NEAR EAST UNIVERSITY

Faculty of Engineering

Department of Electrical & Electronic Engineering

POWER FLOW PROGRAM IN MATLAB USING DECOUPLED NEWTON-RAPHSON METHOD

Graduation Project
EE-400

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ABSTRCACT

Normal power system operation requires that; the supplies (generation),the demands (loads),losses,bus voltage magnitudes,generators operate within specified real and reactive limits, transmission lines and transformers are not overloaded.We use power flow analisys or load flow analysis to calculate the approximate values for these required conditions. Power flow analysis computes the voltage magnitude and angle at each bus in a power system.Power flow also computes real and reactive power flows for lines or transformers interconnecting the buses,as well as their losses.

The input data for power flow calculation normally given for loads and generators is in complex power form, the power flow problems is therefore formulated as in a set of non-linear equations. İterative methot are used to calculate these linear equations,such as Gauss-Sidel, Newton-Raphson method. In this project the examples are solved by using Newton-Raphson and DECOUPLED-Newton-Raphson method. The equatios of the power flow problem are complex and take iteration to get approximated values. This can not be simple to solve by hand calculation with large number of buses.Because hand calculation takes much time and easily gives chance to make mistakes. This can be simplified by solving power flow equations with computer programs.

The goal of this project is to get familiar with the power flow quations and its solution methods by the aid of computer based program such as MATLAB. For this purpose the basic consepts in electric power system which are necessary to understand power flow are briefly described,the formulation and mathematical calculations involved in power flow analisys are explained in detail by hand and by computer based program MATLAB.

INTRODUCTION

Power flow analysis is concerned with describing the operating state of an entire power system, by which we mean a network of generators, transmission lines,and loads that could represent an area as small as a municipality or as large as several states. Given certain known quantities—typically, the amount of power generated and consumed at different locations—power flow analysis allows one to determine other quantities. The most important of these quantities are the voltages at locations throughout the transmission system, which, for alternating current (a.c.), consist of both a magnitude and a time element or phase angle. Once the voltages are known, the currents flowing through every transmission link can be easily calculated. Thus the name power flow or load flow, as it is often called in the industry: given the amount of power delivered and where it comes from, power flow analysis tells us how it flows to its destination.

Owing mainly to the peculiarities of a.c., but also to the sheer size and complexity of a real power system—its elaborate topology with many nodes and links, and the large number of generators and loads—it turns out to be no mean feat to deduce what is happening in one part of the system from what is happening elsewhere, despite the fact that these happenings are intimately related through well-understood, deterministic laws of physics. Although we can readily calculate voltages and currents through the branches of small direct current (d.c.) circuits in terms of each other even a small network of a handful of a.c. power sources and loads defies our ability to write down formulas for the relationships among all the variables: as a mathematician would say, the system cannot be solved analytically; there is no closed-form solution. We can only get at a numerical answer through a process of successive approximation or iteration. In order to find out what the voltage or current at any given point will be, we must in effect simulate the entire system. Historically, such simulations were accomplished through an actual miniature d.c. model of the power system in use. Generators were represented by small d.c. power supplies, loads by resistors, and transmission lines by appropriately sized wires. The voltages and currents could be found empirically by direct measurement. To find out how much the current on line A would increase, for example, due to Generator X taking over power production from Generator Y, one would simply adjust the values on X and Y and go read the ammeter on line A. The d.c. model does not exactly match the behavior of the a.c. system, but it gives an approximation that is close enough for most practical purposes. In the age of computers, we no longer need to physically build such models, but can create them mathematically.

With plenty of computational power, we can not only represent a d.c. system, but the a.c. system itself in a way that accounts for the subtleties of a.c. Such a simulation constitutes power flow analysis. Power flow answers the question, What is the present operating state of the system, given certain known quantities? To do this, it uses a mathematical algorithm of successive approximation by iteration, or the repeated application of calculation steps. These steps represent a process of trial and error that starts with assuming one array of numbers for the entire system, comparing the relationships among the numbers to the laws of physics, and then repeatedly adjusting the numbers until the entire array is consistent with both physical law and the conditions stipulated by the user. In practice, this looks like a computer program to which the operator gives certain input information about the power system, and which then provides output that completes the picture of what is happening in the system, that is, how the power is flowing.

Power flow analysis is used to obtain information on the current stane and conditions of the system in term sof voltage magnitudes and angels as well as real and reaktive power. From power flow analysis we can get infomation about what is happenning in the system,how the power is flowing in the lines to the loads.For the solution of power flow problem we have o solve the non-linear equations for the system which may not have the exact solution so we apply *numerical analysis.*

Generally Gauss-Sidel and Newton-Raphson iterative methods are used to solve these types of equations.the calculation involve in the power flow analysis is not very simple.For large systems it is even more complex and time consuming to solve it by hands.

In this project computer based program using Decoupled Newton-Raphson Method developed in MATLAB is considered for the solution of the power flow equations.the project consist *of 4 chapters and conclusion.*

Chapter one describes the history of the electric power industry,electric power transfer related with the AC power transfer.Also explain the theory of alternating current and voltage.*description of complex quanities such as reactance and impedance.*

Chapter two presents the definition of power in AC circuit.The description of real and reactive power.Some information about losses,stability in power system.

Chapter three the theory of power flow analysis.the representation of power system by one-line diagram and per-unit system.the description of buses in power system.the description of variables used in power flow.

Chapter four the formulation power of power flow equations and solutions.the calculation procedure of the newton raphson method.the solution of an example solved with decoupled newton-raphson method. MATLAB program used to solve power flow equations.

Finally the conclusion part presents the important result obtained within the project.

CHAPTER 1: History of the Electric Power Industry

Although electricity had been known to be produced as a result of the chemical reactions that take place in an electrolytic cell since Alessandro Volta developed the voltaic pile in 1800, its production by this means was, and still is, expensive. In 1831, Michael Faraday devised a machine that generated electricity from rotary motion, but it took almost 50 years for the technology to reach a commercially viable stage. In 1878, in the US, Thomas Edison developed and sold a commercially viable replacement for gas lighting and heating using locally generated and distributed direct current electricity

The world's first public electricity supply was provided in late 1881, when the streets of the Surrey town of Godalming in the UK were lit with electric light. This system was powered from a water wheel on the River Wey, which drove a Siemens alternator that supplied a number of arc lamps within the town. This supply scheme also provided electricity to a number of shops and premises.

Coinciding with this, in early 1882, Edison opened the world's first steam-powered electricity generating station at Holborn Viaduct in London, where he had entered into an agreement with the City Corporation for a period of three months to provide street lighting. In time he had supplied a number of local consumers with electric light. The method of supply was direct current (DC)

It was later on in the year in September 1882 that Edison opened the Pearl Street Power Station in New York City and again it was a DC supply. It was for this reason that the generation was close to or on the consumer's premises as Edison had no means of voltage conversion. The voltage chosen for any electrical system is a compromise. Increasing the voltage reduces the current and therefore reduces resistive losses in the cable. Unfortunately it increases the danger from direct contact and also increases the required insulation thickness. Furthermore some load types were difficult or impossible to make for higher voltages. It was later on in the year in September 1882 that Edison opened the Pearl Street Power Station in New York City and again it was a DC supply. It was for this reason that the generation was close to or on the consumer's premises as Edison had no means of voltage conversion. The voltage chosen for any electrical system is a compromise. Increasing the voltage reduces the current and therefore reduces resistive losses in the cable. Unfortunately it increases the

danger from direct contact and also increases the required insulation thickness. Furthermore some load types were difficult or impossible to make for higher voltages.

Nikola Tesla, who had worked for Edison for a short time and appreciated the electrical theory in a way that Edison did not, devised an alternative system using alternating current. Tesla realised that while doubling the voltage would halve the current and reduce losses by three-quarters, only an alternating current system allowed the transformation between voltage levels in different parts of the system. This allowed efficient high voltages for distribution where their risks could easily be mitigated by good design while still allowing fairly safe voltages to be supplied to the loads. He went on to develop the overall theory of his system, devising theoretical and practical alternatives for all of the direct current appliances then in use, and patented his novel ideas in 1887, in thirty separate patents

In 1888, Tesla's work came to the attention of George Westinghouse, who owned a patent for a type of transformer that could deal with high power and was easy to make. Westinghouse had been operating an alternating current lighting plant in Great Barrington, Massachusetts since 1886. While Westinghouse's system could use Edison's lights and had heaters, it did not have a motor. With Tesla and his patents, Westinghouse built a power system for a gold mine in Telluride, Colorado in 1891, with a water driven 100 horsepower (75 kW) generator powering a 100 horsepower (75 kW) motor over a 2.5-mile (4 km) power line. Almarian Decker finally invented the whole system of three-phase power generating in Redlands, California in 1893. Then, in a deal with General Electric, which Edison had been forced to sell, Westinghouse's company went on to construct a power station at the Niagara Falls, with three 5,000 horsepower (3.7 MW) Tesla generators supplying electricity to an aluminium smelter at Niagara and the town of Buffalo 22 miles (35 km) away. The Niagara power station commenced operation on April 20, 1895.

Tesla's alternating current system remains the primary means of delivering electrical energy to consumers throughout the world. While high-voltage direct current (HVDC) is increasingly being used to transmit large quantities of electricity over long distances or to connect adjacent asynchronous power systems, the bulk of electricity generation, transmission, distribution and retailing takes place using alternating current

1.1. Electric power transmission

Electric power transmission, a process in the delivery of electricity to consumers, is the bulk transfer of electrical power. Typically, power transmission is between the power plant and a substation near a populated area. Electricity distribution is the delivery from the substation to the consumers. Electric power transmission allows distant energy sources (such as hydroelectric power plants) to be connected to consumers in population centers, and may allow exploitation of low-grade fuel resources that would otherwise be too costly to transport to generating facilities.

Due to the large amount of power involved, transmission normally takes place at high voltage (110 kV or above). Electricity is usually transmitted over long distance through overhead power transmission lines. Underground power transmission is used only in densely populated areas due to its high cost of installation and maintenance, and because the high reactive power produces large charging currents and difficulties in voltage management.

A power transmission system is sometimes referred to colloquially as a "grid"; however, for reasons of economy, the network is not a mathematical grid. Redundant paths and lines are provided so that power can be routed from any power plant to any load center, through a variety of routes, based on the economics of the transmission path and the cost of power. Much analysis is done by transmission companies to determine the maximum reliable capacity of each line, which, due to system stability considerations, may be less than the physical or thermal limit of the line. Deregulation of electricity companies in many countries has led to renewed interest in reliable economic design of transmission networks. However, in some places the gaming of a deregulated energy system has led to disaster, such as that which occurred during the California electricity crisis of 2000 and 2001.

1.2. AC power transmission

AC power transmission is the transmission of electric power by alternating current. Usually transmission lines use three phase AC current.Single phase AC current is sometimes used in a railway electrification system.In urban areas, trains may be powered by DC at 600 volts or so.

Overhead conductors are not covered by insulation. The conductor material is nearly always an aluminum alloy, made into several strands and possibly reinforced with steel strands. Conductors are a commodity supplied by several companies worldwide. Improved conductor material and shapes are regularly used to allow increased capacity and modernize transmission circuits. Conductor sizes in overhead transmission work range in size from #6 American wire gauge (about 12 square millimetres) to 1,590,000 circular mils area (about 750 square millimetres), with varying resistance and current-carrying capacity. Thicker wires would lead to a relatively small increase in capacity due to the skin effect, that causes most of the current to flow close to the surface of the wire.

Today, transmission-level voltages are usually considered to be 110 kV and above. Lower voltages such as 66 kV and 33 kV are usually considered sub-transmission voltages but are occasionally used on long lines with light loads. Voltages less than 33 kV are usually used for distribution. Voltages above 230 kV are considered extra high voltage and require different designs compared to equipment used at lower voltages.

Overhead transmission lines are uninsulated wire, so design of these lines requires minimum clearances to be observed to maintain safety.

1.3. Alternating current

An alternating current (AC) is an electrical current whose magnitude and direction vary cyclically, as opposed to direct current, whose direction remains constant. The usual waveform of an AC power circuit is a sine wave, as this results in the most efficient transmission of energy. However in certain applications different waveforms are used, such as triangular or square waves.

Used generically, AC refers to the form in which electricity is delivered to businesses and residences. However, audio and radio signals carried on electrical wire are also examples of alternating current. In these applications, an important goal is often the recovery of information encoded (or modulated) onto the AC signal.

1.3.1. Properties of Alternative Current

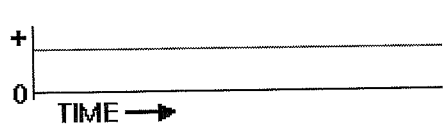


figure 1.1

A DC power source, such as a battery, outputs a constant voltage over time, as depicted in the top figure to the right. Of course, once the chemicals in the battery have completed their reaction, the battery will be exhausted and cannot develop any output voltage. But until that happens, the output voltage will remain essentially constant. The same is true for any other source of DC electricity: the output voltage remains constant over time.

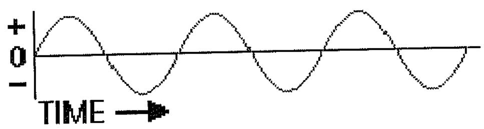


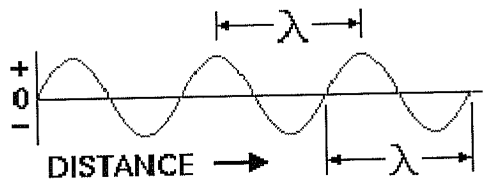
figure 1.2

By contrast, an AC source of electrical power changes constantly in amplitude and regularly changes polarity, as shown in the second figure to the right. The changes are smooth and regular, endlessly repeating in a succession of identical cycles, and form a sine wave as depicted here.

Because the changes are so regular, alternating voltage and current have a number of properties associated with any such waveform. These basic properties include the following list:

- **Frequency.** One of the most important properties of any regular waveform identifies the number of complete cycles it goes through in a fixed period of time. For standard measurements, the period of time is one second, so the *frequency* of the wave is commonly measured in *cycles per second* (cycles/sec) and, in normal usage, is expressed in units of *Hertz* (Hz). It is represented in mathematical equations by the letter 'f.' In North America (primarily the US and Canada), the AC power system operates at a frequency of 60 Hz. In Europe, including the UK, Ireland, and Scotland, the power system operates at a frequency of 50 Hz.
- **Period.** Sometimes we need to know the amount of time required to complete one cycle of the waveform, rather than the number of cycles per second of time. This is logically the reciprocal of frequency. Thus, *period* is the time duration of one cycle of the waveform, and is measured in seconds/cycle. AC power at 50 Hz will have a period of 1/50 = 0.02 seconds/cycle. A 60 Hz power system has a period of 1/60 = 0.016667 seconds/cycle. These are often expressed as 20 ms/cycle or

16.6667 ms/cycle, where 1 ms is 1 millisecond = 0.001 second (1/1000 of a



second).

figure 1.3

- **Wavelength.** Because an AC wave moves physically as well as changing in time, sometimes we need to know how far it moves in one cycle of the wave, rather than how long that cycle takes to complete. This of course depends on how fast the wave is moving as well. Electrical signals travel through their wires at nearly the speed of light, which is very nearly 3×10^8 meters/second, and is represented mathematically by the letter 'c.' Since we already know the frequency of the wave in Hz, or cycles/second, we can perform the division of c/f to obtain a result in units of meters/cycle, which is what we want. The Greek letter λ(lambda) is used to represent wavelength in mathematical expressions. Thus, $\lambda = c/f$. As shown in the figure to the right, wavelength can be measured from any part of one cycle to the equivalent point in the next cycle. Wavelength is very similar to period as discussed above, except that wavelength is measured in distance per cycle where period is measured in time per cycle.
- **Amplitude.** Another thing we have to know is just how positive or negative the voltage is, with respect to some selected neutral reference. With DC, this is easy; the voltage is constant at some measurable value. But AC is constantly changing, and yet it still powers a load. Mathematically, the *amplitude* of a sine wave is the value of that sine wave at its peak. This is the maximum value, positive or negative, that it can attain. However, when we speak of an AC power system, it is more useful to refer to the *effective* voltage or current. This is the rating that would cause the same amount of work to be done (the same effect) as the same value of DC voltage or current would cause. We won't cover the mathematical derivations here; for the present, we'll simply note that for a sine wave, the effective voltage of the AC power system is 0.707 times the peak voltage. Thus, when we say that the AC line voltage in the US is 120 volts, we are referring to the voltage amplitude, but we are describing the effective voltage, not the peak voltage of nearly 170 volts. The effective voltage is also known as the *rms voltage*.

1.3.2. Why Use Alternating Current?

- Since some kinds of loads require DC to power them and others can easily operate on either AC or DC, the question naturally arises, "Why not dispense entirely with AC and just use DC for everything?" This question is augmented by the fact that in some ways AC is harder to handle as well as to use. Nevertheless, there is a very practical reason, which overrides all other considerations for a widely distributed power grid. It all boils down to a question of cost.
- DC does get used in some local commercial applications. An excellent example of this is the electric trolley car and trolley bus system used in San Francisco, for public transportation. Trolley cars are electric train cars with power supplied by an overhead wire. Trolley busses are like any other bus, *except they are electrically* powered and get their power from two overhead wires. In both cases, they operate on 600 volts DC, and the overhead wires span the city.
- The drawback is that most of the electrical devices on each car or bus, including all the light bulbs inside, are quite standard and require 110 to 120 volts. At the same time, however, if we were to reduce the system voltage, we would have to increase the amount of current drawn by each car or bus in order to provide the same amount of power to it. (Power is equal to the product of the applied voltage and the resulting current: $P = I \times E$.) But those overhead wires are not perfect conductors; they exhibit some resistance. They will absorb some energy from the electrical current and dissipate it as waste heat, in accordance with Ohm's Law ($E = I \times R$). With a small amount of algebra, we can note that the lost power can be expressed as:

$$P_{lost} = I^2R$$

- Now, if we reduce the voltage by a factor of 5 (to 120 volts DC), we must increase the current by a factor of 5 to maintain the same power to the trolley car or bus. But lost power is a function of the *square* of the current, so we will lose not five times as much power in the resistance of the wires, but *twenty-five* times as much power. To offset and minimize that loss, we would have to use much larger wires, and pay a high price for all that extra copper. A cheaper solution is to mount a motor-generator set in each trolley car and bus, using a 600 volt dc motor and a lower-voltage generator to power all the equipment aboard that car.

