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AN ESSENTIAL INDUSTRY AT THE CROSSROADS:
DEREGULATION, RESTRUCTURING, AND A NEW MODEL FOR THE UNITED STATES' BULK POWER SYSTEM

by

Jeffrey Thomas Hein
B.S.E.E., Michigan Technological University, 1989

A thesis submitted to the
University of Colorado at Denver
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An Essential Industry at the Crossroads: Deregulation, Restructuring, and a New Model for the United States' Bulk Power System

Thesis directed by Professor Pankaj K. Sen

ABSTRACT

Today, the electric utility industry faces an uncertain future. Political, regional and intra-industry debates are delaying legislation and rules for industry operation - which are needed to ensure the viability of this essential industry and its service. This thesis proposes a new architecture, or model, for this industry. This new architecture will ensure all consumers throughout the United States, receive reliable and cost-effective electricity.

This thesis briefly reviews the history of the electric utility industry, from its competitive beginnings to its regulation as a natural monopoly and finally, to its evolution into the present day configuration of three interconnected transmission networks that cover North America.

The thesis also examines the effects on the industry of several compounding factors: the 1970s energy crisis, increased electricity costs, improved generation technologies, and the desire to deregulate the generation sector, previously a natural monopoly. Industry policy issues ranging from the Public Utility Regulatory Policies Act

(PURPA) up to the Federal Energy Regulatory Commission (FERC) Standard Market Design (SMD) White Paper are reviewed and summarized.

Finally, the problems associated with present-day restructuring efforts are summarized, and an architecture, or model, which resolves these problems and introduces benefits to industry restructuring, is proposed. The architecture of this new model, as proposed by this thesis, calls for the creation of a two-Independent Transmission Operator (ITO) model for the entire United States with national oversight by a newly established National Power Administration (NPA). Transmission is a national and interstate concern and should be treated accordingly. To optimize the cost-benefit operation of the nation's bulk power system, issues must be addressed by interconnection across the entire nation.

This abstract accurately represents the content of the candidate's thesis. I recommend its publication.

Signed Pankaj Kumar Sen

DEDICATION

To Heather, my incredible wife, whose infinite amounts of love, patience, understanding and support made this possible.

In addition, thanks to my loving parents, Jim and Barb, for instilling in me ethics of hard work and dedication.

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Many thanks to my advisor Dr. Pankaj Sen, whose vast knowledge, wonderful advice, tremendous demeanor, undying desire to improve power systems, and countless hours of effort, made this possible.

In addition, thanks to Western Area Power Administration and the many industry professionals I contacted during my research, of which there are too many to list.

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Chapter 1.0 - Introduction

The purpose of this thesis was to examine deregulation and restructuring efforts within the electric utility industry in the United States from a technical perspective. During the research process, it became clear that to fully understand this topic and make a contribution to our industry, it was necessary to widen the scope, in both time and perspective. Therefore, this thesis evolved into one that examines the past – the various reasons behind the desire to deregulate and the issues involved with deregulation and restructuring efforts – and the future, by proposing a new model for the national bulk power system. In addition, proposing a new model meant expanding the perspective from a technical one to one that included a myriad of economical and policy issues. By expanding the scope of this thesis, the goal is to bridge technical, economical and policy issues, in order to assist the transition to a viable, secure, cost-effective, and reliable industry, as it once was, for the future protection of the consumer and the nation.

This thesis reviews the history of the United States' electric utility industry and presents theoretical concepts for changing its present structure. The following paragraphs are intended to serve as both summary and road map to the content of this thesis.

First, in Chapter 2, this thesis briefly reviews the history of the electric utility industry. This chapter examines its competitive beginnings in 1879 to its evolution into three interconnected systems of the late 1960s that cover North America. Pioneers of the industry and their contribution(s) are reflected upon to give the reader a sense of the industry roots.

Next, in Chapter 3, this thesis examines the effects of several compounding factors and the resulting policies on the industry. This chapter reviews a “perfect storm” of factors that struck the industry in the early 1970s up to the Standard Market Design (SMD) White Paper issued in April 2003. Industry policies reviewed include the Public Utility Regulatory Policies Act of 1972 (PURPA), the Energy Policy Act of 1992 (EPAct), FERC Order Nos. 888, 889 and 2000 and the Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR). Since the SMD NOPR was issued jurisdictional and regional debates have raged.

In Chapter 4, the problems associated with present-day restructuring efforts are summarized, and an architecture, or model, which resolves these problems and introduces benefits to the industry is proposed. This thesis proposes a new architecture, or model, for the bulk power system portion of this industry. This new architecture will ensure that all consumers throughout the United States receive reliable and cost-effective electricity. The architecture of this new model consists of a two-Independent Transmission Operator (ITO) model for the entire United States with national oversight by a newly established National Power Administration (NPA), all federal government agencies The federal government would assume jurisdiction over most aspects of the bulk power system. Precedence for this was set in the early 1900s, when states assumed jurisdictional authority over electric utilities from local governments. Now is the time that jurisdiction over all transmission, and certain aspects of generation, be shifted to federal oversight (from states). Transmission and certain aspects of generation are interstate issues and need to be treated accordingly, with substantial state involvement. This is also a unique opportunity to streamline many industry processes, given the concurrent evolution of our industry. We can simplify and streamline our industry for the benefit of all and to meet the needs of the nation, while at the same time addressing the issue of declining numbers of personnel entering our industries’ work force.

Finally, Chapter 5 provides a brief summary and several parting thoughts.

Today, the electric utility industry faces an uncertain future. As a result of deregulation and restructuring efforts, political, regional and intra-industry debates are delaying legislation and rules regarding industry operation, which are needed to ensure the viability of this essential industry and its service. As this delay continues, load growth and societal demands continue to rise on an aging transmission and generation infrastructure, much of which is 30-50 years old.

Deregulation efforts were initiated to save consumers money and protect the environment, through improved generation technologies and their operation. It was once said, "the road to hell is paved with good intentions." Merely four years after wide-sweeping deregulation legislation was introduced in 1996, unchecked greed reappeared within our industry, after having been prevented for nearly 70 years under regulated operation. The story of California and the terrible fallout is known by all.

More recently, on August 14, 2003 , the largest blackout in United States' history occurred. During this blackout, 62,000 MW of load was lost, which impacted one-fifth of the nation's population, contributed to two deaths and resulted in revenue losses totaling nearly $1 billion in New York City alone. Early estimates to upgrade the transmission infrastructure are nearly $10 billion.

During recent times, a bulk power system whose reliability was taken for granted turned into a system that's susceptible to regional blackouts and brownouts with volatile price swings for service. In addition, what was once secure stock for both investor and utility has turned into a very questionable investment.

After reading this thesis, and processing the information contained within it, the question of deregulation that must be asked is, “Do the potential downfalls outweigh and out-cost the anticipated benefits?” Does deregulation apply to the electric utility industry? The electric utility industry is much more complicated and critical than other deregulated industries like telecommunications and airlines. The electric utility industry is the most capital-intensive industry on the planet, requiring years of lead time for adding infrastructure. This industry must operate in a proactive manner to ensure it can meet the needs of the nation during the periods of economic upswing and expansion.

Whether deregulation efforts continue or the industry is re-regulated, the new bulk power system model proposed within this thesis should be enacted to ensure the most reliable, cost-effective electricity continues to be available to its customers and our nation’s security, economy and way of life.

Chapter 2.0 - History of the United States' Electric Utility Industry

2.1 Origins & Early Developments (1879 – 1895) [8], [9], [37], [61], [64]

Electricity was a revolutionary, new technology back in the late 1800s very much like the Internet is a new technology of modern times. This section reviews its beginnings (Figure 2-1).

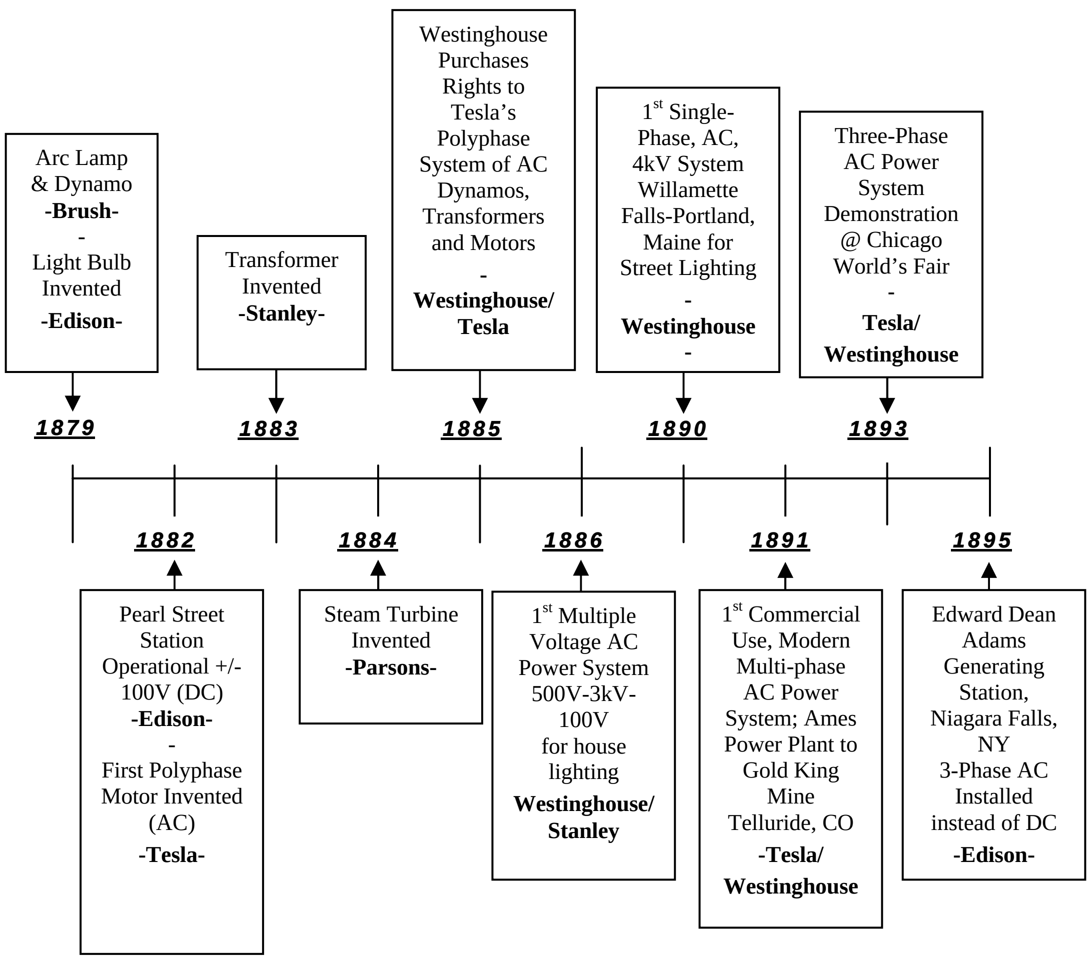


Figure 2-1 - Timeline: 1879 - 1895

2.1.1 Let There Be Light (at Night)

The roots of the modern day electric utility industry can be traced back to two events that occurred in the year 1879. The first occurred when Charles Brush (Figure 2-2) invented a dynamo and arc lamp lighting system for street lighting, which he put to use in Cleveland, Ohio. That same year Thomas Alva Edison (Figure 2-2) and his team of researchers invented the incandescent light bulb for home lighting, the predecessor of the light bulb in use today.

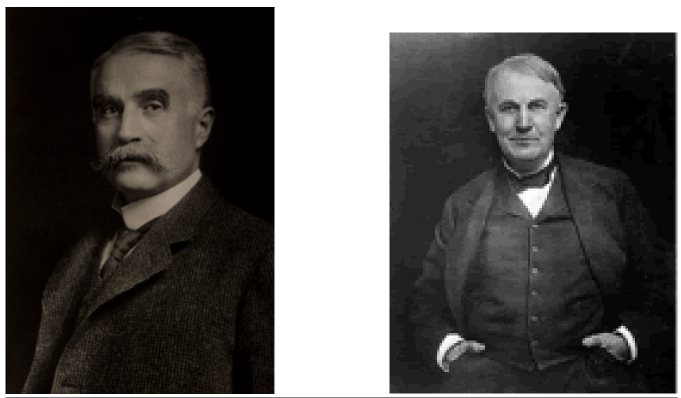


Figure 2-2 - Charles Brush (l) & Thomas Edison (r) [61], [64]

In New York City in 1882, Pearl Street Station was the first central electricity-generating station constructed to support the light bulb invention. Using a DC, +/-100-volt generation and distribution system (with neutral), Pearl Street Station used reciprocating steam engines to provide the mechanical energy required to create electricity. Lighting was the first application for electricity (Figure 2-3).

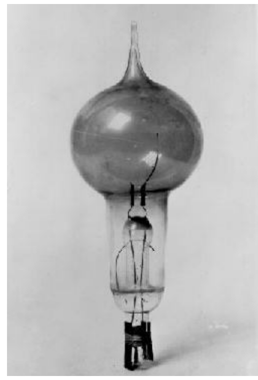


Figure 2-3 - The First Incandescent Electric Light Bulb [64]

In 1878 Edison created the Edison Electric Light Company, which evolved into the General Electric Company by 1892, of which Edison was a major stockholder.

The need for electricity would grow as appliances, such as irons and even electric streetcars, were introduced. While their predecessors used wood or coal, which was dirty, Edison and others were developing a market for cleaner electricity (Figure 2-4).

Figure 2-4 - Early Electric Fan (note wires in gas tubing "conduit") [37]

2.1.2 Development & Competition

Soon electricity was being hailed as a modern marvel that would revolutionize households and industry nationwide. Optimists envisioned increased demand for electricity and others sought entry into this growing market. Central generating stations and distribution systems (wires and poles) began sprouting up in many cities, after receiving approval from municipal governments. Competition between providers was commonplace. ***Initially, the United States' electric utility industry operated in a competitive, market-based environment.***

Because low voltage restricted distribution to about one mile from the generating station, many generating stations and distribution systems were built. In Chicago alone 45 electric utilities competed for customers. This industry design was repeated again and again within cities throughout the United States.

2.1.3 Competing Technologies [63]' [65]

During this same time period, another form of electricity - "alternating current (AC)" was being developed. The primary developers were Nikola Tesla, William Stanley, Jr., and George Westinghouse (Figure 2-5).

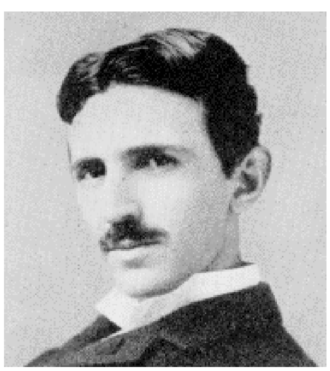
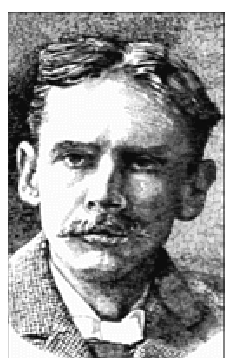
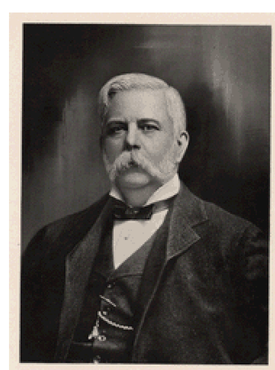




Figure 2-5 - Nikola Tesla (l), William Stanley, Jr. (c), & George Westinghouse (r) [65], [63] In 1883, Stanley invented the first modern-day transformer used in AC electrical. Tesla invented the AC polyphase motor in 1885 and married it with the transformer. The AC technology was more efficient because it could increase low-voltage generation to high-voltage for long distance transmission then back to low-voltage distribution for end use. While DC power systems had a head start and were more widely used than AC systems, AC power systems were still being developed and installed. Together with the finances of George Westinghouse, the AC electric system created a strong competitor to DC systems. Westinghouse Electric Company was founded in 1886. The first AC system, upon which today's is based, was built in 1891, to provide power from the Ames hydro-power station (Figure 2-6) to the Gold King Mine near Telluride, CO.

Figure 2-6 - Ames Power Station, near Telluride, CO (today)

These two technologies would eventually compete for control of the United States' electricity market. This head-to-head competition occurred during the development of the Niagara Falls' Edward Dean Adams power station (Figure 2-8). The Niagara Power Commission, wishing to deliver power to Buffalo nearly 23 miles away, awarded this contract to the Tesla/Westinghouse AC generators, based on their

Chicago World's Fair exhibit (Figure 2-7). This was a major defeat for Edison and the DC power systems he envisioned.

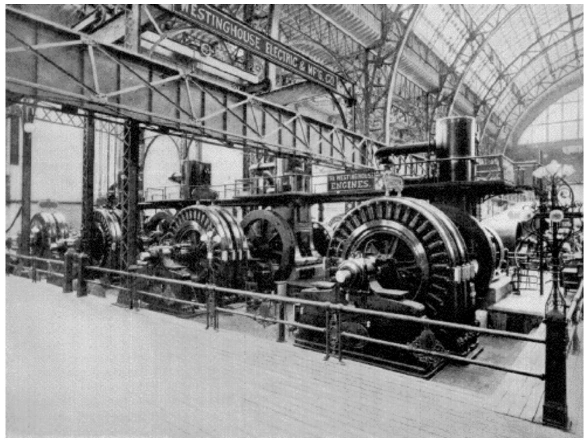


Figure 2-7 - AC Generators, Chicago World's Fair [37]

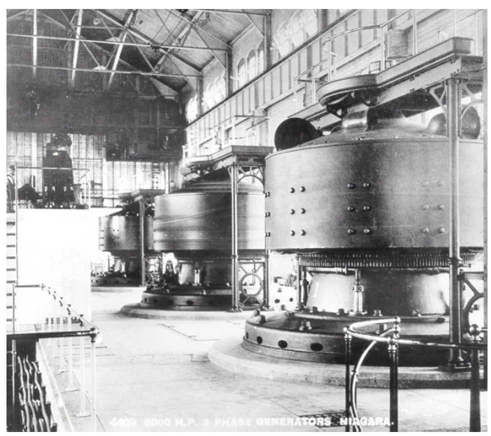


Figure 2-8 - Edward Dean Adams Power Station

2.2 The Electric Industry Evolves - Competition, Consolidation, State Regulation & Tremendous Growth (1896 – 1928) [8], [9], [10], [11]

The next major development in the electric utility industry occurred in 1903 with the introduction of turbine generators (Figure 2-9).

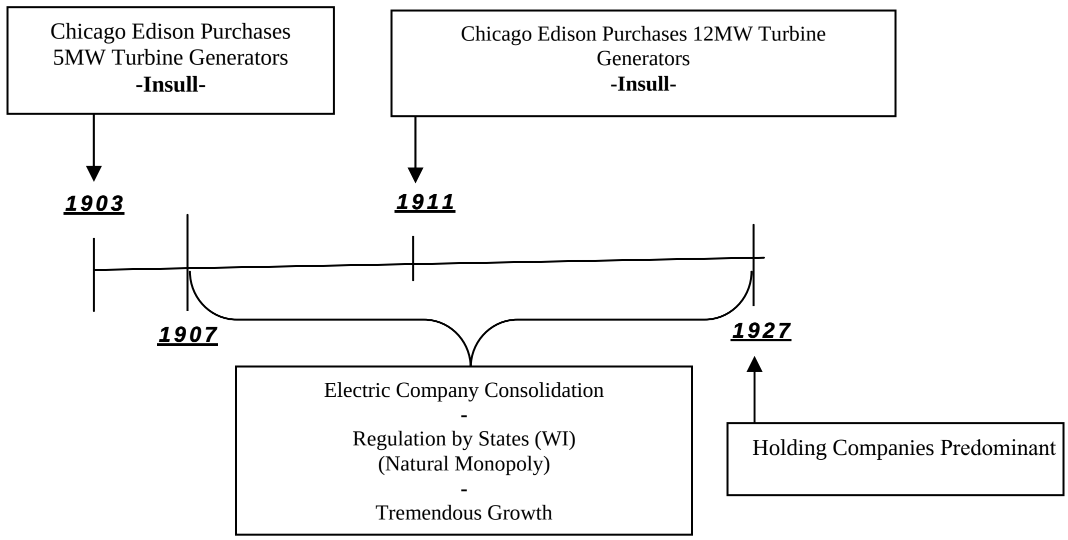


Figure 2-9 -Timeline: 1903-1927

Chicago Edison, under the guidance of President Samuel Insull (Figure 2-10), installed a turbine-generator set(s) that produced 5 MW of AC power at Fisk Street Station (Figure 2-11) in Chicago. A turbine-generator set was revolutionary because it used a new technology known as a steam turbine as the generator's prime mover. The rotating steam turbine, developed in England in 1884 by Charles Parsons (Figure 2-10) was far superior to its predecessor, the reciprocating steam engine.

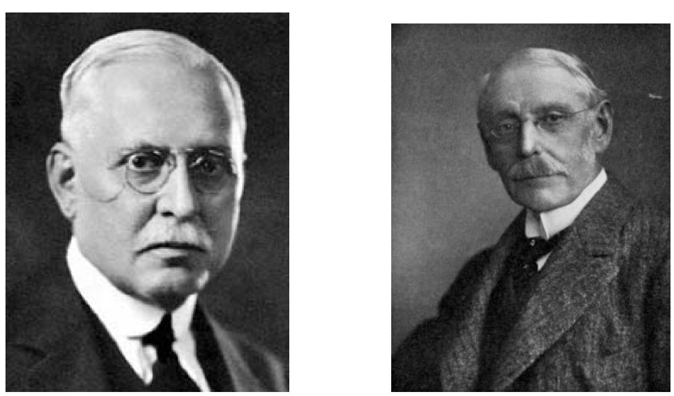


Figure 2-10 - Samuel Insull (l) & Charles Parsons (r) [36], [66]

<u>Figure 2-11 - Fisk Street Station, Commonwealth Edison Co., Chicago [37]</u>

The new steam turbine was much smaller in size, produced equal amounts of energy, and could be scaled up to produce more power for little additional capital cost. These new machines could now produce more electricity at a cheaper cost. Adjusted to 1992 terms, new AC technologies lowered electricity costs to $1.56 per kilowatt-hour (kWh) in 1912, compared with a rate of more than $4.00 per kWh in 1892.

The downfall of the widespread DC electricity system Edison envisioned was imminent.

<u>2.2.1 Consolidation, Regulation & Early Growth</u>

Insull realized that a competitive market environment would not result in enough profits to pay back investment costs. He began acquiring other utilities, eliminating competition and thus began consolidation. By 1907, Chicago Edison had acquired 20 other utility companies and changed its name to Commonwealth Edison.

Consolidation occurred in many other cities, with the local electric utility controlling the market – a natural monopoly.

Using the railroads as precedence, initially cities, then states created pubic utility commissions (PUC) to oversee electric companies to protect consumers. States assumed jurisdictional authority over electric utilities which was initially held by local government(s) [10]. Utilities were protected from competition and in return were obligated to serve all customers.

As a result, during the 1910s and 1920s, utilities saw tremendous growth (Figure 2-12) and were able to charge their expanding customer base for all services they provided. Utility generation and transmission expanded from 5.9 million kWh in 1907 to 75.4 million in 1927 while per unit costs of electricity declined 55 percent.

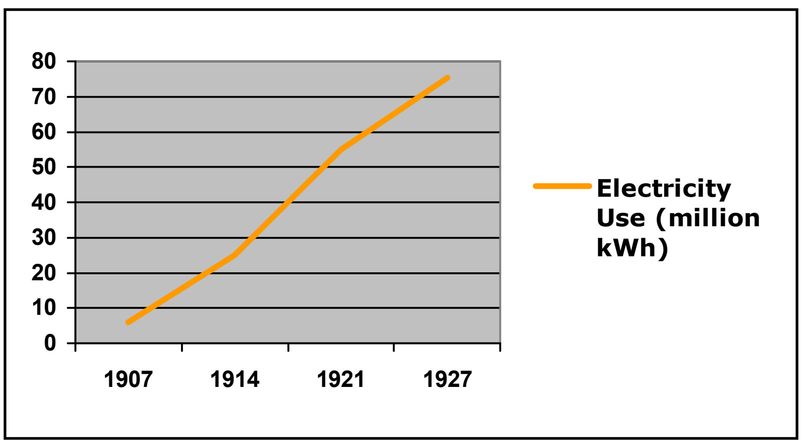


Figure 2-12 - Early Electricity Growth in the U.S.

2.3 Holding Companies: Benefits and Abuses, and Federal Intervention (1929 – 1936) [8], [9], [10], [11]

The next major series of events impacting the industry involved holding companies and the federal government to prevent industry abuses (Figure 2-13).

2.3.1 Holding Companies: Benefits and Abuses

Commonwealth Edison and other utilities soon began to form an operational structure known as a holding company. Holding companies acquired various utilities (electric and railway), known as operating companies. Organized into a pyramid scheme covering many states, holding companies acquired sub-holding companies and the corresponding operating companies. During this time, three holding companies controlled 45 percent of the entire U.S. electric utility industry.

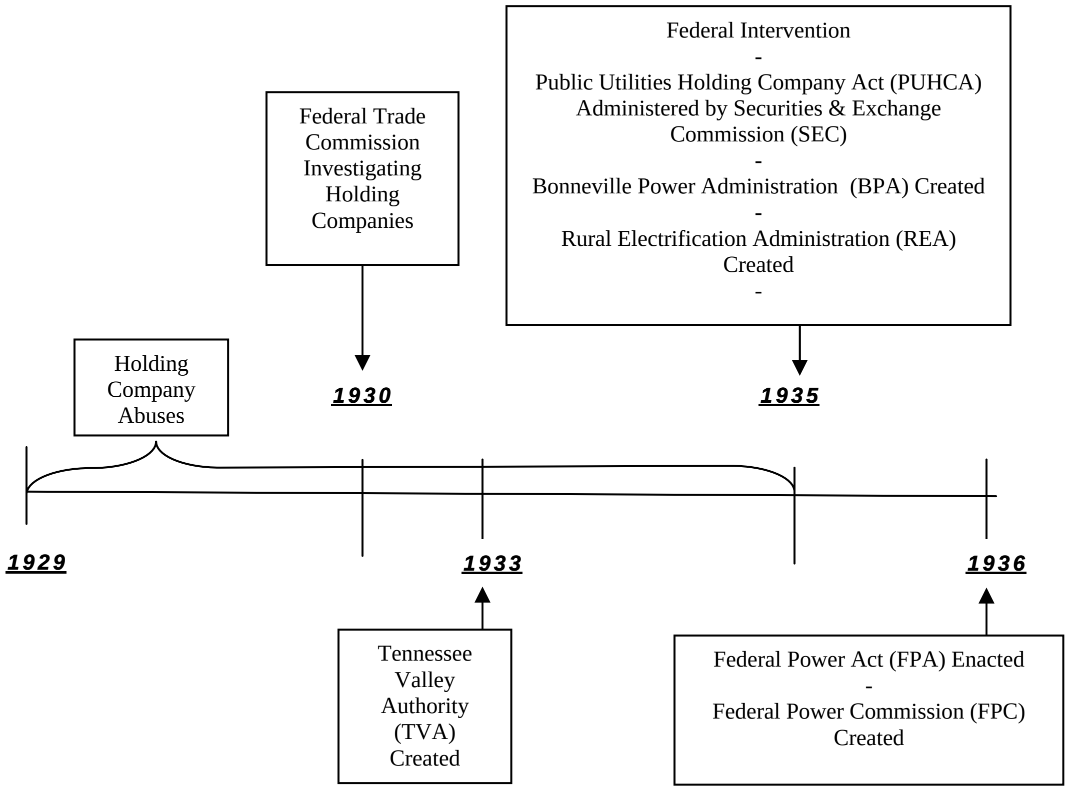


Figure 2-13 - Timeline: 1929-1936

The holding company structure offered many benefits. Operating companies used the holding company's centralized engineering, management, and purchasing services. In addition, holding companies increased reliability by interconnecting their operating companies. The electricity system grew quickly.

However, in the 1920s, holding companies began abusing this structure. The holding companies were essentially monopolies and began charging exorbitant service fees and overvaluing purchases, which were then added to the service rate.

The interstate operating structure allowed holding companies to evade state-based regulatory commissions because these issues were under the jurisdiction of the federal government, and there were no federal authorities providing industry oversight.

Public distrust of these holding companies came to a head when the stock market crashed in 1929. Many investors lost their investments in holding companies, whose weak organizational architecture was susceptible to complete collapse.

Franklin Roosevelt (Figure 2-14), campaigning for the presidency in 1932, promised to reform the corrupt electric utility industry and create government agencies to provide electricity to rural areas, long ignored by the electric utilities.

Figure 2-14 - Franklin D. Roosevelt [67]

2.3.2 Federal Intervention

Roosevelt was true to his campaign promises. With the approval of Congress, he created the Tennessee Valley Authority (Figure 2-15) in 1933 [59] and the Rural

Electrification Administration and the Bonneville Power Administration (Figure 2-15) in 1935 [60].

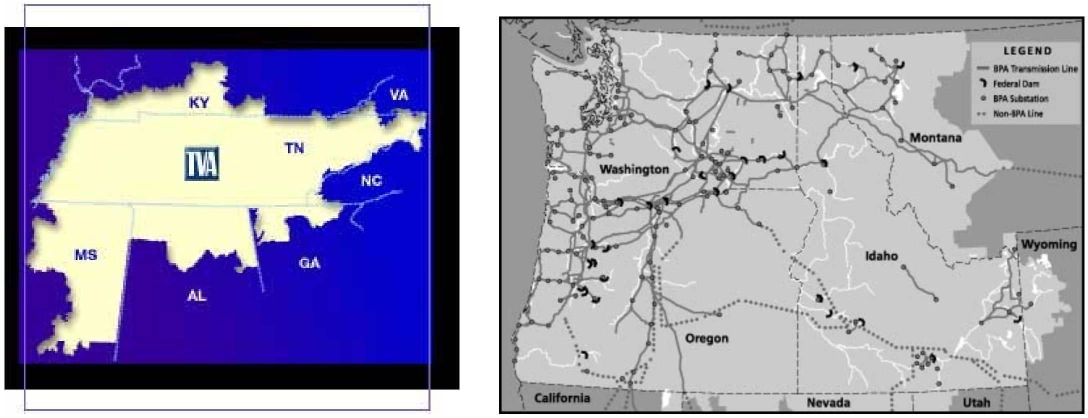


Figure 2-15 - Tennessee Valley Authority (l) & Bonneville Power Administration (r)

These government agencies proved that electricity could be generated and delivered cost effectively to remote, rural areas. As a result, the standard of living in these remote areas rose tremendously. *These rural loads proved to be the largest customer base in the country at the time and continue to be today.*

To prevent future similar abuses, Congress passed the Public Utility Holding Company Act of 1935 (PUHCA). PUHCA created effective state and federal regulations for regulating the holding companies.

2.3.3 Federal Power Act - 1935

Enacted by Congress in 1935, the Federal Power Act (FPA) increased the Federal Power Commission's (FPC) responsibilities to oversee and "regulate the transmission and sale of electric energy in interstate commerce." Originally, the FPC was established to oversee/regulate power projects on navigable waterways under the Federal Water Power Act.

2.3.4 Vertically Integrated Electric Utilities & Regulated Operations

The post-federal intervention era created the foundation for vertically integrated electric utility companies (VIU). Operating as natural monopolies primarily in or near urban areas, they were vertically integrated and responsible for providing generation, transmission and distribution of electricity to customers (Figure 2-16). To control the balance of energy supplied and used, each utility created a control area. Regulatory oversight was the responsibility of state PUCs for IOUs, and municipal leaders for municipal power agencies. To ensure customer abuses did not occur, service rates were under constant scrutiny through the Uniform System of Accounts method.

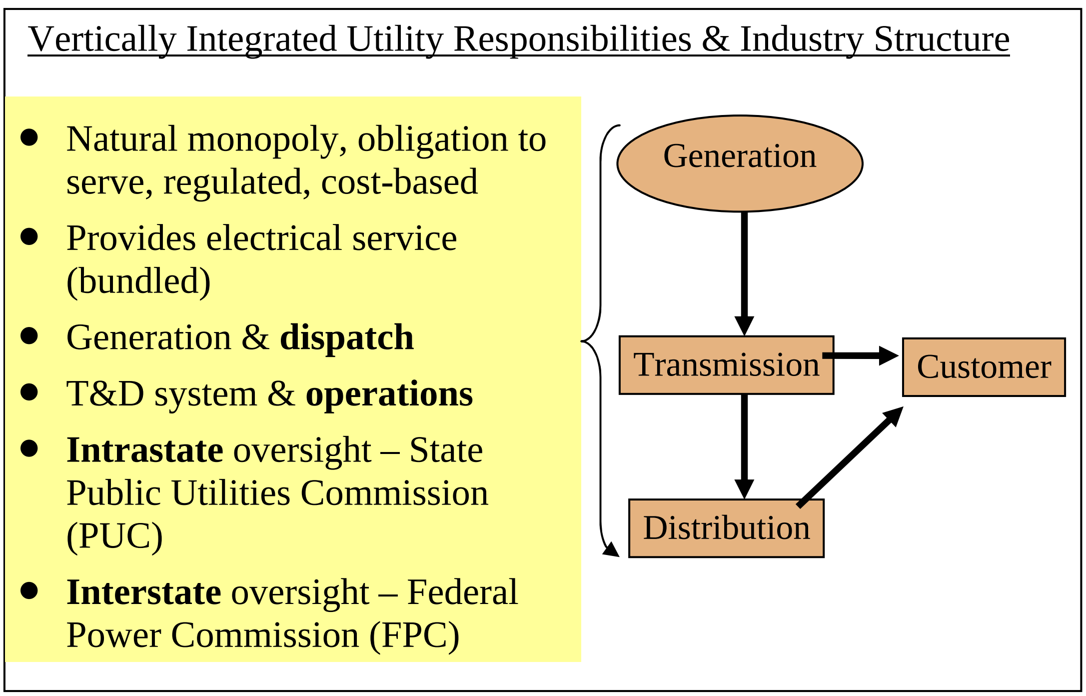


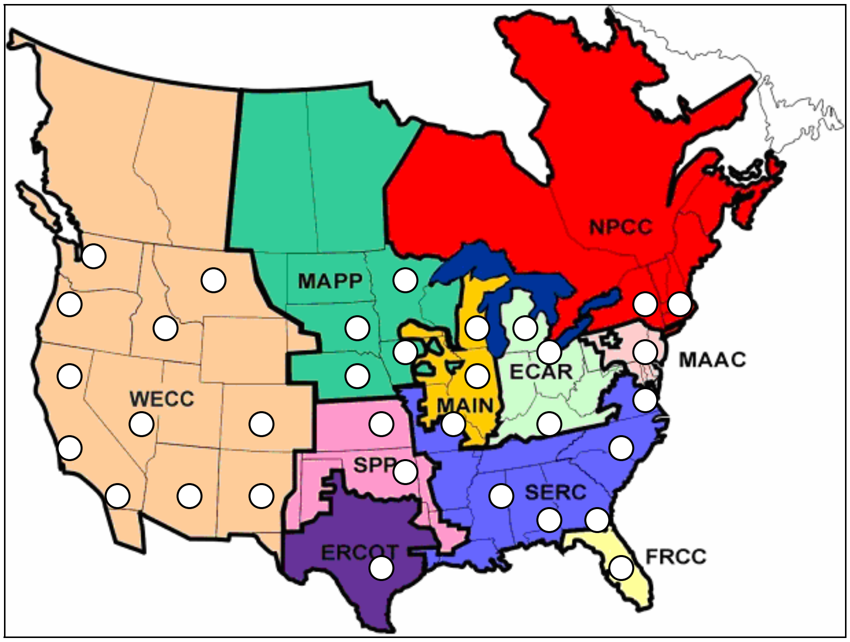
Figure 2-16 - Vertically Integrated Utility Organization & Industry Operations

Operating in a regulated, cost-based environment, utilities would plan and build infrastructure to meet the needs of the customers they were obligated to serve. The utility would recover its operating costs plus regulated profit (approximately 10 percent) through their approved service rates. Electric utilities were under state PUC oversight, in practice, due to their vertical integration structure and bundled services operation.

