Incentive Structure for Electric Power Transmission
Investment in a Deregulated Environment

By

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Abstract

The US power industry is in the midst of unprecedented change. For nearly a century, it had been dominated by vertically integrated monopolies that generated, transmitted and distributed electric power in their franchised territory. In exchange for this right, industry players had an obligation to serve all their customers in their territory. They were allowed a fair return on their investment as defined by state and federal regulators.

In an attempt to bring competition into the marketplace, the government has introduced deregulation in one sector of this industry—generation. Deregulation of this $250 billion industry is certain to create numerous market opportunities. Most states are in various phases of implementing deregulation in the generation sector.

The transmission sector of the power industry still remains a regulated entity. The issue of insufficient investment in transmission lines has worried observers of and participants in the American electricity industry. As the US has committed to a market-based competitive private electricity sector, its only tool to encourage such investment is sending the right pricing signals to market actors. While in the past, it was an independent regulatory body that determined transmission incentives, the future model envisions a system where it is the spot market based on locational pricing of power that provides the price signaling. Putting the necessary conditions in place to create such a market-based incentive system is a daunting regulatory task.

Studying the different regulatory designs created to address this problem leaves the reader with the unsettling conclusion that none of these have so far managed to achieve their objectives. It seems that the light handed regulation approach has proven insufficient shortly after its introduction. While the independent regulatory agency design seems to have fared better, given the fragility of the American electricity system one cannot claim it a success either. Nevertheless, the argument put forward in this thesis is that such independent regulatory commission can create an institutional framework in which the proper incentive structure will overcome the problems of underinvestment.
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I dedicate this work to my mother for her unselfish commitment to her children; to my wife for her unwavering belief in me; and to my son for his patience and understanding during the past two trying years.
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Chapter 1

Introduction

The issue of insufficient investment in transmission lines has worried observers of and participants in the American electricity industry. As the US has committed to a market-based competitive private electricity sector, its only tool to encourage such investment is sending the right pricing signals to market actors. While in the past, it was an independent regulatory body that determined transmission incentives, the future model envisions a system where it is the spot market based on locational pricing of power that provides the price signaling. Putting the necessary conditions in place to create such a market based incentive system is a daunting regulatory task.

The thesis begins by analyzing the power industry in order to understand why the sector has traditionally been regulated under a vertically integrated monopoly model. The assertion that both social distribution and market failures have necessitated such regulation at least in the past rests on arguments about the social infrastructure and natural monopoly nature of the power industry.

The second section of this investigation argues that certain sectors of the electricity industry have shed their natural monopoly characteristics leaving the crucial transmission as the bottleneck that potentially inhibits the development of competition in the generation and retail supply sectors.

Based on the analysis of the electricity industry and of case examples in other infrastructure sectors, this thesis posits that the underlying question in infrastructure provision is ensuring access to the part of the industry value chain that remains plagued by network externalities. Such access must be priced in a way that the infrastructure owner will be incentivized to invest in the maintenance and upgrade of the system. Hence determining the right incentive structure becomes crucial from a social welfare perspective.
Studying the variety of regulatory designs created to address this problem leaves the reader with the unsettling conclusion that none of these have thus far managed to achieve their objectives. It seems that the light-handed regulation approach has proven insufficient shortly after its introduction. While the independent regulatory agency design seems to have fared better, given the fragility of the American electricity system, it cannot be claimed to be a success either. Nevertheless, the argument put forward in this thesis is that an independent regulatory commission can create an institutional framework in which the proper incentive structure will overcome the problems of underinvestment.
1.1 Electric Utility Overview

The U.S. utility market generated revenue in 1997 in excess of $215 billion. This market is expected to exhibit steady growth over the next 20 to 25 years. A market of such large size commands the attention of many players in the economy. The residential market generated $91 billion in revenue in 1997, the commercial and industrial markets generated $117 billion, and a mixture of other end users accounted for $7 billion. The U.S. utility market contained 3,195 utility companies as of December 31, 1996. A subset of these utility companies, the 243 investor-owned electric utilities representing only 7.6 percent of the total number of utilities, provides the bulk of electricity in the U.S. market. In fact, investor-owned utilities account for 75.6 percent of sales to ultimate consumers and 45 percent of sales in the wholesale electricity market. In the past, all of these players coexisted in a highly regulated industry where federal and state legislation and public utility commission regulations governed access and rate setting in geographically defined utility markets.

1.1.1 Electric Power Infrastructure

The energy industry has undergone major changes in the last two decades, and more are expected. These changes affect how our energy infrastructure operates. While the electricity industry was once vertically integrated, it has become increasingly separated into three isolated segments: generation, transmission and distribution. But the energy infrastructure has failed to keep pace with the changing requirements of the energy system. The electricity transmission system is constrained by insufficient capacity.

