Economics of Traditional Planning Methods

1.0 Introduction

These notes are largely adaptations of information from the two sources in the bibliography [1, 2]. Both of these sources provide an excellent treatment of traditional electric utility economic planning procedures. In spite of the fact that the electric utility industry has changed significantly since the development of these two sources, the principles outlined are still heavily used in the planning done by regulated utilities, especially for transmission planning.

Construction of new electric generation and transmission is a capital-intensive activity. In addition, it is generally not possible to quickly build generation or transmission. A full time-table for design and construction of such facilities usually requires at least 2-3 years and more frequently 3-5 years or more. Therefore, any organization that intends to invest in new generation or transmission must have the ability to access large quantities of money with significantly delayed payback revenue stream.

There are planning needs at the distribution level but those needs focus mainly on the distribution wires or cables and often make use of the available roadside utility right-of-way.

We will focus on the bulk electric power system planning needs. These are more complicated for two reasons.

1. Bulk electric power system planning involves both generation (or resource planning), as well as transmission

planning, and there usually exist complex interdependencies between the two. Efforts at planning one of them without consideration of the plans for the other will typically result in less desirable plans in terms of reliability or in terms of economics, or in terms of both.

2. Bulk electric power system planning often involves acquisition of new land, either for power plants of for transmission right-of-way. This in itself is a socially complex issue that involves many constituencies, most of whom have at best a layman's understanding of electric power engineering and economics. Such people must be contacted, educated about the needs, and given time to respond with concerns. The acronym "NIMBY," which means "Not In My Back Yard" was coined to reflect a common position taken by many people and communities when confronted with the possibility of a new power plant or transmission line located nearby their living or working location. There are many reasons for this position, but possibly the most common are aesthetic, environmental, and health.

Planning involves simultaneous economic and reliability evaluation of alternatives. Either one may motivate interest in or the need for new investment.

The implicit assumption of material treated in these notes is that the planner has become aware that future operation of the existing transmission system has non-negligible potential to result in violation of electric reliability criteria or undesirably high costs (including "costs" associated with lost opportunities). Therefore it is of interest to identify possible alternative decision paths that can be taken.

So the objective of economic analysis is to determine the economic consequences of project alternatives so that management can make an informed decision in selecting the most desirable alternative.

1.1 Economic issues

Two economic issues that have always been important in making planning decisions are

1. What is the investment cost of each alternative?
2. How is the yearly operational cost impacted by each alternative?

Since the creation of electricity markets, it is also important to understand the impact of each alternative on the operation of the market. An alternative might be selected in order to maximize profits in the electricity markets.

1.2 Reliability issues

It is inevitable, if the usage of the transmission system is growing or changing through load growth or load shifting or through generation growth or generation shifting, that existing generation and transmission will at some point become insufficient, leading to an unreliable system. To better frame this notion, the industry has established two different categories of reliability. They are:

- Adequacy: The ability of the power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Security: The ability of the power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The North American Electric Reliability Corporation (NERC), maintains an extensive set of standards that address system adequacy and security, system modeling data requirements, system protection and control, operations, system restoration, and so on. These standards are located at www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html.

In addition to planning standards, individual regional councils may develop their own regional planning criteria. These are evaluated to ensure that the regional criteria are consistent with NERC's planning standards. A fundamental part of these standards is the disturbance-performance table. This table is based on the planning philosophy that a higher level of performance (or lower level of severity) is required for disturbances generally having a higher frequency (or higher probability) of occurrence. This table is given below. The criteria given in it must never be violated when planning the system.

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. • May involve substantial loss of customer Demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

2.0 Types of expenditures

Expenditures incurred on a project can be divided into two types: capital investments and maintenance & operation (M&O) expenses, i.e., ***investments*** and ***expenses***.

Investment is the amount of money required to purchase or construct an asset having a service life beyond a year.