Therefore, as the demand for electricity grew, utilities could add to their system infrastructure with a guaranteed return on their investment. Utilities would add facilities and get paid for this investment from service rates paid by their customers.

The utility industry continued to grow and grow quickly. Utilities would construct generation close to their customers in urban areas to reduce system losses, which are very costly. The electric utilities were primarily under state PUC oversight and control since their activities remained predominantly intrastate. PUCs reviewed every aspect of utility operation, from siting to service requirements, through final rate development. Initially, each utility operated a control area for the cities they served. Control areas ensured system operation by matching electrical generation to load requirements and use. The beginnings of the industry consisted of discreet, smallish power grids scattered throughout the United States centered at major cities with connections to outlying areas.

There were regional interconnections in operation, namely the Pennsylvania-Jersey-Maryland interconnection, but no large-scale bulk power system interconnections (e.g., across Western United States) as we know them today (Figure 2-17).



○- Indicates Control Area

Figure 2-17 – Example of Early Control Areas Before Interconnections [20]

Early development of the electric utility industry occurred concurrently, without many interconnections (note the lack of lines between control areas when compared to figure 2-25). The landscape of the industry consisted primarily of each utility, typically located within a city, operating their own control area (Figure 2-17).

2.4 Technology Improvements and Regional Interconnection (1937 – 1964) [8]

From the 1930s through the 1960s the industry saw tremendous improvements in generation and transmission technology (Figure 2-18).

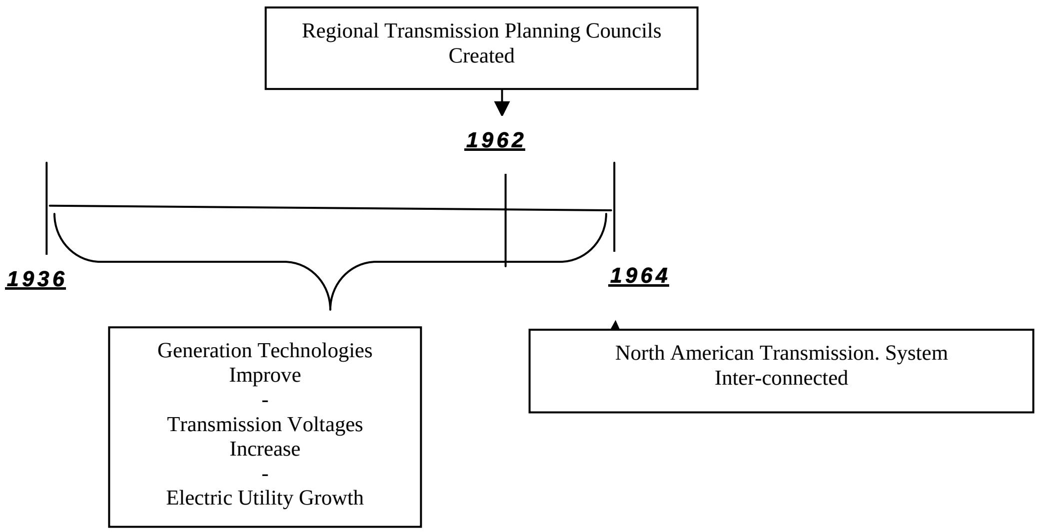


Figure 2-18 - Timeline: 1936-1964

Over a relatively short period of time however, improved efficiencies of scale in the generation sector were realized. With larger generators, electricity could be generated more efficiently and, therefore, cheaper (Figure 2-19).

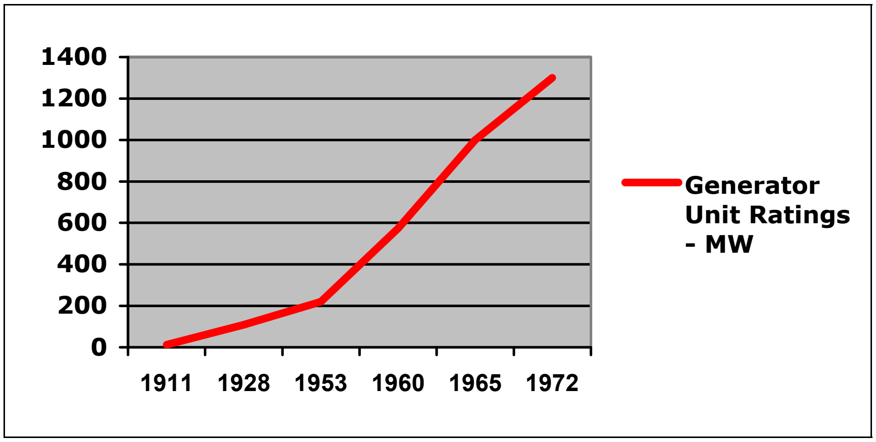


Figure 2-19 - Generator Unit MW Ratings, 1911 - 1972

At the same time, transmission voltages increased in order to reduce losses (Figure 2-20). Larger, central, state-of-the-art, generating stations located nearer their fuel supply, and connected to high voltage transmission lines, began replacing the smaller generating stations connected to lower voltage sub-transmission and distribution lines. This configuration resulted in the cheapest electricity possible while improving reliability and use of resources.

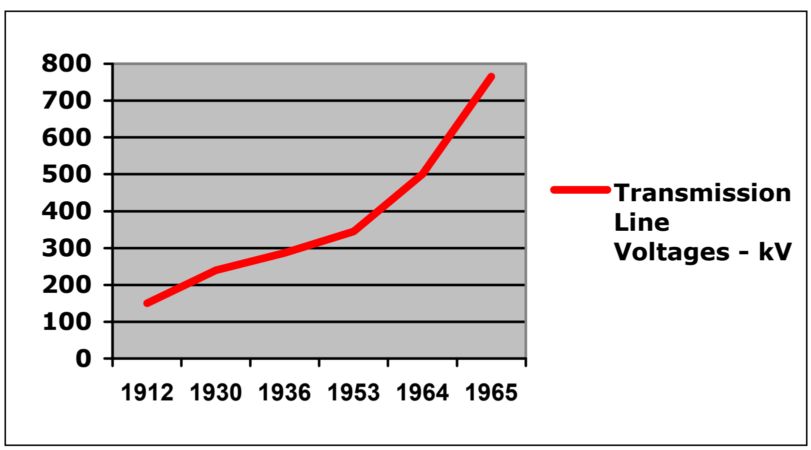


Figure 2-20 - Transmission Line Voltage Ratings, 1912 – 1965

From 1927 to 1967 electricity prices dropped from 55 cents to 9 cents per kWh, again in 1992 terms. As a result of this system, the United States' electric system evolved from many locally operated, geographically smaller grids, to one where interstate transmission lines interconnected many different utility systems. Each utility served its respective customers either with its own generation or through purchases with neighboring utilities called "wheeling" using "contract path" pricing. The individual utility control areas still played a very important role in scheduling electricity sales to neighboring utilities.

The Federal Power Act and individual state laws controlled how the utility industry operated through regulatory oversight, primarily at the state level, and to a lesser extent, the federal level. Reliability of the electric system was now both a regional and local control area concern because three interconnected power systems covered the entire US (Figure 2-21) and Canada.

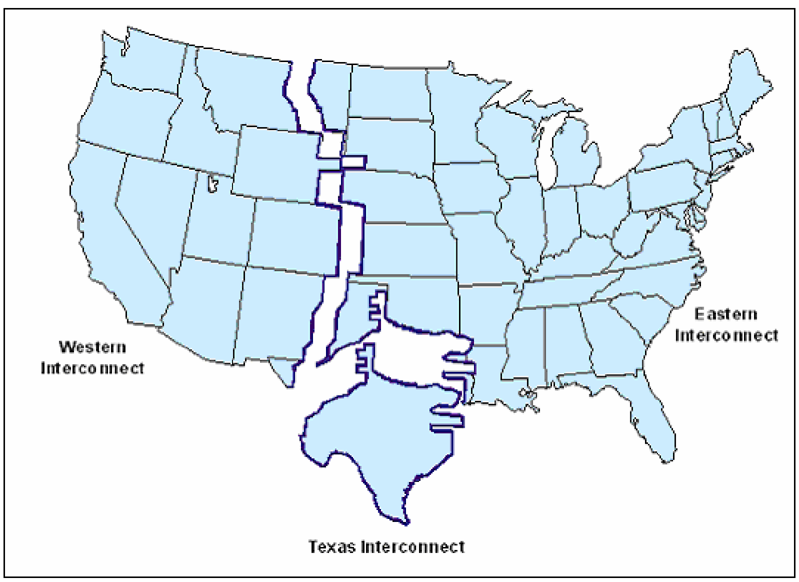


Figure 2-21 - US Interconnections [9]

2.5 Northeast Blackout and Regional Reliability (1965 – 1969) [8], [9], [10], [11]

As the bulk power system became more interconnected, benefits were realized, unforeseen problems arose, and means to correct these problems were developed (Figure 2-22).

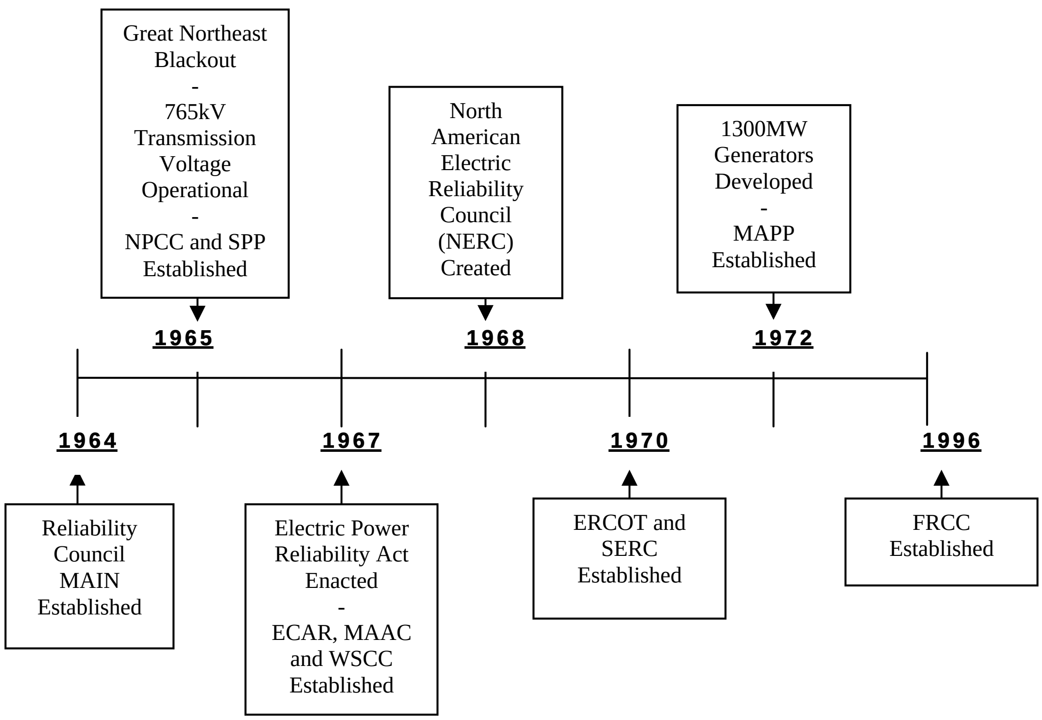


Figure 2-22 - Timeline: 1965- 1977

The great Northeast Blackout of 1965 uncovered a weakness in the United States' and Canada's interconnected electric grid. A disturbance in one section of a large interconnected grid could interrupt service across a wide geographical area. The blackout interrupted electric service over 80,000 square miles (eight states) in the

Northeastern US and large parts of Canada (Figure 2-23). This blackout started with a single 345kV transmission line relaying failure near Toronto, Canada.

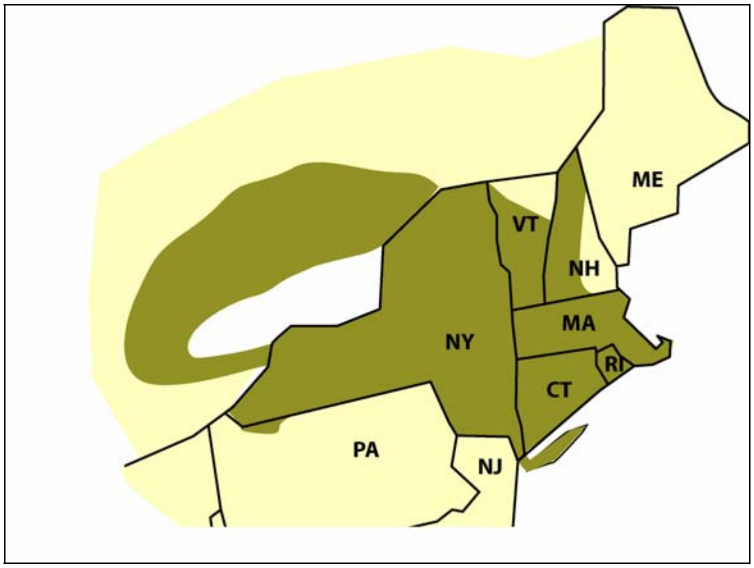


Figure 2-23 - Great Northeast Blackout of 1965

It was determined that a regional coordinating body should be created to ensure regional reliability over a large geographic area. The North American Electric Reliability Council (NERC) was formed on June 1, 1968, under the Electric Power Reliability Act of 1967.

Today, NERC is responsible for overall reliability, planning and coordination of electricity supply in North America. NERC is a non-profit agency comprised of 10 regional reliability councils, which represent smaller regions of North America (Figure 2-24). Each reliability council coordinates activities between the many control areas of the utilities it encompasses and their interconnections (Figure 2-25).

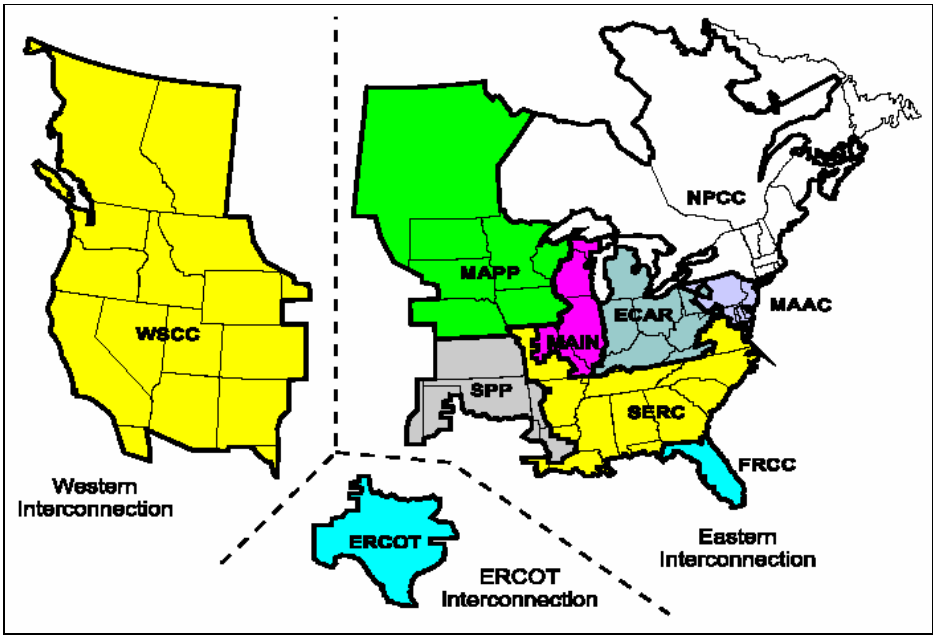
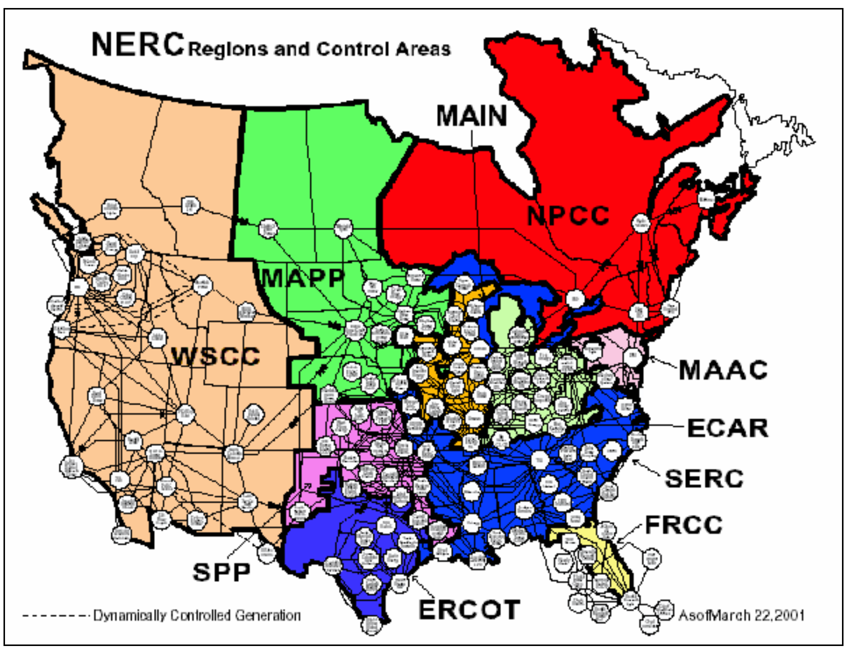


Figure 2-24 - NERC & Regional Reliability Councils [20]



****note: Each white circle indicates a control area operator*.**

Figure 2-25 - Electric Utility Control Areas of North America [20]

Through this model, North America's interconnected electric power system produced the cheapest, most reliable electricity in the world. This is essentially how utilities operated before conservation, deregulation, and restructuring legislation began to appear.

Chapter 3.0 - Winds of Change

3.1 General

The next chapter in the industry's history began in the late 1960s / early 1970s with growing environmental concerns, the energy crisis and energy conservation programs. This would prove to be the start of very difficult times for the industry. Electricity prices would rise, consumers would become disgruntled, and a desire of some to deregulate the generation sector (because of new generation technologies) would emerge (Figure 3-1). To address these issues, industry policies were enacted. This chapter reviews those policies and the reasons behind them.

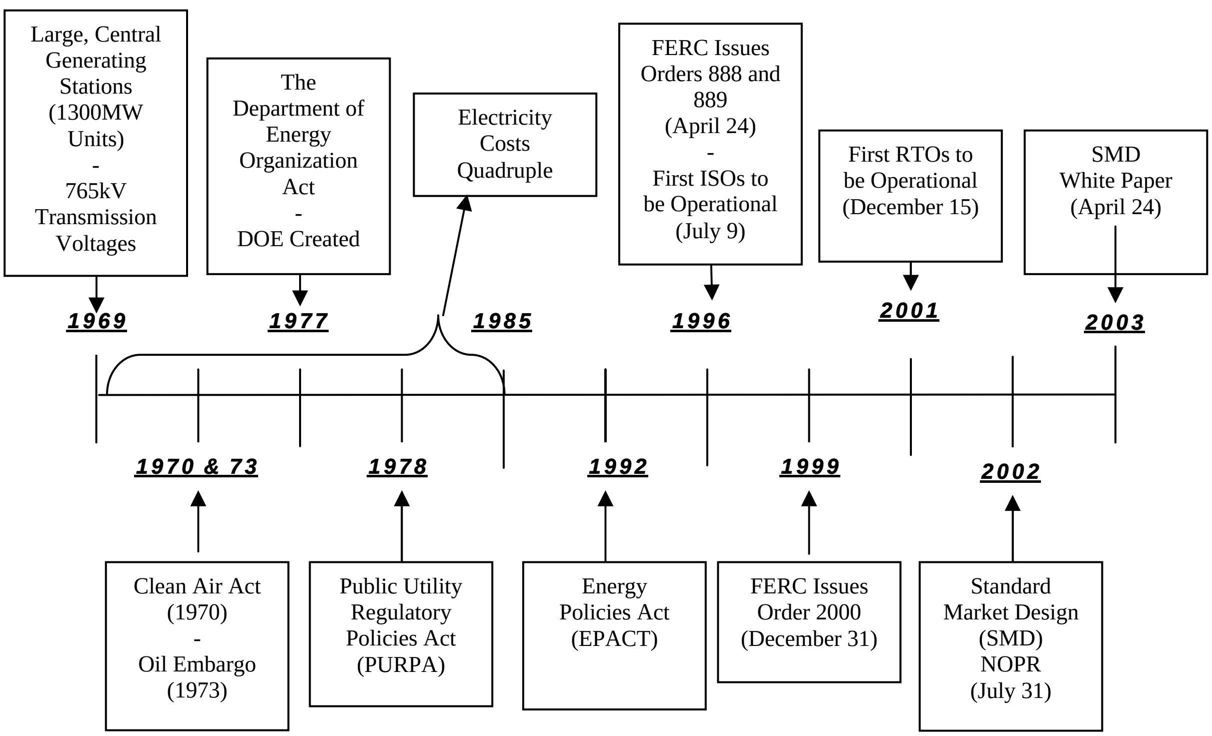


Figure 3-1 - Deregulation Timeline: 1969 – 2002

3.2 Environmental Issues, The Energy Crisis and Rising Electricity Prices [1], [8]

The 1970s were the start of difficult times for the electric utility industry. Prices of electricity would quadruple between 1970 and 1985. This was not due to poor management of utilities for they continued to operate with their customers' best interest in mind by employing techniques (large central stations and HV/EHV transmission) to continue delivering reliable, cheap electricity. It was due, instead, to a perfect storm of unforeseen, uncontrollable events that occurred at or near the same time. The perfect storm was comprised of environmental and conservation concerns, an energy crisis, a poor economy, inflation, occupational safety issues, and low load growth.

In 1970, environmental concerns resulted in passage of the Clean Air Act by Congress. This act forced substantial reductions in allowable emission levels (SO^2) from coal-fired power plants because of acid rain concerns. This was followed by the Water Pollution Control Act of 1972. Both acts substantially reduced the amount of electrical power the state-of-the-art, large, central generating stations could create, thereby reducing the amount of generation available to the interconnected power system.

The energy crisis of 1973, fueled by the OPEC oil embargo, raised electric generation fuel prices. This led to a mindset of conservation and energy efficiency. The Energy Supply & Environmental Coordination Act of 1974 (ESECA) required utilities to stop using natural gas or other petroleum based products to generate electricity. This, followed by the Resource Conservation & Recovery Act of 1976, amendments to the 1970 Clean Air Act issued in 1977, the Power plant & Industrial Fuel Use Act of 1978, and the National Energy Conservation Policy Act of 1978 all contributed to further reductions in generating capacity of the large power plants.   In response to the precarious national energy situation, several Federal agencies, including the DOE and the FERC were created by the Department of Energy Organization Act in 1977. FERC was given the jurisdictional authority previously assigned to the FPC.

This was also a difficult time for the US economy. Inflation grew and economic expansion slowed to a crawl or stopped altogether. The utility industry reflected minimal or no load growth.

However many state-of-the-art, large, central station power plants were under construction to supply the forecasted load growth. These power plants were primarily coal and nuclear which were very costly and took years to build. Not only did these plants cost more as a result of inflation, financing cost increases, safety concerns and regulatory requirements, but there was no need for them once completed due to the drastically reduced load growth. The result was excessive generation capacity reserve margins. These additional costs incurred by the utility were passed on to customers resulting in dramatic price increases (Figure 3-2). Average residential customers paid $2.2 per kWh in 1969, and $6.6 in 1985. Industrial customers paid $1.5 per kWh in 1970 and $6.0 in 1985.

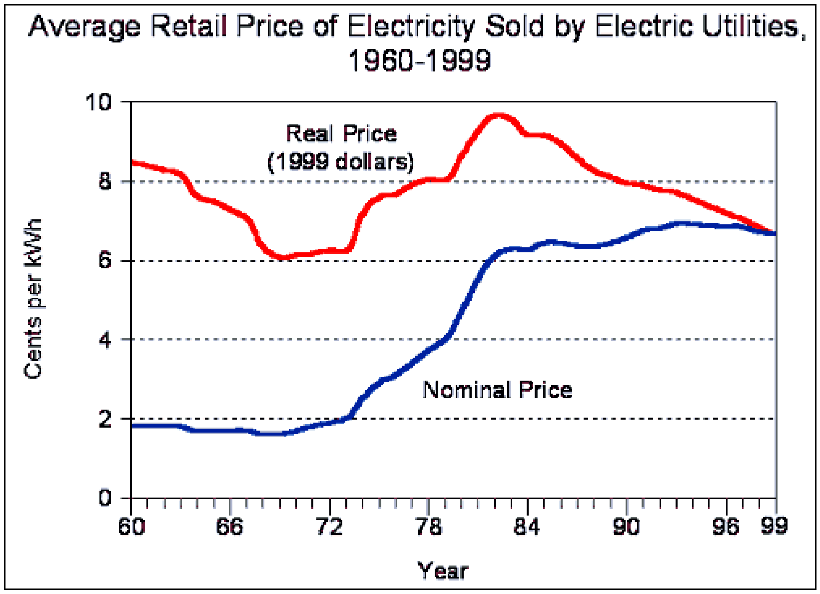


Figure 3-2 - Cost of Electricity Rises [18]

The utility managers were trying to operate their companies effectively, but given the unforeseen "perfect storm" factors, essentially a run of what was "bad luck", it appeared to the public that utilities were mismanaged. These generation stations' costs were added to the rate base. Ultimately, because it was a cost-based industry with obligation to serve requirements, the costs of these unnecessary generating stations were passed onto the public sector, a legitimate practice, causing electricity service rates to rise. Rising electricity costs and declining utility investment dividends coupled with difficult economic times caused public outcry.

In response, public actions were taken to explore ways to reduce the cost of electricity service.

New, alternative forms of generation technologies appeared in the late 1970s (combined cycle, gas powered turbines and fluidized bed combustion). These new technologies were more efficient, reliable, responsive, required less construction time, required less maintenance and “down-time”, and as a result required less capital than their larger predecessor. This new type of generation was more cost effective with less financial risk. In addition to the expense benefits, the new technologies were more environmentally friendly than their predecessors. The modern generating unit now had an optimal operating rating of 50-150MW as compared to its 500-1300MW predecessor. These newer units could now produce electricity for 3-5 cents per kWh whereas their larger predecessors could produce electricity for 4-7 cents per kWh in coal-fueled plants and 9-15 cents per kWh in nuclear-fueled plants.

Economies of scale no longer favored bigger generating units since they were no more efficient than their smaller competitors. Bigger was no longer better.

In order to develop these alternate forms of generating electricity, FERC needed to create legislation mandating industry reorganization and new operating characteristics that would allow a fair system to allow this new form of generation. This legislation was the Public Utility Regulatory Policies Act of 1978 (PURPA).

3.3 Public Utility Regulatory Policies Act of 1978 (PURPA) [1], [8], [9], [10], [11]

Public Utility Regulatory Policy Act’s provisions created a tremendous ripple effect throughout the electric utility industry that would impact it for many years to come and which continues today.

The intent of PURPA was to introduce more efficient, cheaper, and environmentally friendly generation to the power system. New generation technologies could produce electricity more cheaply than their large predecessors. Economies of scale favored these new technologies - bigger was no longer better. Reduced US dependency on foreign oil and more generation capacity was needed.

PURPA accomplished this through the introduction of FERC approved, non-utility generation called Qualifying Facilities (QF) or non-utility generators (NUG). Utilities were required to purchase this generation from the QFs. The additional capacity QFs supplied was relatively small due to limitations imposed upon them.

Other PURPA provisions included the addition of sections 210, 211 and 212 to the FPA, which gave FERC authority over QF interconnections and transmission wheeling.

Near-term results of PURPA legislation was cheaper and cleaner generation technology development, which was added to the power system via QFs and larger Independent Power Producers (IPPs). There were other more subtle effects – discussion of deregulating the generation sector.

At this time, the natural gas sector was also being deregulated under FERC's oversight. This led many to believe the same could be applied to the generation sector. Many believed the generation sector was no longer a natural monopoly since most companies could now afford to construct power plants using new generation technologies. Many believed replacing the regulated, cost-based sector with a deregulated, or competitive, market-based approach would result in cheaper electricity through improved business decisions combined with the cheaper generation technologies.

Not knowing the direction the industry would take; utilities began to reduce generation, transmission, distribution and employment costs. In addition, public resistance to new infrastructure being built was rising. Terms like "BANANA" – Build Absolutely Nothing Anywhere Near Anybody, "NIMBY" – Not In My

Backyard, and finally "NOPE" – Not On Planet Earth were commonplace and reflected public opinion. As a result generation and transmission reserve capacity began to decline.

Between 1978 and 1987, other industries in the US were deregulated. These other industries included the airline industry in 1978 and telecommunications (AT&T) in 1984. Further deregulation in the natural gas industry opened access to the pipelines and created a "spot market" in 1986 and 1987. It was believed deregulation would lower costs to consumers and increase supply and reliability

3.4 Energy Policies Act of 1992 (EPAct) [1], [8], [9], [10], [11]

The primary intent of the EPAct was to create open access to the transmission system for all generating companies, both utility and non-utility (QFs and IPPs - a.k.a. NUGs). There were instances reported to FERC of VIUs preventing QF and IPP generation being dispatched through manipulation of transmission system operations, both still under the control of VIUs and their control area operators. It was believed by FERC and Congress that without open access to the transmission system, the anticipated benefits of new generation technologies (cheaper and more environmentally friendly electricity) would not be realized.

Primary provisions of EPAct included FERC approval of Exempt Wholesale generators (EWGs) and added section 213 to the FPA. EWGs were allowed to sell electricity to the bulk power market, and section 213 extended FERC jurisdictional authority and oversight over transmission access issues. As a result of EPAct, transmission tariff structures improved and open access tariffs had to be filed (with FERC) before access to lucrative contracts would be granted by FERC. In 1992, for the first time, generation added by NUGs exceeded that added by traditional utilities.

The next series of figures shows the history of generation added to the electric utility industry. The first figure (Figure 3-3) shows total generation capacity added for both utility and non-utility generators.

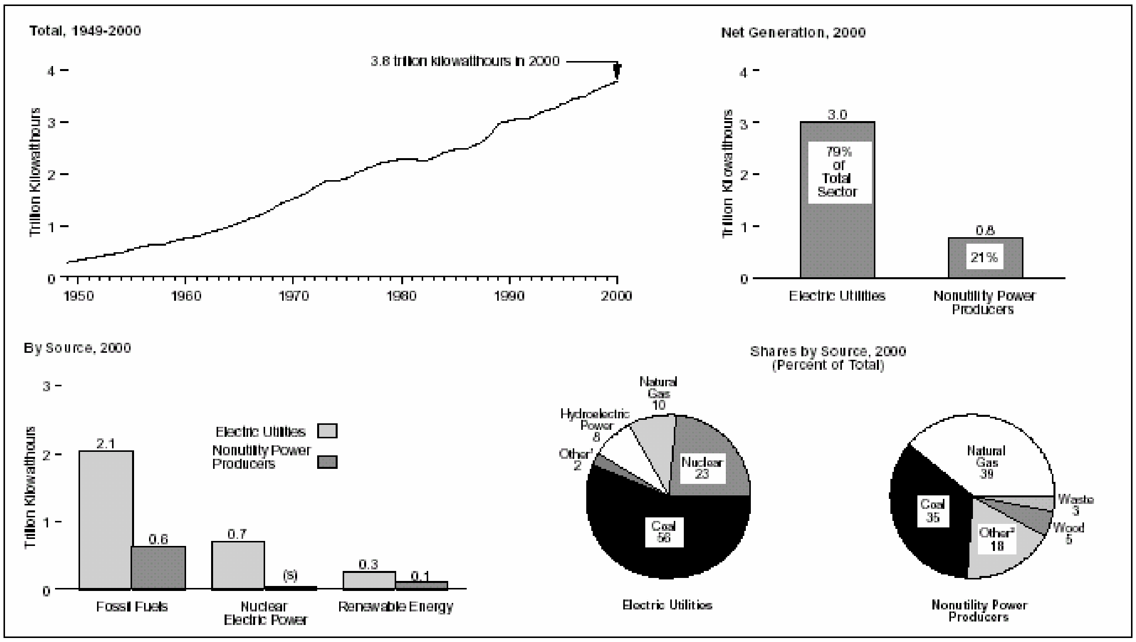


Figure 3-3 - Historical & Present Day Net Generation Statistics [18]

The next two figures separate the information shown in Figure 3-3 into typical electric utility companies and non-electric utility companies or NUGs. Generation capacity added to the US electric utility industry by typical electric utility companies (Figure 3-4) covers years 1949 through 2000 while capacity added by NUGs, (Figure 3-5) covers years 1989 through 2000.

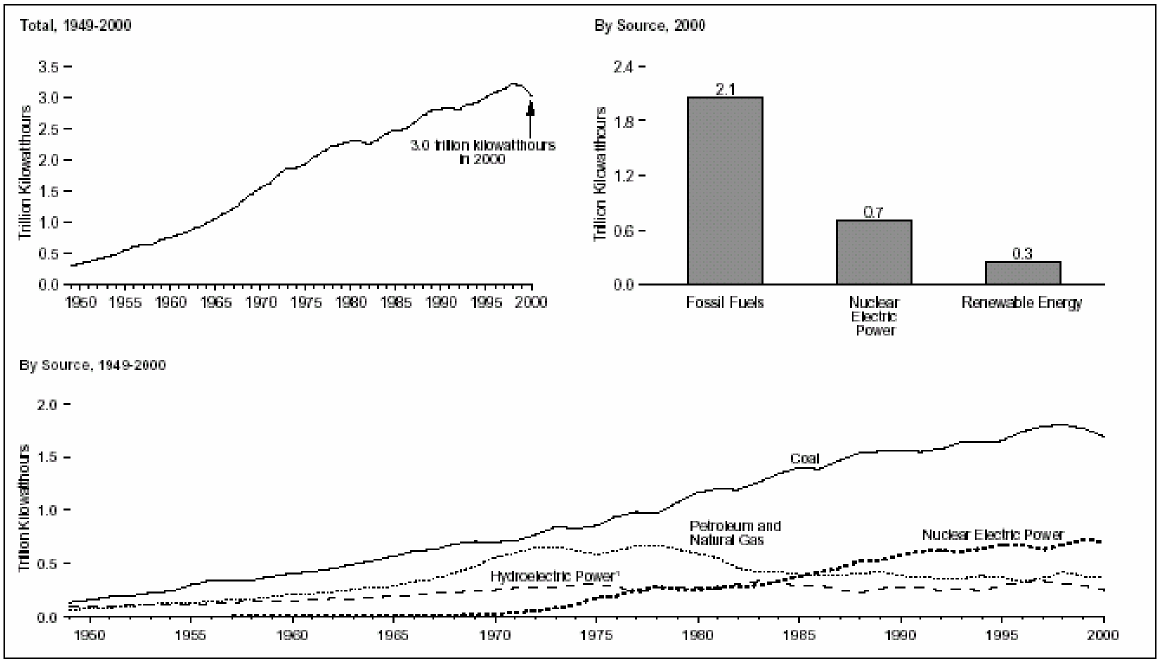


__Figure 3-4 - Electricity Generation by Electric Utility Sector [18]__

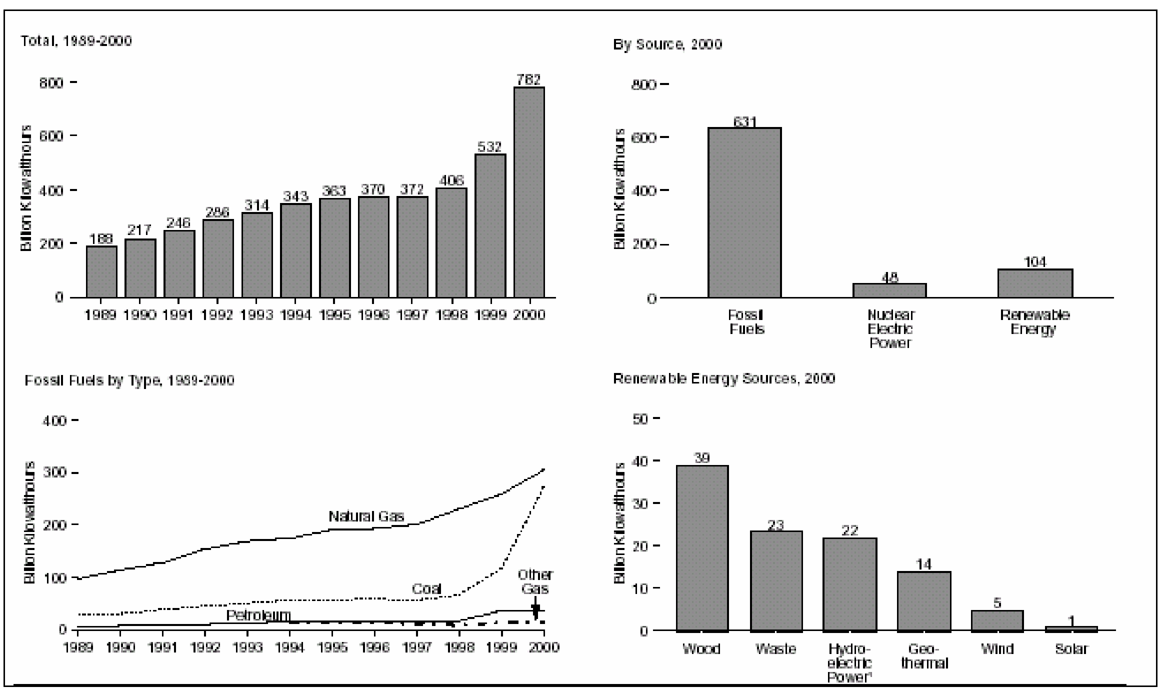


__Figure 3-5 - Electricity Generation by Non-Electric Utility Sector (NUGs) [18]__

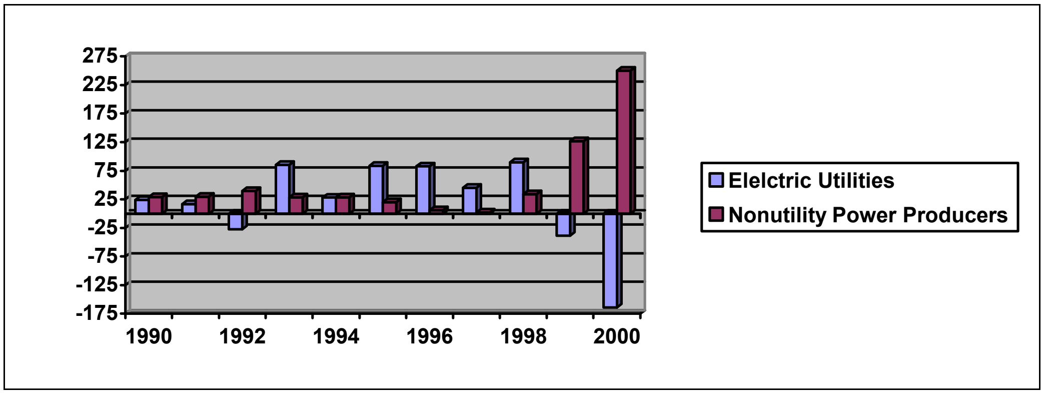


Figure 3-6 - Generation Additions Since 1990

After the EPAct and up through 1995, transmission system access discrimination by VIUs continued to be reported to FERC. The VIUs were able to prevent open access to transmission because they still dispatched generation and operated the transmission system. The VIUs would operate the transmission system and dispatch generation in a way that benefited the VIU generation over their non-utility (e.g. IPPs) competitors. In response FERC, acknowledging transmission was still a natural monopoly and should be treated as such, issued several policy statements. These policies did not achieve the goal of ensuring open access to transmission. IPPs continued to report instances of discrimination by VIUs. To promote generation sector competition and correct the open access issue once and for all, FERC issued Orders 888 and 889.