The electricity infrastructure includes a nationwide power grid of long-distance transmission lines that move electricity from region to region, as well as local distribution lines that carry electricity to homes and businesses. Electricity originates at power plants, which are primarily fueled by coal, nuclear energy, natural gas, water and, to a lesser
extent, oil. To facilitate competition at the wholesale level, approximately 204,000 miles of long-distance transmission lines move power from region to region.

1.1.2 Electricity Generation

There are roughly 5,000 power plants in the US, with a total generating capacity of nearly 800,000 megawatts. Over the past few years, there has been an explosion of “merchant” power plants proposed by independent power producers seeking to sell into wholesale markets. In spite of this interest, a number of regions of the country are experiencing capacity shortages as a result of wholesale market design problems and barriers to siting and building new power plants. Over the next ten years, demand for electric power is expected to increase by about 25 percent, and more than 200,000 megawatts of new capacity will be required. However, under current plans electric transmission capacity will increase by only 4 percent -- a shortage could lead to serious transmission congestion and reliability problems.

1.1.3 Transmission System

The US does not have a national transmission grid. Instead, there are four integrated transmission grids serving North America: the Western Interconnection, the Eastern Interconnection, the Electric Reliability of Council of Texas, and the Canadian province of Quebec. These regional grids themselves are international, encompassing the US, Canada and part of Mexico. Transactions between the four integrated transmission grids are very limited because they are interconnected at only a few locations through inter-ties. So, for all practical purposes, they can be viewed as separate transmission grids. The four integrated transmission grids break down into a series of smaller regions, largely defined by transmission constraints. Altogether, 204,000 miles of transmission lines in North America move power from the point of generation to where electricity is needed. There are 157,810 miles of transmission lines in the US. Transmission grid
expansions are expected to be slow over the next ten years, with additions totaling only 7,000 miles.

The transmission system is the highway system for interstate commerce in electricity. Transmission allows the sale of electricity between regions. In a particular region, transmission can be a substitute for generation, allowing that region to import power that otherwise would have to be generated within that particular region. In some cases, transmission expansion may be more cost-effective than generation additions, allowing a region better access to lower-cost generation. Transmission constraints limit these power flows, resulting in consumers paying higher prices for electricity.

Figure 1.1: Transmission investment vs Peak Demand
1.2 Transmission development

The future of regulation in transmission remains highly uncertain. Irrespective of how regulation unfolds, an analysis of the historical development of transmission development reveals that the combination of regulatory uncertainty and other factors have conspired to create an aged and constrained transmission system that threatens the reliability of electricity supply.

There is a need to ensure that transmission rates create incentives for adequate investment in the transmission system, especially as restructuring leads to the creation of transmission companies whose only business is the operation of transmission facilities. The Federal Energy Regulatory Commission (FERC) recognizes this need and has expressed a willingness to consider innovative transmission pricing proposals.

Adequacy in the transmission construction is difficult to determine. To satisfy the requirement of adequacy, a highly technical analysis of the locations and magnitudes of generation and demand and the current configuration of the transmission grid would be required. However, there are sufficient indicators of trends in generation capacity additions and demand growth that indicate a deficiency in transmission development.\(^3\)

Transmission expansion is primarily driven by four factors: 1) new or increased loads, 2) new generation connection, 3) the need to reduce congestion and losses to serve loads more economically, and 4) the need to improve system reliability. Before the mid-1970s transmission has steadily kept pace with growth in electricity demand. Since then, though, transmission development has slowed down dramatically.

To determine whether these capacity additions are sufficient for growing loads, a comparison to peak demand is appropriate. When normalized for peak demand, the MW per MW-demand increased 3.5% per year between 1978 to 1982, but decreased between 1982 to 1998 by 1.2% per year. Normalizing for generating capacity, transmission capacity increased 2% per year between 1978 to 1984, but remained unchanged from
1984 to 1998. However, this overstates transmission adequacy, as generating capacity grew more slowly than demand.

<table>
<thead>
<tr>
<th>Start</th>
<th>End</th>
<th>Transmission Capacity Additions (miles/yr)</th>
<th>Total Transmission at year end (miles)</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>1970</td>
<td>1974</td>
<td>3,800</td>
<td>102,400</td>
<td></td>
</tr>
<tr>
<td>1974</td>
<td>1984</td>
<td>2,900</td>
<td>131,400</td>
<td>-23%</td>
</tr>
<tr>
<td>1984</td>
<td>1994</td>
<td>2,300</td>
<td>154,400</td>
<td>-21%</td>
</tr>
<tr>
<td>1994</td>
<td>1998</td>
<td>0</td>
<td>154,400</td>
<td>-100%</td>
</tr>
</tbody>
</table>

Figure 1.2: Transmission Capacity additions

NERC regional reports indicate that transmission systems are constrained. Originally, transmission was built by each utility to benefit its own load and provide local emergency support. Now, under Order 888, the use of the system has changed dramatically. The electricity volume is now traveling across the system from much farther distances with relatively unknown actual impact and cost to the overall system. The strain from this added dimension is evidenced by the various regions’ seasonal assessments, which acknowledge the possibility that heavy line loadings in adjoining regions may cause conditions that would require the invocation of transmission loading relief (TLR).