An expense is the amount of money required to own, operate, and maintain existing assets and also includes the amount of money required to purchase or construct assets having a service life of one year or less. Expenses may be categorized into two forms:

1. Variable costs are a function of the amount of production and/or use associated with the facility. Generally, M&O costs are the primary cost associated with variable costs.
2. Fixed costs are related to the amount of capital invested in the asset. There are typically five kinds of fixed costs:
   a. Cost of capital (return on investment): The return to the stockholders helping to finance the project, or the interest on bonds used to finance the project. Bond interest paid, unlike dividends on stock, is deductible as a business expense in the computation of federal and state income taxes.
   b. Depreciation: The expense of systematically returning capital to the investors as an asset declines in value.
   c. Federal and state income taxes: Taxes levied on the basis of income, paid to federal and state governments.
   d. Ad valorem (property) tax: Tax levied on the basis of property values and paid to local jurisdictions such as county governments or school districts.
   e. Insurance costs: The costs of premiums for insurance policies or expenses of self-insurance programs.

The above fixed charges are often captured in total using the so-called “fixed charge rate.” Fixed charge rates have an annual variation that might begin at 28%/year and decrease to a value of 14%/year at age 30 years as interest decreases.

Detailed computation of each of the above components of the fixed charge rate is outlined in [2, pp. 58-64].

3.0 More on cost of capital

A very basic concept of which you need to be aware is that of the electric utility balance sheet. The left-hand-side of the balance sheet lists all of the assets:

- Plant at original costs
- Less depreciation,
- Plus construction work in progress,
- Plus cash, accounts receivable, materials/supplies on hand

The first two are essentials in any electric utility regulator's *rate-base* assessment.

The right-hand-side of the balance sheet lists the *liabilities* and *owner's equity*:

- Long-term debt: Money the utility has borrowed through bonds at a stipulated interest rate and a stipulated maturity
- Total owner's equity: Utilities issue stock on the stock exchanges, which permits public ownership of the utility. There are two forms:
    - Common stock: This is usually where the bulk of ownership resides. Each common stockholder is entitled to vote in electing the board of directors. But common stock has no fixed yield but rather, dividends are paid to each stockholder at the end of the year in proportion to

the company's annual profit and the number of shares owned by the stockholder. *This dividend is according to the regulators allowed rate of return*.

  - Preferred stock: This has a fixed yield but no vote.

- Current liabilities: This includes short-term debt, accounts payable, and customer deposits.

The *accounting equation* of the balance sheet is then very sensible:

Assets=Liabilities+Owner's Equity

The discount rate is typically a weighted average over the different interest rates paid for the cost of capital. For example, a utility could finance its new assets as follows:

- 50% with bonds at an interest of 7%
- 10% with preferred stock at a dividend yield of 11%
- 40% with common stock expected to achieve a (regulated) 15% return

So the discount rate is computed as
i=0.5*0.07+0.1*0.11+0.4*0.15=0.0746
Therefore, the discount rate would be 7.46%.

4.0 Time value of money

Amounts of money at different points in time cannot be directly compared due to the time value of money.

The value of money received today is higher than the same amount of money received in the future because money received today can be invested to yield the original investment plus interest. Therefore, in order to compare alternatives having cash flows at different times, amounts of money must be expressed in equivalent amounts at common points in time.

The process of calculating equivalent values is referred to as discounting if amounts are brought back in time; it is referred to as compounding if amounts are moved forward into the future. These techniques may be applied to both single amounts and annuities. An annuity is a series of equal payments made at regular intervals.

The following relations are used in computing equivalent values of money. The interest rate per period, called the discount rate, is *i*; the number of periods is *N*.

Single Amounts moved in time:

The present worth factor (PWF) is used to determine the equivalent present value of a future expenditure:

$$\text{Present Value} = \text{Future Value} \times \text{PWF} = \text{Future Value} \times \frac{1}{(1+i)^N}$$

The compound amount factor (CAF) is used to determine the equivalent future value of a present expenditure:

$$\text{Future Value} = \text{Present Value} \times \text{CAF} = \text{Present Value} \times (1+i)^N$$

Annuities to single amounts:

The series present worth factor (SPWF) is used to determine the equivalent present value of a series of equal payments (an annuity):

$$\text{Present Value} = \text{Annity payment} \times \text{SPWF} = \text{Annuity Payment} \times \frac{(1+i)^N - 1}{i(1+i)^N}$$

The series compound amount factor (SCAF) is used to determine the equivalent future value of a series of equal payments (an annuity):

$$\text{Future Value} = \text{Annity payment} \times \text{SCAF} = \text{Annuity Payment} \times \frac{(1+i)^N - 1}{i}$$

<u>Single amounts to annuities</u>:

The sinking fund factor (SFF) is used to determine the annuity that is equivalent to a future expenditure.

$$\text{Annuity Payment} = \text{Future Value} \times \text{SFF} = \text{Future Value} \times \frac{i}{(1+i)^N - 1}$$

The Capital Recovery Factor (CRF) is used to determine the annuity that is equivalent to a present expenditure:

$$\text{Annity payment} = \text{Present Value} \times \text{CRF} = \text{Present Value} \times \frac{i(1+i)^N}{(1+i)^N - 1}$$

It is common convention to assume that all capital investments or expenses occur at the beginning of the year, and all fixed and variable costs associated with capital investments occur at the end of the year. Annuity payments are assumed to occur at the end of each time period.

5.0 Economic evaluation methods

It is important to recognize the difference between planning within

- a competitive business enterprise and
- an organization where rate of return on the rate-base is fixed by regulators.

In a competitive business enterprise, the most widely used economic evaluation method is called a "discounted cash-flow rate of return method." In this method, the expectation is that future cash flows will provide a return on the original investment. Therefore, for each alternative,

1. Future cash flows are examined through the time horizon of the evaluation.
2. The discount rate is identified which results in future cash flows equaling the initial investment. This rate is called the "discounted cash-flow rate of return."
3. All projects that have a discounted cash-flow rate of return that exceeds the cost of money are considered worth-while projects. The project with the highest discounted cash-flow rate of return is considered the best project.

In contrast, as we have seen, a regulated organization has its rate of return that can be provided to common stockholders fixed by the regulator agency. As a result, the "discounted cash-flow rate of return method, which compares different alternatives based on a computed rate of return, should not be used. Rather, methods which compare different alternatives based on a computed equivalent cost, for a fixed rate of return, make more sense.

The most common approach for economic evaluation of alternatives used by utilities is called the *revenue requirements method*.

Revenue requirements consist of two items: the annual fixed charges on a new investment and the annual expenses for fuel, operation, and maintenance. Calculations are made using the formula accounting for time value of money, to enable proper comparison between the alternatives.

One approach is to discount all costs associated with a project, present & future, to a specific point in time, usually the beginning of the study period. Then the present value of the costs for one alternative can be directly compared with the present value of the costs for the other alternatives.

One disadvantage of this approach is that the present value of all costs for an alternative can be quite large. To help make the total cost for an alternative easier to comprehend and to give the analyst a better feel for the annual differences between alternatives, the costs can be expressed on an equivalent annual cost basis.

Equivalent annual costs, also called level annual costs, represent the annuity which is exactly equivalent to all the costs incurred in an alternative. One method of making this calculation is to first determine the present value of all costs for an alternative (at the beginning of the study period), and then multiple this present value by the capital recovery factor for the length of the study period to “levelize” the costs over the study period

These costs are sometimes referred to as the levelized annual revenue requirements (LARR).

It is important to understand the distinction between LARR and actual revenue requirements. Since actual revenue requirements are seldom constant each year over the life of a project, it is difficult to compare actual revenue requirements between alternative projects. Thus, LARR represents the annuity that is equivalent to the actual revenues the company should receive.

6.0 Economic analysis steps

Each economic analysis is different, but there are some common steps, as follows:

1. State objective
2. Define alternatives: Include the "do-nothing" alternative. Each admitted alternative should (a) be feasible and (b) accomplish the objective.
3. Identify incremental costs of each alternative: These are the costs that are not incurred with all alternatives. Costs that will be incurred in the future and are common to all the alternatives are of no significance since they will occur regardless of which alternative course of action is chosen. Similarly, costs that have occurred in the past are usually irrelevant in the economic analysis because no future course of action can change the fact that these costs have already been incurred.

4. Choose study period: The study period represents that period of time over which costs are analyzed. The study period must extend far enough into the future to include all incremental costs for the alternatives being analyzed.

One interesting difficulty often arises in the above type of analysis that requires further discussion here.

Since alternatives are compared on the basis of total project cost, the alternatives must be defined so that they provide

- equal service (output, capacity)
- for equal lengths of time.

Otherwise, an alternative providing less service, or the same service for less time, may appear to result in lower costs and therefore might be chosen as the best alternative when in fact this alternative may result in greater total costs to the customers than one or more other alternatives.