3.5 FERC Order No. 888 [1], [3], [9]

These two orders were issued concurrently and were the first attempt at wide-sweeping changes to promote deregulation of the generation sector. Order No. 888 addressed open access to transmission issues. Order No. 889 addressed the issue of access to transmission system information by all interested parties.

Why deregulate the US electric utility industry, the world's most reliable and cheapest system?

There were three primary reasons: [68]

1) to reduce the cost of electricity through new technologies and improved business decisions.

   Anticipated annual cost savings were estimated at:

   - $250.00 for each residential household (based on a typical family of four - $20,000,000.00 national total)
   - $100,000.00 for each industrial customer
   - Reduced electricity costs totaling $3.8 to $5.4 billion per year

2) to accelerate the introduction of new generation technologies; and

3) to provide regions (e.g. California and the Northeast) with expensive electricity access to cheaper electricity that existed in other US regions (e.g. Northwest and Midwest (Figure 3-7).

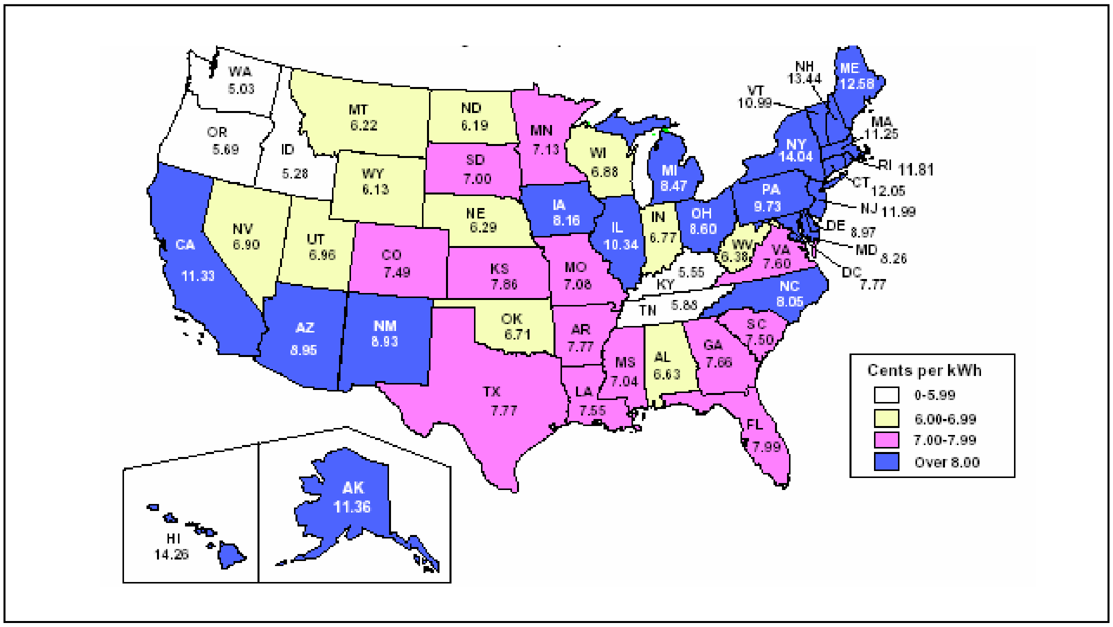


Figure 3-7 - Cost of Electricity, Residential Rates (cents per kWh) **[18]**

It’s important to note that FERC’s **deregulation efforts apply only to the generation sector** at the national level. Deregulation, would move the generation sector from a regulated industry to a competitive, market–based environment where utility and non-utility generating companies (GENCO) would compete for customers. Markets would dictate which would survive.

The industry needs **restructuring to ensure transmission system open access** for the competing generating companies. The transmission sector would remain regulated, and restructured to promote open access to all GENCOs.

Order 888’s primary objective was to promote generation sector competition and provide non-utility generators (EWGs, IPPs, QFs) and utility generators open access to the transmission system. The primary provisions to accomplish this were: 1) all jurisdictional utilities were required to file an open-access transmission tariff; 2) require IOUs to **functionally un-bundle wholesale generation from transmission services nationally**; reciprocity for non-jurisdictional utilities; recovery of generation-related stranded costs; and allow other areas of utility operations like ancillary services, comparable service, mergers, etc.

The industry would be restructured through the creation of entities termed Independent System Operators responsible for operating the transmission system, and requiring jurisdictional utilities to unbundle their generation and transmission functions (Figure 3-8). Functional unbundling would separate the ties VIUs had between generation and transmission thus removing discrimination, allowing open access to transmission and promoting generation sector competition.

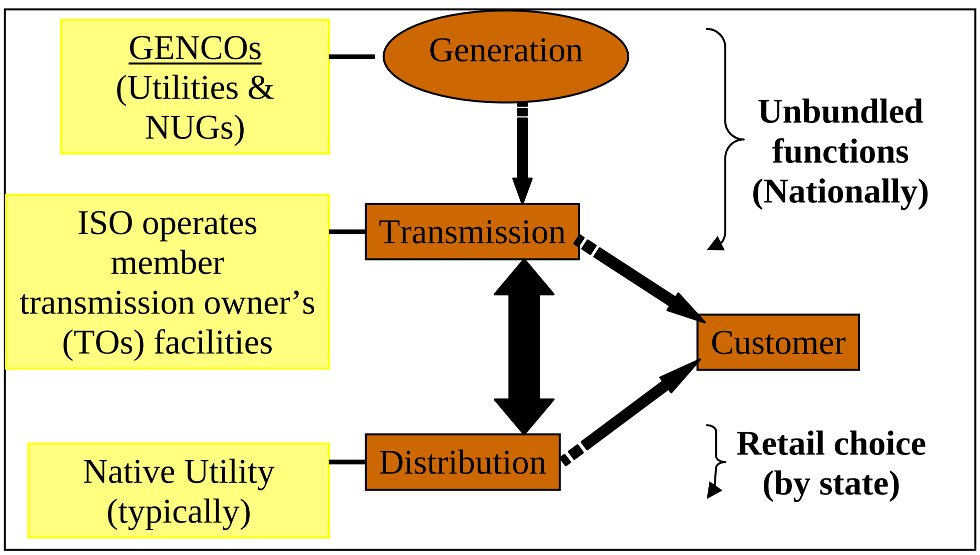


Figure 3-8 - Industry Restructuring – Unbundled Functions

Independent system operators (ISO) would be created (Figure 3-9). Order 888 outlined 11 ISO operational principles and guidelines. It made ISOs responsible for operating the transmission system, OASIS, generation dispatch (and queue) and the ISO control area power markets (generation and transmission).

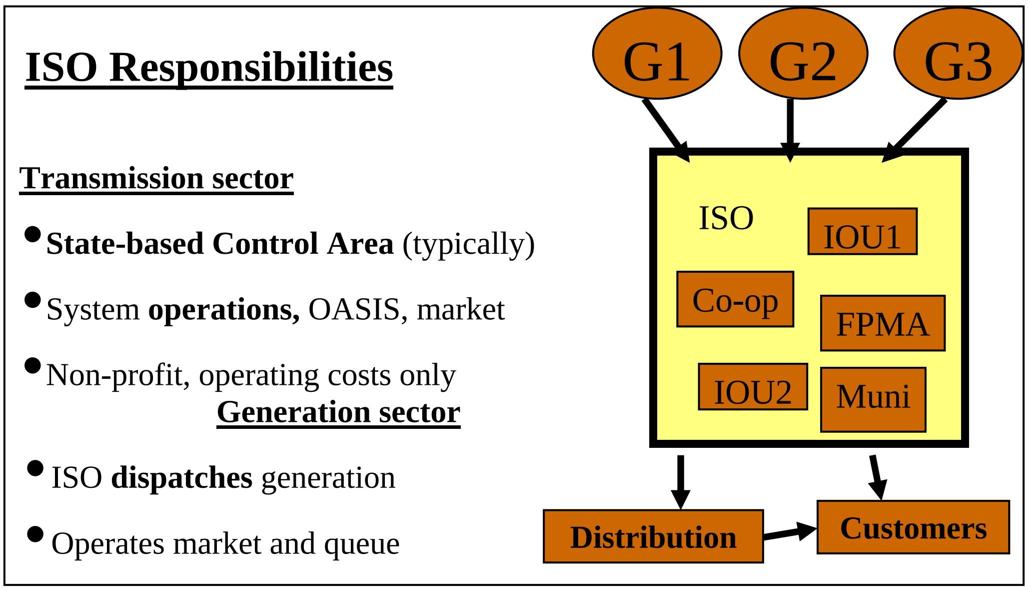


Figure 3-9 - ISO Responsibilities

3.5.1 ISO Operational Principles (& Responsibilities):

- The ISO's governance should be structured in a fair and non-discriminatory manner.

- An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

- An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

- An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

- An ISO should have control over the operation of interconnected transmission facilities within its region.

- An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

- The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.

- An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

- An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

- An ISO should develop mechanisms to coordinate with neighboring control areas.

- An ISO should establish a first instance dispute resolution process.

3.5.2 Provisions of Order No. 888

This section summarizes the provisions of Order No. 888.

3.5.2.1 Scope of the Rule

To achieve the goals of Order 888 the following were FERC's final rules as they pertain to the topics shown below.

- **Functional Unbundling.** Utilities that use their own transmission system for selling and purchasing electrical power must be separated from other activities like generation and distribution.

- **Market-Based Rates.** In order to sell electricity at market-based rates, whether from new or existing capacity, the seller must not have or must have mitigated market power in generation and transmission and not control other barriers to entry.

- **Merger Policy.** Mergers will be allowed if FERC determines them to be pro-competition.

- **Contract Reform.** Current contracts are not voided under this rule. Contracts may be modified but only after the approval of FERC.

3.5.2.2 Legal Authority

Under sections 205 and 206 of the Federal Power Act (FPA), FERC has the authority to oversee the restructuring of the United States' high-voltage transmission system.

3.5.2.3 Comparability

Any entity wanting to buy or sell electricity must provide the same level of service they would give themselves. This applies to transmission capacity used presently and that for future use.

3.5.2.4 Ancillary Services

The following six (6) ancillary services, required for proper operation and reliability of the grid, are required to be included in the transmission tariff. The transmission provider must offer these six ancillary services. The ancillary services are:

- Scheduling, System Control and Dispatch Service
- Reactive Supply, and Voltage Control from Generation Sources Service
- Regulation and Frequency Response Service
- Energy Imbalance Service
- Operating Reserves – Spinning Reserve Service
- Operating Reserves – Supplemental Reserve Service

3.5.2.5 Real-Time Information Networks

This item addresses the creation of an independent, objective, real-time transmission information system known as an "Open Access Same time Information System" (OASIS). The OASIS system will be discussed in more detail in the next section.

3.5.2.6 Coordination Arrangements

Each public utility must unbundle their existing, pre-Order 888 transmission rates and take service under their new tariffs created under the requirements of Order 888. By breaking up existing agreements, preferential transmission pricing and access will be eliminated creating "comparability" or equal access to the transmission system.

3.5.2.7 Pro-Forma Tariff

The goal was to initiate open access to the transmission system, owned and/or operated by others, through pricing mechanisms that force the owning and/or controlling utility to charge eligible customers the same they would charge themselves for its use (for both point-to-point transmission systems, network transmission systems and ancillary services).

3.5.2.8 Implementation

Deadline for submitting this open access tariff: July 9, 1996.

3.5.2.9 Federal and State Jurisdiction: Transmission/Local Distribution

FERC asserts it has jurisdictional authority over unbundled and wholesale (wheeling) transmission. Jurisdictional boundaries are set by seven tests for determining which facilities are transmission and those that are distribution.

3.5.2.10 Stranded Costs

Utilities were allowed to recover "stranded costs" in generation and transmission sectors associated with long-term contracts made under the regulated environment previous to deregulation efforts. One example of stranded cost recovery was in the form of an “exit fee” paid to the utility by the customer if they were changing providers.

3.6 FERC Order No. 889 [2], [3], [9]

Order No. 889 mandated the sharing of transmission system information, previously exclusive to VIUs, through the creation of an “Open Access Same-time Information System”, or OASIS. OASIS made this information transparent to all interested parties, which addressed the issue of insufficient sharing and knowledge of transmission system information, which was one way VIUs had discriminated against IPPs (as reported to FERC) in the past. Typical types of information included on OASIS sites are:

- Transmission Services: Available and Total Transfer Capacity, Available Service(s), etc.
- Ancillary Services Information
- Tariff Information

3.7 Post FERC Order Nos. 888 & 889 [3], [8], [9], [39], [40], [41], [44], [45], [51]

ISOs proposed after Orders 888 and 889 were typically organized by state boundaries or slightly larger areas (Figure 3-10).

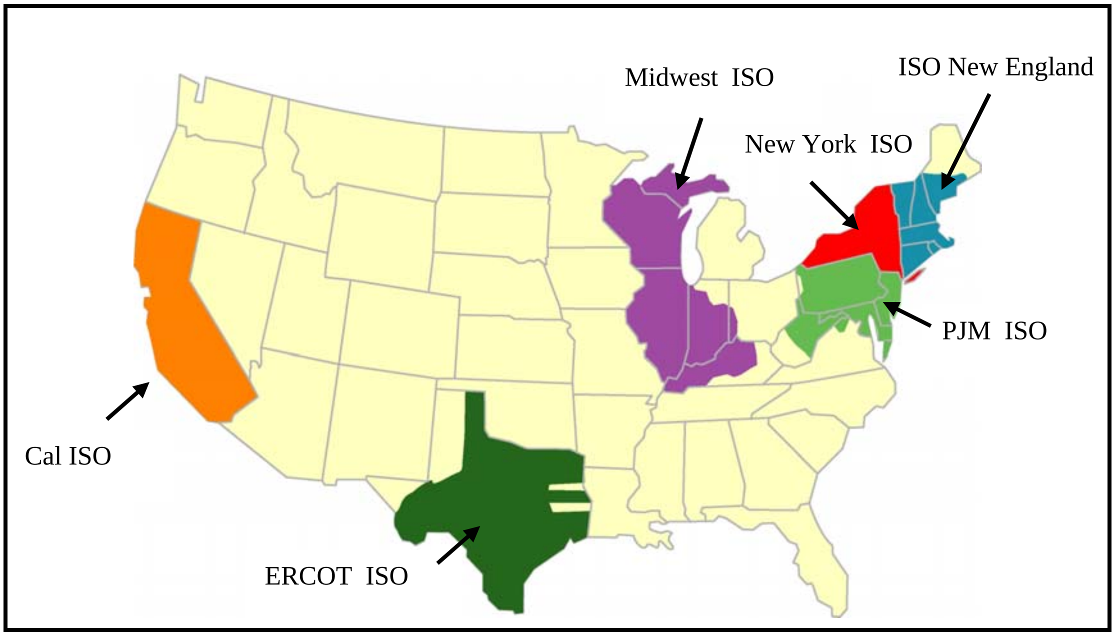


Figure 3-10 - ISOs Proposed

After operating under the provisions of Order 888 for several years, FERC determined that substantial barriers to functional deregulation continued to exist, specifically inadequate geographic scope, and would need to be corrected. As a means to that end, FERC issued Order No. 2000 on Dec. 20, 1999.

3.8 FERC Order No. 2000 [3], [4], [9]

Order 888 had two primary shortcomings: inefficient operation and expansion of the transmission system; and continued transmission system access discrimination. Order No. 2000, FERC's second attempt at wide-sweeping changes in how the electric utility industry operated, was issued primarily to address these two issues. Other benefits were anticipated, lower electricity prices plus a creation of lighter handed regulation.

FERC believed that transmission would be more effective and efficient (cheaper) if it were addressed on a regional, multi-state scale. This is important because electricity follows the laws of physics, not the boarders established by laws of man. All states within an interconnection are impacted by disturbances within it, as evidenced by the Western interconnection (WECC) disturbances in the summer of 1996. ISOs should be larger than just the state boundaries, FERC asserted. To that end, the Commission created Regional Transmission Organizations (RTO) intended to replace its ISO predecessor. FERC intended to have transmission as reliable now as it had been before deregulation.

Under FERC's plan, RTOs would operate the transmission facilities (above 69kV) of their member transmission owners (TO) that comprised an RTOs control area, but these organizations would be larger, appropriately-sized versions of their ISO predecessors (Figure 3-11). RTOs, through their guidelines, would end continued transmission system access discrimination.

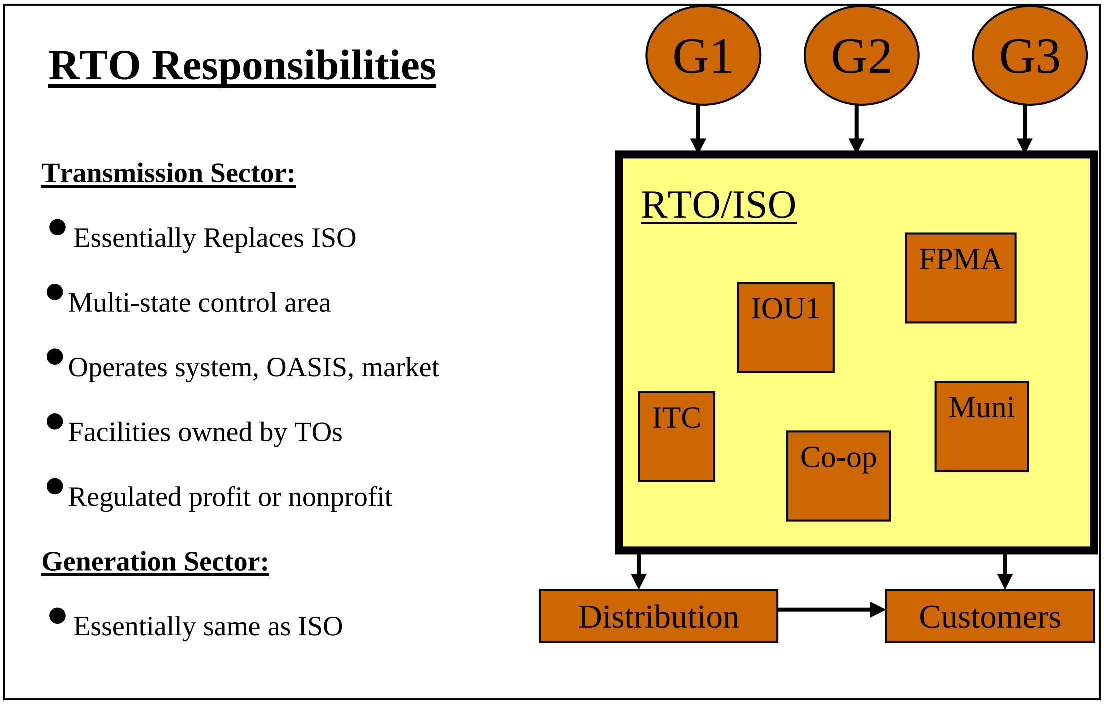


Figure 3-11 - RTOs Guidelines and Responsibilities

At or near this time, Independent Transmission Companies began to appear. An ITC is a collection of transmission owners combining to form one large transmission company (e.g. – TRANSLink). FERC specified that ITCs could participate as a member of an RTO or form their own. Therefore, an RTO could be a non-profit organization which was previously an ISO or it could be a regulated for profit Transco.

In order to be an approved RTO, certain guidelines (FERC approved) had to be met. These guidelines consisted of four characteristics and eight functions, discussed in greater detail (sections 2.8.1 and 2.8.2). The ISOs already in operation were required to prove they met these criteria to receive FERC approval as an RTO. There were differences between RTOs and ISOs. RTOs could be operated to earn a regulated profit for financing infrastructure expansion, whereas ISOs were non-profit organizations. Another significant difference was that RTOs typically encompassed a larger geographic area than their ISO predecessor. FERC encouraged a voluntary approach for transmission owners to hand over control of their facilities to an RTO of which they were a member.

Specific points addressed by the FERC Order 2000 were:

3.8.1 Approach to RTO Formation

FERC felt the following approach (to RTO creation) was best.

- **Voluntary Approach.** A voluntary approach should be used.
- **Organizational Form.** Proposed structures could vary from a non-profit ISO to a regulated profit Transco or a hybrid as long as the proposed RTO meets the minimum characteristics, functions and other requirements of Order No. 2000.
- **Degree of Specialty in the Rule.** These are flexible, non-specific guidelines and goals for proposed RTOs to follow and meet with a feeling of "teamwork".
- **Legal Authority.** FERC has the authority to oversee RTO formation in accordance with sections 205 and 206 of the Federal Power Act.

3.8.2 Minimum Characteristics of an RTO

FERC felt proposed RTOs should meet the following four minimum characteristics.

- **Independence.** The RTO must be independent of market participants.

- **Scope and Regional Configuration.** The RTO's region (control area) must be large enough, with regard to scope and regional configuration, to effectively perform its required functions.
- **Operational Authority.** The RTO will have complete authority for the operation of the transmission system it's controlling.
- **Short-Term Reliability.** The RTO will be responsible for and have the authority to maintain the short-term reliability of the transmission grid it controls.

3.8.3 Minimum Functions of an RTO

FERC felt proposed RTOs should meet the following four minimum functions.

- **Tariff Administration and Design.** Tariff administration and design shall be the exclusive responsibility of the RTO.
- Congestion Management. Congestion management policies shall be the exclusive responsibility of the RTO.
- **Parallel Path Flow.** Concerns and problems arising from parallel path flows shall be addressed within a three (3) year period of the start-up date.
- **Ancillary Services.** Ancillary services, as defined by Order No. 888, shall be provided by the RTO on a competitive basis where possible.
- **OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC).** The RTO shall have one OASIS node and shall be responsible for all information placed on it.
- **Market Monitoring.** The RTO is responsible to provide an objective market monitoring plan to prevent and/or mitigate market power.
- **Planning and Expansion.** The RTO must develop a system planning and expansion plan.

- **Interregional Coordination.** Each RTO is to ensure the integration of reliability practices within an interconnection and market interface between regions.

3.8.4 Open Architecture

An open architecture style of organization (structure, regional scope, market and operations) will be allowed and give the proper flexibility to evolve with the needs of the electricity market it operates within.

3.8.5 Transmission Rate Making Policy

Each RTO should develop rates taking into consideration the following:

- Pancaked rates should be eliminated (reduce electricity costs).
- Reciprocal waiving of access charges between RTOs.
- Uniform access charges for all RTOs.
- Congestion pricing mechanism development to properly address associated costs.
- Service to transmission-owning utilities not participating in an RTO will have a separate and different tariff.
- Performance-Based Rate Regulation (PBR) containing financial incentives.
- Incentive-based transmission service rates which are unique and innovative.

3.8.6 Other Issues

The following issues were addressed:

- Public power entities are encouraged to place their transmission facilities under RTO control for an effective transmission system.

- Canadian and Mexican entities' participation are encouraged.
- Existing contracts won't be automatically dissolved by FERC, but will be addressed by RTO.
- RTOs will determine a need for power exchanges.
- Effect on states with low-cost generation will be to lower to cost in the long run.
- No specific states roles were stated, but generation siting is one example of states' roles.
- Uniform System of Accounts will continue to be used, modifications to it are encouraged.
- Bid-based markets are expected to be central to RTO formation. Markets shall address multiple products (supply and demand), feasibility, real-time balancing, market participation, demand-side bidding, market information and monitoring and several others.

3.8.7 Collaborative Process

A regional, voluntary, collaborative process should be used to create RTOs involving all interested parties.

3.8.8 Deadline for RTO Operation

RTO Startup – December 15, 2001

3.9 Post FERC Order NO. 2000 [5], [14], [19], [17], [39-54]

RTOs proposed after Order 2000 were typically geographically larger than their ISO predecessors, but were still not as large as FERC believed necessary to be truly effective. FERC envisioned five RTOs for the entire U.S. transmission system –

Northeast, Southeast, Midwest, Texas and the entire Western Interconnection (Figure 3-12).

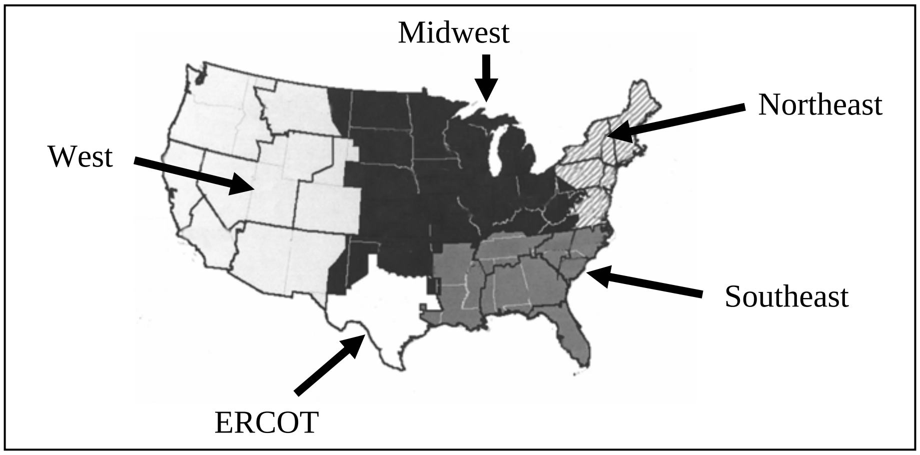


Figure 3-12 - FERC's RTO Vision [14]

This did not occur. Instead thirteen separate, non-continuous RTOs were initially proposed, each with its own unique transmission and wholesale market rules (Figure 3-13).

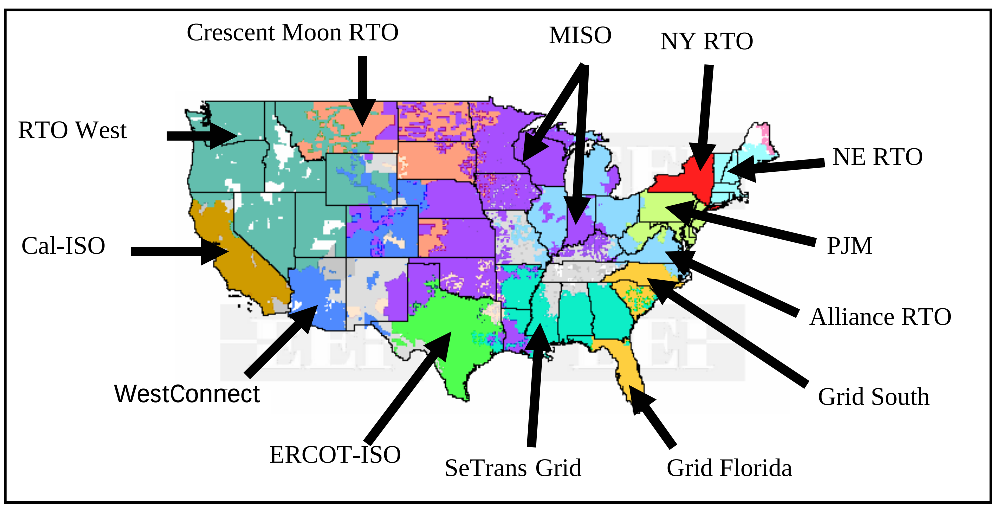


Figure 3-13 - Actual Proposed RTOs [70]

FERC did not approve several of these RTOs and requested they combine with a neighboring RTO. The number of proposed RTOs decreased to nine, but each still retained its own operating rules.

As a result of this patchwork landscape, a problem arose at the boundaries of neighboring RTOs referred to as “seams issues”. Due to their different operating rules, seams are problems related to resolving schedules and payments for electrical service when coordinating power flows between RTOs. As reported to FERC, seams issues allowed continued open access discrimination (to transmission) and impediments to wholesale power competition. Inadequate geographical scope of RTOs continued to plaque restructuring and deregulation efforts by allowing discrimination to continue. To correct this, FERC issued the Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR) on July 31, 2002.

3.10 Standard Market Design (SMD) Notice Of Proposed Rulemaking (NOPR)

In general, and a continuing theme, the goal of FERC by issuing SMD was to build on Order 888 and create a transmission sector that operates in a fashion that ensures the anticipated benefits of a competitive wholesale electricity market (generation sector) is delivered to all consumers.

To that end, the primary goal of SMD was to eliminate seams issues by standardizing the way generation and transmission markets would work for all RTOs. This design would also create an effectively larger geographic region, which FERC also preferred. It was believed SMD would also better mitigate market power, promote transmission planning and expansion, lower the cost of electricity and create a framework for cooperative state and federal regulation.

To accomplish this goal, major provisions of SMD called for the introduction of independent transmission providers to replace RTOs. ITPs would retain many RTO responsibilities, plus others, to accomplish the primary goal of SMD (Figure 3-14). This ITP entity would be responsible for ensuring the transmission grid viability to meet the nation's needs (Figure 3-14). Therefore RTOs and ISOs could apply to be approved as an Independent Transmission Provider (ITP).

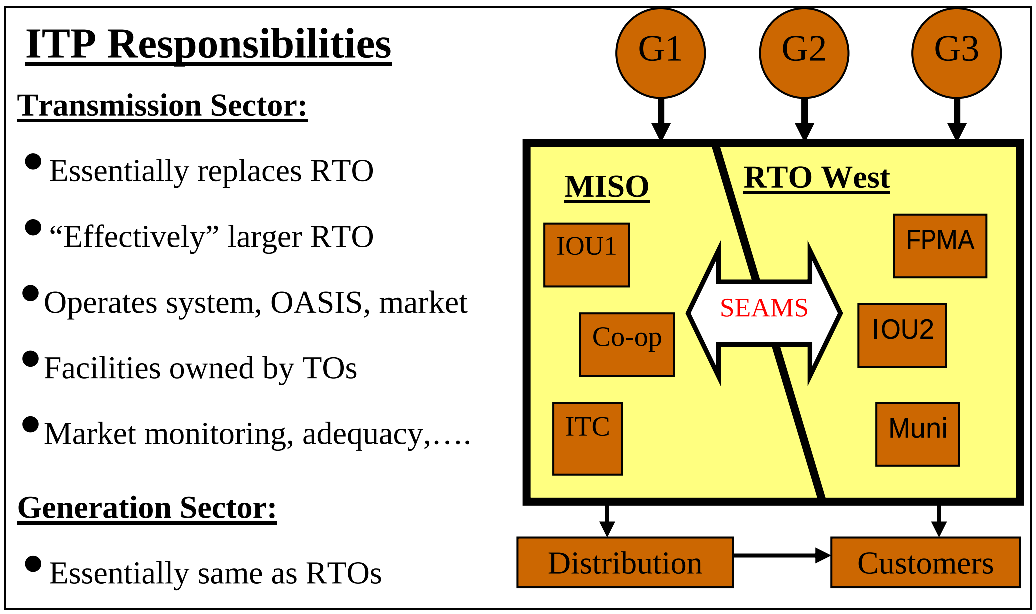


Figure 3-14 - SMD & Seams Issues

Under the SMD proposal, jurisdictional utilities had to file new transmission tariffs. Non-jurisdictional utilities would follow reciprocity guidelines established under Order No. 888. Locational marginal pricing and congestion revenue rights were introduced as new transmission pricing policies to address the transmission congestion issue. FERC asserted it had jurisdictional authority over bundled transmission, market power and, if required, mitigate market power abuses. Finally, FERC proposed to develop resource adequacy guidelines and a regional planning process to sustain a viable electrical power system.

3.10.1 Summary of SMD Primary Provisions [4], [5], [19], [69]

- Creation of an independent transmission entity termed "Independent Transmission Provider" (ITP) to replace RTOs, and assign to it the tasks required for design, operation and growth of the nation's high voltage and extra-high voltage transmission network.

- Remedy continuing undue discrimination in receiving transmission service by issuing and enforcing a single, nondiscriminatory open access transmission service tariff (based on Network Access Service of Order 888), thereby level the playing field for all market participants. This tariff would be administered by FERC and applied to wholesale transmission (wheeling), unbundled transmission (ITPs) and bundled transmission (load serving entities).

- Eliminate "seams" between regional electric wholesale market by creating and mandating the same rules for: 1) reserving and scheduling transmission; and 2) scheduling generation.

- Require all jurisdictional transmission owners (TO) to join an ITP and relinquish operational control of their transmission facilities to this ITP.

- Expand FERC jurisdiction to include bundled retail transmission service in addition to wholesale transmission and unbundled retail transmission service it presides over today.

3.10.2 Summary of ITP Responsibilities

- Operation of a pricing mechanism for providing transmission service termed "Network Access Service" (NAS). NAS consists of two components: one similar to Network Integration Transmission Service and one similar to Point-to-Point Service, both presently used today. All services required for effective transmission service will be addressed (i.e. – ancillary services). Network access service allows flexibility in transmission service options while integrating resource and loads (similar to Network Integration Transmission Service of today) in addition to providing specific reassignment rights of transmission service agreements as long as the reassignment transaction is feasible under security-constrained guidelines (similar to Point-to-Point service of today).