- The same reality of Ohm's Law and resistive losses holds true in the country-wide power distribution system. We need to keep the voltage used in homes to a reasonable and relatively safe value, but at the same time we need to minimize resistive losses in the transmission wires, without bankrupting ourselves buying heavy-gauge copper wire. At the same time, we can't use motor-generator pairs all across the country; they would need constant service and would break down far too often. We need a system that allows us to raise the voltage (and thus reduce the current) for long-distance transmission, and then reduce the voltage again (to a safe value) for distribution to individual homes and businesses. And we need to do this without requiring any moving parts to break down or need servicing.
- The answer is to use an AC power system and transformers. (We'll learn far more about transformers in a later page; for now, a *transformer* is an electrical component that can convert incoming AC power at one voltage to outgoing power at a different voltage, higher or lower, with only very slight losses.) Thus, we can generate electricity at a reasonable voltage for practical AC generators (sometimes called *alternators*), then use transformers to step that voltage up to very high levels for long-distance transmission, and then use additional transformers to step that high voltage back down for local distribution to individual homes.
- In practice, this is done in stages. The really high-voltage transmission lines hanging from long glass insulators on the arms of tall steel towers carry electricity cross-country at several hundred thousand volts. This is stepped down to about 22,000 volts for distribution to multiple neighborhoods — these are the wires you see at the top of the telephone poles in many areas. Additional transformers mounted on some of these telephone poles step this voltage down again for distribution to several homes each.
- The design of the system minimizes the overall cost by balancing the cost of transformers against the cost of heavier-gauge copper wire, as well as the cost of maintaining the system and repairing damage. This is how the cost of

electricity delivered to your home or business is kept to a minimum, while maintaining a very high level of service.

1.4. Voltage

Voltage (sometimes also called *electric* or *electrical tension*) is the difference of electrical potential between two points of an electrical or electronic circuit, expressed in volts.[1] It measures the potential energy of an electric field to cause an electric current in an electrical conductor. Depending on the difference of electrical potential it is called extra low voltage, low voltage, high voltage or extra high voltage.

1.5. Electrical resistance

Electrical resistance is a measure of the degree to which an object opposes an electric current through it, measured in ohms. Its reciprocal quantity is electrical conductance measured in siemens. Assuming a uniform current density, an object's electrical resistance is a function of both its physical geometry and the resistivity of the material it is made from:

$$R = \frac{l \cdot \rho}{A}$$

Where;

"l" is the length

"A" is the cross sectional area, and

"ρ" is the resistivity of the material

For a wide variety of materials and conditions, the electrical resistance does not depend on the amount of current through or the amount of voltage across the object, meaning that the resistance R is constant.

1.6. Reactance

Reactance is the imaginary part of electrical impedance, a measure of opposition to a sinusoidal alternating current. Reactance arises from the presence of inductance andcapacitance within a circuit, and is denoted by the symbol X. The SI unit of reactance is the ohm.

Both reactance $\mathrm{X}$and resistance $R$are required to determine the impedance $\tilde{Z}$; although in some circumstances the reactance may dominate the impedance; at least an approximate knowledge of the resistance is required to establish this.

$$\tilde{Z} = R + j\mathrm{X}$$

Both the magnitude $|\tilde{Z}|$and the phase $\theta$of the impedance depend on both the resistance and the reactance.

$$|\tilde{Z}| = \sqrt{ZZ^*} = \sqrt{R^2 + \mathrm{X}^2}$$

$$\theta = \arctan\left(\frac{\mathrm{X}}{R}\right)$$

The magnitude is the ratio of the voltage and current amplitudes, while the phase is the voltage–current phase difference.

If $\mathrm{X}>0$, the reactance is said to be *inductive*

If $\mathrm{X}=0$, then the impedance is purely *resistive*

If $\mathrm{X}<0$, the reactance is said to be *capacitive*

1.6.1. Inductance(Inductive Reactance)

An electric current *i* flowing around a circuit produces a magnetic field and hence a magnetic flux Φ through the circuit. The ratio of the magnetic flux to the current is called the inductance, or more accurately self-inductance of the circuit. The term was coined by Oliver Heaviside in February 1886. It is customary to use the symbol *L* for inductance, possibly in honour of the physicist Heinrich Lenz but perhaps simply from the word **Loop**. The quantitative definition of the inductance in SI units (webers per ampere) is

$$L = \frac{\Phi}{i}.$$

In honour of Joseph Henry, the unit of inductance has been given the name **henry (H)**: 1H = 1Wb/A.

In the above definition, the magnetic flux Φ is that caused by the current flowing through the circuit concerned. There may, however, be contributions from other circuits. Consider for example two circuits C_1, C_2, carrying the currents i_1, i_2. The magnetic fluxes Φ_1 and Φ_2 in C_1 and C_2, respectively, are given by

$$\Phi_1 = L_{11} i_1 + L_{12} i_2,$$
$$\Phi_2 = L_{21} i_1 + L_{22} i_2.$$

According to the above definition, L_{11} and L_{22} are the self-inductances of C_1 and C_2, respectively. It can be shown (see below) that the other two coefficients are equal: $L_{12} = L_{21} = M$, where M is called the **mutual inductance** of the pair of circuits.

Self and mutual inductances also occur in the expression

$$W = \frac{1}{2} \sum_{m,n=1}^{N} L_{m,n} i_m i_n$$

for the energy of the magnetic field generated by N electrical circuits carrying the currents i_n. This equation is an alternative definition of inductance, also valid when the currents don't flow in thin wires and when it thus is not immediately clear what the area encompassed by a circuit is and how the magnetic flux through the circuit is to be defined. The definition $L = \Phi / i$, in contrast, is more direct and more intuitive. It may be shown that the two definitions are equivalent by equating the time derivate of W and the electric power transferred to the system (see below).

1.6.2. Capacitance (Capacitive Reactance)

Capacitance is a measure of the amount of electric charge stored (or separated) for a given electric potential. The most common form of charge storage device is a two-plate capacitor. If the charges on the plates are +Q and −Q, and V gives the voltage difference between the plates, then the capacitance is given by

$$C = \frac{Q}{V}$$

The SI unit of capacitance is the farad; 1 farad = 1 coulomb per volt.

1.7. Admittance

In electrical engineering, the admittance (*Y*) is the inverse of the impedance (*Z*). The SI unit of admittance is the siemens. Oliver Heaviside coined the term in December 1887.

$$Y = Z^{-1} = 1/Z$$

Where;

Y is the admittance, measured in siemens

Z is the impedance, measured in ohms

Note that the synonymous unit mho, and the symbol ℧ (an upside-down Omega Ω), are also in common use.

Admittance is a measure of how easily a circuit or device will allow a current to flow. Resistance is a measure of the opposition of a circuit to the flow of a steady current, while impedance takes in to account not only the resistance but dynamic effects (known as reactance) as well. Likewise, admittance is not only a measure of the ease with which a steady current can flow (conductance, the inverse of resistance), but also takes in to account the dynamic effects of susceptance (the inverse of reactance).

1.8. Impedance

Electrical impedance, or simply impedance, describes a measure of opposition to a sinusoidal alternating current (AC). Electrical impedance extends the concept of resistance to AC circuits, describing not only the relative amplitudes of the voltage and current, but also the relative phases. In general impedance is a complex quantity $\tilde{Z}$and the term *complex impedance* may be used interchangeably; the polar form conveniently captures both magnitude and phase characteristics,

$$\tilde{Z} = Ze^{j\theta}$$

where the magnitude Zgives the change in voltage amplitude for a given current amplitude, while the argument θgives the phase difference between voltage and current. In Cartesian form,

$$\tilde{Z} = R + jX$$

where the real part of impedance is the resistance $R$and the imaginary part is the reactance X. Dimensionally, impedance is the same as resistance; the SI unit is the ohm. The term *impedance* was coined by Oliver Heaviside in July 1886.

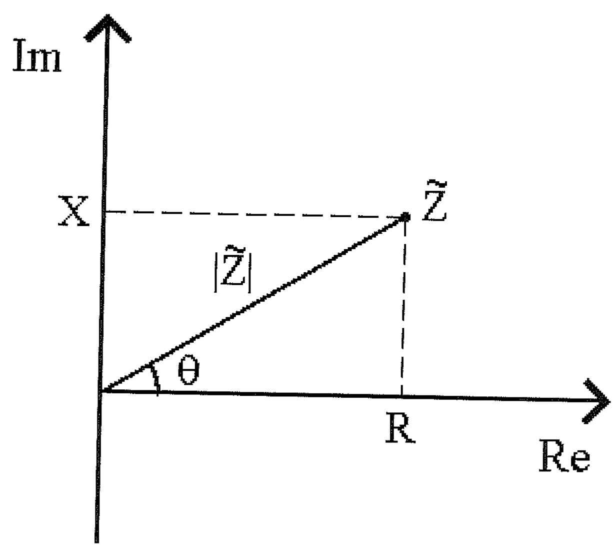


figure 1.4

1.9. Conversion from impedance to admittance

The impedance, Z, is composed of real and imaginary parts,

$$Z = R + jX$$

Where;

R is the resistance, measured in ohms

X is the reactance, measured in ohms

$$Y = Z^{-1} = \frac{1}{R + jX} = \left(\frac{1}{R + jX}\right) \cdot \left(\frac{R - jX}{R - jX}\right) = \left(\frac{R}{R^2 + X^2}\right) + j\left(\frac{-X}{R^2 + X^2}\right)$$

Admittance, just like impedance, is therefore a complex number, made up of a real part (the conductance, *G*), and an imaginary part (the susceptance, *B*), shown by the equation:

$$Y = G + jB$$

$$Y = G + jB = \left(\frac{R}{R^2 + X^2}\right) + j\left(\frac{-X}{R^2 + X^2}\right)$$

Then *G* (conductance) and *B* (susceptance) are given by;

$$G = \Re(Y) = \left(\frac{R}{R^2 + X^2}\right)$$

$$B = \Im(Y) = \left(\frac{-X}{R^2 + X^2}\right)$$

The magnitude and phase of the admittance are given by;

$$|Y| = \sqrt{G^2 + B^2} = \frac{1}{\sqrt{R^2 + X^2}}$$

$$\angle Y = \arctan\left(\frac{B}{G}\right) = \arctan\left(\frac{-X}{R}\right)$$

Where; *G* is the conductance, measured in siemens

B is the susceptance, measured in siemens

CHAPTER 2: Electric power

Electric power is defined as the rate at which electrical energy is transferred by an electric circuit. The SI unit of power is the watt.

Electric power, like mechanical power, is represented by the letter *P* in electrical equations. The term *wattage* is used colloquially to mean "electric power in watts."

In direct current resistive circuits, instantaneous electrical power is calculated using Joule's Law, which is named after the British physicist James Joule, who first showed that heat and mechanical energy were interchangeable.

$$P = VI$$

Where;

P is the power (watt or W)

V is the potential difference (volt or V)

I is the current (ampere or A)

For example:

$$2\,\mathrm{A} \cdot 12\mathrm{V} = 24\,\mathrm{W}$$

Joule's law can be combined with Ohm's law to produce two more equations:

$$P = I^2 R = \frac{V^2}{R}$$

Where;

R is the resistance (Ohm or Ω).

For example:

$$(2\,\mathrm{A})^2 \cdot 6\,\Omega = 24\,\mathrm{W}$$

And

$$\frac{(12\,\mathrm{V})^2}{6\,\Omega} = 24\,\mathrm{W}$$

2.1. AC power

Power is defined as the rate of flow of energy past a given point. In alternating current circuits, energy storage elements such as inductance and capacitance may result in periodic reversals of the direction of energy flow. The portion of power flow that, averaged over a complete cycle of the AC waveform, results in net transfer of energy in one direction is known as real power. On the other hand, the portion of power flow due to stored energy, which returns to the source in each cycle, is known as reactive power.

2.1.1. Real, reactive, and apparent power

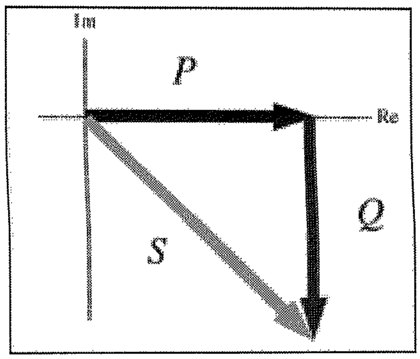


Figure 2.1 : The apparent power is the vector sum of real and reactive power

Engineers use the following terms to describe energy flow in a system (and assign each of them a different unit to differentiate between them):

Real power (*P*) [Unit: W – Watt]

Reactive power (*Q*) [Unit: VAR - Volt-Ampere Reactive]

Complex power (*S*) [Unit: VA - Volt-Ampere]

Apparent Power (|*S*|) [Unit: VA]: i.e. the absolute value of complex power *S*.

In the diagram, *P* is the real power, *Q* is the reactive power (in this case negative), *S* is the complex power and the length of *S* is the apparent power.

The unit for all forms of power is the watt (symbol: W), but this unit is generally reserved for the real power component. Apparent power is conventionally expressed in **volt-amperes** (VA) since it is the simple product of rms voltage and rms current. The unit for reactive power is the "var", which stands for volt-amperes reactive. Since reactive power flow transfers no net energy to the load, it is sometimes called "wattless" power.

Understanding the relationship between these three quantities lies at the heart of understanding power engineering. The mathematical relationship among them can be represented by vectors or expressed using complex numbers

$$S = P + jQ$$ (where j is the imaginary unit).

The complex value S is referred to as the **complex power.**

Consider a simple alternating current (AC) circuit consisting of a source and a load, where both the current and voltage are sinusoidal. If the load is purely resistive, the two quantities reverse their polarity at the same time, the direction of energy flow does not reverse, and only real power flows. If the load is purely reactive, then the voltage and current are 90 degrees out of phase and there is no net power flow. This energy flowing backwards and forwards is known as reactive power. A practical load will have resistive, inductive, and capacitive parts, and so both real and reactive power will flow to the load.

If a capacitor and an inductor are placed in parallel, then the currents flowing through the inductor and the capacitor tend to cancel out rather than adding. Conventionally, capacitors are considered to generate reactive power and inductors to consume it. This is the fundamental mechanism for controlling the power factor in electric power transmission; capacitors (or inductors) are inserted in a circuit to partially cancel reactive power of the load.

The apparent power is the product of voltage and current. Apparent power is handy for sizing of equipment or wiring. However, adding the apparent power for two loads will not accurately give the total apparent power unless they have the same displacement between current and voltage (the same power factor).

2.1.2. Power factor

Power factor equals 1 when the voltage and current are in phase, and is zero when the current leads or lags the voltage by 90 degrees. Power factors are usually stated as "leading"or "lagging" to show the sign of the phase angle, where leading indicates a negative sign. For two systems transmitting the same amount of real power, the system with the lower power factor will have higher circulating currents due to energy that returns to the source from energy storage in the load. These higher currents in a practical system will produce higher losses and reduce overall transmission efficiency. A lower power factor circuit will have a higher apparent power and higher losses for the same amount of real power transfer

Purely capacitive circuits cause reactive power with the current waveform leading the voltage wave by 90 degrees, while purely inductive circuits cause reactive power with the current waveform lagging the voltage waveform by 90 degrees. The result of this is that capacitive and inductive circuit elements tend to cancel each other out

2.1.3. Losses

Transmitting electricity at high voltage reduces the fraction of energy lost to Joule heating. For a given amount of power, a higher voltage reduces the current and thus the resistive losses in the conductor. For example, raising the voltage by a factor of 10 reduces the current by a corresponding factor of 10 and therefore the I^2R losses by a factor of 100, provided the same sized conductors are used in both cases. Even if the conductor size is reduced x10 to match the lower current the I^2R losses are still reduced x10. Long distance transmission is typically done with overhead lines at voltages of 115 to 1,200 kV. However, at extremely high voltages, more than 2,000 kV between conductor and ground, corona discharge losses are so large that they can offset the lower resistance loss in the line conductors.

Transmission and distribution losses in the USA were estimated at 7.2% in 1995, and in the UK at 7.4% in 1998.

As of 1980, the longest cost-effective distance for electricity was 4,000 miles (7,000 km), although all present transmission lines are considerably shorter. (see Present Limits of High-Voltage Transmission).

In an alternating current transmission line, the inductance and capacitance of the line conductors can be significant. The currents that flow in these components of transmission line impedance constitute reactive power, which transmits no energy to the load. Reactive current flow causes extra losses in the transmission circuit. The ratio of real power (transmitted to the load) to apparent power is the power factor. As reactive current increases, the reactive power increases and the power factor decreases. For systems with low power factors, losses are higher than for systems with high power factors. Utilities add capacitor banks and other components throughout the system — such as phase-shifting transformers, static VAR compensators, and flexible AC transmission systems (FACTS) — to control reactive power flow for reduction of losses and stabilization of system voltage.

Electrical power is always partially lost by transmission. This applies to short distances such as between components on a printed circuit board as well as to cross country high voltage lines. The major component of power loss is due to ohmic losses in the conductors and is equal to the product of the resistance of the wire and the square of the current:

$$P_{loss} = RI^2.$$

For a system which delivers a power, P, at unity power factor at a particular voltage, V, the current flowing through the cables is given by $I = \frac{P}{V}$. Thus, the power lost in the lines,

$$P_{loss} = RI^2 = R\left(\frac{P}{V}\right)^2 = \frac{RP^2}{V^2}.$$

Therefore, the power lost is proportional to the resistance and inversely proportional to the square of the voltage. A higher transmission voltage reduces the current and thus the power lost during transmission.

In addition, a low resistance is desirable in the cable. While copper cable could be used, aluminium alloy is preferred due to its much better conductivity to weight ratio making it lighter to support, as well as its lower cost. The aluminium is normally mechanically supported on a steel core.

2.2. Power System Stability

2.2.1. Basic Concepts

Power system stability denotes 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 system integrity is preserved. Integrity of the system is preserved when practically the entire power system remains intact with no tripping of generators or loads, except for those disconnected by isolation of the faulted elements or intentionally tripped to preserve the continuity of operation of the rest of the system. Stability is a condition of equilibrium between opposing forces; instability results when a disturbance leads to a sustained imbalance between the opposing forces.

