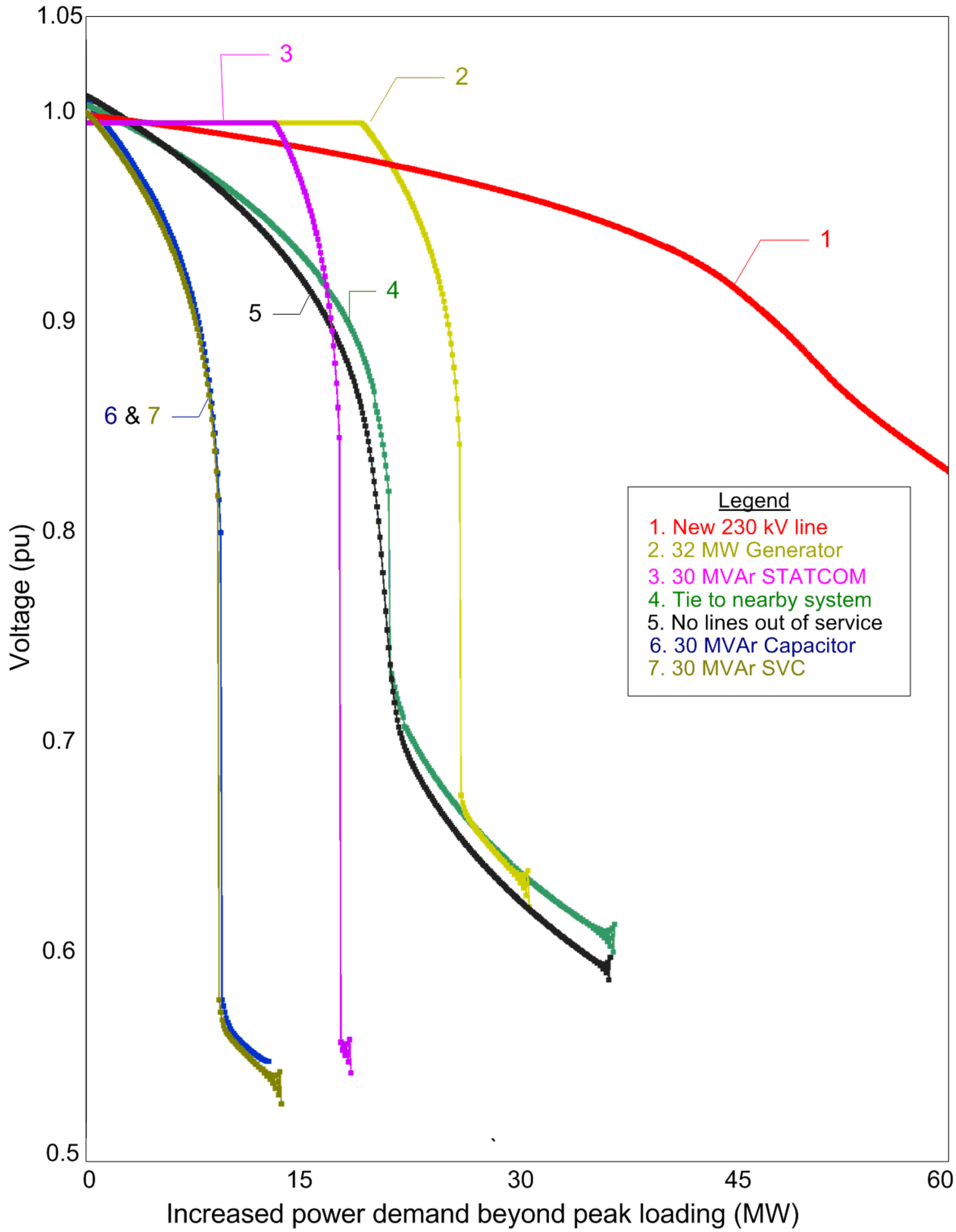

Figure 5.18: Graph comparing the P-V curves of the different solutions.