  Network Access Service charges are intended to recover the embedded costs various TOs have invested in the transmission grid. The NAS will operate day-ahead and real-time markets for transmission service and ancillary services. FERC anticipates bilateral contracts, long-term and short-term between supplier and customer, to make-up a predominant portion of the transmission service arrangements. The spot market will make up the remainder of required transmission service arrangements needed to fulfill all electrical service needs. The spot-market will be operated in the day-ahead and real-time mode (long-term bilateral contracts are scheduled every day, in the day-ahead market).

- Operate a congestion management system known as "Locational Marginal Pricing" (LMP), and "Congestion Revenue Rights" (CRR) described in section “3.12 Present Day Pricing Mechanisms”. This system uses differential pricing on a nodal, or substation bus, basis to assign costs for electricity based on what generation units are dispatched which results in no system overloads, as explained in previous section.

Congestion Revenue Rights (CRRs) were intended as a hedging mechanism to lock in transmission service costs (offset additional costs for transmission service as a result of nodal generation costs which might be higher than other nodes within the transmission system). CRRs will be allocated to entities serving native load and others that wish to purchase it via auction, as explained in the previous section. Assigning or purchasing CRRs may change or evolve over the next four years after practical experience using them is attained.

- Operate energy imbalance markets to allow market participants to sell or buy their imbalances in a fair and nondiscriminatory manner.

- Oversight to ensure customer service after issuance of SMD is equal to or better than present levels prior to the issuance of SMD.

- Authority to develop market power monitoring and mitigation procedures for the day-ahead and real-time markets.

- Assure long-term adequacy of electrical energy generation and delivery systems on a regional basis.

- Involve representation from states, and their input, in how ITPs operate the grid in their respective state. This may apply to many aspects of ensuring grid reliability (i.e.- planning and operation) to ensure their specific, legitimate and reasonable requirements are met.

- Authority to require all users of the transmission system comply with all standards to ensure transmission system reliability and security.

3.10.3 Schedule for SMD Operation

- July 31, 2003 – An INTERIM OATT must be filed by jurisdictional transmission utilities (own, operate or control).

- December 1, 2003 – All jurisdictional transmission utilities that must file a revised OATT that meets or exceeds SMD guidelines, which will become effective no later than September 30, 2004, or other date as determined by FERC.

- September 30, 2004 – OATT filed that includes bundled retail transmission for all public transmission utilities.

3.11 Post SMD NOPR [5], [19], [32], [34], [38]

Some states (Northeast, Midwest and Texas) and utilities approved of SMD while some (Southeast and Northwest states) did not. Those that did not approve of SMD, and voiced strong opposition to it, were concerned with: 1) jurisdictional overreach by FERC, 2) destabilizing economic effects (cost shifting) and participant funding, 3) incomplete operational specifics of how the markets will work and 4) inadequate attention to regional needs.

As a compromise, FERC issued a white paper on April 28, 2003. The new term for SMD is now Wholesale Power Market Platform (WPMP).

Primary features of the WPMP are: 1) it allows regional flexibility, 2) it permits cost benefit studies to justify certain functions, and 3) it requires seams issues be resolved. The term RTOs will be retained and ITP will not be used.

3.12 Present Day Pricing Mechanisms [1], [15], [41]

This section will acquaint the reader with terms and a broad understanding of the various pricing mechanisms in use today and proposed for the future. An in-depth analysis of each of mechanism lies outside the scope of this document (for they each could be a thesis).

The deregulation of the generation sector ("wholesale market") and restructuring of the industry (elimination of the vertically integrated utility through functional unbundling) has created the need to develop other pricing mechanisms to account for providing the many "invisible functions" the vertically integrated utility's bundled pricing mechanisms performed. Today's pricing mechanisms can be grouped into the following broad categories: 1) generation, 2) transmission, 3) distribution, 4) ancillary services, and 5) demand response.

In the end, there will most-likely be three separate line items that will comprise electricity bills – one line each for generation costs, transmission costs, and distribution costs.

3.12.1 Electronic Tagging System [20]

The system by which all electrical service transactions are performed within the industry today uses the "Electronic-Tag" or "E-Tagging" system. E-Tagging was developed by NERC in 1995 for addressing the operational needs of the new and evolving deregulated environment the electric utility industry now found itself in. E-Tagging is the process by which an electronic identifier is "tagged" to a "packet" of electricity. This packet contains a large amount of information specific to that transaction. A small representation of this information included within an E-tag is as follows:

- electricity quantity: "MW amount"
- point-to-point location information: "BUS A to BUS B"
- type of service paid for: "firm" or "non-firm" contract agreement (firm meaning high reliability, non-firm meaning lower reliability, service can be disconnected for economic reasons)

There are many more types of data associated with this tag, but hopefully this gives the reader a general idea as to what kind of information is included within an E-tag.

3.12.2 Summary: Present Day Pricing Mechanisms

This section will acquaint the reader with the general pricing mechanism concerns, and functional concepts present today, not an in-depth analysis.

For ease of explaining the new operating characteristics of deregulated generation market and restructured transmission market, the familiar sectors of generation, transmission and distribution pricing mechanisms will be addressed first, followed by the ancillary market and demand response mechanisms.

3.12.3 Functional Concepts & Concerns: Present Day Pricing Mechanisms

The intent of this section is to provide the reader with enough information pertaining to each mechanism for a working knowledge and understanding of each. We will discuss, in order, the following sectors: generation, transmission, distribution, ancillary services, and finally demand-response. Because this thesis addresses the transmission sector primarily, the distribution sector will not be discussed in as much detail (as the other sectors) and lies outside the scope of this document. These pricing mechanisms reflect all mechanisms used throughout the RTO landscape of today. The term RTO will be used since that is the present term approved by FERC when referring to transmission sector operations.

3.12.3.1 The Generation Market Pricing Mechanism

Because the generation sector (wholesale power market) is the only truly competitive market within the industry today, we start here. This market has generating companies (GENCOs), both with and without roots to vertically integrated utilities, competing against one another for the ability to supply electrical energy to meet the load requirements of the Regional Transmission Organization RTO as determined by the RTO “schedulers”. Schedulers are RTO employees that record requests for electrical service from the RTO customers. There are many schedules received by the RTO, which then sums up these many service requests and then in turn must find an adequate quantity of GENCOs to satisfy this sum of service requests. Each scheduled electricity service request must be fulfilled by the RTO. This responsibility is in the hands of the RTO system operators. Operators, as the title suggests, operate the transmission system of the RTO to deliver electricity to their scheduled customers.

GENCOs bid on the electrical energy service requirements of the RTO. The low bidder(s) will be selected until the RTO service requirements are met and then it will pay the highest bid ($/MWh) to all GENCOs.

Two markets will be operated for the generation sector, they are the "day-ahead" and "real-time" markets. The day-ahead market is expected to address most service requirements since they tend to be long in duration by nature through long-term bilateral contracts. The real-time, or "spot-market" is expected to address any outages unforeseen in the day-ahead market, and it is "security-restrained, bid-based". Security-restrained, bid-based refers to those measures to assure operations will not jeopardize grid reliability, while bid-based describes the proposed auction for imbalance energy. These two markets will trade both electrical energy and ancillary service requirements.

In addition to these two generation markets, a pricing mechanism called "Locational Marginal Pricing" (LMP), developed by PJM, will impact the cost of electricity as supplied at generation busses or "nodes". LMP will be discussed in greater detail in the "Transmission Service Market Pricing Mechanisms", but is mentioned briefly here for the aspects that affect the generation market. LMP is a tool to relieve transmission congestion, indicate where congestion exists on the system, and assign additional costs to congestion at each specific generation bus (node). These additional costs are passed on to customers but as a result, there are surplus revenues paid to the RTO. Therefore, if there is congestion on the system, electricity costs at generation busses is increased by the RTO and the RTO will take in more money than it pays out. In the case of PJM, where they operate non-profit, this revenue surplus is refunded to the various GENCOs.

Installed capacity requirements will be determined by the LSEs who are responsible for guaranteeing the load requirements of their customers. LSEs will also pay for real power losses of the system, which means if their loads total 250MW with a corresponding 5MW of losses, then the LSE will have to schedule 255MW of electrical power.

Previous generation markets did not always function as expected due to lack of generation capacity, lack of transmission capacity, flawed market rules, and unethical business practices (ENRON) which resulted in price volatility and blackouts as was witnessed in California.

Under these new market pricing mechanisms, it is anticipated a majority of market manipulation techniques discovered as a result of the California debacle will be prevented. Lessons learned from previous generation market failures (California) and successes will be applied to subsequent FERC rulings addressing deregulation and restructuring.

3.12.3.2 Transmission Service Market Pricing Mechanism(s)

This section addresses the pricing mechanisms RTOs will use for pricing transmission services.

- Bilateral Contracts, Long and Short Term

  The primary pricing mechanism anticipated to be used for all RTOs nation-wide will use bilateral contracts. A bilateral contract for electricity is an agreement between a buyer and seller for the sale and purchase of electrical energy, or "Firm Transmission Rights". It is anticipated these contracts will be used extensively to "lock-in" electricity costs, since LMP may cause electricity costs to fluctuate (increase) during system congestion. The short-term transmission markets, explained later, will be designed to accommodate and complement these bilateral agreements.

- Network Access Service

  This service will consist of a single access fee plus a region-wide transmission rate. The single access fee will recover the transmission owner's embedded/stranded costs associated with transmission infrastructure and the region-wide transmission rate will be the cost associated with the use of the transmission system. The region-wide transmission rate may be "license plate", "postage stamp" or "zonal".

  All three transmission rate pricing mechanisms are designed to improve the amount of or eliminate altogether pancaking of transmission rates. (Pancaking refers to summing of transmission tariffs across all involved service areas.)

- License Plate Rate Pricing

  This reference is derived from how license plates work in that if you buy a license plate for your car in your state, you have access to the entire United States region.

  Similarly, this transmission service pricing mechanism charges a single rate for transmission service in the geographic sub-region within the RTO where the transmission service is delivered. The transmission customer then has access to the entire RTO region. The transmission rate under the license plate pricing mechanism is based on the embedded cost of the transmission infrastructure where the service is received.

Within a RTO there will be different rates for transmission service for each RTO sub-region, which is usually based geographically on control areas. Each sub-region's rates are based on or calculated from the embedded costs similar to how the cost-based tariff system worked.

Therefore, like a license plate, in which there are different costs in each state, once you buy a license plate in your state you can drive anywhere in the United States. Applied to transmission, you buy transmission service in your RTO sub-region, which gives you access to electricity attained throughout by the RTO in its entire regional control area.

Although this mechanism is successful in eliminating pancaking of rates, it creates other problems related to transmission of electricity. Specifically it does not 1) allow owners of the transmission infrastructure it traveled over to recover their embedded costs, thereby shifting those costs to those native customers not benefiting from this service and 2) support long-term transmission infrastructure investment to connect low-cost generation to customers located far away.

This is the most prevalent pricing mechanism in RTO filings made to date, which is unfortunate.

- <u>Postage Stamp Rate Pricing</u>

  This pricing mechanism uses one rate for **transmission service,** throughout entire RTO control area independent of geographical location within the system. The embedded cost of all transmission owners embedded costs are averaged together and used as the basis to create the transmission service rate.

It derives its name from how a postage stamp is used. Like a postage stamp which is the same price in every state for a class of service throughout the U.S., electricity service is the same price throughout the entire RTO control area for a type of service.

This pricing mechanism also prevents pancaking and it allows embedded costs to be recovered but it too creates other problems.

Two such problems with the postage stamp pricing system are: 1) it promotes more expensive transmission systems and 2) low cost transmission providers, either through high load density or through cost containment processes, will be at a disadvantage since they will be either punished for their system makeup or rewarded for their cost-containment processes. This system treats "low load density" systems favorably by shifting costs to the higher density systems. ISO New England and New York ISO uses this mechanism.

- Highway-Zone

  This **transmission service** rate pricing mechanism employs the best attributes of license plate and postage stamp pricing mechanisms.

Instead of excessive generalizations to one extreme or the other, the zonal approach creates transmission service rates based on transmission system usage. The transmission system is broken up into either highway or zonal systems. Highway systems are energized at higher voltages (>200kV) and tend to be regional while zonal systems are energized at lower voltages (<200kV) and tend to be local (Figure 3-15). Because of this breakdown, highway rates are postage stamp based, while zonal rates are license plate based.

Zonal rates are further broken down into supply and load zone rates. Supply zone rates correspond to recovering facility infrastructure costs associated with generator interconnection facilities for “supplying” electrical energy. Load zone rates apply to facilities that supply load.

Supply zone rates are typically applied to facilities energized at 115kV and above that are not included within the Highway so the costs for these facilities can be recovered.

The load zone is applied to all facilities not included in the Highway or Supply Zone which are energized at 100kV or less. Load zone rates are also “load Density” dependant meaning higher transmission service rates for lower load density areas and vice versa, as a mechanism to further increase accurate revenue recovery.

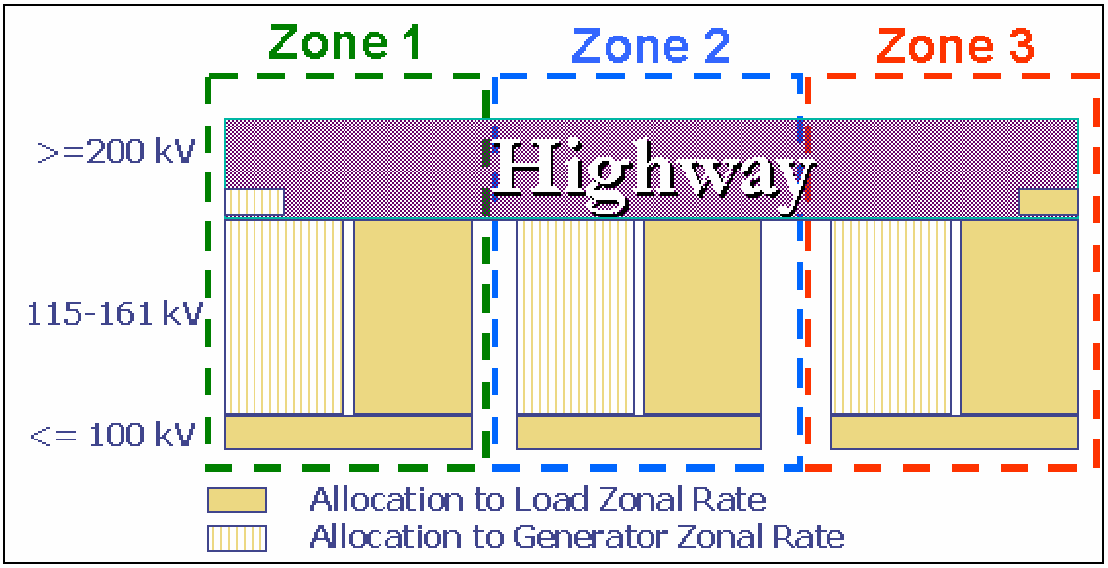


Figure 3-15 - Highway-Zonal Tariff Graphic [46]

- Congestion Management

  Congestion occurs when system transfer requests exceed the transmission system ability to transfer electricity. The mechanisms the SMD has proposed to address transmission congestion are locational marginal pricing (LMP) and congestion revenue rights (CRR).

- Locational Marginal Pricing

  Locational Marginal Pricing (LMP) is designed to identify congestion points, also called flowgates, assign costs of congestion which are then passed on to customers.

  The LMP pricing mechanism is the recommended choice for managing congestion nation-wide. The intent of this pricing mechanism is to relieve congestion by dispatching the cheapest generation possible given real-time system conditions. By using the LMP mechanism, it is expected that the cheapest possible generation will be dispatched, congestion will be avoided and market abuses, like those seen in California will be prevented.

Locational Marginal Pricing (LMP) is used by PJM/PJM West to **determine electricity costs at each node throughout system in real-time**. LMP uses real-time information to determine electricity generation costs at each supply node throughout PJM system. These nodal generation costs are what the GENCOs are paid by the Transmission Provider.

LMP is defined as “the marginal cost of supplying the next increment of electric demand at a specific location (bus or node) on the electric power network, taking into account both generation marginal cost and physical aspects of the transmission system”. As mentioned previously LMPs are nodal and provide market pricing signals associated with congestion. If the transmission system is unconstrained or uncongested, LMPs are the same value each node throughout the transmission system (Figure 3-16 through Figure 3-18).

To explain this further, figure 3-16 shows a dispatchable system which results in no congestion. The corresponding power flows (red arrows) shown in Figure 3-17 are below the thermal capacity of the transmission system. Therefore, since there is no congestion, all system nodes or busses have the same price for generation costs. Economic dispatch of the cheapest generation can occur since all load can be supplied without exceeding the transmission thermal capacity, therefore all LMPs are the same or equal.

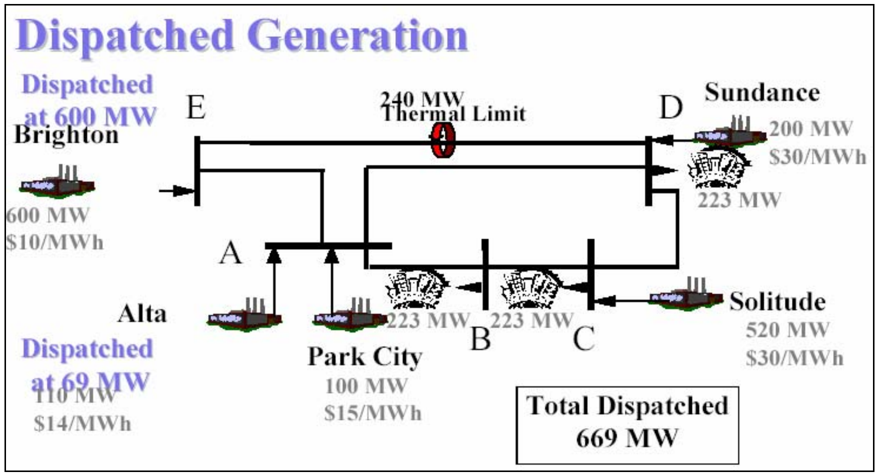


Figure 3-16 - Dispatched Generation Without Transmission Congestion [41]

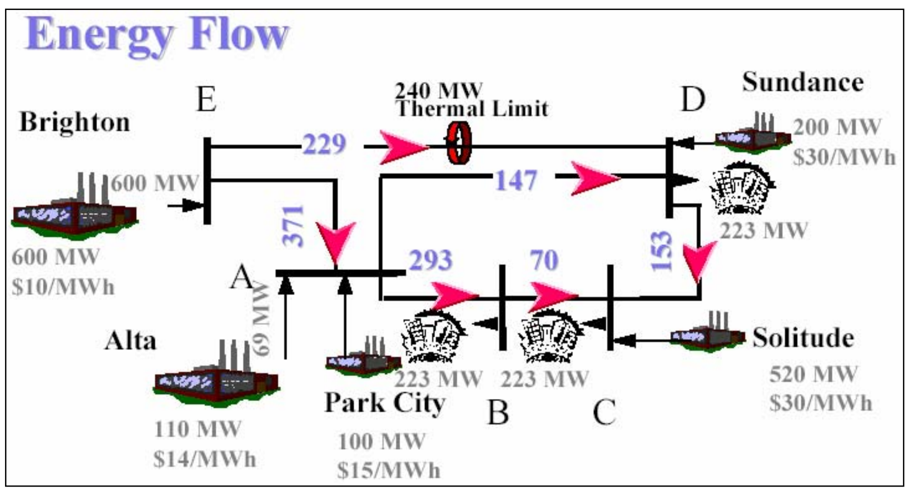


Figure 3-17 - Energy Flow Without Transmission Congestion [41]

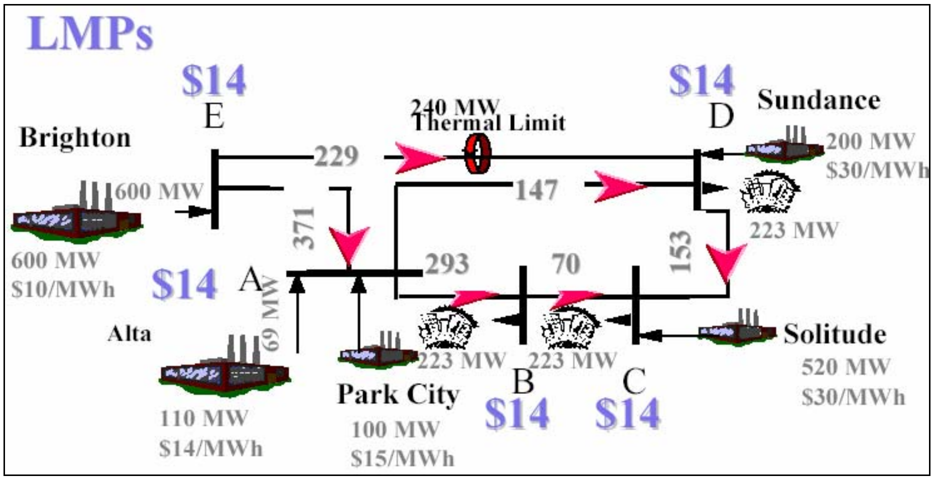


Figure 3-18 - LMPs Without Transmission Congestion [41]

If the transmission system is constrained or congested, LMPs vary by node (bus) throughout the system (Figure 3-19 through Figure 3-23). LMPs are based on actual energy flows and actual system operating conditions (i.e. planned outages). The factors that impact LMP values are: 1) Demand for Energy, 2) Available Generation for Dispatch, 3) Economic Dispatch of Generation, 4) Transmission Network Configuration, and 5) Transmission Constraints. The PJM transmission system operating conditions are given from the PJM state estimator. From this information, electricity prices are calculated for each node on the system, which is repeated every 5 minutes. Accounting settlements occur hourly, so the 5 minute LMPs are integrated at the end of the hour period to determine the hourly cost.

Figure 3-19 shows a system which results in congestion. Generation and loads are bid. The corresponding power flows (red arrows) shown in Figure 3-20 are above the thermal capacity of the transmission system – specifically on the bus E-to-D line. To avoid thermal damage to this line, generation will have to be dispatched non-economically, or more expensive generation will need to be used (Figure 3-21).

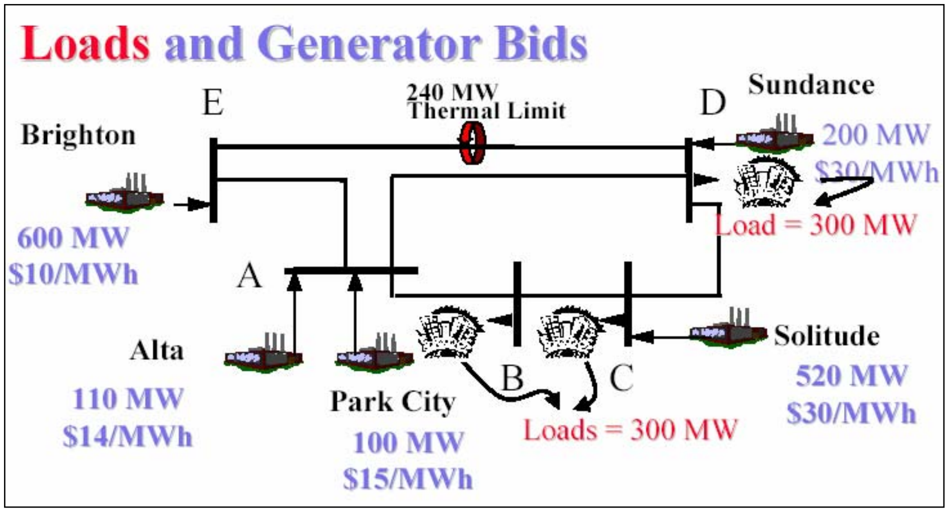


Figure 3-19 - Load & Generator Bids [41]

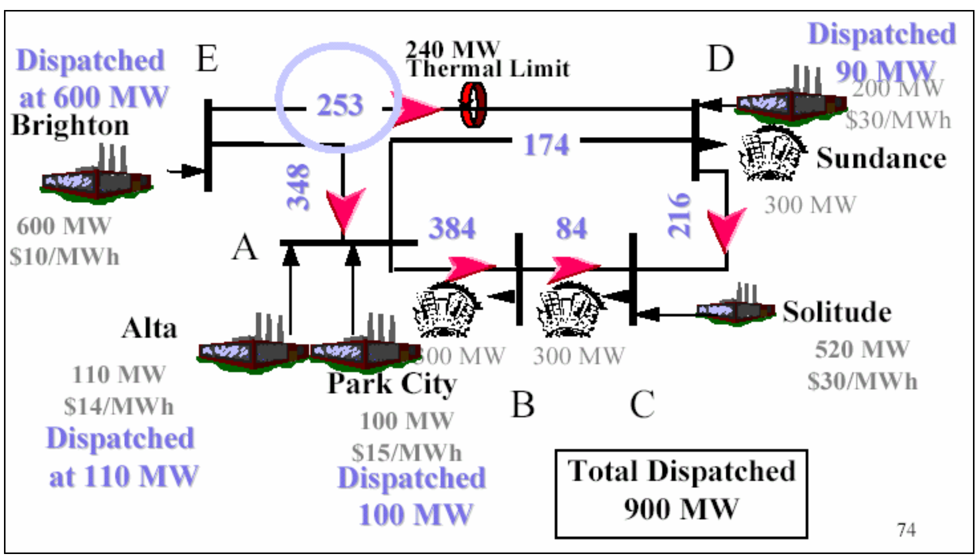


Figure 3-20 - Dispatch Solution Ignoring Thermal Limits (of Transmission Line) [41]

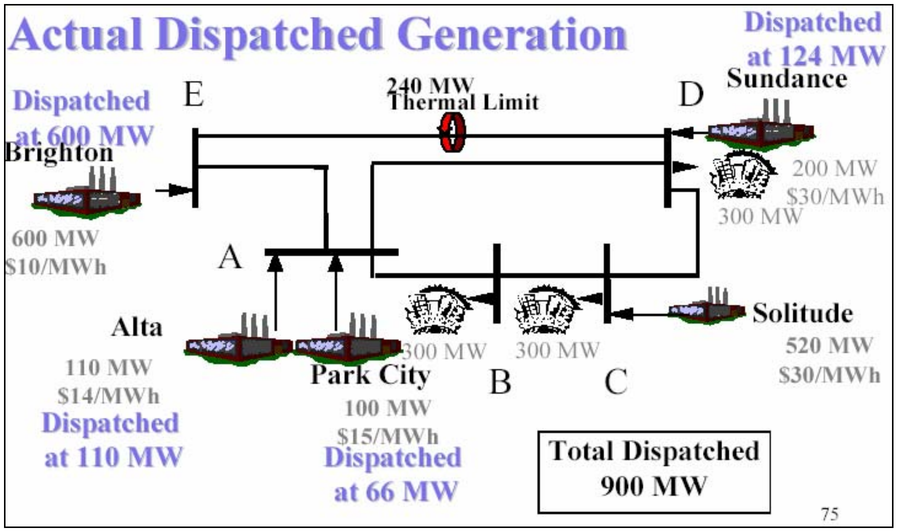


Figure 3-21 - Actual Dispatched Generation Accounting for Congestion [41]

Since there is congestion, and more expensive generation needs to be dispatched to meet the 240MW thermal limit of the E-D line (Figure 3-22), the cost of electricity will be different on all system nodes or busses (Figure 3-23) as calculated from real-time data retrieved from the system (Figure 3-24).

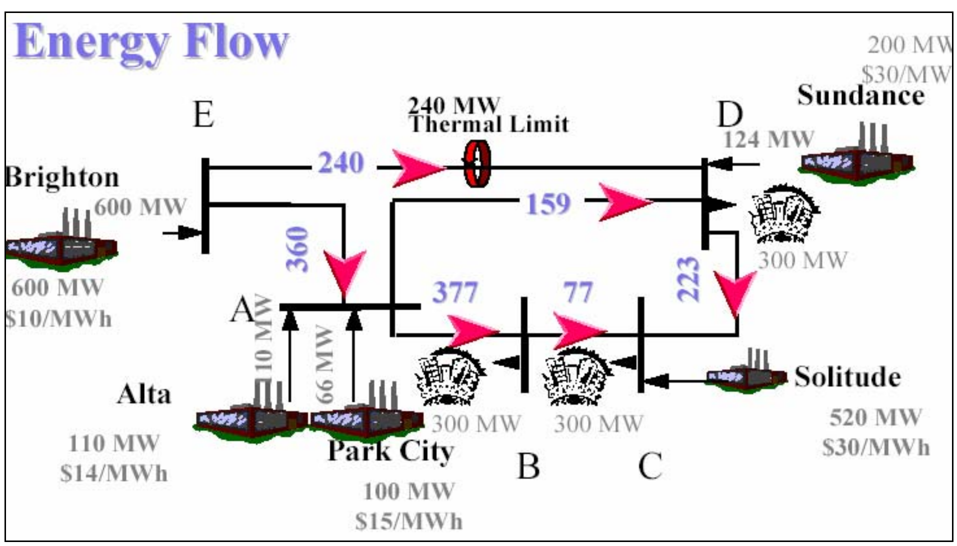


Figure 3-22 - Actual Energy Flow Corresponding to Actual Dispatch [41]

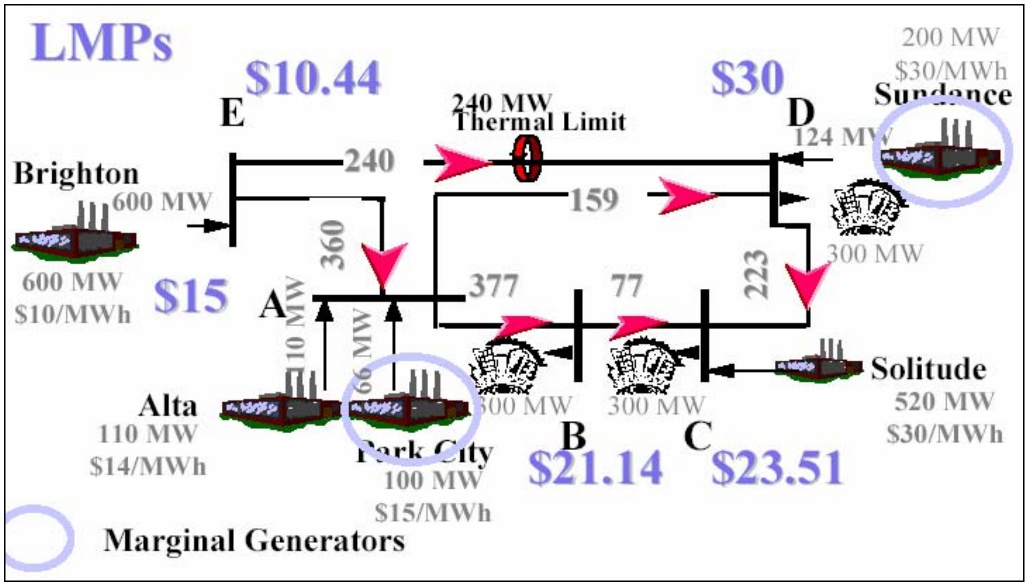


Figure 3-23 - Actual LMPs Corresponding to Actual System Conditions [41]

- **Park City** and **Sundance** supply the next increment of load on the system
- Attempt to serve an additional increment of load (1 MW)
- Resulting Sensitivity Factors determine LMP

Bus Location	Sensitivity Factors for 1 MWh of Load Supplied from:		Calculation Details
	Park City@ $15/MWh	Sundance@ $30/MWh	
A	1.00 MWh	0.00 MWh	1.00($15) + 0.00($30) = **$15**
B	0.59 MWh	0.41 MWh	0.59($15) + 0.41($30) = **$21.14**

Figure 3-24 - LMP Costs for Generation [41]

- Congestion Revenue Rights

  Under LMP, congestion costs will vary based on the price to relieve congestion and losses. Instead of a system of physical reservations, financial reservation rights called Congestion Revenue Rights (CRR) will be used. CRRs are a system of financial rights used to give transmission customers the ability to protect themselves from uncertain congestion costs. These rights will be used to pay the RTO offsetting the increased cost of service due to congestion costs. Initially these CRRs will be available from receipt point-to-delivery point obligation rights for the available transfer capability on the grid, but not in excess of the transfer capability of the system. In the future other CRR like receipt point-to-delivery point options and flowgate rights may be available in the future. Under CRR there may be a situation where the RTO owes more CRR than what it receives from increased revenue for congestion costs. In this case this revenue shortfall will be charged to the transmission owner whose facilities are out of service. There will be a secondary market for trading CRRs.

3.12.3.3 Distribution Sector

The RTO customer or LSE purchases electrical service from the TO in accordance with the pricing provisions of the OATT and then sells to their distribution customers. These distribution sales can be either cost-based at PUC approved rates in a state where retail access or deregulation has not been allowed or at competitive rates where retail access or deregulation is allowed. Deregulation at the distribution level is a state-by-state issue and is also referred to as retail (where the generation sector is referred to as wholesale).

3.12.3.4 Ancillary Services Sector

As defined previously, these six services that are to be provided by the RTO are included in the tariff pricing mechanisms, if an entity, other than the RTO is to provide these services, then they would be bid-based, similar to the generation market mechanism.

3.12.3.5 Demand-Response Sector

The demand response pricing mechanism is bid-based as well. Customers bid to the RTO for the cost they (the customer) can charge the RTO for interruption of their electric service in the event that available generation will not meet load requirements the RTO is required to supply. This is similar to the generation sector in that the higher the bid for interruption, the less chance you have in your bid being selected.

3.13 Prices since Deregulation [18]

The following chart (Figure 3-25) shows residential prices for electricity since deregulation efforts began. Overall there is a general rise in prices primarily due to lack of generation supply and transmission adequacy issues. In states where electricity costs declined before this rise (e.g. – California), state PUCs mandated service rate reductions for all customers before native utilities could enter into the deregulated retail choice markets. Many states reported "electricity cost savings" as a result of deregulation and the corresponding improved industry operations. In actuality they weren't really "savings", instead theses "savings" were due to mandated rate reductions by the PUC. In many cases native utilities are asking for rate increases (e.g., utilities within Texas).

In addition, recent reports state that retail choice programs do not reduce electricity costs for residential customers but may help reduce costs associated with larger commercial or industrial customers.

Retail choice is discussed in somewhat greater detail within the next section.

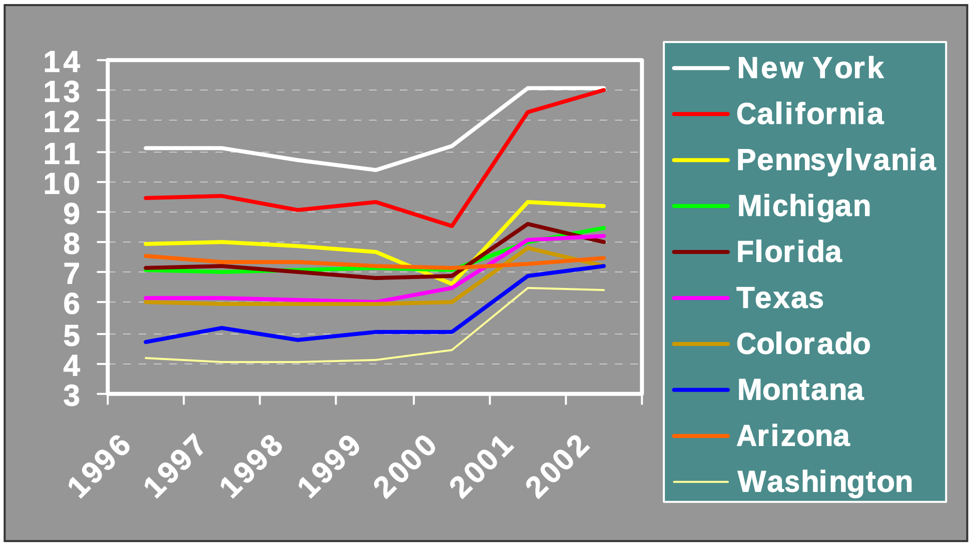


Figure 3-25 –Residential Electricity Costs Since Order No.s 888 & 889

3.14 Status of Retail Choice Within the United States [18]

This topic is outside the scope of this document. A brief summary however, follows to familiarize the reader its general terms and concepts.

Presently, the status of deregulation in states across the US is quite varied (Figure 3-26). Retail choice is state-based and occurs within the distribution sector of the industry.