The power system is a highly nonlinear system that operates in a constantly changing environment; loads, generator outputs, topology, and key operating parameters change continually.When subjected to a transient disturbance, the stability of the system depends on the nature of the disturbance as well as the initial operating condition. The disturbance may be small or large. Small disturbances in the form of load changes occur continually, and the system adjusts to the changing conditions. The system must be able to operate satisfactorily under these conditions and successfully meet the load demand. It must also be able to survive numerous disturbances of a severe nature, such as a short-circuit on a transmission line or loss of a large generator.Following a transient disturbance, if the power system is stable, it will reach a new equilibrium state with practically the entire system intact; the actions of automatic controls and possibly human operators will eventually restore the system to normal state. On the other hand, if the system is unstable, it will result in a run-away or run-down situation; for example, a progressive increase in angular separation of generator rotors, or a progressive decrease in bus voltages. An unstable system condition could lead to cascading outages and a shut-down of a major portion of the power system.

The response of the power system to a disturbance may involve much of the equipment. For instance, a fault on a critical element followed by its isolation by protective relays will cause variations in power flows, network bus voltages, and machine rotor speeds; the voltage variations will actuate both generator and transmission network voltage regulators; the generator speed variations will actuate prime mover governors; and the voltage and frequency variations will affect the system loads to varying degrees depending on their individual characteristics. Further, devices used to protect individual equipment may respond to variations in system variables and thereby affect the power system performance. A typical modern power system is thus a very high-order multivariable process whose dynamic performance is influenced by a wide array of devices with different response rates and characteristics. Hence, instability in a power system may occur in many different ways depending on the system topology, operating mode, and the form of the disturbance.

Traditionally, the stability problem has been one of maintaining synchronous operation. Since power systems rely on synchronous machines for generation of electrical power, a necessary condition for satisfactory system operation is that all synchronous machines remain in synchronism or, colloquially, ''in step.'' This aspect of stability is influenced by the dynamics of generator rotor angles and powerangle relationships.

Instability may also be encountered without the loss of synchronism. For example, a system consisting of a generator feeding an induction motor can become unstable due to collapse of load voltage. In this instance, it is the stability and control of voltage that is the issue, rather than the maintenance of synchronism. This type of instability can also occur in the case of loads covering an extensive area in a large system.

In the event of a significant load=generation mis match, generator and prime mover controls become important, as well as system controls and special protections. If not properly coordinated, it is possible for the system frequency to become unstable, and generating units and=or loads may ultimately be tripped possibly leading to a system blackout. This is another case where units may remain in synchronism (until tripped by such protections as under-frequency), but the system becomes unstable.

Because of the high dimensionality and complexity of stability problems, it is essential to make simplifying assumptions and to analyze specific types of problems using the right degree of detail ofsystem representation. The following subsection describes the classification of power system stability into different categories.

2.2.2. Classification of Power System Stability

Power system stability is a single problem; however, it is impractical to deal with it as such. Instability of the power system can take different forms and is influenced by a wide range of factors. Analysis of stability problems, including identifying essential factors that contribute to instability and devising methods of improving stable operation is greatly facilitated by classification of stability into appropriate categories. These are based on the following considerations (Kundur, 1994; Kundur and Morison, 1997):

. The physical nature of the resulting instability related to the main system parameter in which instability can be observed.

. The size of the disturbance considered indicates the most appropriate method of calculation and prediction of stability.

. The devices, processes, and the time span that must be taken into consideration in order to determine stability.

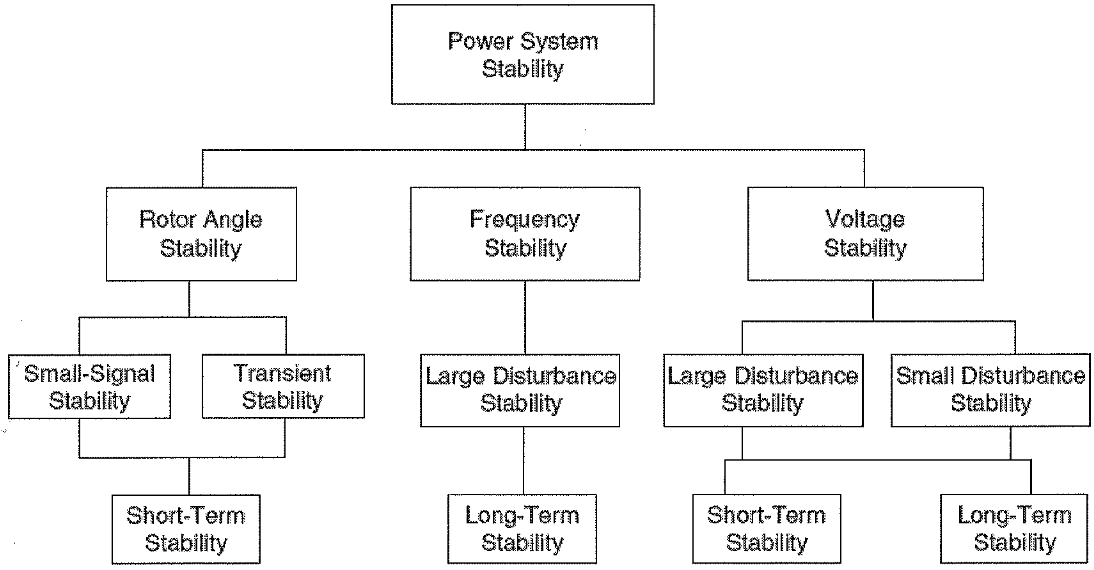


Figure 2.2 : Classification of power system stability.

2.2.3. Rotor Angle Stability

Rotor angle stability is concerned with the ability of interconnected synchronous machines of a power system to remain in synchronism under normal operating conditions and after being subjected to a disturbance. It depends on the ability to maintain=restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators.

The rotor angle stability problem involves the study of the electromechanical oscillations inherent in power systems. A fundamental factor in this problem is the manner in which the power outputs of synchronous machines vary as their rotor angles change. The mechanism by which interconnected synchronous machines maintain synchronism with one another is through restoring forces, which act whenever there are forces tending to accelerate or decelerate one or more machines with respect to other machines. Under steady-state conditions, there is equilibrium between the input mechanical torque and the output electrical torque of each machine, and the speed remains constant. If the system is perturbed, this equilibrium is upset, resulting in acceleration or deceleration of the rotors of the machines according to the laws of motion of a rotating body. If one generator temporarily runs faster than another, the angular position of its rotor relative to that of the slower machine will advance. The resulting angular difference transfers part of the load from the slow machine to the fast machine, depending on the power-angle relationship. This tends to reduce the speed difference and hence the angular separation. The power-angle relationship, as discussed above, is highly nonlinear. Beyond a certain limit, an increase in angular separation is accompanied by a decrease in power transfer; this increases the angular separation further and leads to instability. For any given situation, the stability of the system depends on whether or not the deviations in angular positions of the rotors result in sufficient restoring torques.

It should be noted that loss of synchronism can occur between one machine and the rest of the system, or between groups of machines, possibly with synchronism maintained within each group after separating from each other.

The change in electrical torque of a synchronous machine following a perturbation can be resolved into two components:

. Synchronizing torque component, in phase with a rotor angle perturbation.

. Damping torque component, in phase with the speed deviation.

System stability depends on the existence of both components of torque for each of the synchronous machines. Lack of sufficient synchronizing torque results in aperiodic or nonoscillatory instability, whereas lack of damping torque results in oscillatory instability.

For convenience in analysis and for gaining useful insight into the nature of stability problems, it is useful to characterize rotor angle stability in terms of the following two categories:

1. Small signal (or steady state) stability is concerned with the ability of the power system to maintain synchronism under small disturbances. The disturbances are considered to be sufficiently small that linearization of system equations is permissible for purposes of analysis. Such disturbances are continually encountered in normal system operation, such as small changes in load. Small signal stability depends on the initial operating state of the system. Instability that may result can be of two forms: (i) increase in rotor angle through a non-oscillatory or aperiodic mode due to lack of synchronizing torque, or (ii) rotor oscillations of increasing amplitude due to lack of sufficient damping torque.

In today's practical power systems, small signal stability is largely a problem of insufficient damping of oscillations. The time frame of interest in small-signal stability studies is on the order of 10 to 20 s following a disturbance. The stability of the following types of oscillations is of concern:

. Local modes or machine-system modes, associated with the swinging of units at a generating station with respect to the rest of the power system. The term ''local'' is used because the oscillations are localized at one station or a small part of the power system.

. Interarea modes, associated with the swinging of many machines in one part of the system against machines in other parts. They are caused by two or more groups of closely coupled machines that are interconnected by weak ties.

. Control modes, associated with generating units and other controls. Poorly tuned exciters, speed governors, HVDC converters, and static var compensators are the usual causes of instability of these modes.

. Torsional modes, associated with the turbine-generator shaft system rotational components. Instability of torsional modes may be caused by interaction with excitation controls, speed governors, HVDC controls, and series-capacitor-compensated lines.

2. Large disturbance rotor angle stability or transient stability, as it is commonly referred to, is concerned with the ability of the power system to maintain synchronism when subjected to a severe transient disturbance. The resulting system response involves large excursions of generator rotor angles and is influenced by the nonlinear power-angle relationship.

Transient stability depends on both the initial operating state of the system and the severity of the disturbance. Usually, the disturbance alters the system such that the post-disturbance steady state operation will be different from that prior to the disturbance. Instability is in the form of aperiodic drift due to insufficient synchronizing torque, and is referred to as first swing stability. In large power systems, transient instability may not always occur as first swing instability associated with a single mode; it could be as a result of increased peak deviation caused by superposition of several modes of oscillation causing large excursions of rotor angle beyond the first swing.

The time frame of interest in transient stability studies is usually limited to 3 to 5 sec following the disturbance. It may extend to 10 sec for very large systems with dominant inter-area swings.

Power systems experience a wide variety of disturbances. It is impractical and uneconomical to design the systems to be stable for every possible contingency. The design contingencies are selected on the basis that they have a reasonably high probability of occurrence.

2.2.4. Voltage Stability

Voltage stability is concerned with the ability of a power system to maintain steady voltages at all buses in the system under normal operating conditions, and after being subjected to a disturbance. Instability that may result occurs in the form of a progressive fall or rise of voltage of some buses. The possible outcome of voltage instability is loss of load in the area where voltages reach unacceptably low values, or a loss of integrity of the power system.

Progressive drop in bus voltages can also be associated with rotor angles going out of step. For example, the gradual loss of synchronism of machines as rotor angles between two groups of machines approach or exceed 1808 would result in very low voltages at intermediate points in the network close to the electrical center (Kundur, 1994). In contrast, the type of sustained fall of voltage that is related to voltage instability occurs where rotor angle stability is not an issue.

The main factor contributing to voltage instability is usually the voltage drop that occurs when active and reactive power flow through inductive reactances associated with the transmission network; this limits the capability of transmission network for power transfer. The power transfer limit is further limited when some of the generators hit their reactive power capability limits. The driving force for voltage instability are the loads; in response to a disturbance, power consumed by the loads tends to be restored by the action of distribution voltage regulators, tap changing transformers, and thermostats. Restored loads increase the stress on the high voltage network causing more voltage reduction. A rundown situation causing voltage instability occurs when load dynamics attempts to restore power consumption beyond the capability of the transmission system and the connected generation (Kundur, 1994; Taylor, 1994; Van Cutsem and Vournas, 1998).

While the most common form of voltage instability is the progressive drop in bus voltages, the possibility of overvoltage instability also exists and has been experienced at least on one system (Van Cutsem and Mailhot, 1997). It can occur when EHV transmission lines are loaded significantly below surge impedance loading and underexcitation limiters prevent generators and=or synchronous condensers from absorbing the excess reactive power. Under such conditions, transformer tap changers, in their attempt to control load voltage, may cause voltage instability.

Voltage stability problems may also be experienced at the terminals of HVDC links. They are usually associated with HVDC links connected to weak AC systems (CIGRE Working

Group 14.05, 1992). The HVDC link control strategies have a very significant influence on such problems.

As in the case of rotor angle stability, it is useful to classify voltage stability into the following subcategories:

1. Large disturbance voltage stability is concerned with a system's ability to control voltages following large disturbances such as system faults, loss of generation, or circuit contingencies. This ability is determined by the system-load characteristics and the interactions of both continuous and discrete controls and protections. Determination of large disturbance stability requires the examination of the nonlinear dynamic performance of a systemover a period of time sufficient to capture the interactions of such devices as under-load transformer tap changers and generator field-current limiters. The study period of interest may extend from a few seconds to tens of minutes. Therefore, long term dynamic simulations are required for analysis (Van Cutsem et al., 1995).

2. Small disturbance voltage stability is concerned with a system's ability to control voltges following small perturbations such as incremental changes in system load. This form of stability is determined by the characteristics of loads, continuous controls, and discrete controls at a given instant of time. This concept is useful in determining, at any instant, how the system voltage will respond to small system changes. The basic processes contributing to small distur bance voltage instabilit y are essentially of a steady state nature. Therefore, static analysis can be effectively used to determine stabilit y margins, identify factors influencing stabilit y, and examine a w ide range of system conditions and a large number of postcontingency scenarios (Gao et al., 1992). A criterion for small distur bance voltage stabilit y is that, at a given operating condition for ever y bus in the system, the bus voltage magnitude increases as the reactive power injection at the same bus is increased. A system is voltage unstable if, for at least one bus in the system, the bus voltage magnitude (V) decreases as the reactive power injection (Q) at the same bus is increased. In other words, a system is voltage stable if V- Q sensitiv it y is positive for ever y bus and unstable if V-Q sensitivi ty is negative for at least one bus.

The time frame of interest for voltage stabilit y problems may var y from a few seconds to tens of minutes. Therefore, voltage stabilit y may be either a shor t-term or a long-term phenomenon.

Voltage instabilit y does not always occur in its pure form. Often, the rotor ang le instabilit y and voltage instabilit y go hand in hand. One may lead to the other, and the distinction may not be clear. However,distinguishing between ang le stabilit y and voltage stabilit y is impor tant in understanding the underly ing causes of the problems in order to develop appropriate design and operating procedures.

2.2.5. Frequency Stability

Frequency stability is concerned w ith the abilit y of a power system to maintain steady frequency w ithin a nominal range follow ing a severe system upset resulting in a significant imbalance between generation and load. It depends on the abilit y to restore balance between system generation and load, w ith minimum loss of load.

Severe system upsets generally result in large excursions of frequency, power flows, voltage, and other system variables, thereby invoking the actions of processes, controls, and protections that are not modeled in conventional transient stabilit y or voltage stabilit y studies. These processes may be ver y slow, such as boiler dynamics, or only triggered for extreme system conditions, such as volts=hertz protection tripping generators. In large interconnected power systems, this t y pe of situation is most commonly associated w ith islanding . Stabilit y in this case is a question of whether or not each island w ill reach an acceptable state of operating equilibrium wi th minimal loss of load. It is determined by the overall response of the island as ev idenced by its mean frequency, rather than relative motion of machines. Generally, frequency stabilit y problems are associated w ith inadequacies in equipment responses, poor coordination of control and protection equipment, or insufficient generation reser ve. Examples of such problems are repor ted by Kundur et al. (1985); Chow et al. (1989); and Kundur (1981).

Over the course of a frequency instabilit y, the characteristic times of the processes and dev ices that are activated by the large shifts in frequency and other system variables will range from a matter of seconds, corresponding to the responses of devices such as generator controls and protections, to several minutes, corresponding to the responses of devices such as prime mover energy supply systems and load voltage regulators.

Although frequency stability is impacted by fast as well as slow dynamics, the overall time frame of interest extends to several minutes.

CHAPTER 3 : Power flow study

In power engineering, the **power flow study** (also known as **load-flow study**) is an important tool involving numerical analysis applied to a power system. Unlike traditional circuit analysis, a power flow study usually uses simplified notation such as a one-line diagram and per-unit system, and focuses on various forms of AC power (ie: reactive, real, and apparent) rather than voltage and current. It analyses the power systems in normal steady-state operation. There exist a number of software implementations of power flow studies.

In addition to a power flow study itself, sometimes called the *base case*, many software implementations perform other types of analysis, such as short-circuit fault analysis and economic analysis. In particular, some programs use linear programming to find the *optimal power flow*, the conditions which give the lowest cost per kilowatt generated.

The great importance of power flow or load-flow studies is in the planning the future expansion of power systems as well as in determining the best operation of existing systems. The principal information obtained from the power flow study is the magnitude and phase angle of the voltage at each bus and the real and reactive power flowing in each line.

3.1. Representation of Power Systems

3.1.1. Per-unit system

In electrical engineering in the field of power transmission a **per-unit system** is the expression of system quantities as fractions of a defined base unit quantity. Calculations are simplified because quantities expressed as per-unit are the same regardless of the voltage level. Similar types of apparatus will have impedances, voltage drops and losses that are the same when expressed as a per-unit fraction of the equipment rating, even if the unit size varies widely. Conversion of per-unit quantities to volts, ohms, or amperes requires a knowledge of the base that the per-unit quantities were referenced to.

A per-unit system provides units for power, voltage, current, impedance, and admittance. Only two of these are independent, usually power and voltage. All quantities are specified as multiples of selected base values. For example, the base power might be the rated power of a transformer, or perhaps an arbitrarily selected power which makes power quantities in the system more convenient. The base voltage might be the nominal voltage of a bus. Different types of quantities are labeled with the same symbol (**pu**); it should be clear from context whether the quantity is a voltage, current, etc.

Per-unit is used primarily in power flow studies; however, because parameters of transformers and machines (electric motors and electrical generators) are often specified in terms of per-unit, it is important for all power engineers to be familiar with the concept.

The relationship between units in a per-unit system depends on whether the system is single phase or three phase.