While inconclusive, the data suggest that existing transmission systems are strained under the new structure. The effects of lagging transmission investment have two major implications on current operations. First, lower than needed capacity additions mean higher utilization. System operators are operating these systems closer to their physical limits. Second, the current transmission system is old, averaging over 25 years old. These two factors, combined with the changing use of the system, indicate that
significant problems may occur in the future if new transmission facilities are not built or rebuilt soon to improve reliability margins.

1.2.1 Factors Contributing to Transmission Construction Lag

There are various reasons why transmission constraints exist. Transmission investment has lagged dramatically over the past decade. The primary factor inhibiting new transmission investment and development is current and future regulatory uncertainty. From an historical perspective, the issue that has hurt large-scale transmission investment the most is the association between electric and magnetic fields (EMF) and incidence of cancer. This fear of EMFs has forged a strong “not in my backyard” (NIMBY) attitude, which has killed off large-scale investment in transmission, as no extra high voltage lines have been built in the last two decades. Recently, however, the National Institute of Environmental Health Sciences (1999) reported that the evidence for a risk of cancer from electric and magnetic fields around power lines is “weak.”

Another cause of transmission constraints is the siting process. Under current law, the siting of transmission facilities is a responsibility of state governments, not the federal government, even though the transmission system is not only interstate but also international, extending into both Canada and Mexico. This stands in stark contrast to siting of other interstate facilities, such as natural gas pipelines, oil pipelines, railroads and interstate highways. At the time, transmission facilities were not inter-state, and there was virtually no interstate commerce in electricity. Congress did not anticipate the development of the interstate and international transmission system.

According to a recent survey of industry participants, current regulation governing site approval is one of the major challenges to building new transmission. To add new transmission capacity, a company must receive approval from a number of federal, state and local agencies. Federal reviews are required when crossing federal lands or navigable rivers, involving a federal power agency (e.g., the Bonneville Power Authority) or interfering with aviation. State reviews involve analyzing project need and
environmental impacts. State agencies that may be involved include the public utility commission, the state energy office, an energy facility siting board, a state environmental department and a state land use agency. Finally, not only must many constituencies be satisfied, but a utility must also seek separate and often sequential permits or approvals, which greatly lengthen the time required for approval.  

Further complications arise for a multi-state project. A project sponsor needs to deal with the agencies in more than one state that may have different requirements and time schedules. Approvals are even more difficult, particularly when the benefits of a project accrue to one state other than the one in which the costs of most of the construction will occur. For example, American Electric Power's Wyoming-Cloverdale 765-kV transmission line proposal connecting southern West Virginia and southwestern Virginia, illustrates well the problems of multi-state projects. Local opponents argue that increased imports to West Virginia will cost jobs by displacing less efficient local power plants. Despite a the ECAR/MAAC/SERC Tri-Regional Study Group (1997) finding that there is potential power supply reliability risk without this project, the project, which was proposed over a decade ago, is forecasted best case for completion by 2004.  

The complications that arise from the siting approval process, in conjunction with the highly negative local view toward building new transmission, create a vicious circle of long delay for approvals, which increases costs, which may cause the project to be cancelled. The pre-emptive force of the site approval process, which may kill projects internally in utilities, further strengthens this circle.  

Future regulatory uncertainty is also a major factor for lagging capacity additions. The recent restructuring of the generation, and the consequent battle to recover stranded costs, have left the industry highly skeptical of making any type of long term, capital-intensive investment. The fear is not only of an inadequate return on capital, but also a risk of return of capital. The best case for a utility that builds transmission is a staid regulated return of 10 to 12%. The worst case is a stranded transmission investment if
the regulatory environment changes unfavorably. Under this system, transmission owners are not able to capture the value of the benefits that accrue to transmission consumers from the greater competition enabled by the transmission expansion.