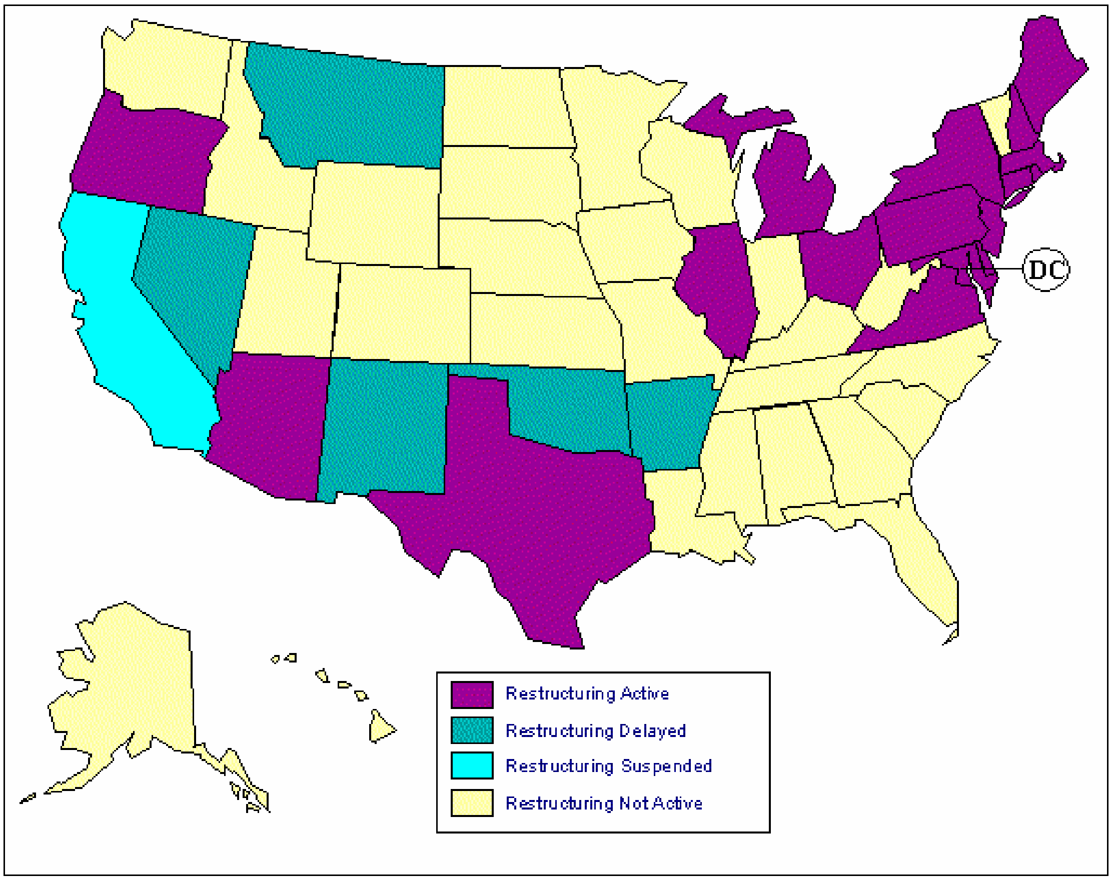


Figure 3-26 – Status of Retail Choice Within the United States [18]

Retail choice in simple terms, works this way: first, the customer, industrial, commercial or residential, selects their GENCO only from the list of competing GENCOs. Transmission costs will be issued through the regional RTO and the native utility will be responsible for the distribution sector – related costs. At the end of the day, utility bills will have three separate charges for the various components of their electrical service. One line will be correspond to the GENCO charges for generation, one charge will be for the servicing RTO ands finally the native distribution company will charge for the distribution-related costs associated with the electrical services received.

That is all that will be discussed regarding state-based, retail-choice programs as they relate to industry deregulation.

In chapter 3, we covered the reasons why certain legislation and policy was enacted and the results. During these times of uncertainty, electric utilities have kept the nation's electric system functioning and America running. However, transmission infrastructure investment is declining due to delays in creating a final restructuring plan. Presently, NERC reports that system capacity appears to be adequate.

The US electric utility industry is mired in politics and regional debates, yet the demands on the electricity system continue to grow. Our nation depends on a viable electric utility system for its security, economy and way of life. While these debates and political discussions continue, its viability hangs in the balance.

Chapter 4.0 - A Restructuring Model for the United States' Bulk Power System

4.1 General

The deregulation and restructuring process is constantly changing. At the time of completing this thesis, the direction of the deregulation and restructuring process remains unknown. In fact, the deregulation and restructuring process is beginning to be questioned. Some states have suspended retail choice programs and others have reversed these programs, ending deregulation efforts.

What can be done to resolve this unrest and uncertainty within the industry? If deregulation efforts continue, a restructuring model must efficiently and effectively transition the industry from one of vertically integrated utilities to one where the generation sector is deregulated and the transmission sector is restructured to address open access issues. The model must meet the needs of the nation, states and companies which comprise it. The model must be fair to consumers and industry participants. The model must result provide heavy oversight of the deregulated generation sector to prevent greed. Finally, and perhaps most important, "at the end of the day", the new model must result in a viable electric utility industry that continues to deliver reliable, cost-effective electricity to consumers.

4.2 Thesis Statement

An essential service is at stake (Figure 4-1) and it is the intent of this thesis to introduce a restructuring model for the bulk power system of the United States' electric utility industry to ensure this essential industry's infrastructure is viable now and into the future.

Figure 4-1 - An Essential Service is at Stake (Earth at Night) [71]

4.2.1 Overview of Restructuring Architecture

This thesis proposes that the present-day, non-continuous patchwork of many RTOs be reduced to two large Independent Transmission Operators (ITO) (Figure 4-2) under the oversight of a newly created federal agency called the National Power Administration (NPA) (Figure 4-3). One ITO (ITO-East) would be given oversight responsibility for the Eastern interconnected transmission system (to include ERCOT) and the other ITO (ITO-West) over the Western interconnected transmission system.

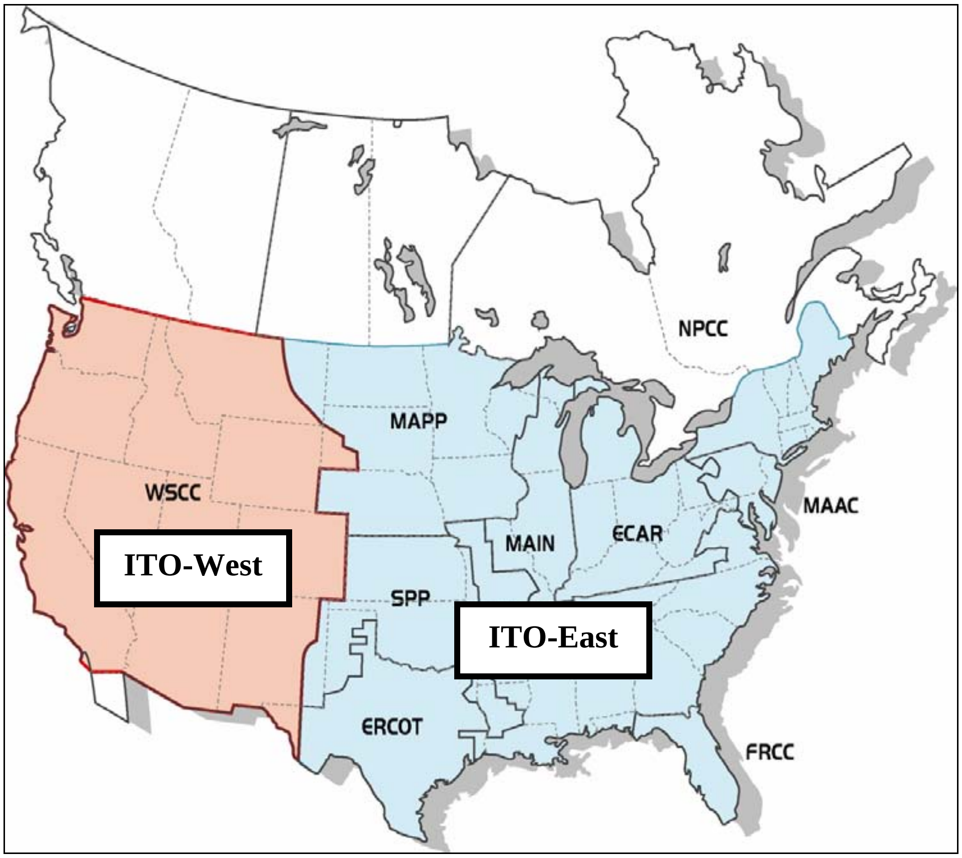


Figure 4-2 - ITO East & ITO West Geographical Scope

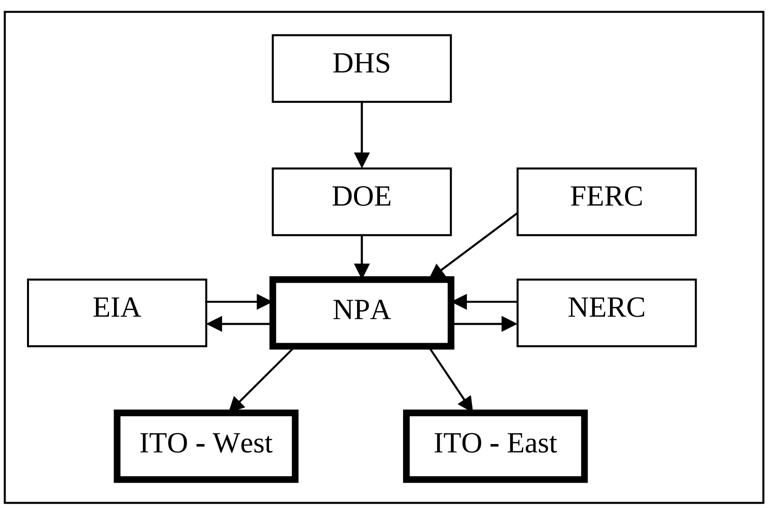


Figure 4-3 - Federal Agency Architecture – Power System Sector

Both ITO-East and ITO-West would be federal government entities operating under the authority of the newly established National Power Administration (NPA) under DOE. This approach centralizes oversight functions, hence improving coordination issues to ensure a reliable bulk power system. This architecture is a continuation of the philosophy used for the creation of the Department of Homeland Security (DHS) and its role in consolidation of vital infrastructure under one entity for coordination and response improvement. FERC's jurisdictional authority would expand to include all transmission (wholesale, unbundled and bundled) with input from states regarding issues of local concern. This expansion or "shift" needs to occur to ensure the viability of the transmission system.

To maximize national transmission system reliability and use of resources for generation, ERCOT would be combined within the eastern interconnection. Studies would need to be performed to ensure acceptable system performance, but the DOE National Transmission Grid Study states a 30 percent reserve margin for generation exists within ERCOT. This margin, combined with recent transmission additions, would lead one to believe integration with the Eastern Interconnection would be feasible. ERCOT might be better suited for inclusion within the Western Interconnection, but studies would confirm this.

Inclusion of Canada and Mexico would most likely be made during this same time period.

4.3 Current Transmission System Status

4.3.1 General

The United States' transmission grid is in need of tremendous upgrades. It operates today only because of the capacity installed 20-30 years ago. Much of the transmission infrastructure is 30–50 years old. At the end of 2001, the American Society of Civil Engineers graded the energy sector infrastructure a "D+" (Figure 4-4). The generation sector has improved but the transmission sector continues to lag severely. The time has come to invest in it and improve it so our nation's standard of living, economy and security can be sustained. Other infrastructure was given comparable grades.

Report Card for America's Infrastructure

D+	**Roads** One-third of the nation's major roads are in poor or mediocre condition, costing American drivers an estimated $5.8 billion a year. Road conditions contribute to as many as 13,800 highway fatalities annually. Nearly one-third of America's urban freeways—which account for more than half of all miles driven—are congested.
C	**Bridges** As of 1998, 29 percent of the nation's bridges were structurally deficient or functionally obsolete, an improvement from 31 percent in 1996. It is estimated that it will cost $10.6 billion a year for 20 years to eliminate all bridge deficiencies.
C-	**Transit** Transit ridership has increased 15 percent since 1995—faster than airline or highway transportation. Capital spending must increase 41 percent just to maintain the system in its present condition.
D	**Aviation** Airport congestion delayed nearly 50,000 flights in just one month in 2000. Congestion also jeopardizes safety—there were 429 near misses on runways reported in 2000, up 25 percent from 1999.
D-	**Schools** Due to either aging or outdated facilities, or severe overcrowding, 75 percent of our nation's school buildings are inadequate to meet the needs of school children. The average cost of capital investment needed is $3,800 per student, more than half the average cost to educate that student for one year. Since 1998, the total need has increased from $112 billion to $127 billion.
D	**Drinking Water** The nation's 54,000 drinking water systems face an annual shortfall of $11 billion needed to replace facilities that are nearing the end of their useful life and to comply with federal water regulations. Non-point source pollution remains the most significant threat to water quality.
D	**Wastewater** The nation's 16,000 wastewater systems face enormous needs. Some sewer systems are 100 years old. Currently, there is a $12 billion annual shortfall in funding for infrastructure needs in this category; however, federal funding has remained flat for a decade. More than one-third of U.S. surface waters do not meet water quality standards.
D	**Dams** There are more than 2,100 unsafe dams in the United States. There were 61 reported dam failures in 1999 and 2000. The number of "high-hazard potential dams"—those whose failure would cause loss of life—increased from 9,281 in 1998 to 9,921 in 2001.
C+	**Solid Waste** The amount of solid waste sent to landfills has declined 13 percent since 1990, while the amount of waste recovered through recycling has nearly doubled. Most states have ten years' worth of landfill capacity and waste-to-energy plants now manage 17 percent of the nation's trash.
D+	**Hazardous Waste** Effective regulation and enforcement have largely halted practices that contaminate. Aided by the best clean-up technology in the world, the rate of Superfund clean-ups has quickened—though not enough to keep pace with the number of new sites placed on the National Priorities List as the backlog of potential sites are assessed.
D+	**Navigable Waterways** The U.S. Army Corps of Engineers has a backlog of $38 billion in active authorized projects. On the inland waterways system, 44 percent of all the lock chambers have already exceeded their 50-year design lives. Key deep-draft channels are inadequate for the mega-container ships, which are the world standard for international trade; and intermodal connectors to ports are in poor condition. Transportation demand on waterways is expected to double by 2020, and serious performance problems are likely if current levels of investment continue.
D+	**Energy** Since 1990, actual capacity has increased only about 7,000 megawatts (MW) per year, an annual shortfall of 30 percent. More than 10,000 MW of capacity will have to be added each year until 2008 to keep up with the 1.8 percent annual growth in demand. The U.S. energy transmission infrastructure relies on older technology, raising questions of long-term reliability.

Figure 4-4 - America's Infrastructure Report Card [31]

4.3.2 System Operation

There are two primary areas of concern: 1) Constrained Paths, or "Congestion"; and 2) Reserve Margins. If either of these two conditions exist, the reliability of the transmission system is substantially degraded. This section will examine the current status of these two areas.

4.3.2.1 Constrained Paths ("Congestion")

Congestion on the transmission system is a major dilemma to proper operation of electricity markets.

An all too familiar term, "congestion" plagues the United States' transmission grid. Our grid, for many years the envy of the globe, now suffers from many corridors of constrained electrical power transfer capacity. A constrained path is one where requests for power exceed allowable transfer of power, therefore, the request cannot be met. These constrained paths are referred to as "constrained paths" or "congestion." Stations at either end of these congested paths are called "flowgates." Today, the congested paths across the U.S. transmission system are shown below (Figure 4-5).

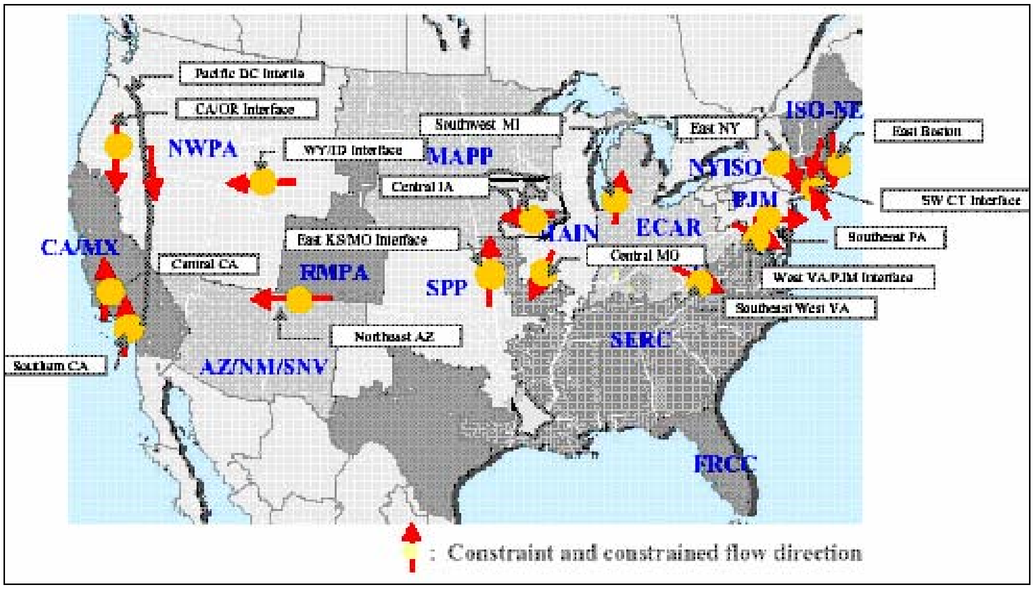
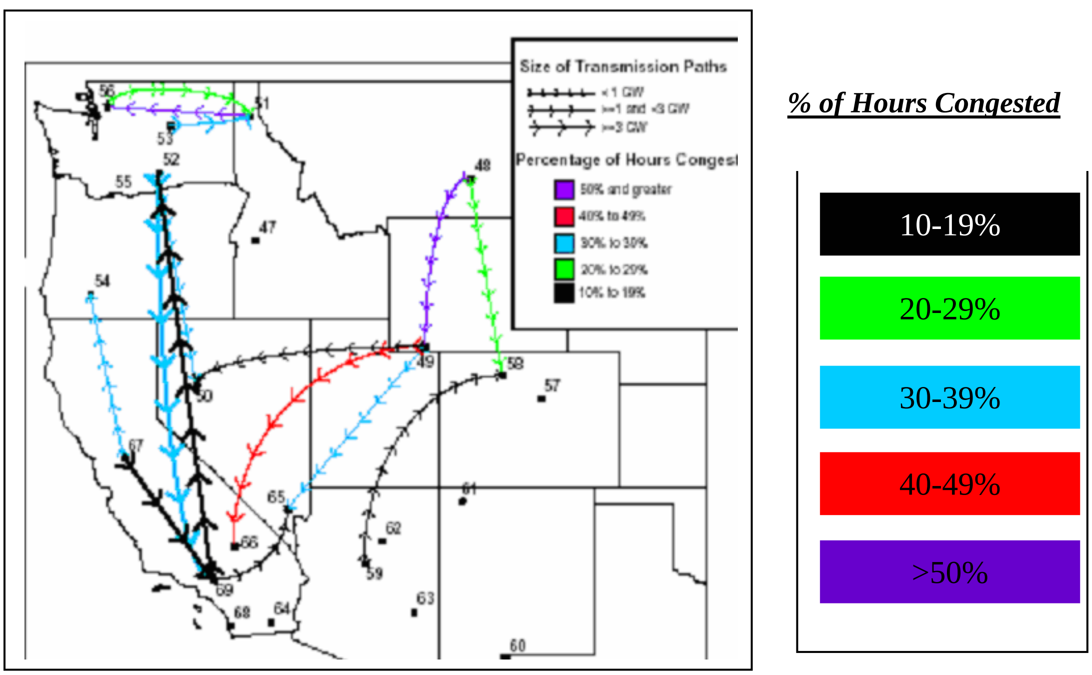


__Figure 4-5 - National Transmission System Congestion [6]__

In the Western U.S. interconnection, the congested paths are shown in greater detail below (Figure 4-6).



<u>Figure 4-6 - Congestion - Western Interconnection [6]</u>

In the Eastern interconnection, the congested paths are shown in greater detail below (Figure 4-7).

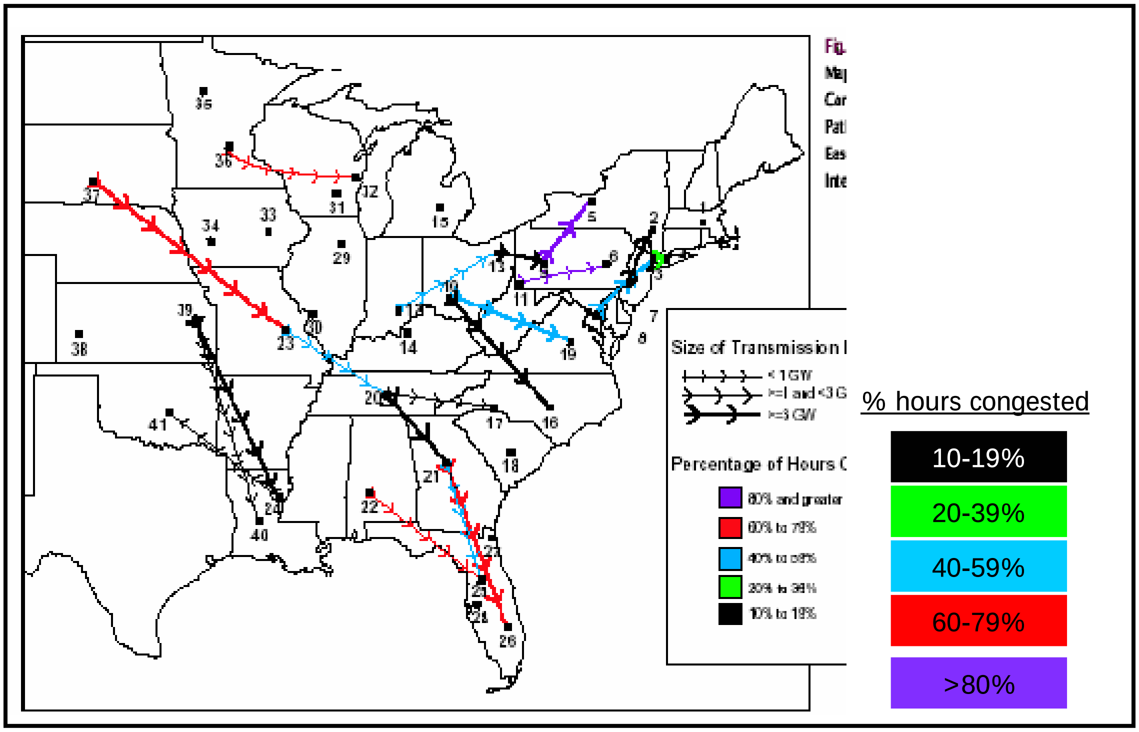


Figure 4-7 - Congestion – Eastern Interconnection [6]

These congested transmission corridors have been "discovered" through industry bulk power marketing operations under deregulation (buying and selling of electrical power). Previous to deregulation, this wasn't as widespread a problem because the system was planned to deliver power between two points in a specific direction (not in a random direction, as power markets and deregulation allow).

4.3.2.2 Transmission Capacity Reserves in Decline

Our transmission infrastructure reserve margins have dwindled to dangerously low levels over the past 10-15 years, due to load growth, and lack of investment. Generation capacity has increased to address increased load growth and it is now transmission's turn for increased investment. There are two primary reasons for this lack of investment. First, undecided regulations concerning how the industry will operate, and hence, how investment costs will be recovered. Second, the desire of many not to allow transmission (or generation) facilities be built throughout the U.S., as illustrated by acronyms such as NIMBY (Not In My Back Yard), BANANA (Build Absolutely Nothing Anywhere Near Anybody), and NOPE (Not On Planet Earth).

4.3.2.3 Industry Legislation is Unknown (i.e., "Rules" are Uncertain)

Delayed restructuring legislation is delaying financial investment in much needed transmission infrastructure. This legislation will determine how investments in transmission infrastructure will be paid back. Until the method for return of investment is determined, there will be no substantial transmission infrastructure investment.

Rules for how this sector of the industry will operate are contained within the FERC rules presently under discussion. Without final rules, the industry will continue to drift with no real direction.

These rules are important because they will determine responsibility and investment repayment mechanisms. The first point, responsibility, needs to be determined so that it is known which entities are responsible for ensuring the viability of the various aspects of a functioning electricity system (e.g. generation, transmission). Second, investment repayment mechanisms must be finalized to ensure investors can assess how they will receive return on their investment. Once these items are complete, adequate investment will return to the industry, badly needed facilities shall be built, and the country and industry shall be spared many traumas.

Specific examples of problems encountered with insufficient transmission infrastructure investment are: 1) Excessive System Congestion; 2) Inadequate Capacity Reserves, and 3) Aging Infrastructure and Insufficient Maintenance.

The above points can't be over emphasized, for, without sufficient transmission infrastructure, the electrical power grid throughout the U.S. will not function properly, which will severely damage (if not cripple) the way of life, economy and security of the United States.

4.4 Problems with a Multi-RTO Landscape (as Currently Proposed)

In chapter 3, we reviewed the present landscape of multiple RTOs (Figure 4-8). There are problems with this landscape of proposed RTOs and with the landscape as envisioned by FERC (although not as problematic as the other options).

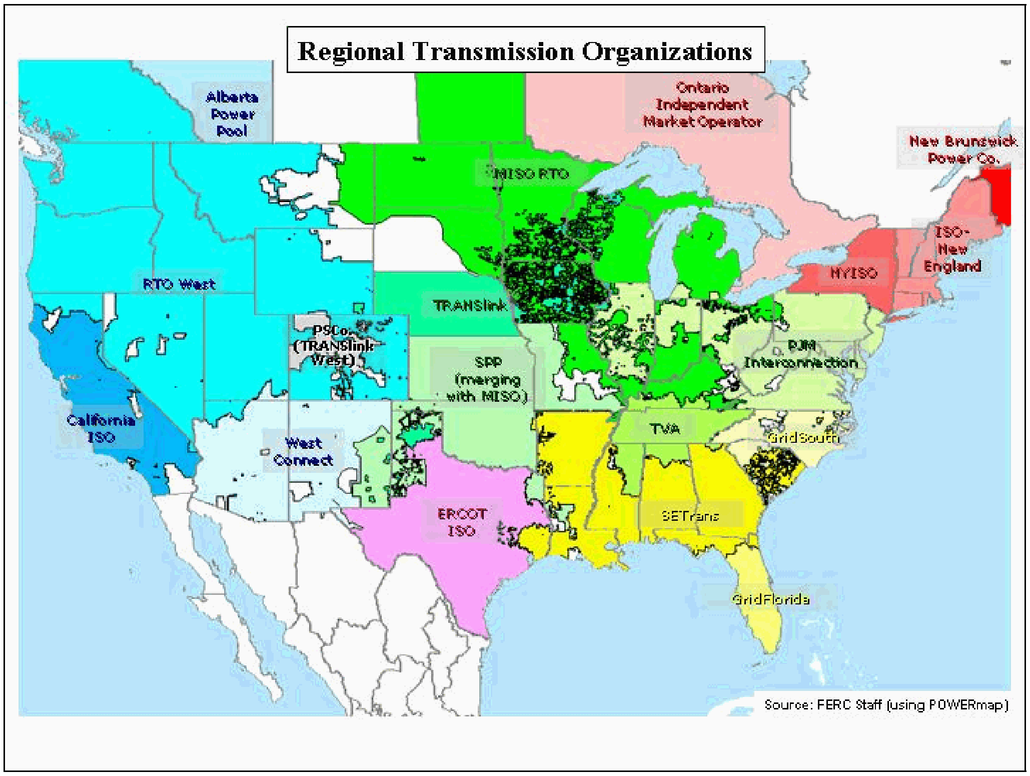


Figure 4-8 - RTOs Proposed (Present Day) [19]

In any multi-RTO scenario where 12, 9, or 5 RTOs exist without a common market design, there will be problems in resolving inter-RTO power flows. Among these problems are: 1) Seams Issues; 2) Geographic Inadequacy; 3) Inaccurate Embedded Cost Accounting; 4) Post-Restructuring Costs, 5) Delays Restructuring Process and 6) Inadequate Investment in Transmission. These problems are now discussed in greater detail.

4.4.1 Seams Issues

Seams Issues are different legal and pricing policies at RTO boundaries used to resolve power flow issues like amount and pricing (Figure 4-9). They need to be the same so electricity can be transmitted among RTOs efficiently and effectively.

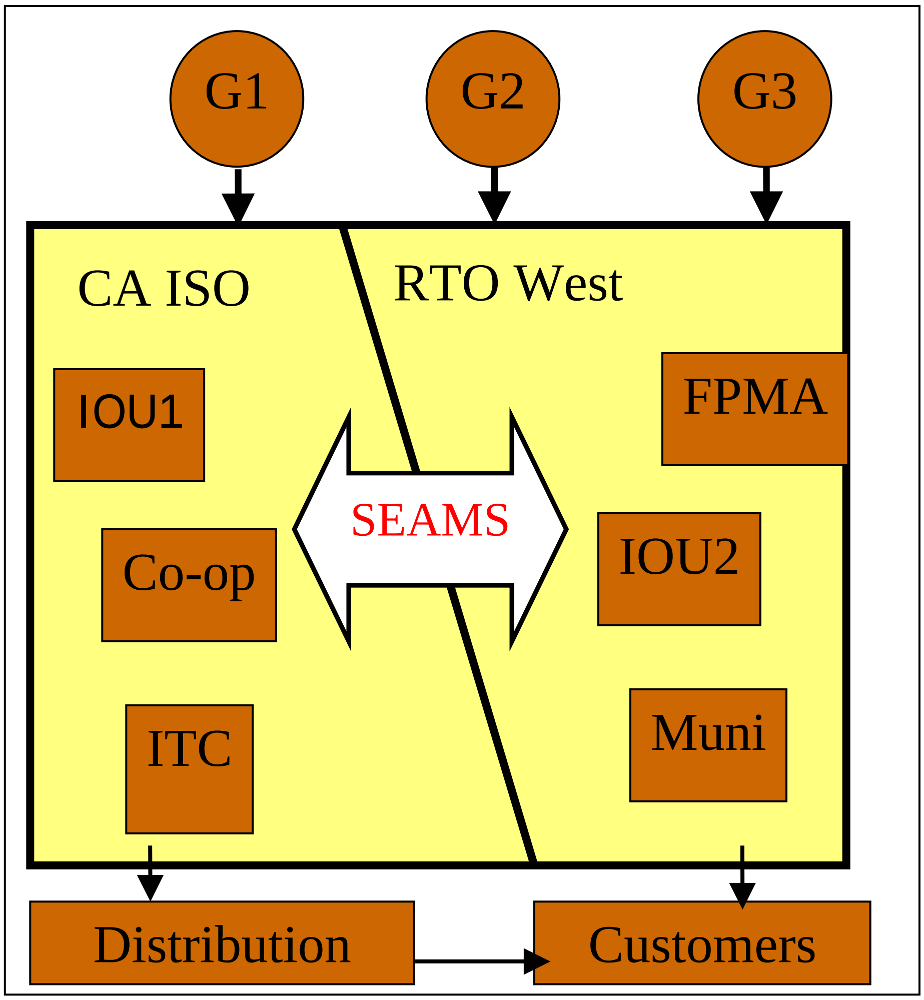


Figure 4-9 - Seams Issues

These issues are fluid and change as the restructuring process continues. At the time this paper was written the seams issues in existence are broken down into the twelve issues listed below:

- *Transmission Service:* Equal transmission service for all market participants across all control areas to reduce market risk, scheduling problems using different systems (resulting in confusion) and overall uncertainty.

- *Long-Term Transmission Service Availability to Support Installed Capacity (ICAP) Transactions*: Reducing and eliminating barriers to electricity markets by external suppliers (GENCOs or Transmission Companies). This can be achieved through removing any requirements for firm transmission reservations to ensure the electricity can be delivered when buying ICAP from external suppliers.

- *Transaction Checkout Failure:* Data incompatibility results in disruptions (curtailments) both to the market and transmission system reliability. This incompatibility issue creates unmatching E-Tag data and incorrect MW values to name two.

- *Transaction Scheduling:* Inter-regional transfers are risky and uncertain due to inconsistent scheduling information and market timing rules (deadline requirements).

- *Transaction Curtailment:* Market timing differences between regions may result in transmission curtailments. Theses timing issues are in addition to system security curtailments due to only system reliability.

- *Failure of Transactions Due to Ramping of Control Area Interchange:* Transactions between control areas might be prevented due to insufficient dispatch capability, when large transfers are revised while maintaining electricity supply/load balance within each control area.

- *Available Transmission Capability (ATC) Differences:* Differences in ATC calculators between control areas that share a common border do not effectively or efficiently allow market participants to determine transfer capabilities, which introduces uncertainty. This damages how the markets operate and how effective the grid can operate.

- *ATC Manipulation:* Market participants, GENCOs or Transmission Providers (TP), schedule transfers, or transactions, in the day-ahead market and beyond without intent of ever using it (schedules). During the real-time market phase, these scheduled transfers are cancelled and, hence, the valuable transmission capacity is unused.

- *Capacity Market:* Fundamental differences in installed capacity (ICAP) requirements, definitions, delivery requirements and how recalls can be ordered between RTO control areas, prevent suppliers from offering their ICAP services.

- *Transmission and Generation Interconnection Procedures:* Each RTO control area has specific and differing requirements for interconnection, generation or transmission. These differences create barriers to market participants and, in some cases, can bias the market to favor certain participants (GENCOs or TPs) over others.

- *Export Charges (Pancaking):* These charges must be replaced with a mechanism that takes pricing into account on a larger regional level instead of a smaller region. Larger regions will result in lower costs for electrical service. Charges include transmission service and ancillary services.

- *Other Emerging Issues:* 1) Control areas that share borders must use consistent scheduling procedures when controllable interconnections are present (phase-shifting transformers, FACTS devices, HVDC); and 2) Congestion between RTO control areas and unscheduled loop flow (parallel path) issues need to be coordinated better between RTO control areas so that transmission infrastructure can be better utilized and cost shifting prevented.

4.4.2 Geographic Inadequacy of RTO Proposals

Proposed RTOs consist of either a state-based RTO or multi-state RTO, not by interconnection. Accordingly, AC power flows in one RTO can impact AC power flows in adjoining RTOs. This impact may limit the amount of power that the adjoining RTO can transfer, therefore damaging its ability to adequately perform electrically and financially. These two issues are further explained below.

Parallel path flow occurs when electricity uses multiple, parallel paths to get from the generator to the customer or load (Figure 4-10). The resulting flows in one RTO can impact a neighboring RTOs ability to transfer electrical power (available transfer capacity). This is very undesirable and can cause operational issues and congestion on the bulk power system.