6.1 Choosing study period

Two methods for choosing the study period that address the possibility that different alternatives may have different service times are as follows:

1. Salvage value approach: In this approach, the study period is set equal to the estimated service life of the alternative with the shortest service life. Then we assign salvage values at the end of the study period for those alternatives that have service lives greater than the study period. These salvage values should reflect the value of the lost service over the remaining service lives of the alternatives due to the hypothetical early retirement of these facilities.

2. Additional service approach: In this approach, the study period is set equal to the estimated service life of the alternative with the longest service life. Then we assign additional service from another source for the alternatives with service lives less than the study period.

Example: A new power plant is required to meet future electric load. There are two alternatives:

Alternative A:	Alternative B:
Service life=30 years	Service life=20 years
Capacity=100 MW	Capacity=100 MW

- Approach 1: Choose a 20 year study period with salvage value for Alternative A:
- Approach 2: Choose a 30 year period assuming you will establish a 10 year contract to buy firm power from a neighboring generation owner for the last decade.

6.2 Equalizing service provided

Here, one must provide for service from another source if alternatives do not have the same output per year. That is, if two alternatives differ in service for some years, the cost of obtaining service elsewhere should be included as a cost to the alternative which provides less output.

Example: A new power plant is required to meet future electric load. There are two alternatives:

Alternative A:	Alternative B:
Service life=20 years	Service life=20 years
Capacity=100 MW	Capacity=50 MW

- Approach 1: Assume Alternative B is comprised of two 50 MW units, rather than one.
- Approach 2: Assume Alternative B must obtain a 20 year contract to buy firm power from a neighboring generation owner over the life of the project.

Appendix

XXXX:

I used to work in PG&E's transmission planning department during 1980's and now I am a university professor at Iowa State University. I think transmission planning has changed significantly since I did it.

I am teaching a course this semester at ISU called "Economic systems for electric power planning."

The course is about optimization, basics of economics, nodal pricing, electricity markets, and planning. I am teaching the course with two other faculty, one is an economist.
There are about 35 students in the course. You can find the schedule of topics at http://www.ee.iastate.edu/~jdm/ee458/ee458schedule.htm.

In regards to planning, I will concentrate on transmission planning.

What overall topics would you think would be good for fresh undergraduate to see if they were preparing to come into your group there?

I realize you do not want to spend much time on a reply to this question, so just a 2-3 high-level bullets that come immediately to mind would be appreciated.

Thanks.

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Jim

Here are some points:

Transmission planning is part of an overall process to supply the customer load in the most cost effective manner. Transmission facilities provide the trade-off between resource that are closed to the load and those that are far away. Success in transmission planning is measured by the number of problems solved in the most cost-effective manner and not by the number, sizes and costs of transmission projects proposed.

Transmission planning is a process to make investment decisions, as compared to operations, which guard against the next worst contingency.

Transmission planning process anticipate future problems over a planning horizon by comparing simulations of system performances under various reasonable adverse system conditions with those required by the Planning Standards. A potential problem exists when simulated system performance do not meet the Applicable Standards. In North America, utilities adhere to the North America Electric Reliability Council (NERC) Planning Standards in addition to Regional Standards (e.g., WECC) and local Standards, as appropriate. Because planning standards determines future investments, they represent a trade-off between costs and risks. It is not always necessary to get rid of all transmission constraints - transmission reinforcements should be made where the benefits (enable the standards to be met or provide economic benefits) outweigh the cost. Some people may want to tag on environmental benefits such as enabling the transfer of renewable resources. However, such environmental benefits (reduce emission) must be off-set by the environment impacts of building more transmission lines, especially if they may be stranded because the resources either do not develop or developed in other locations.

Jim,

In taking a few minutes to read the information on the link you provided, it sounds like an interesting and timely course. I think it will hit upon a item which we struggle with continually - which is the identification of transmission projects which will be enough of a band-aid to grant an entity transmission service versus implementing a more strategic solution (usually more costly and time prohibitive to grant the original transmission service request). **A typical struggle is the decision to re-conductor a line versus building another line - which tends to make stability limits more prevalent.**

A couple of additional topics that immediately come to mind for your consideration for the limited time you will have:

Project prioritization with deterministic versus probabilistic planning techniques

Stability constraints caused by concentration of generation near fuel sources (gas lines) with inadequate transmission paths(including transient, small signal, voltage stability)

One more bullet item that I can't believe I forgot to include: the impact of load models on TP study results. As we are planning closer to the edge, our load model assumptions are critical - for both loadflow type analysis and stability analysis. A new graduate engineer with an appreciation of load modeling issues would have a huge "leg up" on the majority of new graduates.