3.1.1.1. Relationship between units

a) Single phase

Assuming that the independent base values are power and voltage, we have:

$$P_{base} = 1pu$$

$$V_{base} = 1pu$$

Alternatively, the base value for power may be given in terms of reactive or apparent power, in which case we have, respectively,

$$Q_{base} = 1pu \qquad or \qquad S_{base} = 1pu$$

The rest of the units can be derived from power and voltage using the equations $S = IV$, $P = Scos(\ )$, $Q = Ssin(\ )$ and $\underline{V} = \underline{IZ}$(Ohm's law), Z being represented by $\underline{Z} = R + jX = Zcos(phi) + jZsin(phi)$. We have:

$$I_{base} = \frac{S_{base}}{V_{base}} = 1pu$$

$$Z_{base} = \frac{V_{base}}{I_{base}} = \frac{V_{base}^2}{I_{base}V_{base}} = \frac{V_{base}^2}{S_{base}} = 1pu$$

$$Y_{base} = \frac{1}{Z_{base}} = 1pu$$

- **Three phase**

Power and voltage are specified in the same way as single phase systems. However, due to differences in what these terms usually represent in three phase systems, the relationships for the derived units are different. Specifically, power is given as total (not per-phase) power, and voltage is line to line voltage. In three phase systems the equations

$P = Scos(\ )$ and $Q = Ssin(\ )$ also hold. The apparent power S now equals

$$S_{base} = \sqrt{3} V_{base} I_{base}$$

$$I_{base} = \frac{S_{base}}{V_{base} \times \sqrt{3}} = 1pu$$

$$Z_{base} = \frac{V_{base}}{I_{base} \times \sqrt{3}} = \frac{V_{base}^2}{S_{base}} = 1pu$$

$$Y_{base} = \frac{1}{Z_{base}} = 1pu$$

3.1.2One-line diagram

In power engineering, a **one-line diagram** is a simplified notation for representing a three-phase power system. The one-line diagram has its largest application in power flow studies. Electrical elements such as circuit breakers, transformers, capacitors, bus bars, and conductors are shown by standardized schematic symbols. Instead of representing each of three phases with a separate line or terminal, only one conductor is represented.

The theory of three-phase power systems tells us that as long as the loads on each of the three phases are balanced, we can consider each phase separately. In power engineering, this assumption is usually true (although an important exception is the asymmetric fault), and to consider all three phases requires more effort with very little potential advantage.

A one-line diagram is usually used along with other notational simplifications, such as the per-unit system. A secondary advantage to using a one-line diagram is that the simpler diagram leaves more space for non-electrical, such as economic, information to be included.

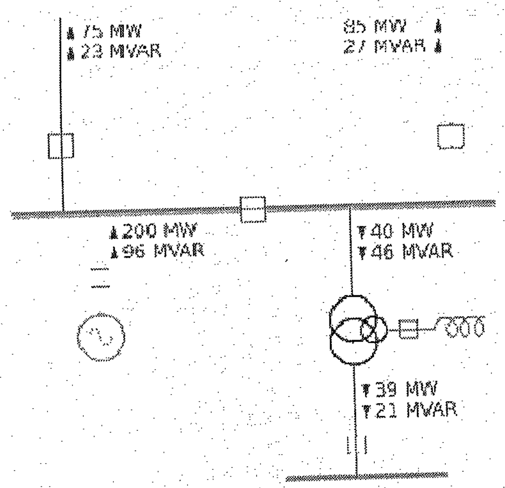


figure 3.1 : A typical one-line diagram with annotated power flows. Red boxes represent circuit breakers, grey lines represent three-phase bus and interconnecting conductors, the orange circle represents a generator, the green spiral is an inductor, and the three overlapping blue circles represent a power transformer.

3.2. Busbar

A busbar in electrical power distribution refers to thick strips of copper or aluminium that conduct electricity within a switchboard, distribution board, substation, or other electrical apparatus.

The size of the busbar is important in determining the maximum amount of current that can be safely carried. Busbars can have a cross-sectional area of as little as 10 mm^2 but electrical substations may use metal tubes of 50 mm in diameter (1,000 mm^2) or more as busbars.

Busbars are typically either flat strips or hollow tubes as these shapes allow heat to dissipate more efficiently due to their high surface area to cross-sectional area ratio. The skin effect makes 50-60 Hz AC busbars more than about 8 mm (1/3 in) thick inefficient, so hollow or flat shapes are prevalent in higher current applications. A hollow section has higher stiffness than a solid rod, which allows a greater span between busbar supports in outdoor switchyards.

A busbar may either be supported on insulators, or else insulation may completely surround it. Busbars are protected from accidental contact either by a metal enclosure or by elevation out of normal reach. Neutral busbars may also be insulated. Earth busbars are typically bolted directly onto any metal chassis of their enclosure. Busbars may be enclosed in a metal housing, in the form of bus duct or busway, segregated-phase bus, or isolated-phase bus.

Busbars may be connected to each other and to electrical apparatus by bolted or clamp connections. Often joints between high-current bus sections have matching surfaces that are silver-plated to reduce the contact resistance. At extra-high voltages (more than 300 kV) in outdoor buses, corona around the connections becomes a source of radio-frequency interference and power loss, so connection fittings designed for these voltages are used.

3.2.1. Busbar Protection

Busbars are vital parts of a power system and so a fault should be cleared as fast as possible. A busbar must have its own protection although their high degrees of reliability bearing in mind the risk of unnecessary trips, so the protection should be dependable, selective and should be stable for external faults, called through faults The most common fault is phase to ground, which usually results from human error.There are many types of relaying principles used in busbar.

A special attention should be made to current transformer selection since measuring errors need to be considered.

3.3. Choice of Variables

So far, we are familiar with the notion of organizing the descriptive variables of the circuit into categories of "knowns" and "unknowns," whose relationships can subsequently be expressed in terms of multiple equations. Given sufficient information, these equations can then be manipulated with various techniques so as to yield numerical results for the hitherto unknowns.

As we know, there are two basic quantities that describe the flow of electricity: voltage and current. Recognizing these quantities in simple d.c. circuits in Chapter 1, we saw that both voltage and current will vary from one location to another in a circuit, but they are everywhere related: the current through each circuit branch corresponds to the voltage or potential difference between the two nodes at either end, divided by the impedance of this branch . It is generally assumed that the impedances throughout the circuit are known, since these are more or less permanent properties of the hardware.

Thus, if we are told the voltages at every node in the circuit, we can deduce from them the currents flowing through all the branches, and everything that is happening in the circuit is completely described. If one or more pieces of voltage information were missing, but we were given appropriate information about the current instead, we could still work backwards and solve the problem. In this sense, the number of variables in a circuit corresponds to the number of electrically distinct points in it assuming we already know all the properties of the hardware, we need to be told one piece of information per node in order to figure out everything that's going on in a d.c. circuit.

For a.c. circuits, the situation is a bit more complicated, because we have introduced the dimension of time: unlike in d.c., where everything is essentially static (except for the instant at which a switch is thrown), with a.c. we are describing an ongoing oscillation or movement. Thus each of the two main variables, voltage and current, in an a.c. circuit really has two numerical components: a magnitude component and a time component. By convention, a.c. voltage and current magnitude are describes in terms of root-mean-squared (rms) values and their timing in terms of a phase angle, which represents the shift of the wave with respect to a reference point in time. To fully describe the voltage at any given node in an a.c. circuit, we must therefore specify twonumbers: a voltage magnitude and a voltage angle. Accordingly, when we solve for the currents in each branch, we will again obtain two numbers: a current magnitude and a current angle. And when we consider the amount of power transferred at any point of an a.c. circuit, we again have two numbers: a real and a reactive component. An a.c. circuit thus requires exactly two pieces of information per node in order to be completely determined. More than two, and they are either redundant or contradictory; fewer than two, and possibilities are left open so that the system cannot be solved.

A word of caution is necessary here: Owing to the nonlinear nature of the power flow problem, it may be impossible to find one unique solution because more than one answer is mathematically consistent with the given configuration.3 However, it is usually straightforward in such cases to identify the "true" solution among the mathematical possibilities based on physical plausibility and common sense. Conversely, there may be no solution at all because the given information was hypothetical and does not correspond to any situation that is physically possible. Still, it is true in principle—and most important for a general conceptual understanding— that two variables per node are needed to determine everything that is happening in the system.

Having discussed voltage and current, each with magnitude and angle, as the basic electrical quantities, which are known and which are unknown? In practice, current is not known at all; the currents through the various circuit branches turn out to be the last thing that we calculate once we have completed the power flow analysis. Voltage, as we will see, is known explicitly for some buses but not for others. More typically, what is known is the amount of power going into or out of a bus. Power flow analysis consists of taking all the known real and reactive power flows at each bus, and those voltage magnitudes that are explicitly known, and from this information calculating the remaining voltage magnitudes and all the voltage angles. This is the hard part. The easy part, finally, is to calculate the current magnitudes and angles from the voltages. power is basically the product of voltage and current, and the relative phase angle between voltage and current determines the respective contributions of real and reactive power. Conversely, one can deduce voltage or current magnitude and angle if real and reactive power are given, but it is far more difficult to work out mathematically in this direction. This is because each value of real and reactive power would be consistent with many different possible combinations of voltages and currents. In order to choose the correct ones, we have to check each node in relation to its neighboring nodes in the circuit and find a set of voltages and currents that are consistent all the way around the system. This is what power flow analysis does.

3.4. Variables for Balancing Real Power

Balancing the system means that all the generators in the system collectively must supply power in exactly the amount demanded by the load, plus the amount lost on transmission lines. This applies to both real and reactive power, but let us consider only real power first. If we tried to specify a system in which the sum of P generated did not match the P consumed, our analysis would yield no solution, reflecting the fact that in real life the system would lose synchronicity and crash. Therefore, for all situations corresponding to a stable operation of the system, and thus a viable solution of the power flow problem, we must require that real power generated and consumed matches up. Of course, we can vary the contributions from individual generators—that is, we can choose a different dispatch—so long as the sum of their P's matches the amount demanded by the system. As mentioned earlier, this total P must not only match the load demand, it must actually exceed that amount in order to make up for the transmission losses, which are the resistive I^2R energy losses

Now we have a problem: How are we supposed to know ahead of time what the transmission losses are going to be? Once we have completed the power flow analysis, we will know what the current flows through all the transmission linesare going to be, and combining this information with the known line impedances will give us the losses. But we cannot tell a priori the amount of losses. The exact amount will vary depending on the dispatch, or amount of power coming from each generator, because a different dispatch will result in a different distribution of current over the various transmission paths, and not all transmission lines are the same. Therefore, if we were given a total P demanded at the load buses and attempted now to set the correct sum of P for all the generators, we could not do it.

The way to deal with this situation mathematically reflects the way it would be handled in actual operation. Knowing the total P demanded by the load, we begin by assuming a typical percentage of losses, say, 5%. We now dispatch all the generators in the system in some way so that the sum of their output approximately matches what we expect the total real power demand (load plus losses) to be: in this case, 105% of load demand. But since we do not yet know the exact value of the line losses for this particular dispatch (seeing that we have barely begun our power flow calculation), we will probably be off by a small amount. A different dispatch might, for example, result in 4.7% or 5.3% instead of 5% losses overall. We now make the plausible assumption that this uncertainty in the losses constitutes a sufficiently small amount of power that a single generator could readily provide it. So we choose one generator whose output we allow to adjust, depending on the system's needs: we allow it to "take up the slack" and generate more power if system losses are greater than expected, or less if they are smaller. In power flow analysis, this one generator bus is appropriately labeled the slack bus, or sometimes swing bus. Thus, as the input information to our power flow analysis, we specify P for one less than the total number of buses. What takes the place of this piece of information for the last bus is the requirement that the system remain balanced. This requirement will be built into the equations used to solve the power flow and will ultimately determine what the as yet unknown P of the slack bus has got to be. The blank space among the initial specifications for the slack bus, where P is not given, will be filled by another quantity, the voltage angle, which will be discussed later in this chapter, following the discussion of reactive power.

3.5. Variables for Balancing Reactive Power

Analogous to real power, the total amount of reactive power generated throughout the system must match the amount of reactive power consumed by the loads.Where as in the case of a mismatch of real power, the system loses synchronicity, a mismatch of reactive power leads to voltage collapse.Also analogous to real power transmission losses, there are reactive power losses. Reactive losses are defined simply as the difference between reactive power generated and reactive power consumed by the metered load.

Physically, these losses in Q reflect the fact that transmission lines have some reactance and thus tend to "consume" reactive power; in analogy to I2R, we could call them I2X losses. The term "consumption," however, like the reactive power "consumption" by a load, does not directly imply an energy consumption in the sense of energy being withdrawn from the system. To be precise, the presence of reactive power does necessitate the shuttling around of additional current, which in turn is associated with some real I2R losses "in transit" of a much smaller magnitude. But these second-order I2R losses (i.e., the side effect of a side effect) are already captured in the analysis of real power for the system. The term "reactive losses" thus does not refer to any physical measure of something lost, but rather should be thought of as an accounting device. While real power losses represent physical heat lost to the environment and therefore always have to be positive,6 reactive losses on a given transmission link can be positive or negative, depending on whether inductive or capacitive reactance plays a dominant role. ın any case, what matters for both operation and power flow analysis is that Q, just like P, needs to be balanced at all times. Thus, just as for real power, all the generators in the system must generate enough reactive power to satisfy the load demand plus the amount that vanishes into the transmission lines.

This leaves us with the analogous problem of figuring out how much total Q our generators should produce, not knowing ahead of time what the total reactive losses for the system will turn out to be: as with real losses, the exact amount of reactive losses will depend on the dispatch. Operationally, though, the problem of balancing reactive power is considered in very different terms. When an individual generator is instructed to provide its share of reactive power, in practice this is not usually done by telling it to generate a certain number of MVAR .Instead, the generator is instructed to maintain a certain voltage magnitude at its bus. The voltage is continually and automatically adjusted through the generator's field current, and is therefore a straightforward variable to control.

Their own bus voltage is in fact the one immediate measure available to the generators for determining whether the correct amount of reactive power is being generated: when the combined generation of reactive power by all the generators in the system matches the amount consumed, their bus voltage holds steady.

Conversely, if there is a need to increase or decrease reactive power generation, adjusting the field current at one or more generators so as to return to the voltage set point will automatically accomplish this objective.The new value of MVAR produced by each generator can then be read off the dial for accounting purposes.

Conveniently for power flow analysis, then, there is no need to know explicitly the total amount of Q required for the system. Specifying the voltage magnitude is essentially equivalent to requiring a balanced Q. In principle, we could specify P and Q for each generator bus, except for one slack bus assigned the voltage regulation (and thus the onus of taking up the slack of reactive power). For this "reactive slack" bus we would need to specify voltage magnitude V instead of Q, with the understanding that this generator would adjust its Q output as necessary to accommodate variations in reactive line losses. In practice, however, since voltage is already the explicit operational control variable, it is customary to specify V instead of Q for all generator buses, which are therefore called P,V buses. In a sense, this assignment implies that all generators share the "reactive slack," in contrast to the real slack that is taken up by only a single generator.

3.6. The Slack Bus

We have now, for our power flow analysis, three categories of buses: P,Q buses, which are generally load buses, but could in principle also be generator buses; P,V buses, which are necessarily generator buses (since loads have no means of voltage control); and then there is the slack bus, for which we cannot specify P, only V. What takes the place of P for the slack bus?

As we saw real power balance manifests operationally as a steady frequency such as 60 Hz. A constant frequency is indicated by an unchanging voltage angle, which for this reason is also known as the power angle, at each generator. When more power is consumed than generated, the generators' rotation slows down: their electrical frequency drops, and their voltage angles fall farther and farther behind. Conversely, if excess power is generated, frequency increases and the voltage angles move forward. While generators are explicitly dispatched to produce a certain number of megawatts, the necessary small adjustments to balance real power in real-time are made (by at least one or more load-following generator) through holding the generator frequency steady at a specified value. Not allowing the frequency to depart from this reference value is equivalent to not letting the voltage angle increase or decrease over time.

In power flow analysis, the slack bus is the one mathematically assigned to do the load following. Its instructions, as it were, are to do whatever is necessary to maintain real power balance in the system. Physically, this would mean holding the voltage angle constant. The place of P will therefore be taken by the voltage angle, which is the variable that in effect represents real power balance. We can think of the voltage angle here as analogous to the voltage magnitude in the context of reactive power, where balance is achieved operationally by maintaininga certain voltage (magnitude) set point at the generator bus. Specifying that the bus voltage magnitude should be kept constant effectively amounts to saying that whatever is necessary should be done to keep the system reactive power balanced. Similarly, specifying a constant voltage angle at the generator bus amounts to saying that this generator should do whatever it takes to keep real power balanced.

We thus assign to the slack bus a voltage angle, which, in keeping with the conventional notation for the context of power flow analysis, we will call u (lowercase Greek theta). This u can be interpreted as the relative position of the slack bus voltage at time zero. Note that this u is exactly the same thing that is elsewhere called the power angle and labeled as d (delta). What is important to understand here is that the actual numerical value of this angle has no physical meaning; what has physical meaning is the implication that this angle will not change as the system operates. The choice of a numerical value for u is a matter of convenience. When we come to the output of the power flow analysis, we will discover a voltage angle u for each of the other buses throughout the system, which is going to take on a different (constant) value for each bus depending on its relative contribution to real power. These numerical values only have meaning in relation to a reference: what matters is the difference between the voltage angle at one bus and another, which physically corresponds to the phase difference between the voltage curves, or the difference in the precise timing of the voltage maximum.10 We now conveniently take advantage of the slack bus to establish a systemwide reference for timing, and we might as well make things simple and call the reference point "zero." This could be interpreted to mean that the alternating voltage at the slack bus has its maximum at the precise instant that we depress the "start" button of an imaginary stopwatch, which starts counting the milliseconds (in units of degrees within a complete cycle of 1/60th second) from time zero. In principle, we could pick any number between 0 and 360 degrees as the voltage angle for the slack bus, but 08 is the simple and conventional choice.

3.7. Summary of Variables

To summarize, our three types of buses in power flow analysis are P,Q (load bus), P,V (generator bus), and u,V (slack bus). Given these two input variables per bus, and knowing all the fixed properties of the system (i.e., the impedances of all the transmission links, as well as the a.c. frequency), we now have all the information required to completely and unambiguously determine the operating state of the system. This means that we can find values for all the variables that were not originally specified for each bus: u and V for all the P,Q buses; u and Q for the P,V buses; and P and Q for the slack bus. The known and unknown variables for

each type of bus are tabulated later in the following paragraph for easy reference.

Type of Bus	Variables Given (Knowns)	Variables Found (Unknowns)
Generator	Real power (P) Voltage magnitude (V)	Voltage angle (θ) Reactive power (Q)
Load or generator	Real power (P) Reactive power (Q)	Voltage angle (θ) Voltage magnitude (V)
Slack	Voltage angle (θ) Voltage magnitude (V)	Real power (P) Reactive power (Q)

TABLE 3.1 : Variables in Power Flow Analysis

Once we know u and V, the voltage angle and magnitude, at every bus, we can very easily find the current through every transmission link; it becomes a simple matter of applying Ohm's law to each individual link. (In fact, these currents have to be found simultaneously in order to compute the line losses, so that by the time the program announces u's and V's, all the hard work is done.) Depending on how the output of a power flow program is formatted, it may state only the basic output variables, as in Table 7.1, it may explicitly state the currents for all transmission links in amperes; or it may express the flow on each transmission link in terms of an amount of real and reactive power flowing, in megawatts (MW) and MVAR.