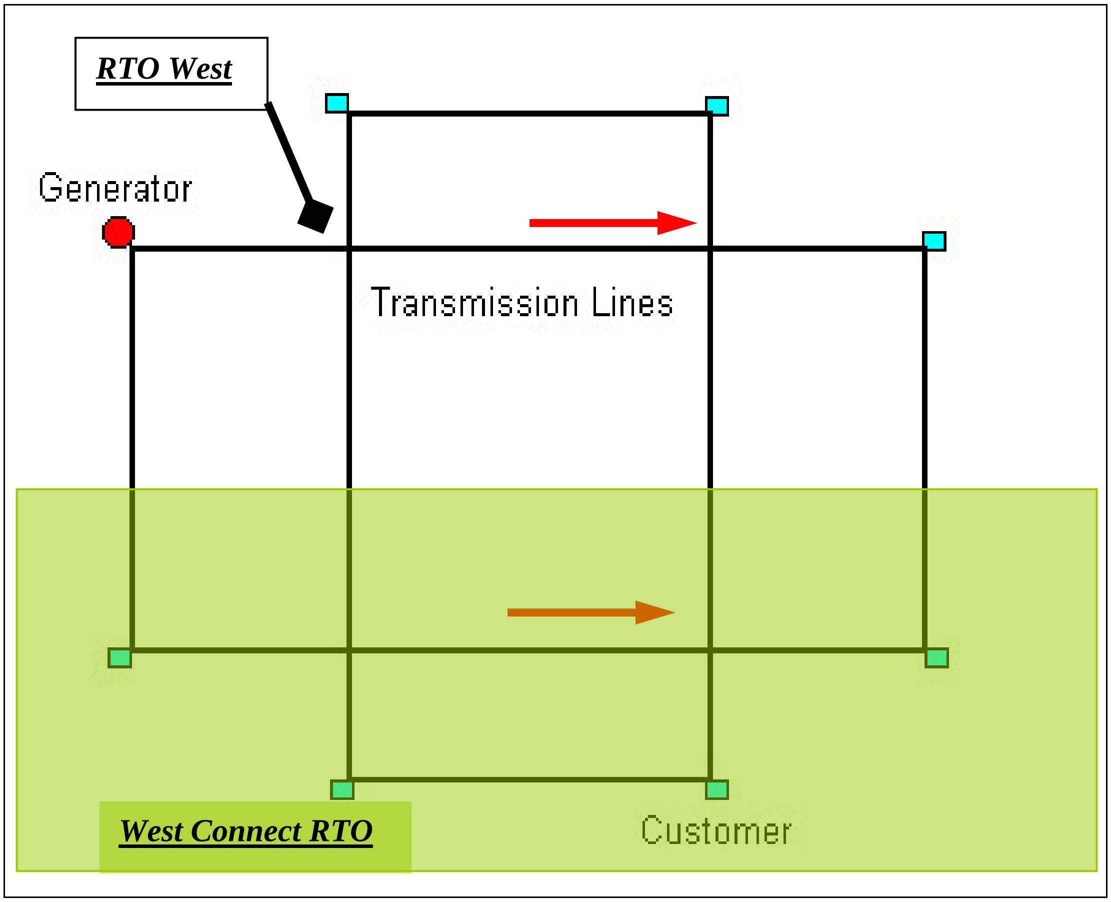


Figure 4-10 - Parallel Path Flows [37]

Loop flows occur when electricity flows through a neighboring RTO on its way from generator to customer or load (Figure 4-11). As in the parallel flow case, this negatively impacts how the neighboring RTO, West Connect RTO in this case, can operate their transmission system and recover embedded costs.

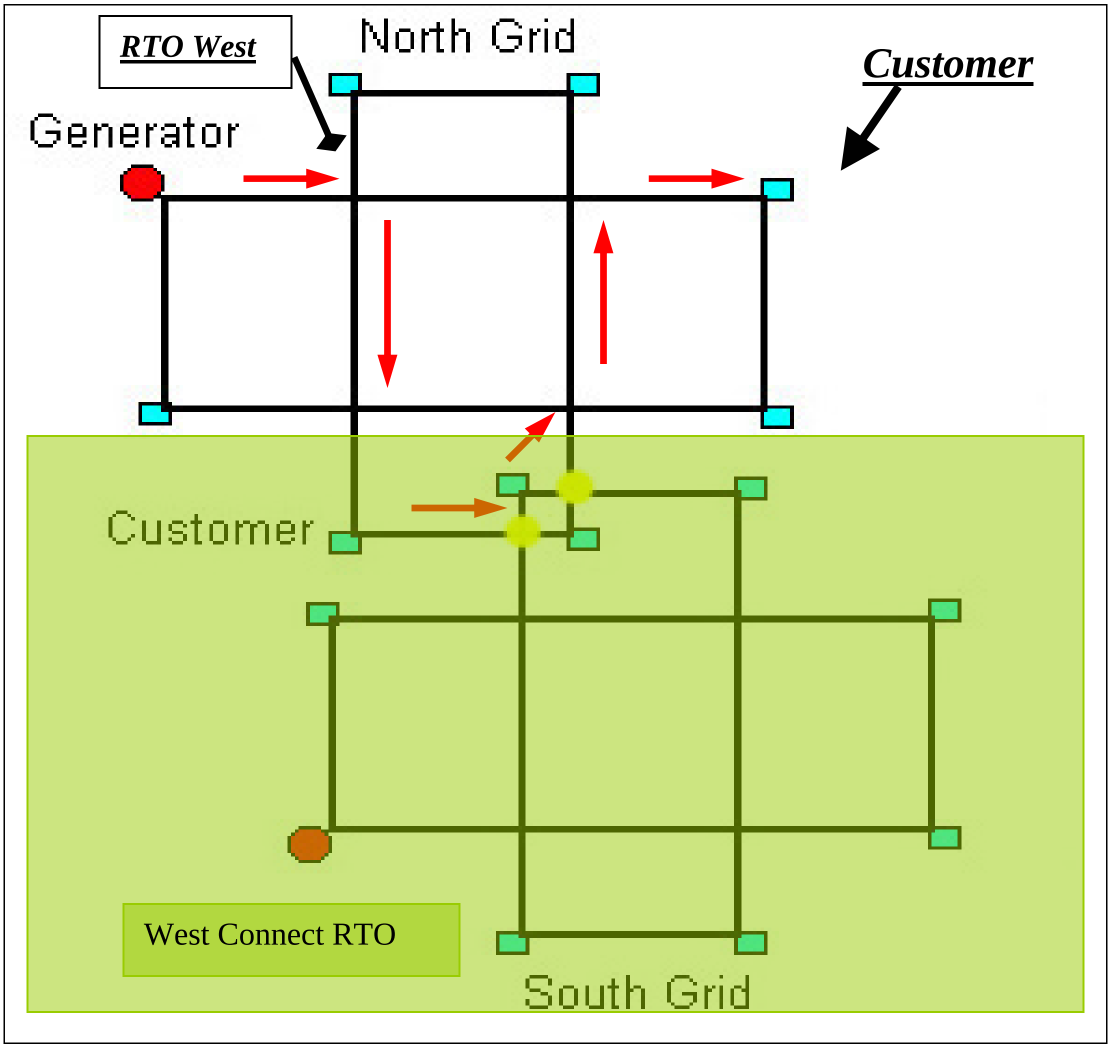


Figure 4-11 - Loop Flows [37]

Finally, RTOs in formation today are patchwork and are not continuous in their TO service territory (Figure 4-12) and they need to be in order to operate effectively. If RTO borders are non-continuous bulk, power transfer problems will arise, in that operations and financial accounting will be too difficult to manage effectively.

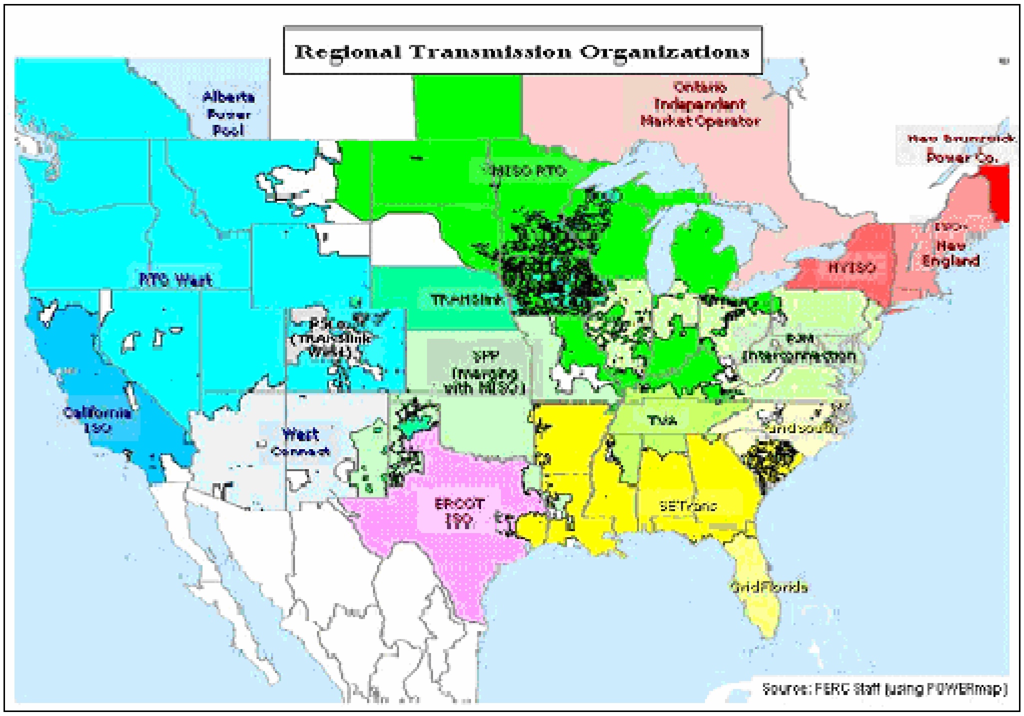


Figure 4-12 - Proposed RTOs 2003 [19]

4.4.3 Inaccurate Embedded Cost Accounting

Inaccurate embedded cost accounting results when multiple RTOs exist within an interconnection. This condition results in some people benefiting from the investment of others. Boundaries for determining embedded cost responsibility should reflect improved system response when elements, or infrastructure, are added to the system.

For example, if a shunt capacitor bank was added within the CAISO near the boundary of CAISO and RTO West service territories, both RTOs would benefit from improved voltage profile in that geographic area (Figure 4-13). However, only the CAISO would include the embedded cost into their rates and the RTO West embedded cost value would not change, hence, no corresponding rate increase. The same can be applied to other reliability improving system additions, power transfer capacity improvements, and many other bulk power system issues.

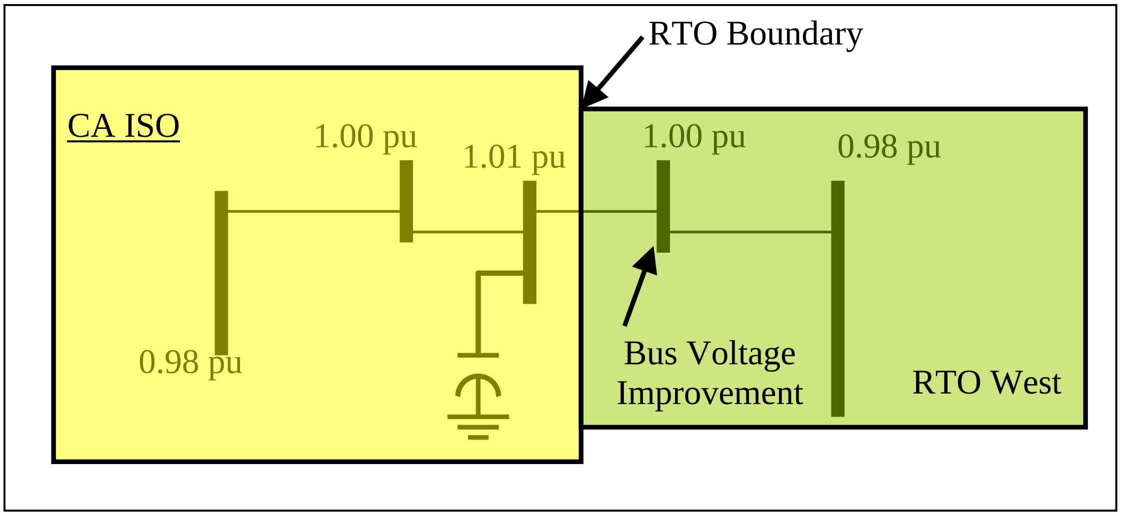


Figure 4-13 - Example of Inaccurate Embedded Cost Accounting

Service rates to recover embedded costs are based upon man-made geographic boundaries, as developed by the native utility service territory boundaries. These man -made boundaries do not accurately reflect who benefits from these electrical system improvements because they do not reflect the system response. Because of this approach, embedded cost responsibility is shifted inaccurately and inappropriately.

4.4.4 Post-Restructuring Electrical Energy System Operating Costs [14]

FERC requested a cost-benefit analysis study conducted by ICF Consulting to examine the potential economic benefits of an RTO landscape over the present system. This study might have critics, but for the purpose of this thesis, FERC's RTO study will be accepted, especially since it shows some objectivity in that it showed the larger RTOs to be more cost-effective than the five RTO scheme it supports.

The ICF study, completed in February of 2002, looked at three different scenarios, variances of the 32-system base case, all with varying numbers of RTOs. Quantities of RTOs studied were 10, 5 and 3. The "Base Case" scenario consisted of an industry configuration with 32 small regions, no RTOs (Figure 4-14). System costs for this base case were determined and are shown below. Three separate RTO landscapes were then modeled and the associated system costs of each landscape configuration were calculated. These three different landscape costs were then compared to the base case costs. The results show RTO-organized transmission results in reduced industry costs, which are summarized in the figures and paragraphs below.

- *Base Case – 32 Small Regions (Non-Restructured)*

Figure 4-14 - Base Case Regions [14]

Anticipated national system operating costs for this 32-region landscape are:

2004 – $89,493 million

2006 – $94,161 million

2010 - $109,489 million

2015 - $129,374 million

2020 - $149,758 million

- *Smaller RTO Landscape (10 RTOs)*

  This aspect of the study researched associated energy costs of ten RTOs throughout the U.S. (Figure 4-15).

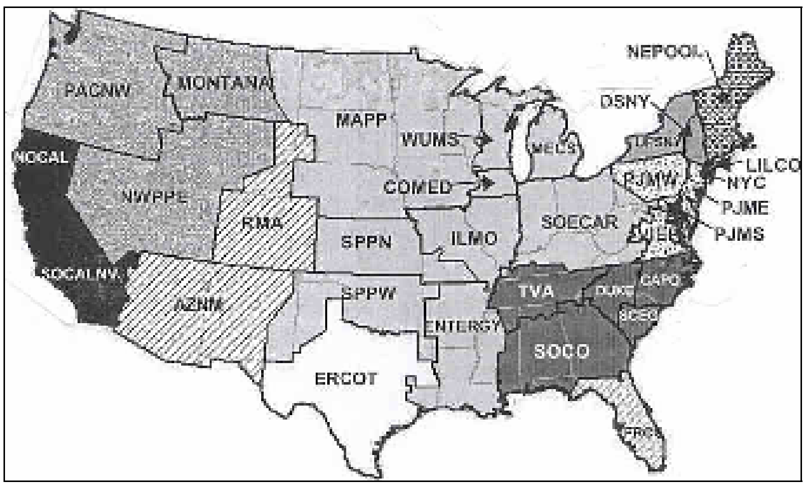


Figure 4-15 – Smaller RTO Landscape [14]

Anticipated cost savings of the smaller RTOs landscape (10-RTO landscape over the base case) are:

2004 – $1,041 million, 1.2%

2006 – $2,130 million, 2.3%

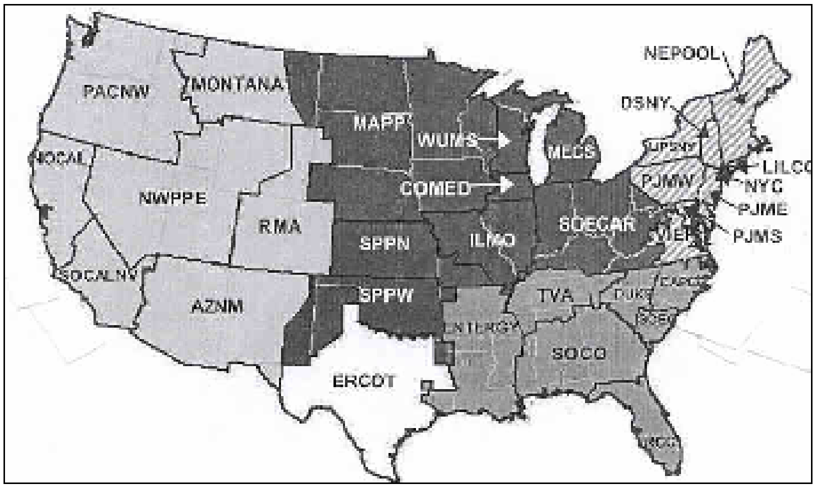
2010 - $5,171 million, 4.7%

2015 - $6,182 million, 4.8%

2020 - $7,390 million, 4.9%

- *<u>Larger RTO Landscape, Five-RTO FERC Policy Case)</u>*

  FERC envisions (prefers) five large RTOs nationwide (Figure 4-16). These RTOs would cover the Northeast, Southeast, Midwest, Texas and the Western Interconnect.



<u>Figure 4-16 – Five-RTO Landscape (RTO Policy Case [14]</u>

<u>Anticipated savings for the Five-RTO landscape (over the base case) are</u>:

2004 – $1,080 million, 1.2%

2006 – $2,189 million, 2.3%

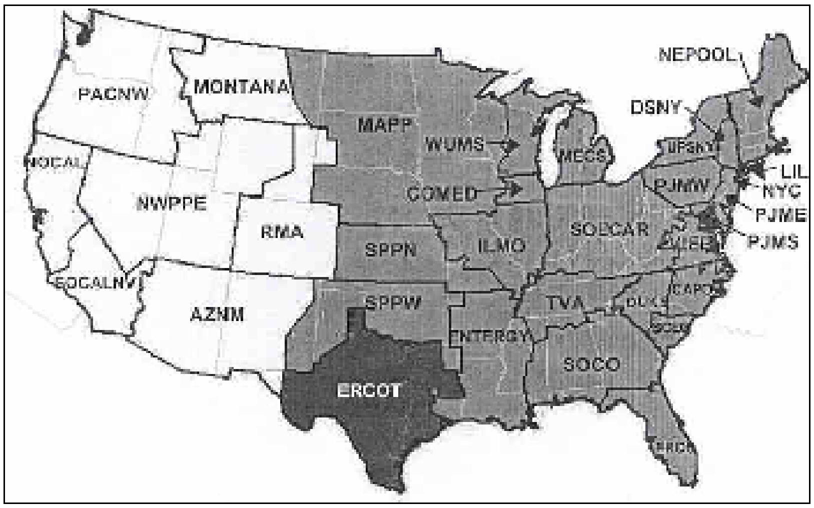
2010 - $5,235 million, 4.8%

2015 - $6,318 million, 4.9%

2020 - $7,470 million, 5.0%

- *<u>Very Large, Three-RTO Landscape</u>*

  This aspect of the study researched associated energy costs of three RTOs throughout the U.S. (Figure 4-17).



<u>Figure 4-17 – Three-RTO (Larger) Landscape [14]</u>

<u>Anticipated cost savings for this Three-RTO landscape (over the base case) are:</u>

2004 – $1,192 million, 1.3%

2006 – $2,267 million, 2.4%

2010 - $5,304 million, 4.8%

2015 - $6,374 million, 4.9%

2020 - $7,568 million, 5.1%

The results of this study show that transitioning to the RTO landscape results in lower electricity costs, both for industry restructuring and overall electricity costs in the future. The lowest costs result from the largest RTO landscape, which is made up of three RTOs. Following this data and the results of this study, it could be deduced that a two-RTO landscape would result in yet greater financial benefits to the electric utility industry and, therefore, all consumers.

4.4.5 Delays Restructuring Process

The myriad of RTOs proposed is causing the restructuring process to be delayed. Regional debates, review and approval of many RTO proposed operating guidelines, and jurisdiction issues between federal and state agencies, to name several, are specific examples of how the restructuring process is being delayed.

4.4.6 Inadequate Investment in Transmission

Because of the delayed restructuring process, much-needed investment in transmission infrastructure is not occurring. Finalizing restructuring will determine the "rules" for how the industry will recover transmission infrastructure investments.

4.5 Benefits of Thesis Restructuring Model

There are seven important benefits of this proposed transmission restructuring model. These benefits are broad, interdependent, and multi-faceted and, therefore, will be stated briefly first and then each benefit will be examined in more detail. The benefits of this thesis model are: 1) Ensured and Improved Transmission System Reliability (for Consumers); 2) Maintain Low Cost of Electrical Service, or Decrease Costs Further; 3) Accountability for Bulk Power System Reliability Established; 4) Restructuring Process Expedited; 5) Investment in Transmission Infrastructure Expedited; 6) Guidelines of FERC Orders 888, 889, 2000 and SMD/WMP are Met; 7) Federal Government Entities (created for efficiency, coordination and oversight).

4.5.1 Ensured and Improved Transmission System Reliability (for Consumers)

This model results in an interconnection-based approach to bulk power system reliability. A coordinated, proactive approach to system planning, addressing generation and transmission resource adequacy, would best meet the needs of the nation and states.

Adequate generation and transmission capacity would result from a proactive design and construction approach instead of reactive. The nation's economy and security must have a dependable electricity infrastructure system. If this includes times of moderate over-construction, this is a preferable situation than the one that confronts us today. The industry cannot wait for adequate return on investment figures to proceed with improvements to infrastructure. This is vital to the proper functioning of any large, interconnected bulk power system for the following three reasons. First, infrastructure additions require one-to-two years (system engineering and equipment manufacturing). Second, these additions are incredibly capital cost intensive requiring many years for investment recovery. Third, this industry must be proactive. Bulk power system infrastructure must be installed prior to when it is needed so that it will function properly when it is called upon to support the needs of a growing society and its security and economy – it must avoid boom-bust cycles.

National oversight and coordination would enable the high-voltage and extra-high-voltage transmission system design to be optimized. **This approach eliminates the "seams" issues by properly establishing the geographic boundaries of the ITO.** Since transmission issues impact an entire interconnection, across many states, it allows the laws of physics and man to peacefully coexist. Loop flows and parallel path flows will continue to occur, but these issues can be resolved within an interconnection as has been demonstrated historically.

Improved system performance would be attained by ensuring that appropriate amounts of transmission capacity existed within both interconnections nationwide. Determining adequate transmission capacity margins would be in accordance with NERC criteria (e.g., Functional Model replaces the Operational Manual). Initially, the present first-contingency approach with a 30-minute loading relief requirement would be used. Eventually, the first contingency approach could be supplemented with a constant transmission capacity margin criteria of 15-20 percent combined with an transmission capacity alert system for capacity levels under 15 percent (e.g., 10 percent = Stage 1 alert, 5 percent = Stage 2 alert, and 2 percent = Stage 3 alert).

The associated costs of increasing transmission capacity would be offset through reduced "loss of service" costs to customers plus the anticipated benefits of the deregulated generation sector. Typical "loss of service" costs are:

- Loss of life
- Lost revenue
- Labor costs
- Equipment and process costs

Increasing transmission capacity reserves will help prevent electricity service-related deaths and result in cost savings. First, it provides the best "return on investment" or "bang for the buck" since it's the most cost-effective sector (0.22 percent of GDP, 10 percent of electric utility industry costs) and second, it allows for improved system operation flexibility and enhances system reliability by providing a bigger "shock absorber" to protect the system against disturbances (system short circuits or "faults") both natural (weather related) and anticipated (terrorism/vandalism). To illustrate this point, and as evidenced by the recent August 14, 2003 blackout in the northeastern

US (and portions of Canada), two lives were lost and revenue losses within New York City alone totaled approximately $1 billion dollars. A preliminary estimate to upgrade the entire transmission system within the US is $9 billion dollars.

Research and development (R&D) activities in the transmission sector would be coordinated and continuous. These new technologies would be spread throughout the nation where applicable and would help to reduce costs and improve reliability. Examples are flexible AC transmission systems (FACTS), Convertible Static Compensators (CSC) that allow more efficient use of existing infrastructure, and super conductors. The cumulative effect would be reduced service costs through better use of existing infrastructure, while reducing the amount of environmental impact.

Interconnection-based ITOs would result in quicker restoration of service during emergencies, through improved cooperation between regions instead of potential competition between regions.

Finally, reliability requirements for transmission should be created so their performance can be analyzed. Reliability indices similar to those used in the distribution sector (e.g., SAIFI and SAIDI) would be implemented. These indices could be based on per-line outages, by means of either a fault or maintenance requirements.

As for generation, this coordinated approach would also allow an optimal balance between central-station and distributed-generation resources, resulting in optimal electrical system reliability and security. In addition, optimal installed-fuel diversification could be ensured. The result would be not only adequate generation resources but a system more reliable and less prone to large price swings due to lack of a specific fuel type (e.g., natural gas). Fuel diversity needs to be maintained for long-term industry integrity and volatile, crippling price swings. This should also be the responsibility of the NPA and ITOs.

Development and introduction of new technologies for generation (solar, wind, and other renewables or improved efficiencies) would continue through the improved oversight functions proposed within this thesis.

Finally, there should be no foreign involvement in any aspect of the U.S. electric utility industry so that security and reliability are retained. This would apply to any form of ownership and operations/control of generation and transmission.

4.5.2 Maintain Low-Cost Electricity Service, or Decrease Costs Further

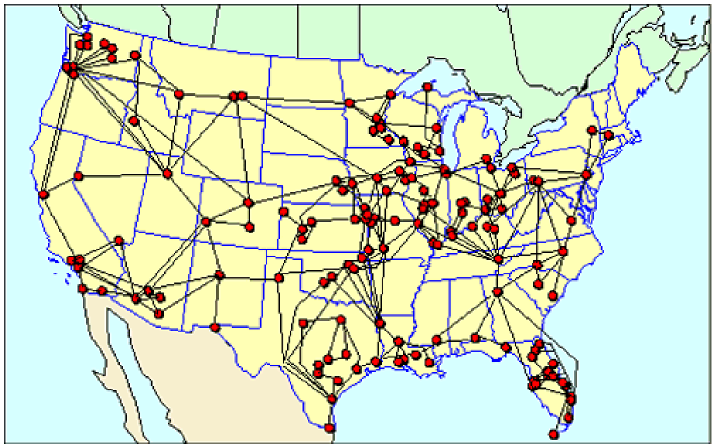
Cost-effective electricity will continue as long as excessive overbuilding of infrastructure is avoided and operations are streamlined. If resources are optimized, it follows that industry costs are minimized, hence, costs to consumers are minimized. The model proposed in this thesis promotes a "best design" philosophy through optimizing capital costs and operational costs of losses. The long-term effect will be lower industry operation costs, and, therefore, lower costs for transmission service to customers. This will be seen in terms of both service rates and costs associated with loss of service.

Specific examples of how this model would reduce long-term transmission service costs are: 1) larger geographic ITOs; 2) improved use of resources through high-voltage and extra-high-voltage interconnections; 3) elimination of redundant functions ranging from control area operations to regulatory oversight; and 4) improved accuracy of service rates.

First, as was reviewed in the previous section, restructuring the transmission sector into larger geographic areas (fewer RTOs) results in lower operating costs for the electric utility industry. Customers would see this reflected in their service costs. Included in this broad statement are the anticipated cost benefit of deregulating the generation sector and improved design efficiency of the bulk power system. A projected benefit of this model would be the eventual transition to a single AC interconnection across the entire nation.

Second, improved use of resources through high-voltage and extra-high-voltage interconnections can be explained by examining the inclusion of ERCOT into the Eastern interconnection. Presently, the generation reserve margin within ERCOT is 30 percent at times [6]. This is a high level of reserve margin that could be shared with other regions within the US. Not only would that capacity assist electricity starved regions in the U.S., but also it would reduce the cost for electricity within Texas. Another result would be improved use of resources (fuel), which is good for the nation. Excess transmission and generation capacity can be used to benefit others in the region. Service reliability is enhanced and generation facilities are used more effectively (with a more inter-connected transmission system).   One last resource use improvement would be the enhanced use of existing transmission infrastructure and right of ways (ROW) through the use of FACTS and CSC systems.

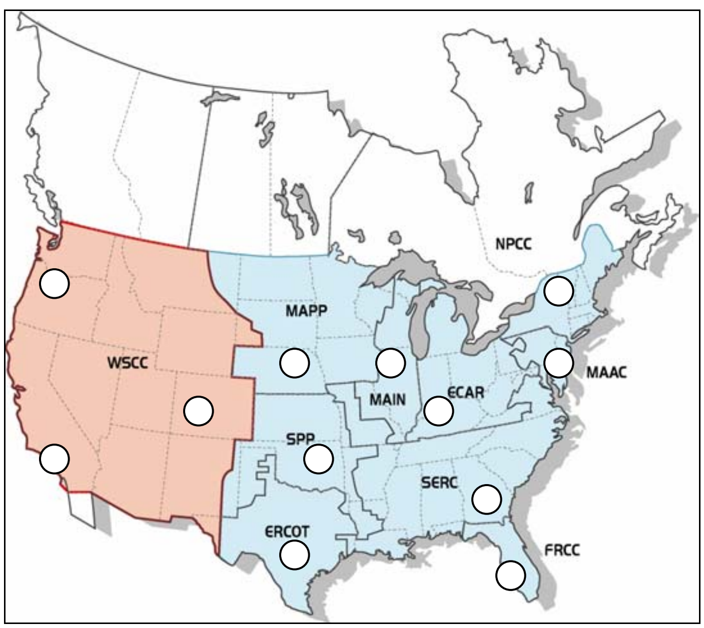
Third, specific examples of eliminating redundant functions are control area consolidation and regulatory oversight. The geographic responsibility for existing control areas (CA) would increase, thereby centralizing operations and easing coordination issues. Initially, existing CAs (Figure 4-18) would function as they do today.



- Control Areas (Present-Day) [20]

Figure 4-18 - Control Areas (Present Day)

In the not-too-distant future, they would consolidate to one CA per reliability council in the Eastern interconnection and three (or perhaps one) in the Western interconnection (Figure 4-19). The previous CAs would be used as a backup if there was ever a need.



- Indicates New Control Areas

Figure 4-19 - Control Areas (Proposed)

Ultimately, if deemed appropriate after gaining operational experience, further consolidation of CAs could continue. This ultimate architecture would consist of one CA per entire RTO with several regional sub-control areas to balance load and generation within the overall, larger CA. Another anticipated benefit of CA consolidation would include improved system operation in real time, as a result of simplification of power transfer processes.

Regulatory oversight of all transmission would occur at the federal level. This would result in smaller government, in that 20 federal regulators would replace the present 49, assuming one regulator per state, not including Alaska. There is precedence for this shift is jurisdictional authority. In the early 1900s, states assumed jurisdictional authority over VIUs although local governments wanted it [10]. Transmission was a state issue back then. Now, transmission is an interstate issue and should be regulated accordingly. This will be discussed in greater detail in the next section.

Regarding design functions, regional coordination for facilities design through proper alignment and application of industry standards (NESC, IEEE, ANSI, ASCE, etc.) as they apply to NESC loading regions, climate data, seismic activity, lightning frequency, etc., would eliminate redundant design responsibilities - which will be required given the decreasing numbers of engineering professionals entering the industry.

Fourth and finally, pricing mechanisms are improved. Pancaking of rates is eliminated, cost shifting is minimized and "participant funding" is removed. Pancaked rates and cost-shifting issues are addressed through the use of zonal transmission pricing combined with bilateral contracts (long and short-term) initially. Spot energy markets would cover the balance of energy transactions. Eventually, the pricing mechanism for transmission service would transition to "Actual Path Pricing"

(APP) to be developed in the not-too-distant future. With APP, stranded costs in transmission infrastructure will need to be addressed similar to what was done in the wholesale, or generation, sector. Transmission service cost protection will be provided through FERC's authority to approve service contract modifications. Pricing mechanisms proposed for this thesis – zonal, initially and APP in the future - will be discussed in a later section.

4.5.3 Improved Accountability Through Creation of NPA & ITOs

This new agency, NPA, and the ITOs it oversees, will coordinate and manage central functions required for a viable bulk power system. The NPA would be responsible for the bulk power system of the United States, specifically, resource adequacy, operations, and overall coordination of generation and transmission capacity. It will operate similar to the Federal Highway Administration in coordination of industry activities (e.g., anticipated projects, distribution of R&D nation wide). Detailed responsibilities of this agency will be discussed in the next section.

As federal agencies, they will operate in an objective fashion, and will ensure fair application of industry rules and guidelines for all participants (e.g., market oversight and mitigation of market power). FERC would continue the regulatory oversight role it possesses today, with possible expansion of personnel, if deemed appropriate.

Technical guidance would continue to be supplied by NERC, regarding system reliability and operations. Industry data would continue to be gathered by the Energy Information Administration. The importance of this information would be elevated to assist in evaluating proper resource adequacy and fuel diversity within the US.

Industry watchdogs, such as American Public Power Association, would continue to perform their important role.

4.5.4 Expedite Restructuring Process

Presently, the industry deregulation and restructuring process is at a standstill due to a myriad of unresolved industry issues (e.g., seams mitigation) and legal disputes regarding FERC authority.

Under this thesis model, industry operations would remain essentially the same, with the exception of the jurisdictional shift regarding transmission and generation and the creation of the NPA. The FPA would need to be amended to assign FERC-enhanced jurisdiction over the entire transmission sector. The NPA would need to be created under an amendment to the DOE Organization Act.

Seams issues, regional debates and lengthy legal disputes would be eliminated through establishment of proper ITO geographic boundaries and FERC jurisdictional responsibilities – which this model proposes. Examples of regional debates and legal disputes include jurisdictional authority of Federal vs. State regulators and, opposition to FERC rulings by utilities, generators, and other entities, between utilities, and between utilities and GENCOs.

Existing service contracts would be reviewed and approved if appropriate.

4.5.5 Expedite Transmission Infrastructure Investment

The uncertainty in final restructuring rules is resulting in inadequate investment in transmission infrastructure. Investors will not invest money without knowing how they will recover their investment. This sector will remain heavily regulated since it is still a natural monopoly.

This model proposes guaranteed rates of return on transmission infrastructure investment similar to the cost-based industry operations before deregulation efforts began. This assures investors their investment will pay dividends. With a guaranteed percentage rate of return on investments, typically near 10 percent, investors will surely invest in the transmission sector, especially considering recent stock market performance (scandals and losses).

In addition, to expedite investment in congested transmission corridors, "incentive" rates of return for congestion-relieving infrastructure will be offered. Incentive returns will earn more than typical transmission investments, proportional to the amount of congestion relieved. This provision concentrates the majority of investments at the biggest problems the bulk power system faces today. The result of this concentrated effort will be the quick removal of transmission congestion.

4.5.6 Guidelines of FERC Orders 888, 889 and 2000 Met or Exceeded

Guidelines of the FERC Orders, as summarized in Chapter 3, are met or, in many cases, exceeded.   FERC approval of this restructuring architecture would be guaranteed and the process to revitalize this needed sector could start quickly.

4.5.7 Federal Government Agencies with Enhanced FERC Jurisdictional Authority

There are many benefits to these entities being within the federal government, as discussed within the paragraphs below.

First, unbiased oversight over industry operations would ensure fair application of industry rules. Second, elimination of redundant state functions would result in reduced electricity service costs. Third, coordination and management of the nation's bulk power system would be improved. Ultimately, they would operate in the best interest of the nation, states and customers, since this is the top priority.

As mentioned previously, FERC would possess jurisdiction over all transmission (wholesale, unbundled and bundled retail) in accordance with Order 888, while working with states for the good of all parties.

Effective market power mitigation would result from the neutral/non-biased government agencies and their authority to operate the bulk power system fairly with the best interest of the system as their goal. For example, elimination of present-day market power abuses such as, transmission loading relief (TLR) abuses, through establishment and enforcement of consistent ATC/TTC calculators for all market participants.

Eminent domain authority is possessed by federal government agencies. This authority will provide the ability to build much needed infrastructure ensuring the viability of the bulk power system. It would only be used for the betterment of the nation where necessary. Hopefully this authority will never be used and/or abused with issues being resolved amicably.

The NPA and ITOs would make industry rules easier to understand, through centralized, consistent policy creation, implementation and enforcement. This would assist in enacting and resolving industry requests, complaints, and/or recommendations.

Market monitoring authority would be simplified since there is one set of rules per interconnection that all participants must adhere to.

This proposed restructuring architecture will reduce the size of government while adding a necessary agency. This architecture will add the NPA, a coordinating body, at the federal level, similar in need to the Department of Homeland Security; however, it will most likely reduce the overall size of government because redundant functions performed at the state level will be eliminated.

4.6 The Restructured Transmission Sector: How It Will Work

This section will look at the following in greater detail: 1) Architecture of the Restructured Transmission Sector; 2) Organizational Structure for ITOE and ITOW; 3) ITOE and ITOW Responsibilities; and 4) Transmission Service Pricing Mechanisms.

This section includes many typical examples of what could or should be feasible. It is outside the scope of this document to develop a comprehensive list of all requirements: organizational needs, responsibilities, and operations for the NPA, ITOs and the architecture of the bulk power system they operate. The concepts developed herein are intended to be a framework, at times tight and other times somewhat loose, upon which to restructure the transmission grid for the benefit of all the United States' citizens. Perhaps future theses could develop certain aspects of this more general work in greater detail.