5.9 Discussion

Voltage stability was defined in section 1.4 as the ability of a system to maintain steady voltage when subjected to a disturbance. Considering this definition in the context of the V-Q and P-V curves, the conclusion can be made that a more stable solution would show the curves closer to 1.0 pu voltage across a wider range of conditions. In both the P-V and V-Q curves, the generator and, to a lesser extent, the STATCOM are most able to accomplish this. However, outside of their operating range, those solutions quickly deteriorate.

A better long-term solution is the 230 kV line. Figure 5.18 shows it with the most shallow slope over a much broader range. Similarly, Figure 5.19 shows the 230 kV line V-Q curve with a steeper slope around 1.0 pu for a broader range of conditions.

The Watt and VAr margins are more an indicator of the room for future growth than of stability. Considering the size of the test network's total load (65 MW) and load growth rate of $< 2\%$, the 30 MVAr STATCOM solution would be sufficient for approximately 15 years, the 40 MW generator would be sufficient for approximately 20 years and the new 230 kV line would be good for approximately 30 years.

5.9.1 Results

There were two unexpected results from the tests. First, was how small the impact of capacitive compensation (the SVC and capacitor) had on the constrained network. This is in contrast to the same size STATCOM which had a much greater impact on both the Watt and VAr margins (because its reactive power output has no V^2 dependency). The 40 MW generator had only a 14 MVAr capacity, yet was able to significantly improve voltage stability.

The second surprising result was that the new 230 kV line which has a thermal rating greater than 650 MW could only supply 45 MW of extra capacity. This result was tested several times. The original suspicion was that the limitation was actually at the 230 kV source. To check this, a generator with unlimited real and reactive power was placed at the 230 kV source bus. The improvement in margin was only from 45 MW to 55 MW. The conclusion is that, while the source may not be very strong, the limitation is mainly due to the line's length and impedance. To improve this solution a series capacitor could be added to reduce the inductive reactance.

5.9.2 Previous studies

At least four other papers were identified that compared the effects of capacitors and FACTS devices on power margins: [Musunuri and Dehnavi, 2010a], [Sode-Yome and Mithulananthan, 2004], [Kamarposhti et al., 2008] and [Kamarposhti and Alinezhad, 2009]. They all had one main difference from this study, they used simplified test networks such as the IEEE 14-bus test network. While the IEEE 14-bus test network is good as a standard, it misses many possible parameters and configurations, like the ones used in this study. Not surprisingly, the papers that used the same test network had similar results, in particular that SVCs and STATCOMs had comparable impacts on improving stability.

Expectations at the onset of this study were that similar results would be reached. However, the STATCOM was clearly a much better solution than the SVC. This implies that the differences can be attributed to the network topology, particularly the long, high impedance, radial source lines. None of the other comparable papers included generation as a solution to voltage instability, though two covered Unified Power Flow Controllers (UPFCs), a FACTS device that generates real power from a energy storage source.

5.9.3 Improvements and ideas for future work

While the generator was the most un-economical solution proposed, generators create revenue. As such, one improvement would be to look at the net-present values of the projects and their lifetime costs, including maintenance. This would make new generation more attractive. As part of the economic analysis, system loss savings should also be included. System loss savings quantifies the economic value of the reduction in system losses.

Along with a better economic analysis, someone could include a mathematical explanation of why the real power had so much greater of an impact on voltage stability.

Finally, it would be a good idea for someone to apply loads with Conservation Voltage Reduction (CVR) to a study like this one. CVR is the notion that reducing voltage served to customers will decrease energy consumption. The theory is based on the loads' voltage dependency. It would be interesting to see what effect artificially reducing voltage would have on stability.

5.9.4 Conclusion

What eventually gets built will be a trade off of the project costs and how much risk the company is willing to accept. Usually a project would be evaluated by its return on investment. In this case the impetus is based more on the possibility of large fines from the outages associated with voltage collapse and the associated public relations problems. While the value of reliability is difficult to appraise, it remains one of the top priorities of electric utility engineering.