Thanks - I appreciate the opportunity for the input.

I hope that helps

Jim,

Some topics you might want to include in your course:

- Optimal Power Flow (Introduction to power flow software i.e, PTI's PSS/E)
- Basic Transmission Equipment Ratings Calculations (Industry standards such as IEEE 738 and CIGRE 22.12)
- **Introduction to the role of Regional Transmission Operators (RTO's) such as MISO, NYISO, PJM and their respective interconnection processes, day-ahead markets, Installed Capacity (ICAP) Market, Transmission Congestion Charge (TCC), Transmission Service Charge (TSC).**
- Static and Dynamic Line Thermal Ratings (CAT-1 System and EPRI's Dynamic Thermal Conductor Rating Software)

I hope the above topics are helpful. Good luck.

Good evening Jim,

Glad to reply and give my opinion for content.

1) Overview of how Planning fits into the control of the Bulk Electric Power Grid.......things to discuss would be how there are 3 main aspects to the control operator's responsibility. The other two are Operations and Markets.

2) I would focus one session on how running generation plants is done and how the market signals that are given influence this day-to-day(or minute to minute) operation. I would stress in this the transmission facilities vital link in this for it to work.

3) I would discuss how Load flow, Short Circuit, & Dynamic analysis works, the measures for establishing if a plant and transmission facility is viable to be built and how a Generation interconnection process Queues are used, like we use, in these efforts.

Understanding of power flows (Stevenson, Gross, or similar). (AC vs. DC power flows - for the purpose of your discussion I would stik to DC flows.

Optimal Power Flow (OPF) vs. power flow (e.g., PowerWorld, PSS/E, PSLF)
Transmission Planning vs. System Operations (Emphasis on System Operations rather than planning - my background is planning but in the world where LMP is king, day to day operations rules the day. This is, of course, from a practical standpoint.

Good luck, and I hope this helps.

Jim,

The primary planning tasks we do are running PSSE contingency load flows for identifying system weak areas in terms of overload, low voltage, transmission congestions, ATC, TRM and CBM requirements. Flowgates limitations and management is another important aspect. **Load forecasts, capital budget planning, project cost/benefit anaylysis for ranking and justification purposes are daily routine works.** Voltage stability and angular stability are also important. From time to time short circuit fault analyses are performed for relay setting purposes.

Hope this will give you enough material for three classes.

Thanks and best,

Jim - Hi! I would break it down into the separate elements of what we are planning, as each has a different approach.

Resource Planning - ensure sufficient MWs are available to serve the load; 1day/10 year rule of thumb criteria; need for more capacity than you have load due to maintenance and forced outages; typical reserve margins are 12-18% depending on system configuration (need a higher amount if you have large generation plants remote from load vs a lower margin if you have highly dispersed small generation plants with few transmission constraints); uses spreadsheet analysis and LOLE programs.

Transmission Planning - ensure sufficient facilities to move power from where it is generated to where it is required to serve load reliably; bulk transmission (moves power long distances/between markets), area transmission (moves power from the bulk system down to specific load areas), sub-transmission (moves power from defined areas to specific load centers' distribution system); voltage level is a function of distance the power needs to be moved and the density of the load; deterministic

criteria driven (for the loss of any single element of the bulk system, no load will be shed); use powerflow programs.

Electric System Reliability Planning - ensure sufficient support systems so the facilities (generation and transmission) can be operated in a reliable and secure manner; determine protection schemes, special operating measures, back-up systems, etc.; use stability analysis, nose curves, etc.

I always like to insert (especially when economists are involved and there are discussions of markets) that you can have reliability as an output from markets when you are talking about resource planning, but transmission reliability is the platform that markets are built on.

Hope that helps and good luck,

[1] Manual of Engineering Economics, second edition, Pacific Gas and Electric Company, 1986.
[2] H. Stoll, "Least-Cost Electric Utility Planning," Wiley, 1989.