4.6.1 General

Transmission is by nature a regional service issue and, therefore, an interstate concern. What happens in Wyoming or Montana effects the grid in California, Arizona and all states in between (e.g., – the 1996 widespread outages throughout the Western U.S. and the 2003 blackout of the northeastern U.S. and parts of Canada). This happens almost instantaneously because electricity moves near the speed of light over a low impedance network. To illustrate this point, electricity takes eight-thousandths of a second to cross the U.S. from Canada to Mexico.

Transmission is also still a "natural monopoly" which demands it be implemented as such and regulated by an overseeing agency, commission or like entity.

For the previous two reasons and others previously addressed, the transmission sector of the electric utility industry must have federal, not state, oversight. This was recently upheld by the Supreme Court of the United States for unbundled wholesale transmission and unbundled retail transmisson service. This authority should be extended to all aspects of transmission including retail bundled transmission service consistent with the Order 888 "tests" which determine distribution from transmission facilities. **This shift in jurisdictional authority, however, would also result in a shift in responsibility and accountability. This increased authority would make the federal government responsible for the reliable planning, operation and maintenance of the transmission system and accountable to the customers it serves, a function that has been and is presently the responsibility of each state and/or RTO.**

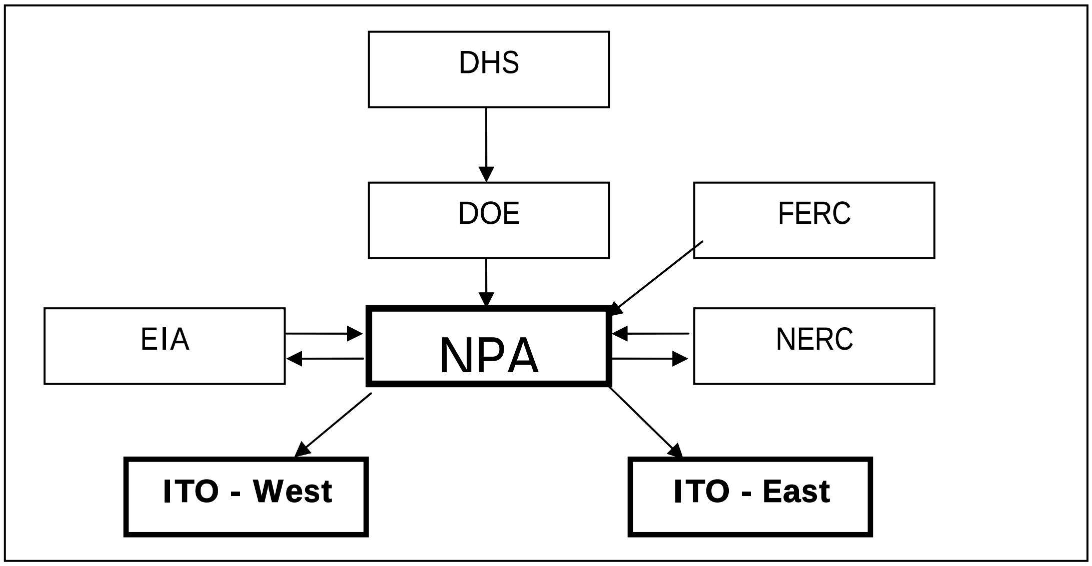


__Figure 4-20 - Architecture of Restructuring Proposal__

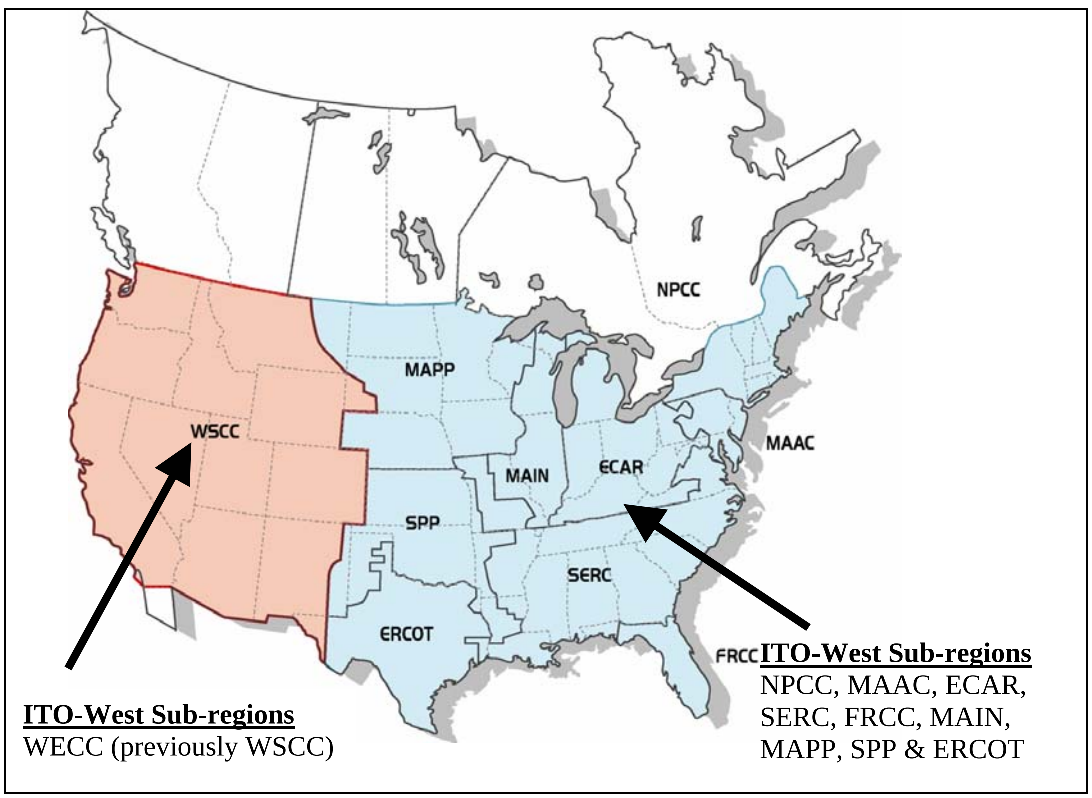


__Figure 4-21 - Architecture of Proposed ITOs__

Roles states would play concerning jurisdictional authority will change slightly to reflect the industry changes. States would continue their present role concerning local transmission matters where the state would be impacted. Some typical state matters would be line routing (with distance parameters given by the ITO to address impedance concerns), siting of substations, siting of communications stations, environmental requirements and other similar issues.

Where the generation sector is concerned, states would retain jurisdictional authority over the generation sector concerning state-specific issues like siting, environmental issues like pollution levels, water use, and other like issues. If a state wanted more generation reserve margins than what NERC recommends, then that state's populus would pay the associated costs. The ITO would establish and enforce system reliability issues such as installed generation capacity, interconnection requirements, with input from the host state, and other similar issues.

Finally, the distribution sector and all service issues associated with it would be the responsibility of each individual state. Distribution falls outside the scope of this document and will not be addressed to the extent of the transmission or generation sectors.

Therefore, the predominant regulatory body regulating and overseeing all transmission and generation adequacy within the United States would be the NPA and the ITOs they oversee under FERC jurisdiction or regulatory oversight.

4.6.2 Transmission Sector Architecture After Restructuring

It is proposed the present-day, non-continuous patchwork of twelve RTOs be reduced to two large transmission systems – one for the Eastern Interconnected Transmission System and one for the Western Interconnected Transmission System (Figure 4-21).

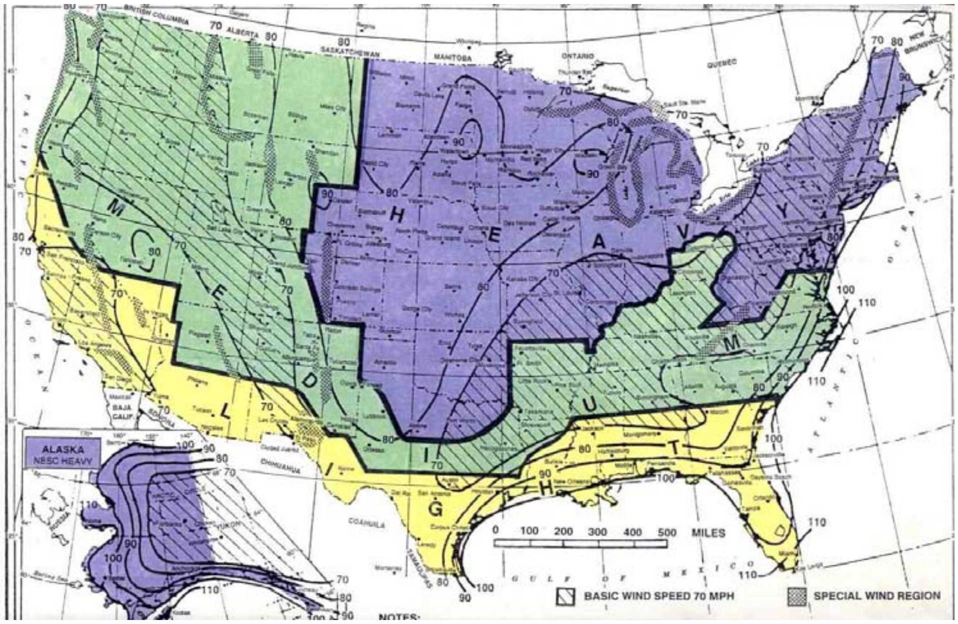
Each of these two systems would be operated by a single independent transmission operator, and for this thesis they will be called Independent Transmission Operator – East (ITO-East) and the Independent Transmission Operator – West (ITO-West). Both ITO-East and ITO-West would be federally operated entities under FERC jurisdiction.

NERC is changing its title to North American Electric Reliability Organization (NAERO) but would continue its technical guidance, operations guidance and E-Tagging system, and reliability oversight role (Figure 4-20).

ITO-East would be responsible for overall operation of the Eastern interconnected bulk power system (EI). The geographic scope would encompass the Eastern interconnection and ERCOT. Initially, its operations and control area architecture would follow the nine NERC sub-regional reliability councils (RC) in operation today. Any regional transmission groups (RTG) operating today would be absorbed into the RC in which they are located. In the future, these nine RCs may be consolidated into a smaller number of RCs if it is determined this would be beneficial to the bulk power system. To maximize transmission system reliability and generation resources, in the nation's best interest, ERCOT would be absorbed into the Eastern (or Western) Interconnect. Studies would need to be performed to ensure acceptable system performance, but the DOE National Transmission Grid Study states generation capacity within ERCOT exceeds load requirements by 30 percent at times. This figure would lead one to believe that integration with the Eastern Interconnect (or Western) is feasible. That can be the study of another thesis at a later date.

ITO-West would be responsible for the operation of the Western interconnected bulk power system (WI). Initially, it would be organized into the sub-regional RC in operation today (WECC), including any RTGs within the region, like has happened within the WSCC, now termed WECC. Control areas would be consolidated into three, as shown previously. Additional studies would need to be performed to finalize this architecture. In the future, this number might be reduced if operational and cost-benefit studies deemed this appropriate. The geographic/regional scope would encompass the WECC as it exists today.

This initial organization would expedite restructuring since each ITO would consist of sub-regions identical to those that comprise the NERC reliability councils (RC) in operation today. Over time, if it was determined to be beneficial and more efficient, these reliability councils could be merged or reconfigured in a manner that would improve the performance of the grid and possibly reduce the cost of electricity service. One recommendation for reorganizing future RCs would be geographically based. Similar to how the NESC organizes its facility loading areas' guidelines, the RCs would be specialists for their particular area. This would remove overlap and inefficiencies between climatically similar regions (Figure 4-22). Other criteria for RC configuration might include altitude, amongst others, which would be studied to determine an adequate organizational structure. Of course, this RC reorganization would be performed by electrical interconnection.



*** Map from National Electric Safety Code**

Figure 4-22 - Future NERC Regions by NESC Loading Criteria

Finally, utilities that own transmission facilities would complete the restructured industry architecture by participating within the RC they presently operate in and either one of the ITOs, depending if they are in the Eastern interconnect or Western interconnect (Figure 4-21). If one transmission owner owns facilities in both ITOs, those facilities within the Eastern interconnect would be operated by ITO-E and similarly for the Western interconnect.

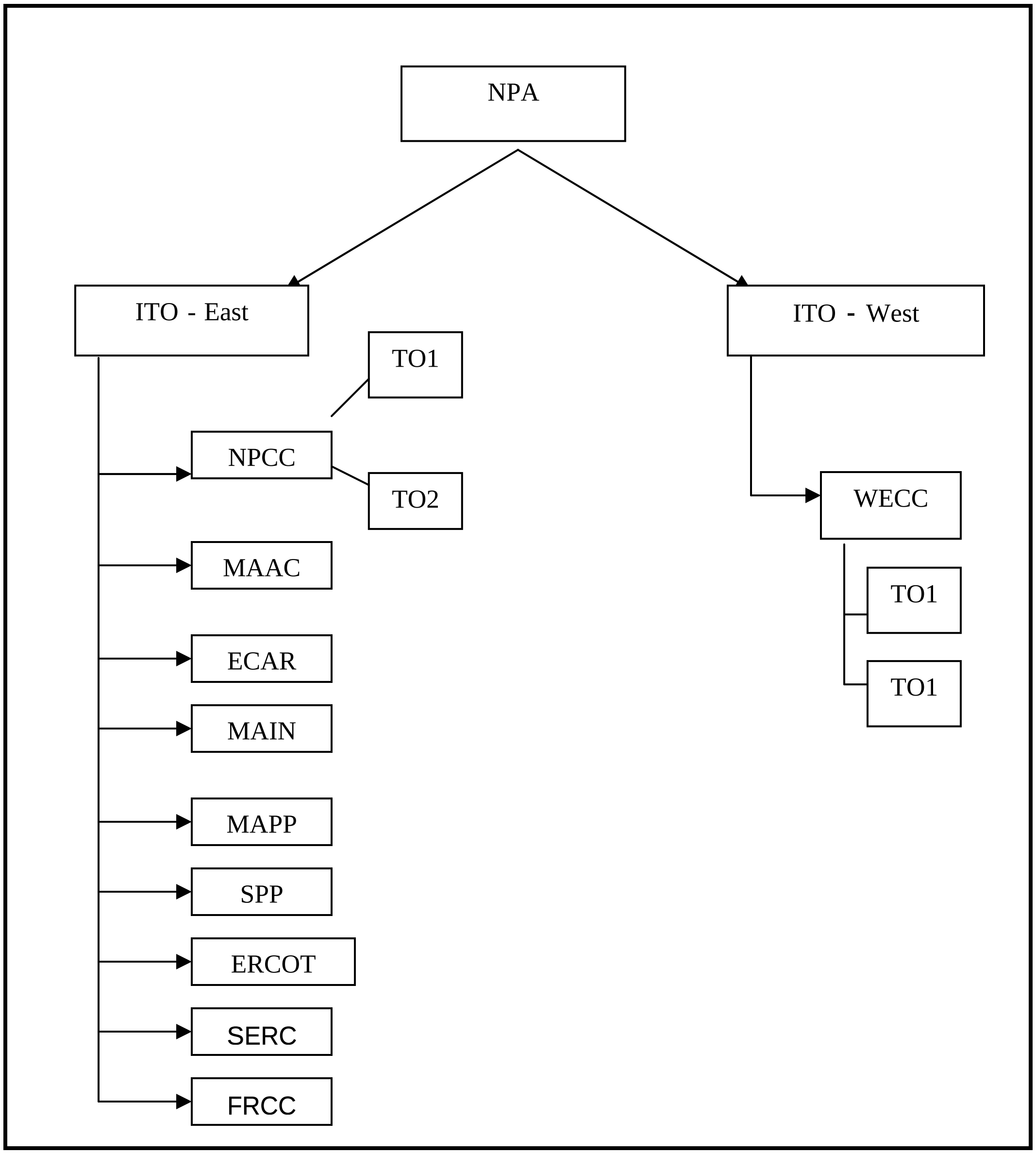


Figure 4-23 - Transmission Owner Architecture

Again, the industry architecture and operation would remain essentially the same and this will expedite the transition process.

All utilities, profit or non-profit, would be included in this restructuring model for both ITO-East (Figure 4-24) and ITO-West (Figure 4-25), as shown in greater detail below.

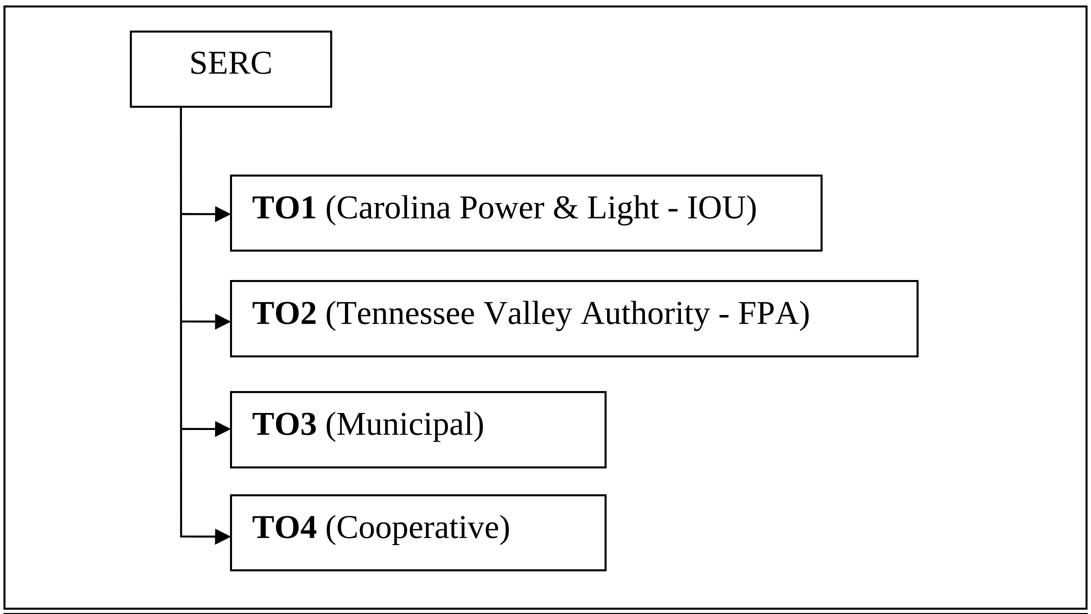


Figure 4-24 - ITO-East Architecture (typical)

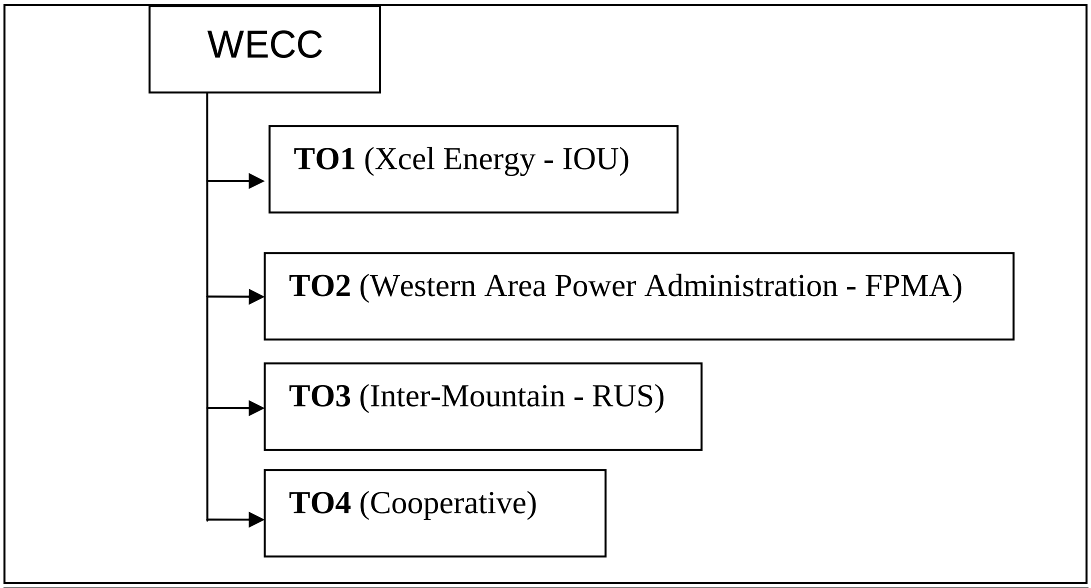


Figure 4-25 - ITO-West Architecture (typical)

Optimizing local and regional generation is the most economical way to supply low-cost and reliable electrical energy because of losses on the transmission system. Until cost-effective superconductivity of 60 Hz electrical power is developed, a combination of the following aspects will result in the lowest cost, highest reliability and most efficient way to deliver electricity to customers.

1. Optimal local and regional generation,
2. High-voltage or extra-high-voltage AC transmission systems of a limited distance, or
3. High-voltage DC transmission Systems beyond the AC distance limitation.
4. Improved transmission system capacity and performance within existing rights of way (ROW) through application of FACTS and CSC devices where congestion exists. These installations evenly distribute loading across parallel transmission lines, resulting in full use of their power delivering capability.

5. Increase transmission line power transfer capacity within existing ROWs by replacing inefficient, single conductor phase conductors (e.g., linear alignment) configuration with bundled phase conductors arranged in a more efficient (fewer losses) configuration (e.g. – delta). Of course these are just examples of possible configurations; system planning would model and test various configurations and phase conductor assemblies to meet the transmission system requirements.

Customers in California and the Northeast may pay more for electricity if it is imported from remote areas of the U.S. (due to transmission system losses) rather than generated locally (NIMBY, BANANA, NOPE).

4.6.3 Responsibilities After Restructuring

To ease difficulties associated with this transition, especially one of this scale, the responsibilities of the various entities within the industry would remain essentially the same, as explained below.

4.6.3.1 General

A myriad of functions must be performed for an electric supply system to operate effectively and efficiently. This section will address which industry regulatory entity - federal or state (either NPA and ITOs under FERC jurisdiction at the federal level or State PUCs) - will be responsible for oversight of the electrical utility industry.

4.6.3.2 Responsibilities of Federal Agencies (NPA, ITOs and FERC)

Responsibilities listed in this section apply to the NPA, ITO-East and ITO-West with FERC oversight. They are organized into the following areas: 1) Transmission; 2) Generation; 3) Ancillary Services; and 4) Demand-Response.

In general, these responsibilities are shown below (Figure 4-26).

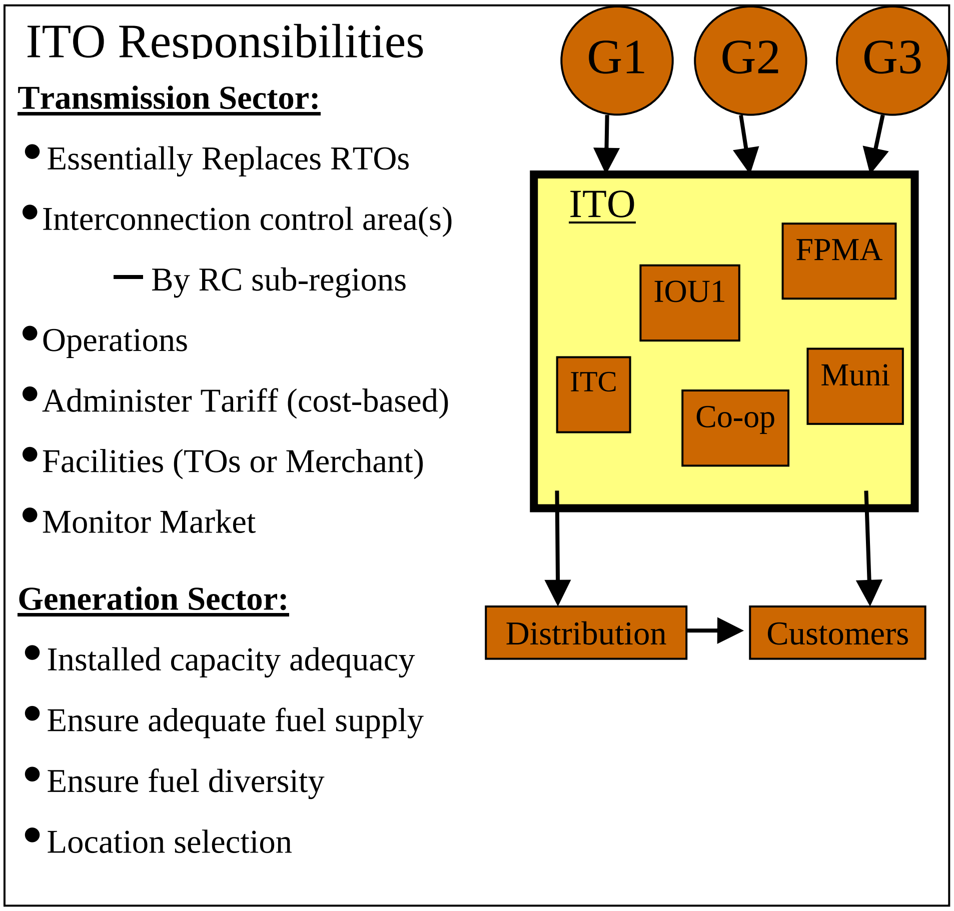


Figure 4-26 - NPA and ITO Responsibilities

The NPA and ITOs, with FERC oversight, will ensure reliable and just electrical service as their “mission statement” at the federal level. They will achieve this through control of the bulk power system (generation and transmission sectors). In general, the NPA and governing ITOs will be responsible for ensuring adequate generation and transmission capacity, as well as operation of those sectors for their respective interconnection. In addition, it will ensure that adequate fuel for generation is supplied. This section reviews the specific functional responsibilities as they pertain to the areas of transmission, generation, ancillary services and demand-response.

Transmission: Jurisdiction over wholesale, unbundled and bundled transmission would belong to FERC as outlined in Order No. 888.

The NPA and ITO must prevent boom/bust cycles and, to that end, would be responsible for overall transmission system operation and performance. The parent ITO would oversee all system planning. It would perform planning internally or receive, review and approve/deny proposed system additions from the member transmission owners. System planning is the first step in the power system design process and includes many discreet functions, some of which are:

- Long-Term Load Forecasting
- Long-Term Generation Requirement Forecasting
- Steady-State Load Flows
- Power System Transient Stability Analysis
- Power System Steady-State Stability Analysis
- Fault (Short-Circuit) Studies
- Power Transfer Studies
- Interconnection Studies
- System Impact Study (system modification requirements and associated costs)
- Application of FACTS
- Review 3rd Party Proposals for System Additions

The system planning function is vital because it determines how the system - and the equipment which comprises it - will function.

Public involvement in the system planning process should also occur. This will expedite the addition of required system upgrades (transmission lines, switching stations and substations), while promoting the system and garnering increased public support.

The ITO would be responsible for transmission service pricing and enforcement (with NPA and FERC oversight). This will be discussed in greater detail later in this thesis.

The NPA and ITOs would be responsible for following NERC's new "Functional Model," which is replacing the Operational Model. System planning would be performed by interconnection, initially using the RC geographic organization and ultimately consolidating to fewer RCs with larger geographic responsibilities.

The ITOs, NPA and FERC, would have oversight authority for market power and their mitigation. They would operate the OASIS – initially by the nine RCs, which could be consolidated to three if deemed appropriate.

ITOs would institute energy emergency alert levels for transmission to ensure reliability. Assuming 15-20 percent transmission reserve margins, whichever margin deemed best, perhaps the following emergency stages could be used:

- Stage 1 – 10%
- Stage 2 – 5%
- Stage 3 – 2.5%

Reliability standards would be developed (e.g. SAIDI, SAIFI) and oversight performed to grade the transmission system and TO performance (similar to the distribution sector). Perhaps these indices could be based on line outages. Further reliability issues would be addressed through the selection of appropriate substation and switching station configurations (based upon cost-benefit criteria developed specifically for this purpose).

Engineering standards for infrastructure would be coordinated through the ITO to optimize use of resources.

Maintenance would be performed by the member TO, and would be diagnostic-based.

Generation: The ITO must avoid boom/bust cycles in this sector. To that end, its responsibilities for this sector would include addition of new generation to replace aging infrastructure and load growth to ensure reserve margins. The ITO would operate the bid-based generation market and queue. In addition, it would ensure adequate regional generation capacity reserve margins (minimum of 10 percent, maximum of approximately 15 percent). Real-time system monitoring would also be performed and, if necessary, issue emergency alert levels for inadequate generation capacity. Possible alert levels may be:

- 10% - Level 1
- 5% - Level 2
- 2.5% - Level 3

The ITO would develop an optimization plan for generation capacity. This plan would include both large, central-plant generation located remotely near fuel supplies, combined with high-voltage and extra-high-voltage transmission, and smaller, distributed generation facilities nearer the load they serve. Another key element to this plan would be to ensure adequate generation fuel diversity. It is outside the scope of this thesis to address the generation sector in any more detail.

Ancillary Services: The ITO would be responsible for operation and performance of the bid-based ancillary services market. The ancillary services are defined in Order No. 888.

Demand-Response: The ITO would be responsible for operation of the consumer-based demand-response market. This market involves customers bidding their ability to lose services if ever there is a need.

To summarize, bulk power systems demand proactive, up-front planning due to the lengthy lead times required for adding bulk power system infrastructure. Adequate performance of these functions should ensure proper bulk power system operation by maximizing reliability while preventing dramatic price swings for electricity service.

4.6.3.3 State PUC Responsibilities

Each state will continue many of its regulatory responsibilities under this proposed restructuring plan (Figure 4-27). Parent states will continue to be responsible for ensuring just and reasonable rates for distribution and will retain certain aspects of power system regulatory oversight. This section reviews the specific functional responsibilities as they pertain to the areas of transmission, generation, ancillary services and demand-response.

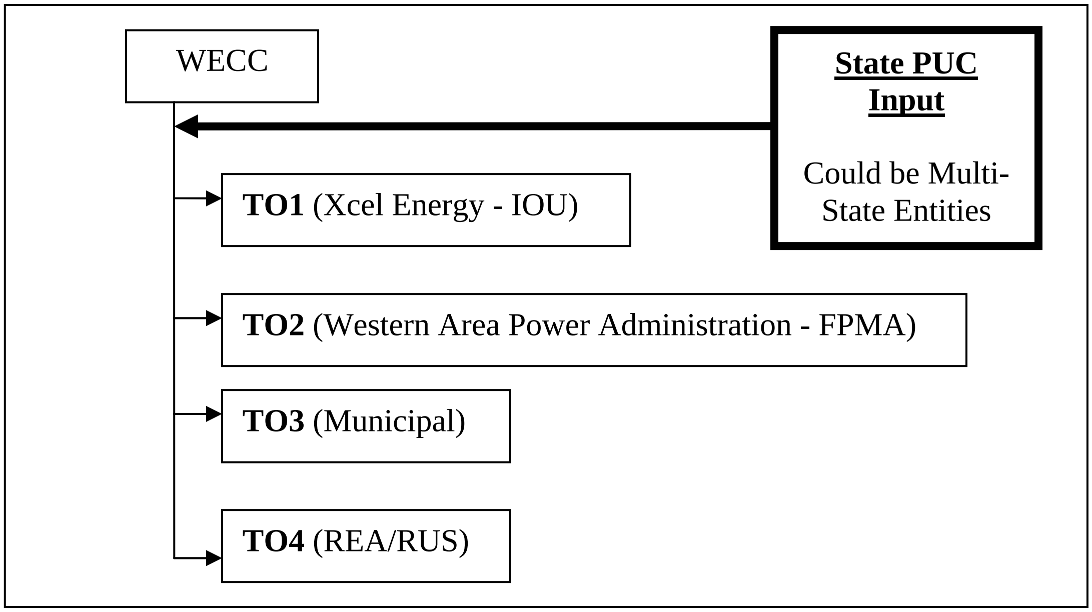


Figure 4-27 - ITO Operations with State PUC Review and Input

The diagram above would also apply to the ITO-East and Eastern interconnection.

Transmission: State PUCs will have jurisdiction over local matters that impact their state (such as routing) but must meet design parameters as established by the parent ITO (e.g., allowable impedance parameters).

Generation: State PUCs will have jurisdiction over matters that impact their state such as siting requirements (environmental impact, pollution levels, noise levels, water consumption, etc.) within a geographic range as determined by the parent ITO's system requirements study.

States will ensure adequate generation capacity reserve margins are attained and will coordinate these needs with the ITO. Additional capacity can be requested, but this would result in higher prices for electricity within that state.

Ancillary Services: The states will not have jurisdiction over ancillary services.

Demand Response: The states will not have jurisdiction over demand-response.

Distribution: The states will have jurisdiction over the distribution sector.

4.6.3.4 Typical Project Example

This section will show the roles and responsibilities of the various agencies involved in a typical transmission project as proposed by this thesis (Figure 4-28).

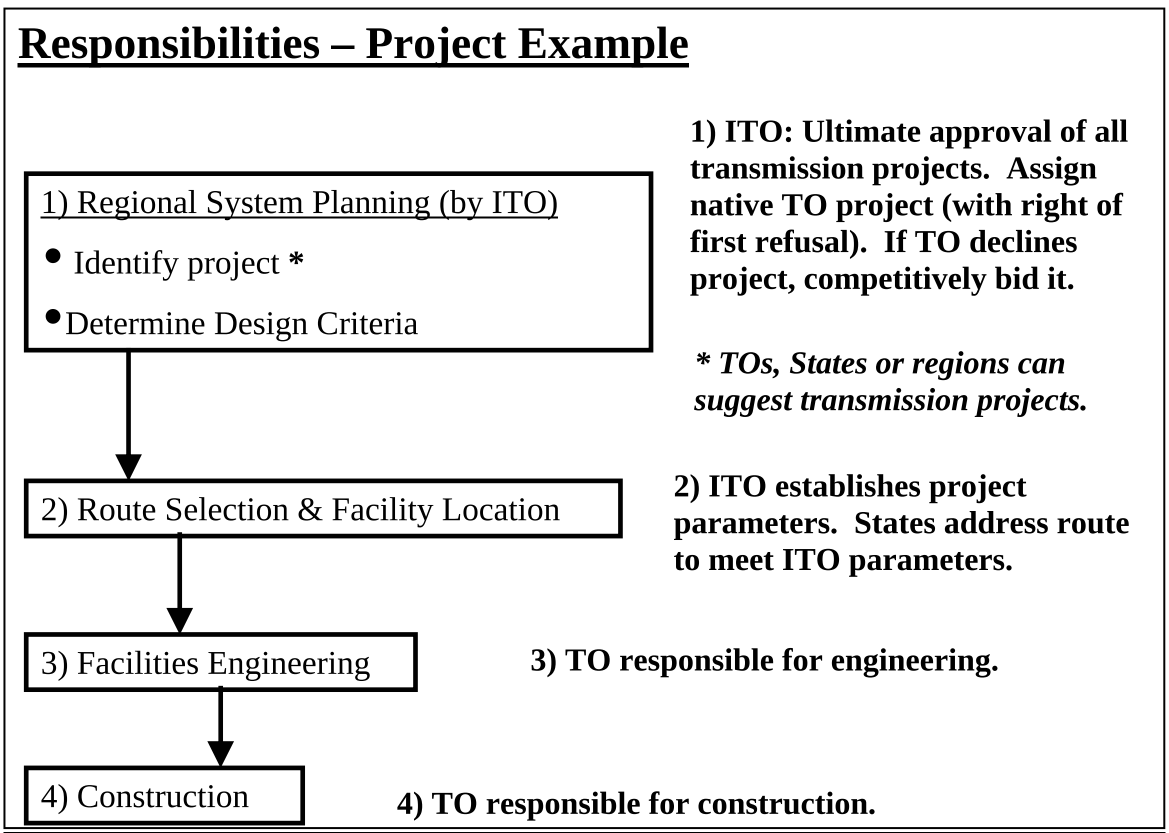


Figure 4-28 - Typical Transmission Project Flowchart

With the discreet responsibilities reviewed, let's take a look at an example of a typical transmission project. The intent is to provide better understanding of the various regulatory roles required and which entity(s) would be responsible for the particular task.