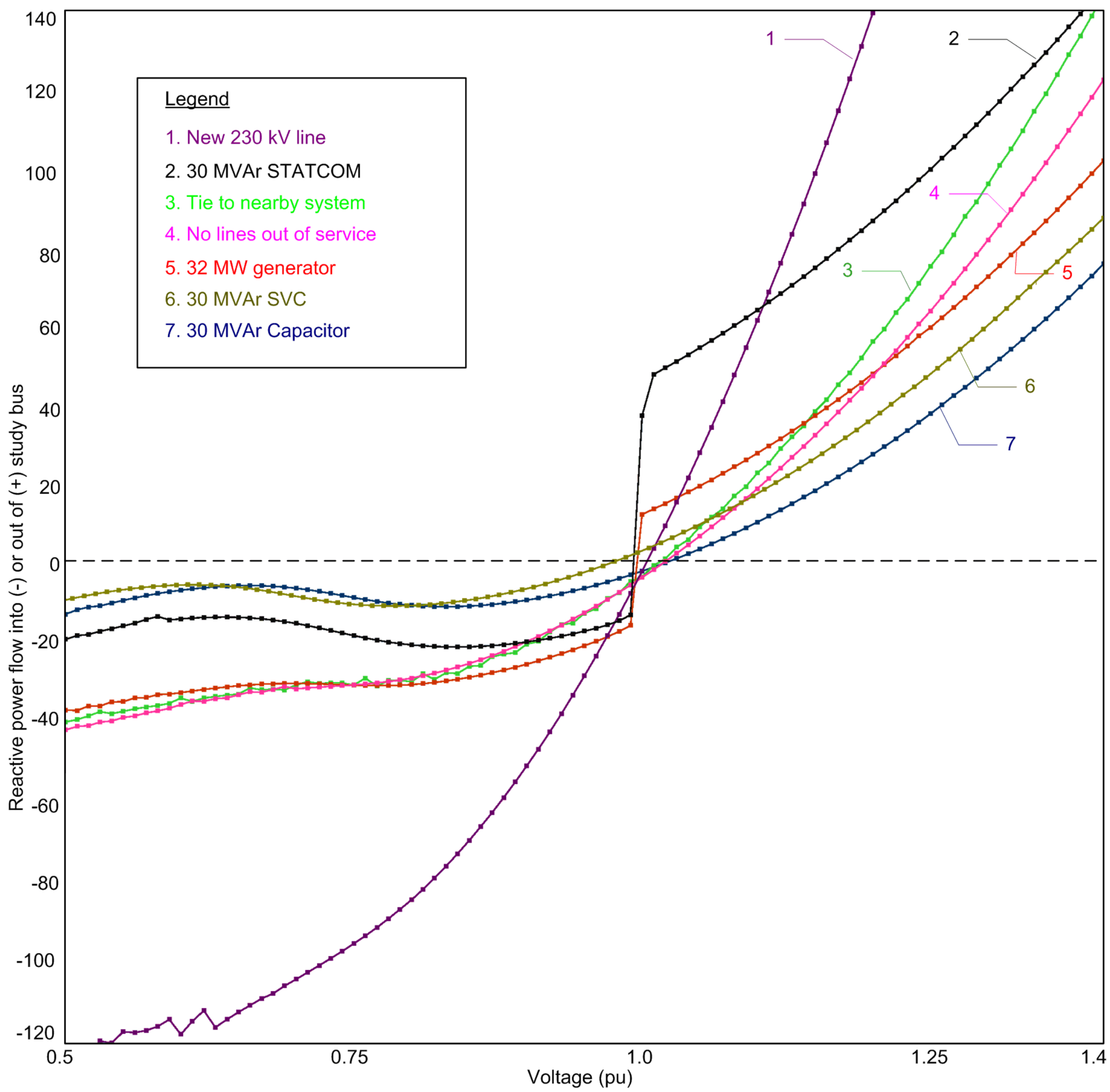

Figure 5.19: Graph comparing the V-Q curves of the different solutions.

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