3.8. Example with Interpretation of Results

3.8.1. Six-Bus Example

Consider the six-bus example illustrated in This example is simple enough for us to observe in detail, yet too complex to predict its behavior without numerical power flow analysis.

Each of the six buses has a load, and four of the buses also have generators. Bus 1, keeping with convention, is the slack bus. Buses 2, 3, and 4, which have both generation and loads, are modeled as P,V buses; the local load is simply subtracted from the real and reactive generation at each. Buses 5 and 6, which have only loads, are modeled as P,Q buses.

The distribution of loads and the generation dispatch, for both real and reactive power, are completely determined somewhere outside the power flow program, whether in the real world or the program user's fantasy. The one exception is the generator at the slack bus, whose real power output varies so as to accommodate systemwide losses. In addition to the MWand MVAR loads and theMWgeneration levels for every generator (except the slack), the user specifies the voltage

magnitudes to be maintained at each generator bus; the program then computes

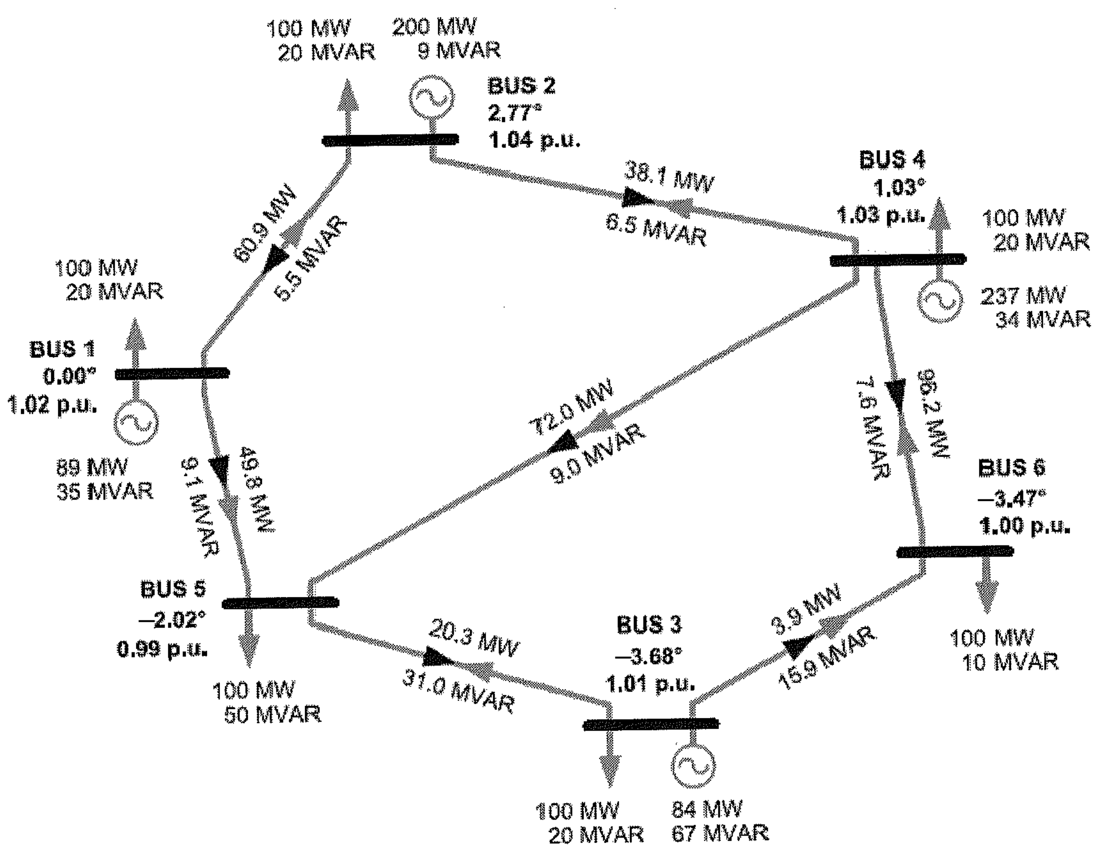


Figure 3.2 : Six-bus power flow example.

the MVAR generation necessary to maintain this voltage at each bus. (It is also possible to specify MVAR generation and allow the program to determine the voltage magnitudes, but, as mentioned earlier, the former method better resembles real-life operations.)

By convention, the voltage angle at the slack bus is set to 0.00 degrees. The power flow program computes the voltage angle at each of the other five buses in relation to the slack bus. We may now begin to observe the relationship between real power and voltage angle: a more positive voltage angle generally corresponds to an injection of power into the system and a more negative voltage angle to a consumption of real power. Buses 2 and 4, which both have generation exceeding local load, have positive voltage angles of 2.778 and 1.038, respectively. Bus 3, though it has a generator, is still a net consumer of real power, with 100 MW load and only 84 MW generated; its voltage angle is 23.688. Buses 5 and 6 have loads only and voltage angles of 22.028 and 23.478, respectively. Note, however, that the voltage angles are not in hierarchical order depending on the amount of power injected or withdrawn at each individual bus. This is because we also must consider the location of each bus relative to the others in the system and the direction of power flow between them. For example, consider Buses2 and 4. Net generation at Bus 4 is greater than at Bus 2 (137 MW compared to 100 MW), yet the voltage angle at Bus 2 is more positive. We can see that this is due to the location of these buses in the system: real power is generally flowing from north to south, that is, from Bus 2 to the neighborhood of Buses 5, 3, and 6 where there is more load and less generation. As indicated by the black arrow on the transmission link, real power is flowing from Bus 2 to Bus 4. As a rule, real power flows from a greater to a smaller voltage angle. This rule holds true for six of the seven links in this sample case; the exception is Link 3–6, where both the power flow and the difference in voltage angle are very small. The reader can verify that throughout this case, while power flow and voltage angle are not exactly proportional, a greater flow along a transmission link is associated with a greater angle difference.

We now turn to the relationship between reactive power and voltage magnitude, which is similar to that between real power and voltage angle. The nominal voltage of this hypothetical transmission system is 138 kV. However, just as the timing or angle of the voltage differs by a small fraction of a cycle at different locations in the grid, the magnitude, too, has a profile across the system with different areas a few percent higher or lower than the nominal value. Because it is this percentage, not the absolute value in volts, that is most telling about the relationship among different places in the grid, it is conventional to express voltage magnitude in per-unit terms. Per-unit (p.u.) notation simply indicates the local value as a multiple of the nominal value; in this case, 138 kV equals 1.00 p.u. The voltage magnitude at Bus 1 is given as 1.02 p.u., which translates into 141 kV; at Bus 5, the voltage magnitude of 0.99 p.u. means 137 kV.

As a rule, reactive power tends to flow in the direction from greater to smaller voltage magnitude. In our example, this rule holds true only for the larger flows of MVAR, along Links 1–5, 3–5, 4–5, and 3–6. The reactive power flows along Links 1–2, 4–2, and 6–4 do not follow the rule, but they are comparatively small. Note that real and reactive power do not necessarily flow in the same direction on a given link. This should not be surprising, because the "direction" of reactive power flow is based on an arbitrary definition of the generation or consumption of VARs; there is in fact no net transfer of energy in the direction of the gray arrow for Q. Also, note that having Q flow opposite P does not imply any "relief" or reduction in current. For example, on Link 3–5, the real power flow P is 20.3 MW and reactive flow Q is 31.0 MVAR. In combination, this gives apparent power S of 37.1 MVA regardless of the direction of Q. (Recall that MVA are the relevant units for thermal line loading limits, since total current depends on apparent power.)

From Figure 3.2, it is possible to evaluate the total real and reactive system losses, simply by observing the difference between total generation and total load. The four generators are supplying 89, 200, 84, and 237 MW, respectively, for a total of 610 MW of real power generated. Subtracting the six loads of 100 MW each, the total real power losses throughout the transmission system for this particular scenario are therefore 10 MW. On the reactive side, total generation is 145 MVAR, while total reactive load is 140 MVAR, and system reactive losses amount to roughly 5 MVAR.

The discerning reader may have noticed, however, that the stated line flows in Figure 3.2, which are average values for each link, cannot all be reconciled with the power balance at each bus. To account for losses in a consistent fashion, we must record both the power (real or reactive) entering and exiting each link. In Figure 3.3, these data are given for real power (MW) in black and reactive power (MVAR) in gray. The numbers in parentheses represent the losses, which are the difference between power flows at either end. Bus power, line flows, and losses are rounded to different decimal places, but the numbers do add up correctly for each bus and each link.

The most significant losses tend to occur on links with the greatest power flow. In this case, Link 4–6 has the greatest power flow with 96.2 MW real and 7.6 MVAR reactive, yielding 96.5 MVA apparent, and the greatest losses. While the real line losses are all positive, as they should be, the negative signs on some of the reactive losses indicate negative losses; we might consider them "gains," although nothing is actually gained. Reactive losses depend on operating conditions and impedance, where the model of a transmission link may incorporate reactive compensation such as capacitors. It is typical for system reactive losses to be positive overall, as they are in this example. Like real losses, reactive losses are related to the current and therefore apparent power flow. Thus, we also observe the greatest reactivelosses in our example on Link 46. The real and reactive losses for every link can be totaled to confirm the estimated system losses given earlier.

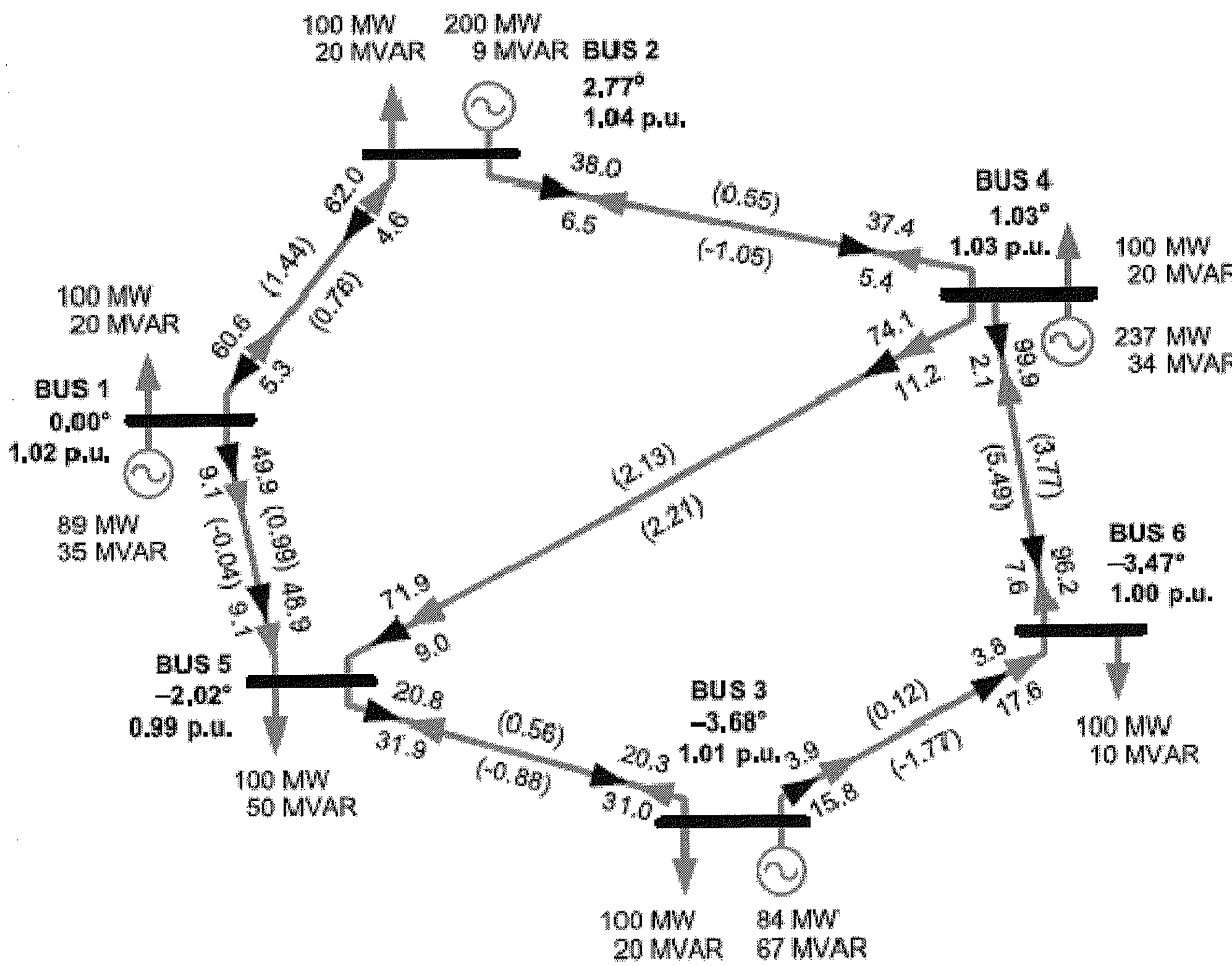


Figure 3.3 : Six-bus power flow example with losses.

3.8.2. Tweaking the Case

To gain a better sense of a power system's behavior and the information provided by power flow modeling, let us now make a small change to the operating state in the six-bus example and observe how the model responds. We simply increase the load at Bus 5 by 20% while maintaining the same power factor, thus changing it from 100 MW real and 50 MVAR reactive to 120 MW real and 60 MVAR reactive. This change is small enough for the generator at the slack bus to absorb, so we need not specify increased generation elsewhere. Indeed, generation at Bus 1 increases from 89 to 110 MW. Note that the difference amounts to 21, not 20 MW, as the increased load also entails some additional losses in the system.

The new scenario is illustrated in Figure 3.4. As we would expect, the line flows to Bus 5 increase by a total of 20 MW. The bulk (about 14.5 MW) of this additional power comes from Bus 1, about 4 Mwfrom Bus 4, and the balance appears as a reduction of about 1.5 MW in the flow to Bus 3. The changes do not stop here, however; they have repercussions for the remainder of the system. Three of the other buses are defined as P,V buses, and therefore have fixed voltage magnitudes. The voltage magnitude at Bus 6 (a P,Q bus) is affected slightly (from 0.9951 to 0.9950 p.u.), although the change does not show up after rounding. In order to maintain the preset voltages at the P,V buses, reactive power generation increases at Buses 4 and 6, as it does at the slack bus. Indeed, system reactive generation now totals 157 MVAR, which are needed to accommodate the additional reactive load introduced at Bus 5 as well as a substantial increase in system reactive losses of 2.33 MVAR (up almost 50% from 4.74 to 7.07 MVAR). While real power is fixed at all buses other than 1 and 5, their voltage angles change as a result of the changed power flow pattern. The most serious repercussion in this example occurs on Link 4–6, which was fully loaded before the change to Bus 5 was made. Owing to the vagaries of network flow, the change at Bus 5 results in a slight increase in real power flow from Bus 4 to Bus 6. Link 4–6 now carries slightly more current and apparent power, going from 100 to 101.5 MVA. This is significant because, in this hypothetical scenario, each transmission link has a thermal limit of 100 MVA. The power flow program thus shows the line becoming overloaded as a result of the change at Bus 5, even though Buses 4 and 6 are located on the opposite geographic end of the system, and neither generation nor load levels there were affected. In reality, this violation would mean that the proposed change is inadmissible and other options would have to be pursued—specifically, a generator other than Bus 1 would be required to increase generation in order to meet the additional load without violating any transmission constraints.

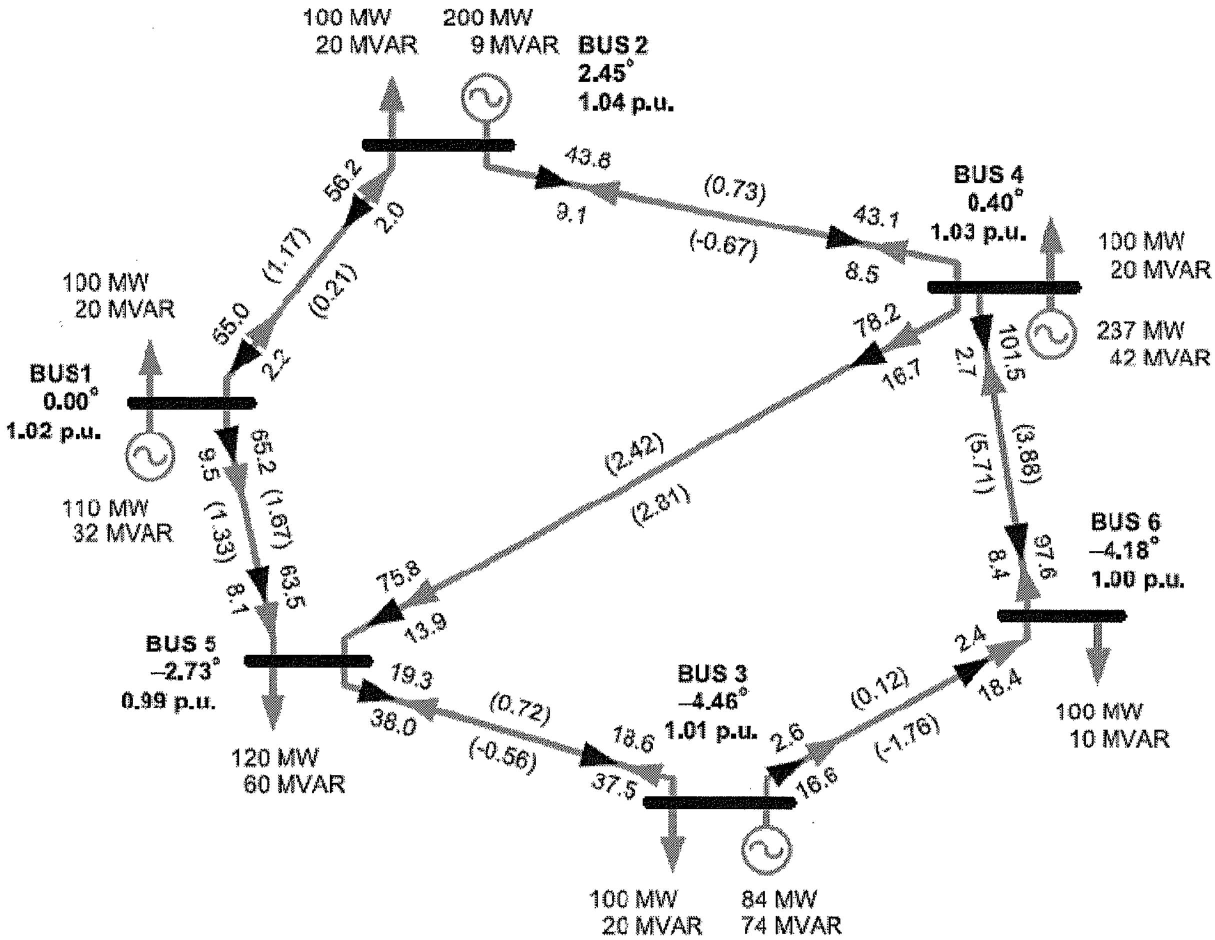


Figure 3.4 : Modified six-bus power flow example.