Most transmission projects (substations, switching stations and/or transmission line) would be initiated by the parent ITO's system planning group, since they are the entity ultimately responsible for how the transmission system will perform. These studies would address regional issues in a coordinated fashion, but could also be performed for local system issues if deemed necessary. Individual member TOs may also perform studies but most likely would address more local concerns within their service territory boundaries. Member TOs would then submit their study to the parent ITO for review and approval. If approved, the parent ITO would then schedule this project for construction.

All proposed projects, either as recommended by the parent ITO or member TO, would go through a series of comprehensive project reviews or project feasibility studies to ensure the requirements of the project would be realized once placed into operation. The parent ITO would develop the performance criteria, with review by the impacted TOs, which may include such concerns as required power transfer capacity, optimizing operational costs (system losses) with installed capital costs (construction materials), stability, voltage/VAR support, load forecasts, and so on. NERC and its RCs would perform the independent project review and project feasibility function, which could include discussions with the initiating ITO. This NERC function might be done internally by NERC or be contracted out.

This structure would also function as a backup system to the ITO planning group to ensure all areas of the transmission system are constructed to meet all customer needs.

Once the need for a transmission system project is identified and approved, the detailed engineering process begins. This process will involve both state and ITO oversight. This oversight will require a coordinated, cooperative approach between the State and ITO so the common goal of reliable, cost-effective and environmentally conscience electrical service can be attained. One example of cooperation between the ITO and each impacted state would be the ITO determines the maximum allowable impedance, or length of the line, and the start and finish points of the line (as determined by system planning studies), and allows the state to determine the routing through the state. The ITO and State would work together to achieve a result that satisfies both of their needs.

Public meetings with Utility personnel and concerned citizens would occur early on in the design process. This forum would allow utility personnel to discuss with the public the need for the project, how it will benefit them, civic problems that will arise if the project isn't completed and address any concerns the citizens have. This is an important step in the process so the public can better understand the project constraints. For example, should the line be overhead or underground? If so, do the customers mind paying extra to remove the visual impact of the project? Public involvement would continue throughout the project with status meetings and site trips until the project was complete.

Who will perform the detailed design, construction (including testing, checkout and commissioning) and energization? After the transmission system project is identified and approved by NERC and the ITO, in which the impacted transmission owners

(TOs) service territory is identified, the impacted TO will have the right of first refusal for completing the project. The detailed design function(s) will include engineering, equipment procurement, construction and energization, to be performed by the service area TO, either directly or contracted out.

Should the impacted TO choose not to perform this project, the ITO will issue competitive bids to other transmission design entities like other TOs (IOUs like SCE, PG&E, ConEd, etc.), independent transmission companies (TransLINK, ATC, etc.), engineering firms (Sargent & Lundy, Black & Veatch, Burns and McDonnell, etc.), federal power marketing agencies (BPA, Western, TVA, etc.), manufacturing firms with engineering groups (ABB, Siemens, GE, Alstom, etc.) or like entities. The ITO and NERC would review each bid to determine which proposal is best. Entities which proposed optimal designs (e.g. - balanced operational losses and installed capital costs) would be included within the bid evaluation and award process.

All entities that exist today are expected to have a role in this industry after the restructuring proposed in this thesis. There will still be a need for IOUs and private firms, fueled by private investment, for profit associated work at FERC approved rates. For non-profit work associated with municipalities, rural service and similar projects, the FPMAs, RUSs or municipalities would be responsible (typically). For example, 1) where large flows are anticipated with associated rate of return profit (e.g., projects between large load centers in urban areas); TOs like IOUs or ITCs would be responsible; and 2) where service to remote rural areas is required and profits aren't as great or non-existent, non-profit agencies like the governments FPMAs, RUSs, Cooperatives and municipalities would most likely perform the work. Either way, the process of "right of first refusal" followed by competitive bids would be adhered to.

Whichever entity performs the project will be entitled to the rate of return guaranteed by FERC for that project. Remember, congestion-relieving projects would receive higher than usual rates proportional to the amount of congestion they relieve.

4.6.3.5 Coordinated Industry Functions

Restructuring the transmission sector presents a unique opportunity to improve efficiencies or "streamline" primary industry functions. These industry functions are standards, research and development (R&D) and facility engineering requirements.

Industry Standards: Industry standards such as ANSI/IEEE, NAESB, NESC, ASCE, UBC and ASTM can be coordinated nationally and regionally by the ITO and NPA (Figure 4-29).

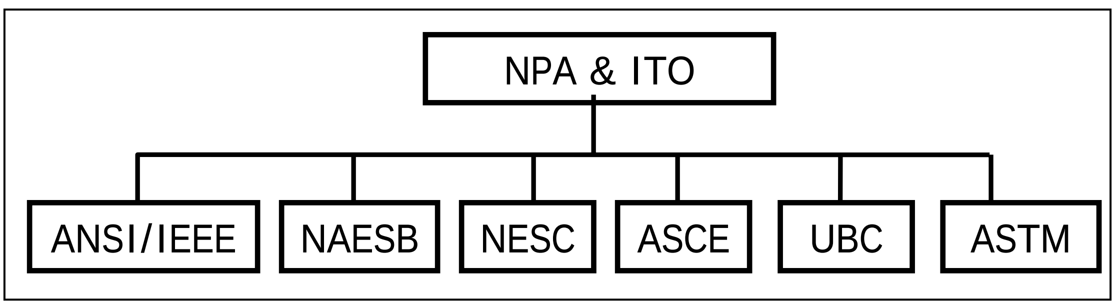


Figure 4-29 - Coordinated Industry Standards and Design

Industry Research and Development (R&D): Industry R&D efforts performed by entities such as EPRI, the Power Systems Engineering Research Center and other similar entities can be coordinated and then distributed nationally and regionally by the ITO and NPA (Figure 4-30).

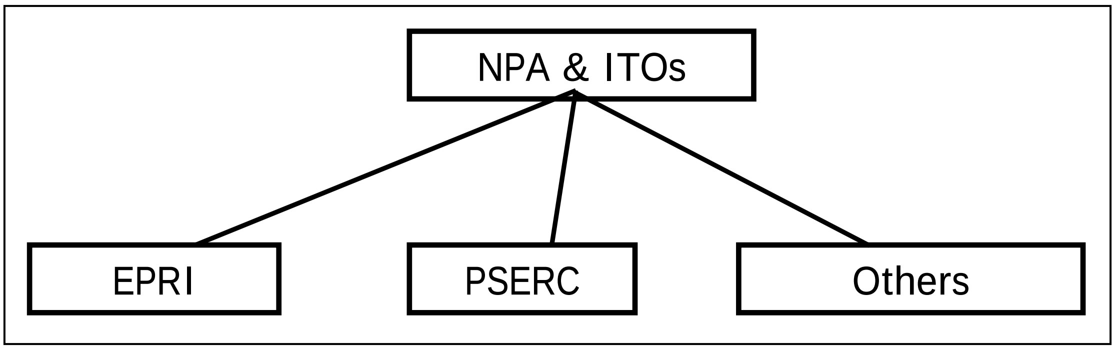


Figure 4-30 - Coordinated Industry R&D Activities

Facility Engineering Requirements: Transmission facilities can be designed using standard engineering approaches within similar regional climate zones. Engineering standards would be developed separately for substations and switching stations (Figure 4-31) and transmission lines (Figure 4-32). This effort would be coordinated by the NPA and ITO by NESC loading region (Figure 4-33). As a result, engineering, procurement and construction costs would decrease, ultimately reducing electricity service costs. This would also address the industry staffing problems, which currently a major concern.

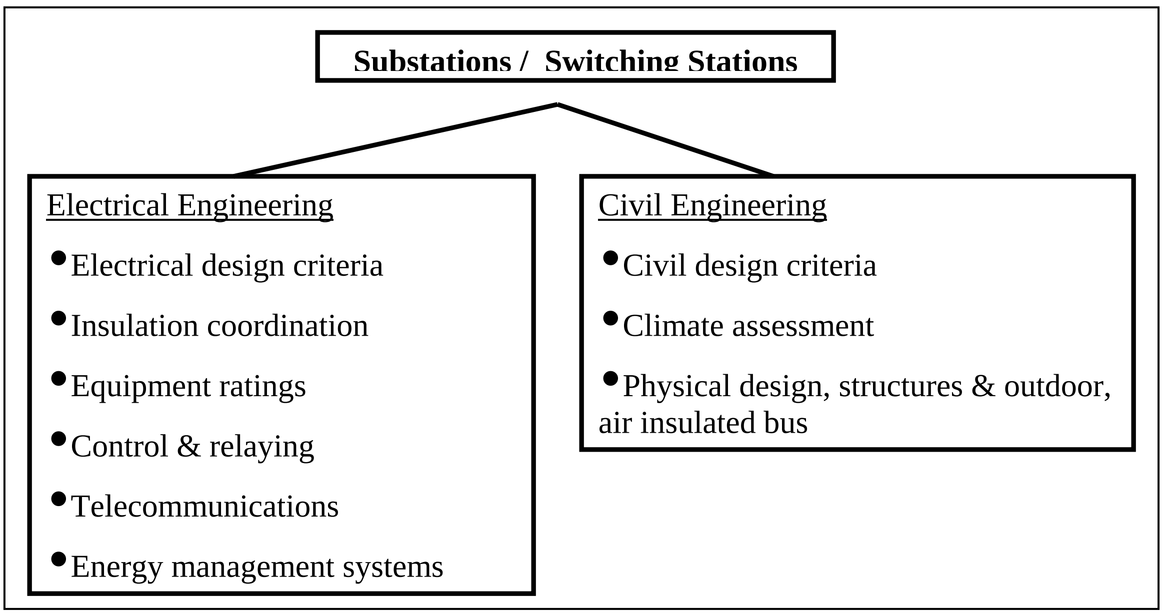


Figure 4-31 –Engineering Standards for Substations & Switching Stations

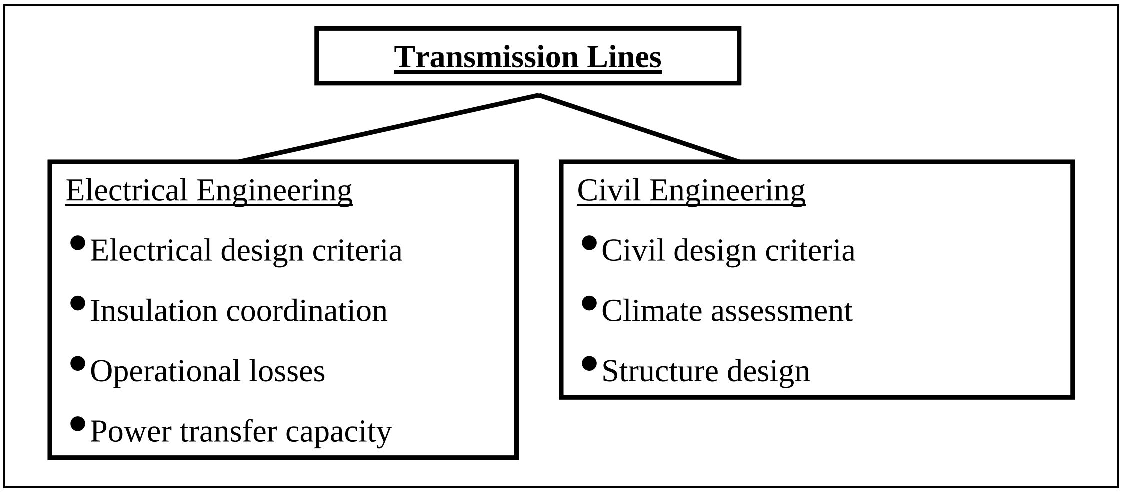


Figure 4-32 –Engineering Standards for Transmission Lines

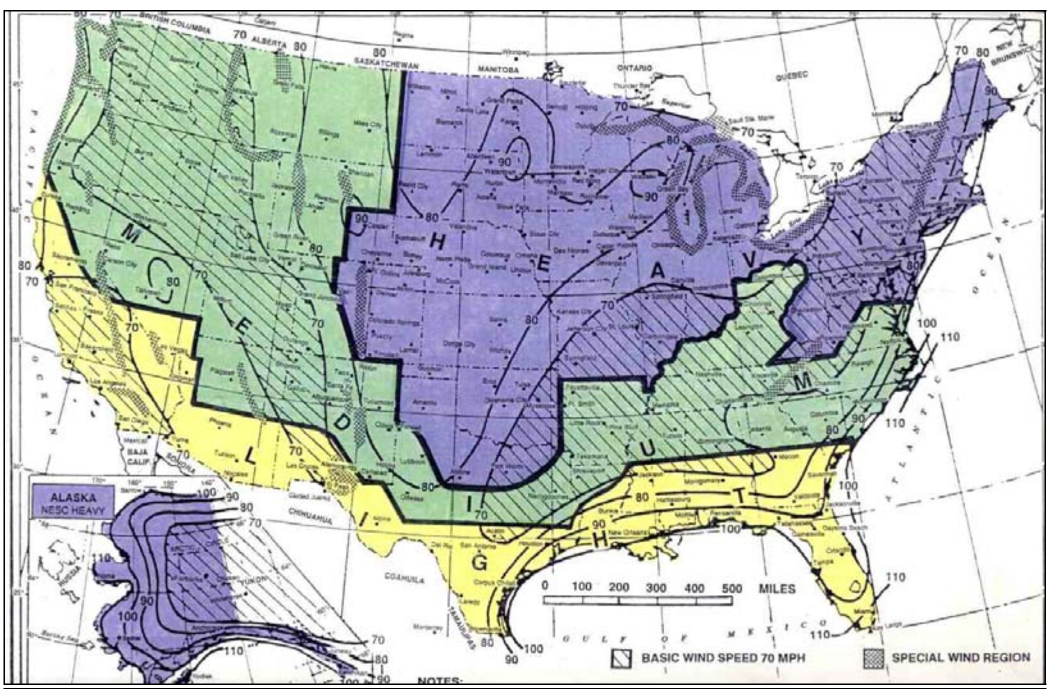


Figure 4-33 - NESC Loading Map

4.6.3.6 Transmission Service Pricing Mechanisms

This thesis proposes several pricing mechanisms for transmission service: 1) Cost-based; 2) Response-based; and finally 3) Actual Path Pricing. Initially, transmission service rates would be determined using embedded cost-based rates with a guaranteed rate of return, approximately 10 percent. Next, after a period of algorithm development, a response-based tariff would be employed. Ultimately, actual path pricing would be used to calculate transmission service rates, which would be based on the actual path electricity took from generation to load. These pricing mechanisms are now reviewed in greater detail.

Embedded-Cost Pricing Mechanism: Bilateral contracts would represent the primary means to receive transmission service with day-ahead and spot markets addressing the balance of transmission service requests. The ITO would be responsible for bilateral contracts review and approval and the operation of the day-ahead market and spot market.

Pricing for transmission service would consist of a network access service fee plus a transmission rate, or tariff, for recovery of embedded costs. Initially, the transmission rate charge would use the highway-zone method, as discussed in chapter 3, combined with LMP and CRRs for congestion management.

Transmission service rates would be determined using embedded cost-based rates with a guaranteed rate of return, approximately 10 percent. **Transmission facilities installed to relieve congestion would receive proportionally more revenue to the amount of congestion the facility removed.**

It is important to reinforce that cost-based transmission service pricing, with guaranteed rate of return for the utilities and their investors, would be used as the funding mechanism for building transmission infrastructure. This guaranteed return on investment of approximately 10 percent minimum, recently thought of as “boring” or “non-lucrative,” **will surely attract investment dollars given the current state of investment prospects generally available today** and into the foreseeable future. In addition, guaranteed rates of higher than 10 percent for congestion relieving projects will attract more investment dollars to the area of the grid that needs it the most.

Non-profit, public power projects will also play a role. In fact, public power entities have the best customer service rating of any electricity service provider.

<u>Response-Based Pricing Mechanism:</u> Next, over a period of time, the highway-zone pricing mechanism would be developed into a more accurate pricing mechanism known as response-based or system response-based. This mechanism would address the issue of inaccurate embedded cost accounting. The accuracy of the highway-zone model would be improved by integrating system planning data. This new pricing mechanism would use a system response-based, geographic approach (not arbitrarily-established, man-made laws and boundaries) for determining proper responsibility of embedded cost payback, which in turn would be charged to the customers served by that system,.

This approach would be ideally implemented into interconnection-based ITOs as proposed by this thesis.

The system diagram below shows inadequate bus voltages. These inadequate bus voltages can cause the nearby transmission lines to “trip”, or disconnect from the transmission system (Figure 4-34). This tripping event, or lack thereof, could cause a myriad of other related system problems that could impact the system within the immediate vicinity or cause a cascading outage situation affecting a wide geographic area.

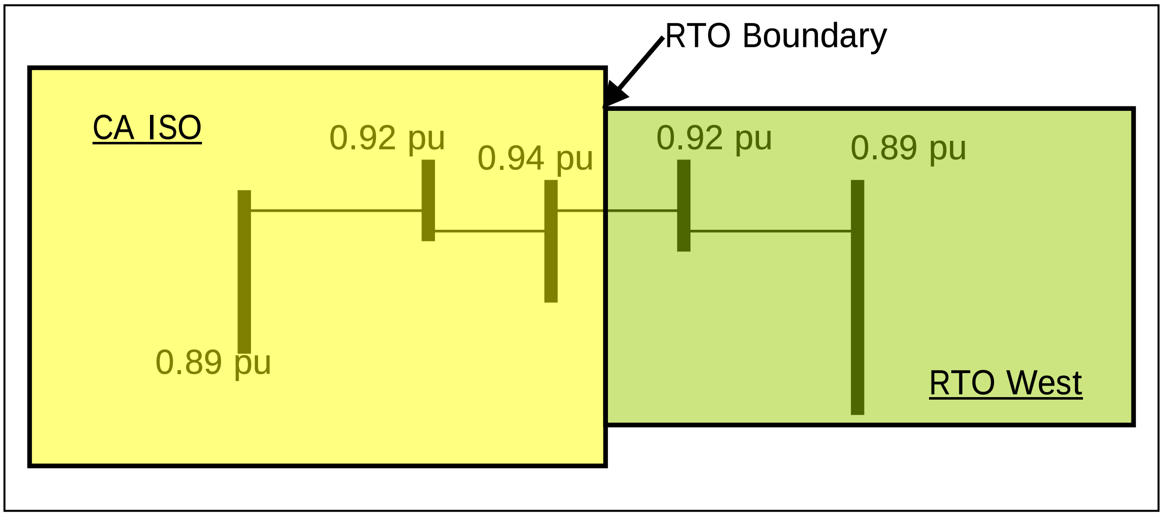


Figure 4-34 – Simplified System with Sagging Bus Voltages

This voltage sag problem must be fixed. To correct this voltage sag problem, shunt capacitors are added to the center bus as shown (Figure 4-35). The system response shows bus voltage improvements over a geographic area represented by the higher per unit voltages, which correspond to the distance between substations. As can be seen, the geographic area of the improved system is partially contained within the CA ISO and RTO West, but the CA ISO and its customers would have to pay for this entire system upgrade. The capacitors represent an embedded cost which must be paid back to the utility which invested in the system upgrade (addition of the shunt capacitors). In this example, the California ISO would pay for the shunt capacitors, yet the RTO West would receive some benefit as well.

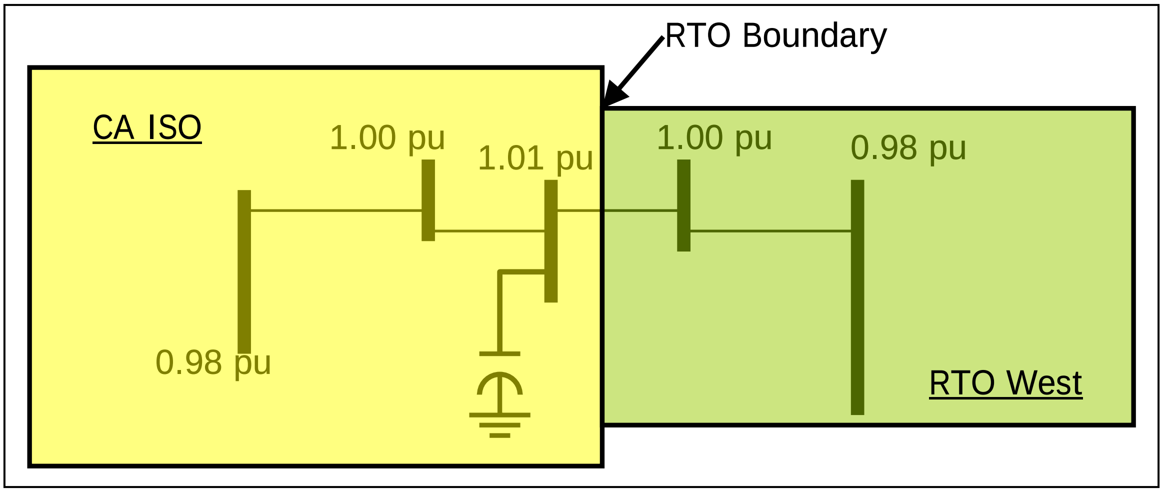


Figure 4-35 – Response-Based Pricing Mechanism

A single ITO per interconnection would alleviate this problem and allow much more accurate recovery of embedded costs through proper assessment of transmission service costs (Figure 4-36). Voltage class categories, similar to those proposed today, would continue to be used in determining embedded cost recovery and corresponding transmission service costs.

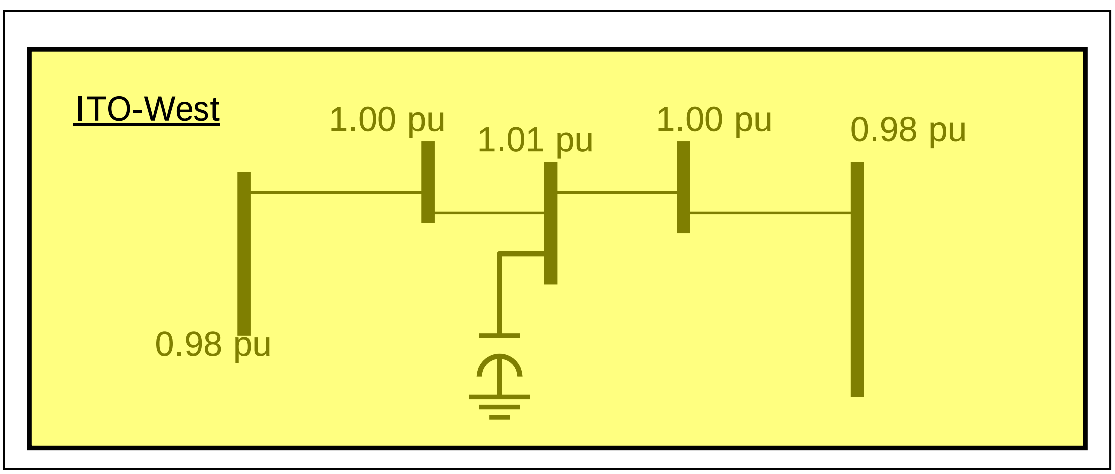


Figure 4-36 – Response-Based Pricing Mechanism with ITO

This pricing mechanism would need feasibility and accuracy studies to determine if the developed algorithms are functional. A cost-benefit analysis should be performed to determine if the increased efforts are justified through significant cost assignment accuracy. Computer simulation should be performed before final implementation. Development of this pricing mechanism could be a future thesis in itself.

Actual Path Pricing: Ultimately, the apex of transmission service pricing would be "Actual Path Pricing" (APP), combined with stranded cost provision(s) for existing transmission infrastructure where required.

Actual path pricing would use actual routes, that elelctricity uses from generation to load for recovery of embedded costs of infrastructure, instead of the contract path pricing in use today.   These costs would include facility capital costs, electrical losses and operator costs, to name several associated with the actual path used (by the power flow).   A "state-estimator" algorithm, which determines the state of the system, would be developed for this, while the response-based, highway-zone pricing mechanism is in use. This state estimator would combine previously run system planning data (base and contingency cases) combined with real-time system information. Actual path resolution would be performed every 5 minutes or less.

The system planning base cases and contingency cases would be stored in a large database and then accessed by the state estimator as needed. Real-time data would be sent to the state estimator from various monitoring systems including the functioning, satellite-based Wide Area Monitoring System, or WAMS (Figure 4-37), transmission line sag monitors, and other sources yet to be developed and implemented.

APP will facilitate the reduction or elimination of inefficient transmission, thereby reducing transmission service costs even further. Stranded cost recovery for existing transmission facilities will need to be made so native load customers won't be negatively impacted. Electricity follows laws of physics, not man-made laws, and APP accurately replicates this, from which finacial agreements can be resolved. APP also addresses national, regional, and state concerns.

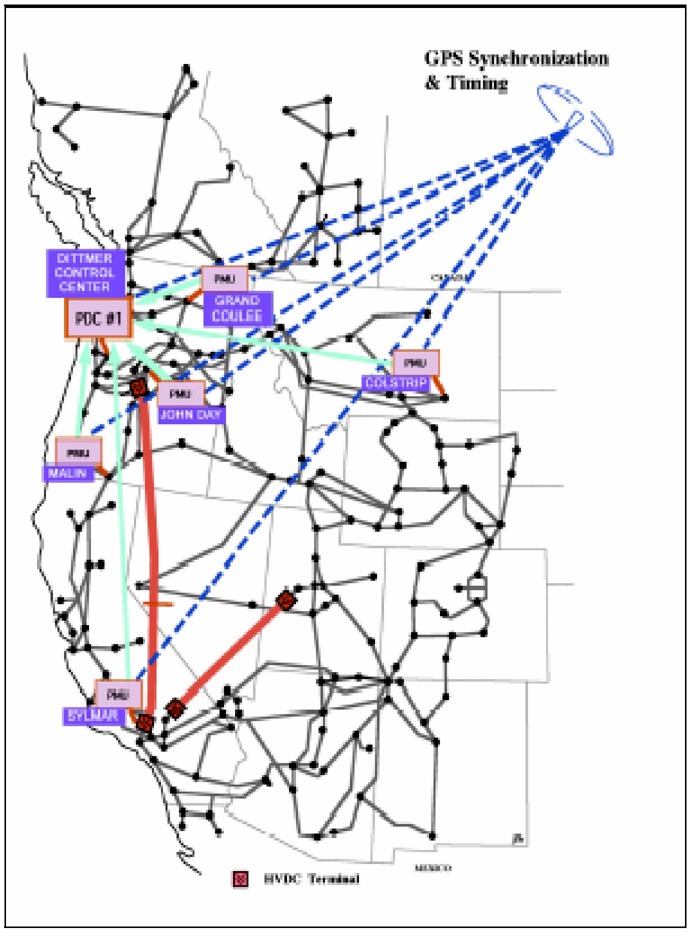


Figure 4-37 - Wide Area Measurement Systems [6]

To summarize, APP is **APP**licable. Using steady-state load flow analysis and real-time data, actual flow paths occuring on the transmission system would be known along with the corresponding losses, both real and reactive. This approach would result in the most accurate and fair way for customers to receive transmission service and the associated costs. This pricing mechanism would be distance-sensitive; therefore, electrical power transmitted over a shorter distance would cost less than if it were transmitted over a longer distance, given both transmission paths were identically designed. It would also promote desperately needed transmission infratructure upgrades.

An algorithm would need to be developed in order to allow this system to work in a real-time, dynamic manner. This is a daunting task; however, it could be achieved by performing load flow analysis on the long-term bilateral contracts given many transmission system and generation outage scenarios. The amount of loading on each line by each transmisssion contract would be assigned a percentage of losses value attached to the percentage of allowable amount of loading that particular line could support. The results of each scenario would then be input into a database and used within the APP algorithm to determine the actual costs assigned to each transmission transaction. The algorithm would need to incorporate many factors, including: 1) line impedance; 2) operational cost (losses); 3) available transmission capacity (ATC); 4) temperature; and 5) installed cost.

Although this thesis does not develop the actual algorithm, it does layout the foundation for it, which could be created by future thesis or PhD research.

Although contract path pricing served its purpose well, we must now harness our modern-day computer power to develop and make APP operational in the not-too-distant future.

Chapter 5.0 - Conclusion and Parting Thoughts

Simply stated, the deregulation and restructuring efforts within the U.S. are incredibly complex and dynamic and require more research. The current process to implement FERC rules is a lengthy one that takes months or years. Jurisdictional debates, regional differences and the involvement of politics further cloud the issues and delay developing an industry direction.

To summarize, the electric utility industry faces an uncertain future. Political, regional and intra-industry debates are delaying legislation and rules for industry operation, which are needed to ensure the viability of this essential industry and its service.

First, this thesis briefly reviewed the history of the electric utility industry from its competitive beginnings to its regulation as a natural monopoly and, finally, to the evolution of the three interconnected transmission networks that cover North America.

Next, it examined the effects of several compounding factors on the industry: the 1970s energy crisis, increased electricity costs, improved generation technologies, and the desire to deregulate the generation sector, previously a natural monopoly. In addition, we reviewed and summarized industry policy issues ranging from the Public Utility Regulatory Policies Act of 1972 to the FERC Standard Market Design White Paper, issued in April of 2003.

Finally, the problems associated with present-day restructuring efforts were summarized and an architecture, or model, which resolves these problems, retains cost-effective transmission service and introduces benefits to the industry restructuring efforts, was proposed. The architecture of this new model, as proposed by this thesis, is the creation of a two-Independent Transmission Operator (ITO) model for the entire United States with national oversight by a newly established National Power Administration (NPA). Transmission is a national and interstate concern and should be treated accordingly. To optimize the cost-benefit operation of the bulk power system, issues must be addressed by interconnection across the nation. These ITOs, in coordination with states, would ensure resource adequacy, generation and transmission of the nation's bulk power system. The industry would be operated essentially as it does today, with the biggest change being the jurisdictional shift that would occur and is necessary. Just as in the early 1900s, when states assumed jurisdictional authority over electric utilities from local governments, now is the time that jurisdiction over all transmission, and certain aspects of generation, be shifted to federal oversight (from states).

The road to deregulation and restructuring was paved with good intentions. These good intentions included 1) reduction of electricity costs and 2) quicker introduction of improved generation technologies. However, the implementation and results of these deregulation and restructuring policies contained significant flaws. These flaws exposed consumers and industry participants to unchecked greed (e.g., California debacle) and uncertainty regarding the industry's future. These flaws, combined with the regional and legal disputes, continue to pose a serious threat to the long-term viability of the US electric utility industry's critical infrastructure.

This research examined the impetus behind the deregulation efforts and all but one primary impetus had substantial justifications. "Resolution of regional price disparity" never took into account different cost-of-living factors that exist within the U.S. today. The research revealed that, when compared to regional cost of living indices, California and the Northeast were paying the same for electricity as a percentage of their wages than most other regions across the U.S. Cost of living is important because regulated, native utilities added wages to the operating costs, which were included in the rates charged to customers. Personnel costs vary by utility but, on average, can total nearly 40 percent. If available, access to cheaper electricity is desirable; however, nothing comes for free. Transmission losses would have added substantially to costs California would need to pay for importing electricity. The cheapest form of electricity is local generation, but because of the BANANA, NIMBY and NOPE opinions, this was not a viable option.

Internationally, deregulation and restructuring has been enacted in the United Kingdom, Sweden, Norway, Australia, New Zealand and Argentina. The European Union has also initiated deregulation efforts, but they are still in the planning stage to work out the various issues between the nations that comprise it. In the cases where overseas deregulation has been implemented and is functioning, the industry operates with a heavily regulated or state-owned transmission sector. This supports the restructuring model as proposed by this thesis.

From a technical perspective, the industry can be restructured to support a deregulated generation sector with modern technologies. However, this will require that we change how the industry operates. We need to move beyond the contract path approach to transmission service and use modern-day tools to accurately determine power flows. These modern-day tools include satellite-based monitoring systems (WAMS) and high-powered computers for state estimation and power flow resolution.

A shift in jurisdictional oversight must occur to where it can be applied effectively. The bulk power system must have federal oversight. The regulation of transmission and generation resource adequacy should occur at the federal level, with states overseeing the particular issues that impact their state specifically. National standards must be determined for allowable EMF levels. This jurisdictional shift should also shift the corresponding areas of accountability and responsibility to either the federal or state agencies.

Some parting thoughts……..

Our industry is at a crossroads. The decisions made now will impact us now and into the future. When making these policy decisions, keep the following in mind:

1. Reliability of the bulk power system is paramount. Profit margins and personal interests are secondary. All parties must work collectively to improve the system and this must start now.

2. Our national security, way of life and economy depend on this critical infrastructure - this is a vital service and should be treated accordingly. This industry must operate proactively to avoid boom and bust cycles. Due to inherent long lead times associated with infrastructure additions, this industry must be ready to accept growth, not react to it.

3. Do the potential downfalls outweigh or out cost the anticipated benefits of deregulation? Electricity industry related expenditures equal 10 percent of the gross domestic product (GDP). The transmission sector equals 0.22 percent of GDP. Are we being penny-wise and dollar-foolish in trying to save a couple percentage points (of the 10 percent and 0.22 percent)? We are putting at risk the world's most reliable and cheapest (of G8 nations) electricity.

4. The laws of physics and the laws of man must peacefully coexist.

5. Although the intentions behind deregulation and restructuring were good, the results of their policies have weakened the bulk power system while allowing unchecked greed to enter the industry.

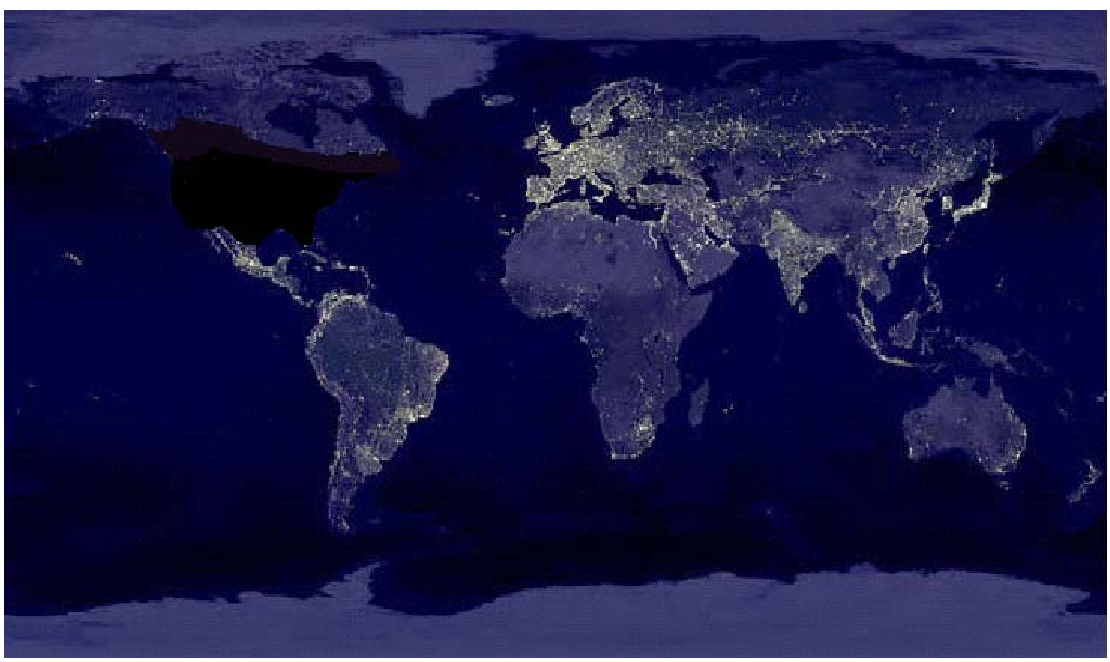
6. Deregulating this industry, the most capital intensive industry in the world, is much more complicated and has many more severe consequences than it did with previously deregulated industries (airlines and telecommunications). Given the recent price abuses (California) and Northeast blackout, continuing deregulation efforts need to be questioned.

In conclusion, our industry today is mired in politics and regional debates, yet the demands on the bulk power system continue to grow. Our nation depends on a viable bulk power system for its security, economy and way of life. While these debates and political discussions continue, the viability of this critical infrastructure hangs in the balance.

If deregulation efforts continue, or if the industry is re-regulated, the model proposed within this thesis should be enacted. In addition, this model moves the industry in a direction away from its current precarious position by addressing the deregulation and restructuring issues present today.

One thing is certain: If measures are not taken soon to ensure the reliability of the bulk power system, it is not a matter of if, but when, our nation will go from:

to:



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