CHAPTER 4: Power Flow Equations and Solution Methods

4.1. Derivation of Power Flow Equations

In last section, we stated the known and unknown variables for each of the different types of buses in power flow analysis. The power flow equations show explicitly how these variables are related to each other. The complete set of power flow equations for a network consists of one equation for each node or branch point in this network, referred to as a bus, stating that the complex power injected or consumed at this bus is the product of the voltage at this bus and the current flowing into or out of the bus. Because each bus can have several transmission links connecting it to other buses, we must consider the sum of power entering or leaving by all possible routes. To help with the accounting, we will use a summation index i to keep track of the bus for which we are writing down the power equation, and a second index k to keep track of all the buses connected to i.

We express power in complex notation, which takes into account the two dimensionality—magnitude and time—of current and voltage in an a.c. system. As we know complex power S can be written in shorthand notation as

$$S = VI^*$$

where all variables are complex quantities and the asterisk denotes the complex conjugate of the current.12 Recall that S represents the complex sum of real power P and reactive power Q, where P is the real and Q the imaginary component. While the real part represents a tangible physical measurement (the rate at which energy is transferred), the imaginary part can be thought of as the flippety component that oscillates. At different times it may be convenient to either refer to P and Q separately or simply to S as the combination. In the most concise notation, the power flow equations can be stated as

$$S_i = V_i \times I_i^*$$

where the index i indicates the node of the network for which we are writing the equation. Thus, the full set of equations for a network with n nodes would look like

$$S_1 = V_1 \times I_1^*$$

$$S_2 = V_2 \times I_2^*$$

$$\dots$$

$$S_n = V_n \times I_n^*$$

We can choose to define power as positive either going into or coming out of that node, as long as we are consistent. Thus, if the power at load buses is positive, that at generator buses is negative.

So far, these equations are not very helpful, since we have no idea what the Ii are. In order to mold the power flow equations into something we can actually work with, we must make use of the information we presumably have about the network itself. Specifically, we want to write down the impedances of all the transmission links between nodes. Then we can use Ohm's law to substitute known variables (voltages and impedances) for the unknowns (currents). Written in the conventional form, Ohm's law is V = IZ (where Z is the complex impedance). However, when solving for the current I, this would require putting Z in the denominator: I = V/Z. It is therefore tidier to use the inverse of the impedance, known as the admittance Y (where Y = 1/Z), so that Ohm's law becomes I = VY. Not only does this avoid the formatting issues of division, it also allows us to indicate the absence of a transmission link with a zero (for zero admittance) instead of infinity (for infinite impedance), which vastly improves the appearance of the imminent matrix algebra. the complex admittance Y = G + jB, where G is the conductance and B the susceptance.

4.2. Simplification of Newton-Raphson Method

The NR method has quadratic convergence characteristics; therefore, the convergence is fast and solution to high accuracy is obtained in the first few iterations. The number of iterations does not increase appreciably with the size of the system. This is in contrast to the Gauss–Seidel method of load flow which has slower convergence even with appropriately applied acceleration factors. The larger the system, the larger are the number of iterations; 50–150 iterations are common.

The NR method, however, requires more memory storage and necessitates solving a large number of equations in each iteration step.

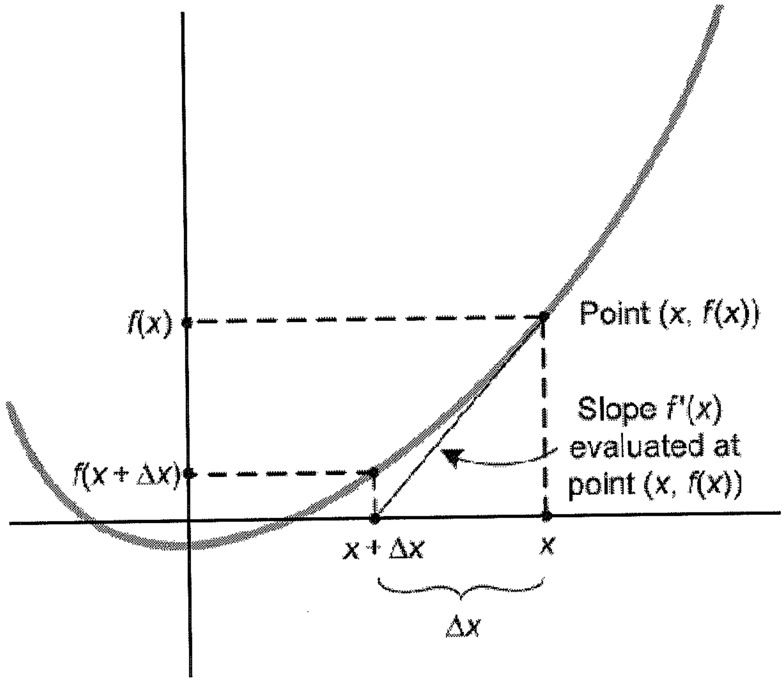


Figure 4.1 : İterative process of approximating

4.3. The Jacobian changes

At each iteration and must be evaluated afresh. The time required for one iteration in the NR method may be 5–10 times that of the Gauss–Seidel method. Some simplifications that can be applied are as follows:

the first equation is;

$$\Delta P_2 = (\partial P_2/\partial e_2)\Delta e_2 + (\partial P_2/\partial h_2)\Delta h_2 + (\partial P_2/\partial e_3)\Delta e_3 + (\partial P_2/\partial h_3)\Delta h_3 + (\partial P_2/\partial e_4)\Delta e_4 + (\partial P_2/\partial h_4)\Delta h_4$$

The change in power at bus 2 is a function of the voltage at bus 2, which is a function of the voltages at other buses. Considering the effect of e2 only:

$$\Delta P_2 \doteq (\partial P_2/\partial e_2)\Delta e_2$$

Thus, the Jacobian reduces to only diagonal elements:

$$\begin{vmatrix} \Delta P_2 \\ \Delta Q_2 \\ \Delta P_3 \\ \Delta Q_3 \\ \Delta P_4 \\ \Delta V_4 \end{vmatrix} = \begin{vmatrix} \partial P_2/\partial e_2 & \cdot & \cdot & \cdot & \cdot & \\ \cdot & \partial Q_2/\partial h_2 & \cdot & \cdot & \cdot & \cdot \\ \cdot & \cdot & \partial P_3/\partial e_3 & \cdot & \cdot & \cdot \\ \cdot & \cdot & \cdot & \partial Q_3/\partial h_3 & \cdot & \cdot \\ \cdot & \cdot & \cdot & \cdot & \partial P_4/\partial e_4 & \cdot \\ \cdot & \cdot & \cdot & \cdot & \cdot & \partial v_4^2/\partial h_4 \end{vmatrix} \begin{vmatrix} \Delta e_2 \\ \Delta h_2 \\ \Delta e_3 \\ \Delta h_3 \\ \Delta e_4 \\ \Delta h_4 \end{vmatrix}$$

Method 2 reduces the Jacobian to a lower triangulation matrix:

$$\Delta P_2 \doteq (\partial P_2/\partial e_2)\Delta e_2$$
$$\Delta Q_2 \doteq (\partial Q_2/\partial e_2)\Delta e_2 + (\partial Q_2/\partial h_2)\Delta h_2$$

$$\begin{vmatrix} \Delta P_2 \\ \Delta Q_2 \\ \Delta P_3 \\ \Delta Q_3 \\ \Delta P_4 \\ \Delta V_4^2 \end{vmatrix} = \begin{vmatrix} \partial P_2/\partial e_2 & . & . & . & . & . \\ \partial Q_2/\partial e_2 & \partial Q_2/\partial h_2 & . & . & . & . \\ \partial P_3/\partial e_2 & \partial P_3/\partial h_2 & \partial P_3/\partial 3e_3 & . & . & . \\ \partial Q_3/\partial e_2 & \partial Q_3/\partial h_2 & \partial Q_3/\partial h_3 & \partial Q_3/\partial h_3 & . & . \\ \partial P_4/\partial e_2 & \partial P_4/\partial h_2 & \partial P_4/\partial e_3 & \partial P_4/\partial h_3 & \partial P_4/\partial e_4 & . \\ \partial V_4^2/\partial e_2 & \partial V_4^2/\partial h_2 & \partial V_4^2/\partial e_3 & \partial V_4^2/\partial h_3 & \partial V_4^2/\partial e_4 & \partial V_4^2/\partial h_4 \end{vmatrix} \times \begin{vmatrix} \Delta e_2 \\ \Delta h_2 \\ \Delta e_3 \\ \Delta h_3 \\ \Delta e_4 \\ \Delta h_4 \end{vmatrix}$$

Method 3 relates P2 and Q2 to e2 and h2, P3 and Q3 to e3 and h3, etc. This is the Ward–Hale method. The Jacobian is

$$\begin{vmatrix} \Delta P_2 \\ \Delta Q_2 \\ \Delta P_3 \\ \Delta Q_3 \\ \Delta P_4 \\ \Delta V_4^2 \end{vmatrix} = \begin{vmatrix} \partial P_2/\partial e_2 & \partial P_2/\partial e_2 & . & . & . & . \\ \partial Q_2/\partial e_2 & \partial Q_2/\partial h_2 & . & . & . & . \\ . & . & \partial P_3/\partial e_3 & \partial P_3/\partial h_3 & . & . \\ . & . & \partial Q_3/\partial e_3 & \partial Q_3/\partial h_3 & . & . \\ . & . & . & . & \partial P_4/\partial e_4 & \partial P_4/\partial h_4 \\ . & . & . & . & \partial V_4^2/\partial e_4 & \partial v_4^2/\partial h_4 \end{vmatrix} \times \begin{Vmatrix} \Delta e_2 \\ \Delta h_2 \\ \Delta e_3 \\ \Delta h_3 \\ \Delta e_4 \\ \Delta h_4 \end{Vmatrix}$$

Method 4: A combination of methods 2 and 3:

$$\begin{vmatrix} \Delta P_2 \\ \Delta Q_2 \\ \Delta P_3 \\ \Delta Q_3 \\ \Delta P_4 \\ \Delta V_4^2 \end{vmatrix} = \begin{vmatrix} \partial P_2/\partial e_2 & \partial P_2/\partial h_2 & . & . & . & . \\ \partial Q_2/\partial e_2 & \partial Q_2/\partial h_2 & . & . & . & . \\ \partial P_3/\partial e_2 & \partial P_3/\partial h_2 & \partial P_3/\partial e_3 & \partial P_3/\partial h_3 & . & . \\ \partial Q_3/\partial e_2 & \partial Q_3/\partial h_2 & \partial Q_3/\partial eh_3 & \partial Q_3/\partial h_3 & . & . \\ \partial P_4/\partial e_2 & \partial P_4/\partial h_2 & \partial P_4/\partial e_3 & \partial P_4/\partial h_3 & \partial P_4/\partial e_4 & \partial P_4/\partial h_4 \\ \partial V_4^2/\partial e_2 & \partial V_4^2/\partial h_2 & \partial V_4^2/\partial e_3 & \partial V_4^2/\partial h_3 & \partial V_4^2/\partial e_4 & \partial V_4^2/\partial h_4 \end{vmatrix} \times$$

$$\begin{vmatrix} \Delta e_2 \\ \Delta h_2 \\ \Delta e_3 \\ \Delta h_3 \\ \Delta e_4 \\ \Delta h_4 \end{vmatrix}$$

Method 5 may give the least iterations for a value of $\beta < 1$, a factor somewhat akin to the acceleration factor in the Gauss–Seidel method (>1). The Jacobian is of the form LDU.

$$\begin{vmatrix} \Delta P_2 \\ \Delta Q_2 \\ \Delta P_3 \\ \Delta Q_3 \\ \Delta P_4 \\ \Delta V_4 \end{vmatrix} = (L+D) \begin{vmatrix} \Delta e_2^k \\ \Delta h_2^k \\ \Delta e_3^k \\ \Delta h_3^k \\ \Delta e_4^k \\ \Delta h_4^k \end{vmatrix} + \beta U \begin{vmatrix} \Delta e_2^{k-1} \\ \Delta h_2^{k-1} \\ \Delta e_3^{k-1} \\ \Delta h_3^{k-1} \\ \Delta e_4^{k-1} \\ \Delta h_4^{k-1} \end{vmatrix}$$

4.4. Decoupled Newton-Raphson Method

The general rule that relates voltage angle mainly to real power and voltage magnitude mainly to reactive power flow derives mathematically from two reasonable assumptions: first, that the reactive properties of transmission lines tend to outweigh the effect of their resistance, and second, that the voltage angle differences between buses are small (usually less than 10°). Specifically, we can pose the question,Which variable does the real (or reactive) power coming out of a bus depend on most—voltage angle or magnitude? In mathematical terms, we are asking, What is the partial derivative of P or Q with respect to u or with respect to V? These are the partial derivatives which, evaluated at each bus in relation to the u or V from each of the other buses, constitute the four partitions of the Jacobian matrix. Readers familiar with calculus can follow the process of taking each of the four types of partial derivatives of the power flow equations. In fact, we must also distinguish whether the index k of the independent variable (uk or Vk) is the same or different from the index i of Pi or Qi—in other words, whether we mean the dependence of real or reactive power on voltage angle or magnitude at the same bus, or at a neighboring bus. We are especially interested, of course, in the voltage relationships between neighboring buses (because we will want to draw conclusions about power flow from one bus to another as a result), so we will consider only the derivatives with unequal indices for now.

It has already been demonstrated that there is strong interdependence between active power and bus voltage angle and between reactive power and voltage magnitude. The active power change _P is less sensitive to changes in voltage magnitude, and changes in reactive power _Q are less sensitive to changes in angles. In other words, the coupling between P and bus voltage magnitude is weak and between reactive power and phase angle is weak.

The Jacobian eq. can be rearranged as follows:

$$\begin{vmatrix} \Delta P_2 \\ \Delta P_3 \\ \Delta P_4 \\ \Delta Q_2 \\ \Delta Q_3 \end{vmatrix} = \begin{vmatrix} \partial P_2/\partial\theta_2 & \partial P_2/\partial\theta_3 & \partial P_2/\partial\theta_4 & \partial P_2/\partial V_2 & \partial P_2/\partial V_3 \\ \partial P_3/\partial\theta_2 & \partial P_3/\partial\theta_3 & \partial P_3/\partial\theta_4 & \partial P_3/\partial V_2 & \partial P_3/\partial V_3 \\ \partial P_4/\partial\theta_2 & \partial P_4/\partial\theta_3 & \partial P_4/\partial\theta_4 & \partial P_4/\partial V_2 & \partial P_4/\partial V_3 \\ \partial Q_2/\partial\theta_2 & \partial Q_2/\partial\theta_3 & \partial Q_2/\partial\theta_4 & \partial Q_2/\partial V_2 & \partial Q_2/\partial V_3 \\ \partial Q_3/\partial\theta_2 & \partial Q_3/\partial\theta_3 & \partial Q_3/\partial\theta_4 & \partial Q_3/\partial V_2 & \partial Q_3/\partial V_3 \end{vmatrix} \begin{vmatrix} \Delta\theta_2 \\ \Delta\theta_3 \\ \Delta\theta_4 \\ \Delta V_2 \\ \Delta V_3 \end{vmatrix}$$

Considering that

$$G_{sr} <<< B_{sr}$$

$$\sin(\theta_s - \theta_r) <<< 1$$

$$\cos(\theta_s - \theta_r) \simeq 1$$

The following inequalities are valid:

$$|\partial P_s/\partial\theta_r| >>> |\partial P_s/\partial V_r|$$

$$|\partial Q_s/\partial\theta_r| <<< |\partial Q_s/\partial V_r|$$

Thus, the Jacobian is

$$\begin{vmatrix} \Delta P_2 \\ \Delta P_3 \\ \Delta P_4 \\ \Delta Q_2 \\ \Delta Q_3 \end{vmatrix} = \begin{vmatrix} \partial P_2/\partial\theta_2 & \partial P_2/\partial\theta_3 & \partial P_2/\partial\theta_4 & . & . \\ \partial P_3/\partial\theta_2 & \partial P_3/\partial\theta_3 & \partial P_3/\partial\theta_4 & . & . \\ \partial P_4/\partial\theta_2 & \partial P_4/\partial\theta_3 & \partial P_4/\partial\theta_4 & & \\ . & . & . & \partial Q_2/\partial V_2 & \partial Q_2/\partial V_3 \\ . & . & . & \partial Q_3/\partial V_2 & \partial Q_3/\partial V_3 \end{vmatrix} \begin{vmatrix} \Delta\theta_2 \\ \Delta\theta_3 \\ \Delta\theta_4 \\ \Delta V_2 \\ \Delta V_3 \end{vmatrix}$$

This is called P–Q decoupling.

4.5. Fast Decoupled Load Flow

Two synthetic networks, P–θ and P–V, are constructed. This implies that the load flow problem can be solved separately by these two networks, taking advantage of P–Q decoupling.

In a P–θ network, each branch of the given network is represented by conductance, the inverse of series reactance. All shunt admittances and transformer offnominal voltage taps which affect the reactive power flow are omitted, and the swing bus is grounded. The bus conductance matrix of this network is termed $\bar{B}^{\theta}$

The second model is called a Q–V network. It is again a resistive network. It has the same structure as the original power system model, but voltage-specified buses (swing bus and PV buses) are grounded. The branch conductance is given by

$$Y_{sr} = -B_{sr} = \frac{x_{sr}}{x_{sr}^2 + r_{sr}^2}$$

These are equal and opposite to the series or shunt susceptance of the original network. The effect of phase-shifter angles is neglected. The bus conductance matrix of this network is called $\bar{B}^v$ The equations for power flow can be written as

$$P_s/V_s = \sum_{r=1}^{r-n} V_r[G_{sr}\cos(\theta_s - \theta_r) + B_{sr}\sin(\theta_s - \theta_r)]$$

$$Q_s/V_s = \sum_{r=1}^{r-n} V_r[G_{sr}\sin(\theta_s - \theta_r) - B_{sr}\cos(\theta_s - \theta_r)]$$

and partial derivatives can be taken as before. Thus, a single matrix for load flow can be split into two matrices as follows:

$$\begin{vmatrix} \Delta P_2/V_2 \\ \Delta P_3/V_3 \\ \cdot \\ \Delta P_n/V_n \end{vmatrix} = \begin{vmatrix} B_{22}^\theta & B_{23}^\theta & \cdot & B_{2n}^\theta \\ B_{32}^\theta & B_{33}^\theta & \cdot & B_{3n}^\theta \\ \cdot & \cdot & \cdot & \cdot \\ B_{n2}^\theta & B_{n3}^\theta & \cdot & B_{nn}^\theta \end{vmatrix} \begin{vmatrix} \Delta\theta_2 \\ \Delta\theta_3 \\ \cdot \\ \Delta\theta_n \end{vmatrix}$$

The correction of phase angle of voltage is calculated from this matrix:

$$\begin{vmatrix} \Delta Q_2/V_2 \\ \Delta Q_3/V_3 \\ \cdot \\ \Delta Q_n/V_n \end{vmatrix} = \begin{vmatrix} B_{22}^v & B_{23}^v & \cdot & B_{2n}^v \\ B_{32}^v & B_{33}^v & \cdot & B_{3n}^v \\ \cdot & \cdot & \cdot & \cdot \\ B_{n2}^v & B_{n3}^v & \cdot & B_{nn}^v \end{vmatrix} \begin{vmatrix} \Delta V_2 \\ \Delta V_3 \\ \cdot \\ \Delta V_n \end{vmatrix}$$

The voltage correction is calculated from this matrix. These matrices are real, sparse, and contain only admittances; these are constants and do not change during successive iterations.

a) Example 1;

Consider a transmission system of two 138-kV lines, three buses, each line modeled by an equivalent π network, as shown in Fig. 4-(a), with series and shunt admittances as shown. Bus 1 is the swing bus (voltage 1.02 per unit), bus 2 is a PQ bus with load demand of 0.25 +j0.25 per unit, and bus 3 is a voltage-controlled bus with bus voltage of 1.02 and a load of 0.5 j0 per unit all on 100 MVA base. Solve the load flow using the NR method, polar axis basis.

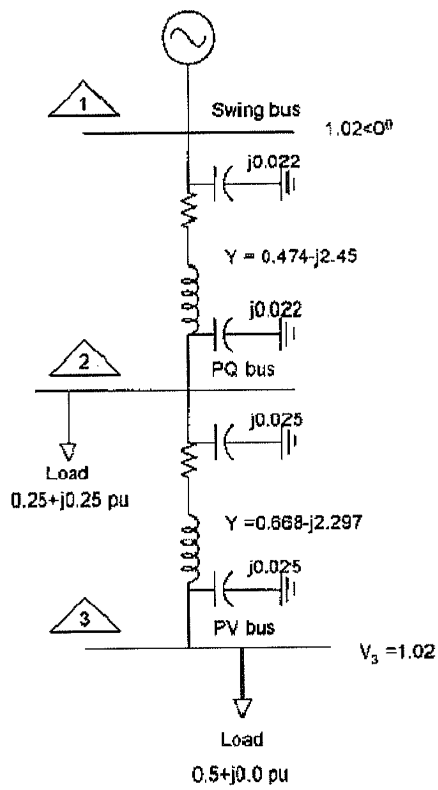


Figure 4.2 (a)

Figure 4-(a) System of Example 1 for load-flow solution; (b) final converged loadflow solution with reactive power injection at PV bus 3; (c) converged load flow with bus 3 treated as a PQ bus.

First, form a Y matrix as follows;

$$\bar{Y} = \begin{vmatrix} 0.474 - j2.428 & -0.474 + j2.45 & 0 \\ -0.474 + j2.45 & 1.142 - j4.70 & -0.668 + j2.297 \\ 0 & -0.668 + j2.297 & 0.668 - j2.272 \end{vmatrix}$$

$$P_1 = 1.02 \times 1.02[0.474\cos(0.0 - 0.0) + (-2.428)\sin(0.0 - 0.0)]$$
$$+ 1.02V_2[(-0.474)\cos(0.0 - \theta_2) + 2.45\sin(0.0 - \theta_2)$$
$$+ 1.02 \times 1.02[0.0\cos(0.0 - \theta_3) + 0.0\sin(0.0 - \theta_3)]$$

$$Q_1 = 1.02 \times 1.02[0.474\sin(0.0 - 0.0) - (-2.428)\cos(0.0 - 0.0)]$$
$$+ 1.02V_2[(-0.474)\sin(0.0 - \theta_2) - 2.45\cos(0.0 - \theta_2)]$$
$$+ 1.02 \times 1.02[0.0\sin(0.0 - \theta_3) - 0.0\cos(0.0 - \theta_3)]$$

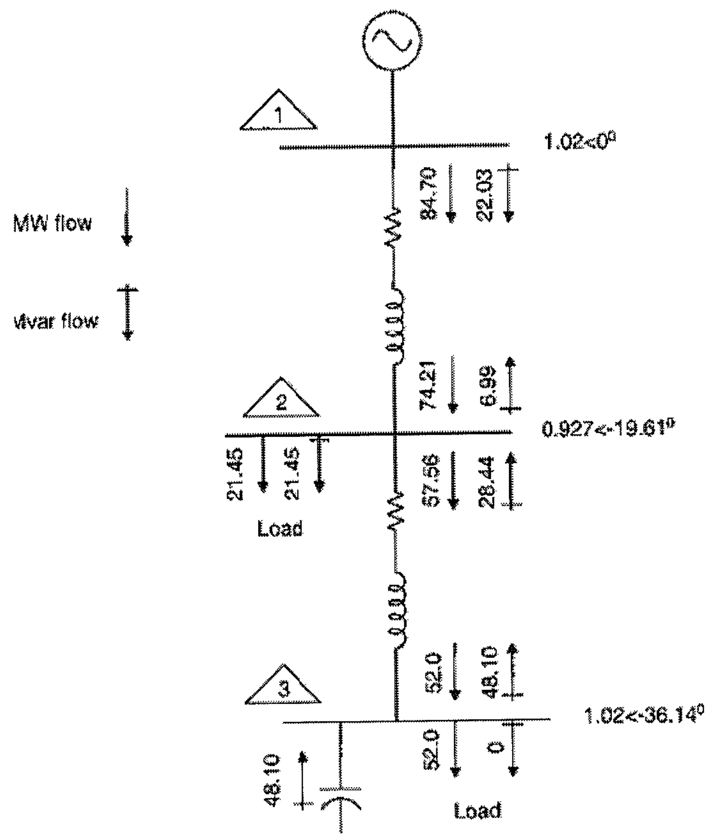


Figure 4.2 (b)

These equations for the swing bus are not immediately required for load flow, but can be used to calculate the power flow from this bus, once the system voltages are calculated to the required tolerance.

Similarly, the active and reactive power at other buses are written;

$$P_2 = V_2 \times 1.02[-0.474\cos(\theta_2 - 0) + 2.45\sin(\theta_2 - 0)] + V_2$$
$$\times V_2[1.142\cos(\theta_2 - \theta_2) + (-4.70)\sin(\theta_2 - \theta_2)] + V_2$$
$$\times 1.02[(-0.668)\cos(\theta_2 - \theta_3) + 2.297\sin(\theta_2 - \theta_3]$$

Substituting the initial values ($V_2 = 1, \theta_2 = 0^\circ$), $P_2 = -0.0228$.

$$Q_2 = V_2 \times 1.02[(-0.474)\sin(\theta_2 - 0.0) - 2.45\cos(\theta_2 - 0.0)] + V_2 \times V_2[1.142\sin(\theta_2 - \theta_2) - (-4.70)\cos(\theta_2 - \theta_2)] + V_2 \times 1.02[(-0.668)\sin(\theta_2 - \theta_3) - 2.297\cos(\theta_2 - \theta_3)]$$

Substituting the numerical values, $Q_2 = -0.142$.

$$P_3 = 1.02 \times 1.02[0.0\cos(\theta_3 - 0.0) + 0.0\sin(\theta_3 - 0.0)] + 1.02 \times V_2[(-0.668)\cos(\theta_3 - \theta_2) + 2.297\sin(\theta_3 - \theta_2)] + 1.02 \times 1.02[0.668\cos(\theta_3 - \theta_3) + (-2.047)\sin(\theta_3 - \theta_3]$$

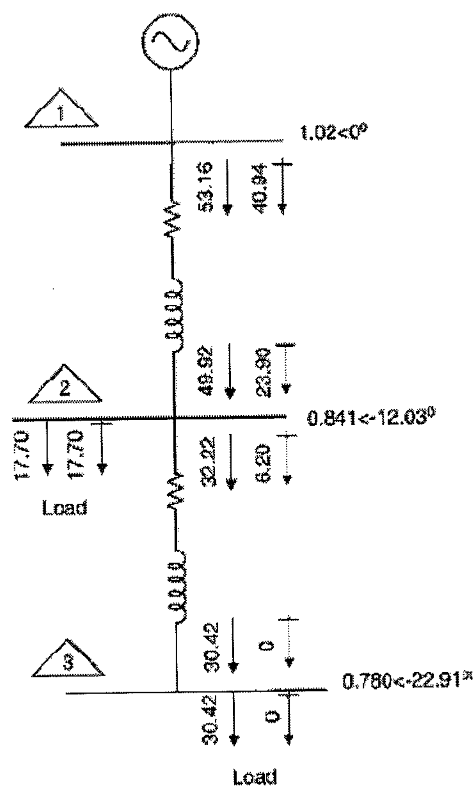


Figure 4.2 (c)

Substituting the values, P3 = 0.0136.

$$Q_3 = 1.02 \times 1.02[0.0\sin(\theta_3 - 0.0) - 0.0\cos(\theta_3 - 0.0)] + 1.02 \times V_2[(-0.668)\sin(\theta_3 - \theta_2) - 2.297\cos(\theta_3 - \theta_2)] + 1.02 \times 1.02[0.668\sin(\theta_3 - \theta_3) - (-2.272)\cos(\theta_3 - \theta_3)]$$

Substituting initial values, Q3 = -0.213.

The Jacobian matrix is;

$$\begin{vmatrix} \Delta P_2 \\ \Delta Q_2 \\ \Delta P_3 \end{vmatrix} = \begin{vmatrix} \partial P_2/\partial\theta_2 & \partial P_2/\partial V_2 & \partial P_2/\partial\theta_3 \\ \partial Q_2/\partial\theta_2 & \partial Q_2/\partial V_2 & \partial Q_2/\partial\theta_3 \\ \partial P_3/\partial\theta_2 & \partial P_3/\partial V_2 & \partial P_3/\partial\theta_3 \end{vmatrix} \begin{vmatrix} \Delta\theta_2 \\ \Delta V_2 \\ \Delta\theta_3 \end{vmatrix}$$

The partial differentials are found by differentiating the equations for P2, Q2, P3, etc.

$$\begin{aligned} \partial P_2/\partial\theta_2 &= 1.02[V_2(0.474)\sin\theta_2 + 2.45\cos\theta_2] + 1.02[V_2(0.668)\sin(\theta_2 - \theta_3) \\ &\quad + V_2(2.297)\cos(\theta_2 - \theta_3)] \\ &= 4.842 \end{aligned}$$

$$\begin{aligned} \partial P_2/\partial\theta_3 &= V_2(1.02)[(-0.668)\sin(\theta_2 - \theta_3) - 2.297\cos(\theta_2 - \theta_3] \\ &= -2,343 \end{aligned}$$

$$\begin{aligned} \partial P_2/\partial V_2 &= 1.02[(-0.474)\cos\theta_2 + 2.45\sin\theta_2] \\ &\quad + 2V_2(1.142) + 1.02[(-0.608)\cos(\theta_2 - \theta_3) + 2.297\sin(\theta_2 - \theta_3)] \\ &= 1.119 \end{aligned}$$

$$\begin{aligned} \partial Q_2/\partial\theta_2 &= 1.02[-V_2(0.474)\cos\theta_2 + 2.45\sin\theta_2] + 1.02[V_2(-0.668)\cos(\theta_2 - \theta_3) \\ &\quad + 2.297\sin(\theta_2 - \theta_3)] \\ &= -1.1648 \end{aligned}$$

$$\begin{aligned} \partial Q_2/\partial V_2 &= 1.02[(-0.474)\sin\theta_2 - 2.45\cos\theta_2] + 2V_2(4.28) \\ &\quad + 1.02[(-0.668)\sin(\theta_2 - \theta_3) - 2.297\cos(\theta_2 - \theta_3)] \\ &= 4.56 \end{aligned}$$

$$\begin{aligned} \partial Q_2/\partial\theta_3 &= 1.02V_2[0.668\cos(\theta_2 - \theta_3) - 2.297\sin(\theta_2 - \theta_3)] \\ &= 0.681 \end{aligned}$$

$$\begin{aligned} \partial P_3/\partial\theta_2 &= 1.02V_2[(0.668)\sin(\theta_3 - \theta_2) - 2.297\cos(\theta_3 - \theta_2)] \\ &= 2.343 \end{aligned}$$

$$\partial P_3/\partial V_2 + 1.02[(-0.668)\cos(\theta_3 - \theta_2) + 2.297\sin(\theta_3 - \theta_2)]$$
$$= 0.681$$

$$\partial P_3/\partial \theta_3 = 1.02[0.668\sin(\theta_3 - \theta_2) + 2.297\cos(\theta_3 - \theta_2)]$$
$$= 2.343$$

Therefore, the Jacobian is;

$$\bar{J} = \begin{vmatrix} 4.842 & 1.119 & -2.343 \\ -1.165 & 4.56 & 0.681 \\ -2.343 & 0.681 & 2.343 \end{vmatrix}$$

The system equations are;

$$\begin{vmatrix} \Delta\theta_2^1 \\ \Delta V_2^1 \\ \Delta\theta_3^1 \end{vmatrix} = \begin{vmatrix} 4.842 & 1.119 & -2.343 \\ -1.165 & 4.56 & 0.681 \\ -2.343 & 0.681 & 2.343 \end{vmatrix}^{-1} \begin{vmatrix} -0.25 - (-0.0228) \\ 0.25 - (-0.142) \\ -0.5 - 0.0136 \end{vmatrix}$$

Inverting the Jacobian gives;

$$\begin{vmatrix} \Delta\theta_2^1 \\ \Delta V_2^1 \\ \Delta\theta_3^1 \end{vmatrix} = \begin{vmatrix} 0.371 & -0.153 & 0.4152 \\ 0.041 & 0.212 & -0.021 \\ 0.359 & -0.215 & 0.848 \end{vmatrix} \begin{vmatrix} -0.2272 \\ 0.392 \\ -0.5136 \end{vmatrix} = \begin{vmatrix} -0.357 \\ -0.084 \\ -0.601 \end{vmatrix}$$

The new values of voltages and phase angles are;

$$\begin{vmatrix} \theta_2^1 \\ V_2^1 \\ \theta_3^1 \end{vmatrix} = \begin{vmatrix} 0 \\ 1 \\ 0 \end{vmatrix} + \begin{vmatrix} -0.357 \\ 0.084 \\ -0.601 \end{vmatrix} = \begin{vmatrix} -0.357 \\ 1.084 \\ -0.729 \end{vmatrix}$$

This completes one iteration. Using the new bus voltages and phase angles the power flow is recalculated. Thus, at every iteration, the Jacobian matrix changes and has to be inverted. In the first iteration, we see that the bus 2 voltage is 8.4% higher than the rated voltage; the angles are in radians. The first iteration is no indication of the final results. The hand calculations, even for a simple three-bus system, become unwieldly. The converged load flow is shown in Fig. 4-(b). A reactive power injection of 43 Mvar is required at bus 3 to maintain a voltage of 1.02 per unit and supply the required active power of 0.5 per unit from the source. There is a reactive power loss of 48.65 Mvar in the transmission line themselves, and the active power loss is 12.22 MW. The bus phase angles are high with respect to the swing bus, and the bus 2 operating voltage is 0.927 per unit, i.e., a voltage drop of 7.3% under load. Thus, even with voltages at the swing bus and bus 3 maintained above rated voltage, the power demand at bus 2 cannot be met and the voltage at this bus dips. The load demand on the system is too high, it is lossy, and requires augmentation or reduction of load. A reactive power injection at bus 2 will give an entirely different result. If bus 3 is treated as a load bus, the Jacobian is modified by adding a fourth equation of the reactive power at bus 3. In this case the bus 3 voltage dips down to 0.78 per unit, i.e., a voltage drop of 22%; the converged load flow is shown in Fig. 4-(c). At this lower voltage of 0.78 per unit, bus 3 can support an active load of only 0.3 per unit. This is not an example of a practical system, but it illustrates the importance of reactive power injection, load modeling, and its effect on the bus voltages. The load demand reduces proportionally with reduction in bus voltages. This is because we have considered a constant impedance type of load, i.e., the load current varies directly with the voltage as the load impedance is held constant. The load types are discussed further.

b) Example 2:

Consider the network of Fig. 4-3(a). Let bus 1 be a swing bus, bus 2 and 3 PQ buses, and bus 4 a PV bus. The loads at buses 2 and 3 are specified as is the voltage magnitude at bus 4. Construct P–θ and Q–V matrices. P–θ Network

First construct the P–θ network shown in $Fig.2-(b)$. The associated matrix is

$$\bar{B}^{\theta} = \begin{vmatrix} 6.553 & -2.22 & -0.333 \\ -2.22 & 5.886 & -3.333 \\ -0.333 & -3.333 & 3.666 \end{vmatrix} \begin{vmatrix} \Delta\theta_2 \\ \Delta\theta_3 \\ \Delta\theta_4 \end{vmatrix} = \begin{vmatrix} \Delta P_2/V_2 \\ \Delta P_3/V_3 \\ \Delta P_4/V_4 \end{vmatrix}$$

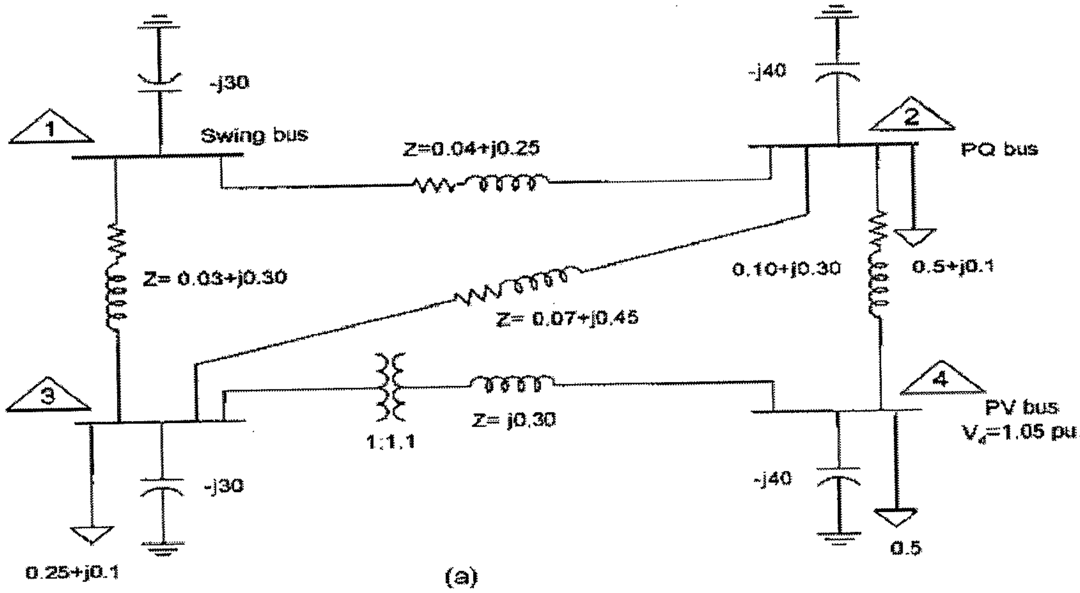


Figure 4.3 (a)

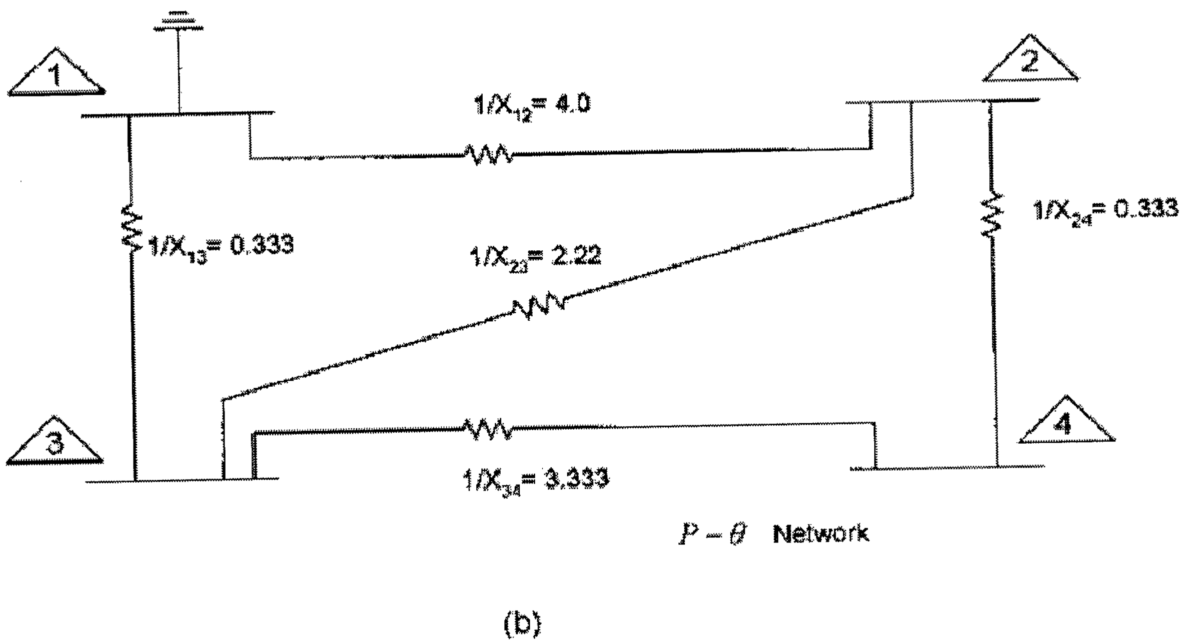


Figure 4.3 (b)

Figure 4.3 (a) Four-bus system with voltage tap adjustment transformer; (b) decoupled P–θ network; (c) Q–V network. Q-V Network.

The Q–V network is shown in Fig. (c). The associated matrix is;

$$\bar{B}^{v} = \begin{vmatrix} 9.345 & -2.22 \\ -2.22 & 9.470 \end{vmatrix} \begin{vmatrix} \Delta V_2 \\ \Delta V_3 \end{vmatrix} = \begin{vmatrix} \Delta Q_2 / V_2 \\ \Delta Q_3 / V_3 \end{vmatrix}$$

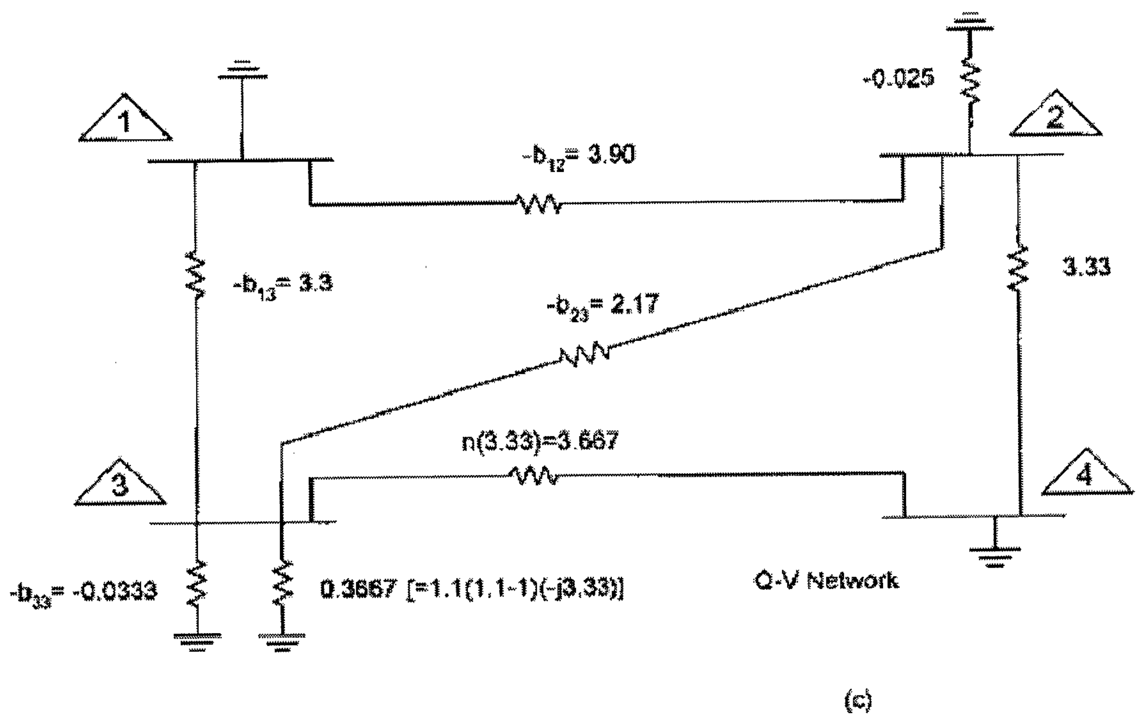


figure 4.3 (c)

4.6. IEEE 14-Bus Test System

4.6.1. Introduction

A single line diagram of the IEEE 14-bus standard system is shown in Figure 4A.1. It consists of five synchronous machines with IEEE type-1 exciters, three of which are synchronous compensators used only for reactive power support. There are 11 loads in the system totaling 259 MW and 81.3 Mvar.

The IEEE 14-BUS was studied using the UWPFLOW and PST programs to obtain the system P-V curves and perform time domain and eigenvalue analyses to study the general performance of the system. SVC, TCSC and PSS controllers were also added to the system , to study their effect in the system and their interactions. The model details are discussed in the following sections, and the corresponding data is given in Appendix.

The example solved by this MATLAB program is an IEEE 14 bus test case. The input data used for the system and the output computed by the program.

Number of devices in the case:

Buses: 14	Loads: 9
Generators: 5	Lines/transformers: 20

4.A. Appendix

Exciter no.	1	2	3	4	5
K_A	200	20	20	20	20
T_A	0.02	0.02	0.02	0.02	0.02
T_B	0.00	0.00	0.00	0.00	0.00
T_c	0.00	0.00	0.00	0.00	0.00
V_{Rmax}	7.32	4.38	4.38	6.81	6.81
V_{Rmin}	0.00	0.00	0.00	1.395	1.395
K_E	1.00	1.00	1.00	1.00	1.00
T_E	0.19	1.98	1.98	0.70	0.70
K_F	0.0012	0.001	0.001	0.001	0.001
T_F	1.0	1.0	1.0	1.0	1.0

Table 4A.1: Exciter data

Generator bus no.	1	2	3	4	5
MVA	615	60	60	25	25
x_l (p.u.)	0.2396	0.00	0.00	0.134	0.134
r_a (p.u.)	0.00	0.0031	0.0031	0.0014	0.0041
x_d (p.u.)	0.8979	1.05	1.05	1.25	1.25
x'_d (p.u.)	0.2995	0.1850	0.1850	0.232	0.232
x''_d (p.u.)	0.23	0.13	0.13	0.12	0.12
T'_{do}	7.4	6.1	6.1	4.75	4.75
T''_{do}	0.03	0.04	0.04	0.06	0.06
x_q (p.u.)	0.646	0.98	0.98	1.22	1.22
x'_q (p.u.)	0.646	0.36	0.36	0.715	0.715
x''_q (p.u.)	0.4	0.13	0.13	0.12	0.12
T'_{qo}	0.00	0.3	0.3	1.5	1.5
T''_{qo}	0.033	0.099	0.099	0.21	0.21
H	5.148	6.54	6.54	5.06	5.06
D	2	2	2	2	2

Table 4A.2: Generator data

Bus No.	P Generated (p.u.)	Q Generated (p.u.)	P Load (p.u.)	Q Load (p.u.)	Bus Type*	Q Generated max.(p.u.)	Q Generated min.(p.u.)
1	2.32	0.00	0.00	0.00	2	10.0	-10.0
2	0.4	-0.424	0.2170	0.1270	1	0.5	-0.4
3	0.00	0.00	0.9420	0.1900	2	0.4	0.00
4	0.00	0.00	0.4780	0.00	3	0.00	0.00
5	0.00	0.00	0.0760	0.0160	3	0.00	0.00
6	0.00	0.00	0.1120	0.0750	2	0.24	-0.06
7	0.00	0.00	0.00	0.00	3	0.00	0.00
8	0.00	0.00	0.00	0.00	2	0.24	-0.06
9	0.00	0.00	0.2950	0.1660	3	0.00	0.00
10	0.00	0.00	0.0900	0.0580	3	0.00	0.00
11	0.00	0.00	0.0350	0.0180	3	0.00	0.00
12	0.00	0.00	0.0610	0.0160	3	0.00	0.00
13	0.00	0.00	0.1350	0.0580	3	0.00	0.00
14	0.00	0.00	0.1490	0.0500	3	0.00	0.00

Table 4A.3:*Bus Type: (1) swing bus, (2) generator bus (PV bus), and (3) load bus (PQ bus)

From Bus	To Bus	Resistance (p.u.)	Reactance (p.u)	Line charging (p.u.)	tap ratio
1	2	0.01938	0.05917	0.0528	1
1	5	0.05403	0.22304	0.0492	1
2	3	0.04699	0.19797	0.0438	1
2	4	0.05811	0.17632	0.0374	1
2	5	0.05695	0.17388	0.034	1
3	4	0.06701	0.17103	0.0346	1
4	5	0.01335	0.04211	0.0128	1
4	7	0.00	0.20912	0.00	0.978
4	9	0.00	0.55618	0.00	0.969
5	6	0.00	0.25202	0.00	0.932
6	11	0.09498	0.1989	0.00	1
6	12	0.12291	0.25581	0.00	1
6	13	0.06615	0.13027	0.00	1
7	8	0.00	0.17615	0.00	1
7	9	0.00	0.11001	0.00	1
9	10	0.03181	0.08450	0.00	1
9	14	0.12711	0.27038	0.00	1
10	11	0.08205	0.19207	0.00	1
12	13	0.22092	0.19988	0.00	1
13	14	0.17093	0.34802	0.00	1

Table 4A.4: Line Data

The one-line diagram for the IEEE 14 us system created by PowerWorld simulator is shown in figure .

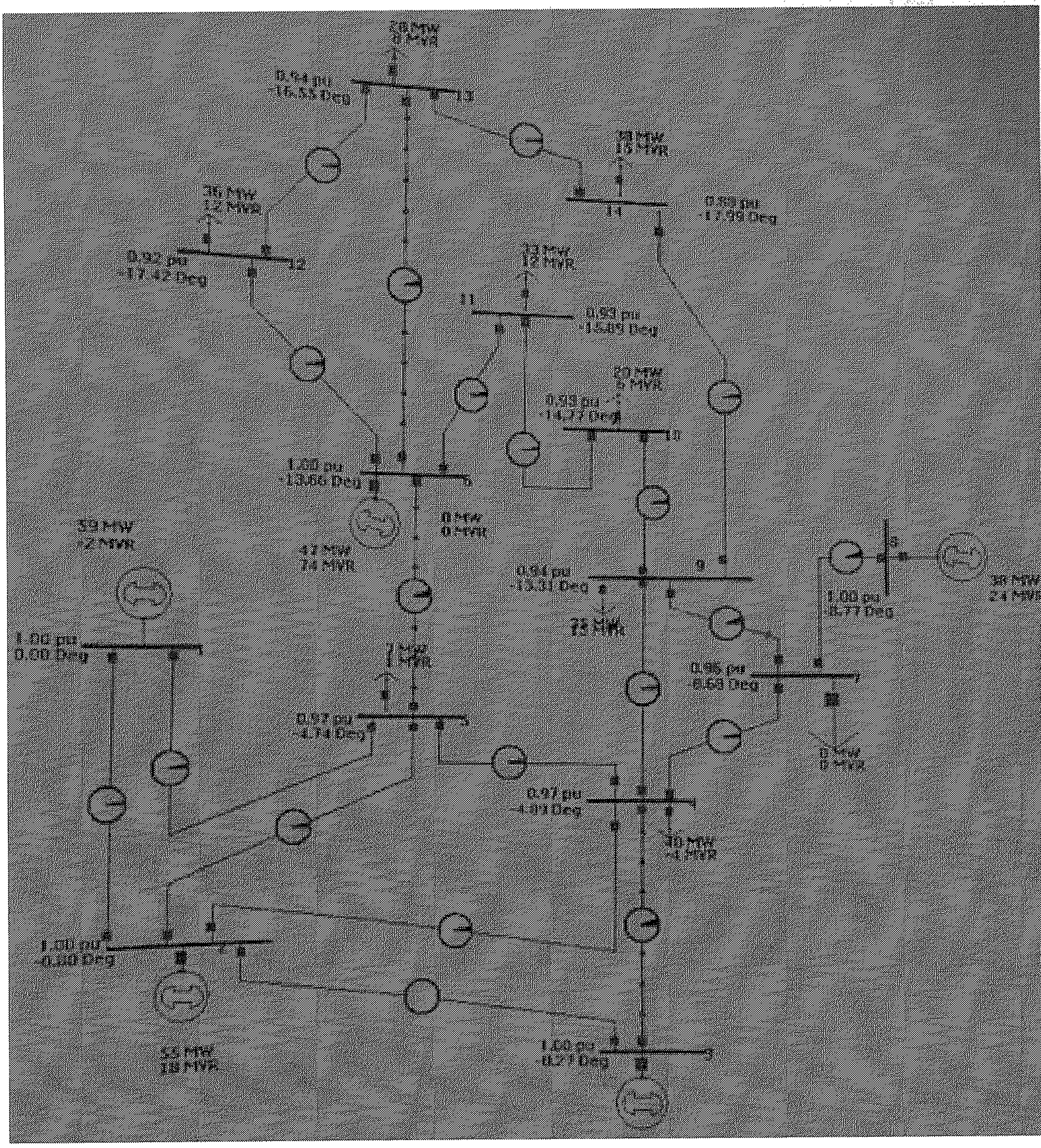


Figure 4A.1: one-line diagram for IEEE 14 bus case

The program is solved after 3 iterations, the voltages magnitudes in per unit and voltage angels in degrees are given below as computed by the program.

Power flow solution						
			Generation		load	
Bus#	Vp.u.	Angle-deg	PGp.u.	QG p.u.	PL p.u.	QLp.u.
1	1.0000	0	0.5852	-0.0325	0	0
2	1.0000	-0.7987	0.5500	0.1531	0	0
3	1.0000	-0.2654	0.5080	-0.0017	0	0
4	0.9707	-4.9141	0	0	0.4000	-0.0400
5	0.9753	-4.7678	0	0	0.0700	0.0100
6	1.0000	-13.6623	0.4700	0.7283	0	0
7	0.9615	-8.6917	0	0	0	0
8	1.0000	-8.7444	0.3800	0.2273	0	0
9	0.9358	-13.3144	0	0	0.3500	0.1500
10	0.9264	-14.7763	0	0	0.2000	0.0600
11	0.9334	-15.8883	0	0	0.3300	0.1200
12	0.9249	-17.4217	0	0	0.3600	0.1200
13	0.9400	-16.5477	0	0	0.2800	0.0800
14	0.8785	-17.9880	0	0	0.3800	0.1500
		TOTAL	*2.4932*	*1.0745*	2.3700	0.6500

Table 4A.5 : solved data by the program for IEEE 14 bus case

Number of iteration : 3

CONCLUSION

In todays,electric power systems are very big and large.they have thousands of parts and equipments.For succesful operation and contro of powersystem,it is necessary to get information instantly and accuratly.Power flow analysis the most efficient tool to get information. The formulation of power flow equations were explained in the project.

It is hard to calculate power flow equation by using hand. Trying to solve the equation by hand takes too much time and it needs hard working. Also it is very easy to make some mistakes during solving. Using computer programs can save times and energy.Most importantly it destroys to chance of the making mistakes. These programs are very easy to learn and use and understand.

In this a programs for power flow using Newton-Raphson methot and Decoupled Newton-Raphson method,written in MATLAB,is considered and the results obtained were quit satisfactory.

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