This poor risk-and-reward scenario is exacerbated by arguments that transmission, because of its regulated nature, is less risky than generation investment, and thus should receive a lower return on equity. A good example of this risk is the case of Southern California Edison (SoCalEd) and Pacific Gas and Electric (PG&E). Both utilities transferred their transmission assets from the state to FERC jurisdiction. In the case SoCalEd, FERC administrative law judge wrote an initial decision granting an ROE of 9.68, 200 bps below the previous state regulated return. Similarly, in the case of PG&E, FERC Trial Staff recommended a 9.8 percent ROE, compared to 12.5 percent under state regulation. FERC Commissioners have not yet issued final orders in either case.

The SoCalEd and PG&E cases also reflect a further regulatory risk of shifting transmission jurisdiction from the local/state government to FERC. In March, 2002, federal power was reaffirmed by a US Supreme Court 6 to 3 ruling that refused the state regulators' challenge to FERC’s 1996 Order 888. The court recognized that state-by-state regulation of an interstate electricity network was unworkable. This ruling is a clear win for FERC chair Pat Wood, who has been actively pushing an agenda to federalize regulation of the nation’s utility grids. While for planning purposes, federal jurisdiction has a higher likelihood of success in implementing a standard market design that will enable a robust inter-regional market across different RTOs, it is unclear how this will affect incumbents and the opportunity of future entrants.

1.3 Transmission Only Companies

While transmission construction as a whole has lagged behind generation, there are a few companies that are involved exclusively in transmission-only business. The concept of an independent transmission company is attractive because it provides both
the regional awareness of investment benefits and the level of regulatory incentives necessary to achieve FERC's goals of a more efficient and regionally integrated transmission system.

Because the independent transmission companies normally serve a much larger region than a single state boundary, they will have a far broader geographic focus than traditional vertically-integrated companies. Further, the investment decision of an independent transmission company is far more focused on improving the value of transmission than is that of the vertically-integrated utility, whose concerns also include a portfolio of regulated and unregulated activities in generation and energy delivery.\(^\text{10}\)

Some of the transmission-only companies are described below.

1.3.1 Trans-Elect, Inc

Trans-Elect is one of the first for-profit independent transmission companies in North America, with over 12,600 miles of transmission assets. It does not participate in generation or distribution, focusing solely on the ownership and management of electric transmission systems. Trans-Elect is the purpose-built solution to a complex industry dilemma and a recognized national need. The company was created by electricity industry professionals to focus solely on transmission by: 1) owning and managing transmission systems, 2) providing operations services, and 3) constructing new transmission lines to provide greater capacity and reliability.

Trans-Elect's projects include AltraLink- purchase of the electric transmission business of Canadian electric utility TransAlta to an international consortium that includes Trans-Elect, METC- purchase of the transmission assets of the Michigan Electric Transmission Company (METC) from Consumers Energy, and California Path 15- a public-private partnership to build the expansion of California's Path 15.
1.3.2 American Transmission Company

The American Transmission Company (ATC) is also one of the first for-profit, transmission-only companies. As a business, it owns, plans, maintains, monitors and operates electric transmission assets in portions of Wisconsin, Michigan and Illinois. When ATC began operations on Jan. 1, 2001, it took responsibility for the transmission systems that previously were owned and operated by multiple electric utilities serving the upper Midwest.

ATC’s system currently includes approximately 8,600 circuit miles of high-voltage lines and approximately 450 substations. It connects local energy users to power plants located across the entire eastern US and Canada. The company operates $630 million transmission system as a single entity, providing comparable service to all of its customers. As a for-profit company, ATC has an economic incentive to provide access to energy markets, to make necessary expansions to the transmission grid, and to provide exceptional customer service.

1.3.3 International Transmission Company

In December 2002, DTE Energy announced that it has signed an agreement to sell its transmission business subsidiary, International Transmission Co. (ITC), to affiliates of Kohlberg Kravis Roberts & Co. (KKR) and Trimaran Capital Partners L.L.C. for approximately $610 million in cash. ITC owns DTE Energy's system of nearly 3,000 miles of high-voltage electric transmission lines and associated facilities and easements. These transmission assets were formerly owned and operated by Detroit Edison, DTE Energy's electric utility subsidiary. Under the terms of the pending agreement, ITC will seek (FERC) approval to cap the transmission rates charged to Detroit Edison's customers at the current levels until December 31, 2005, thereafter, the rates will be subject to adjustment by FERC. In addition, KKR and Trimaran intend to invest in ITC, allowing them to capitalize on opportunities to best serve their customers.
1.4 Conclusions

The transmission infrastructure is old and insufficient to meet the growing and changing electric energy needs of US consumers. Originally, transmission was built by each utility to benefit its own load and provide local emergency support. Now, under FERC Order 888, the use of the system has changed dramatically. The electricity volume is now traveling across the system from much farther distances, with relatively unknown actual impact and cost to the overall system.

While generation additions and load demand have increased over the past decades, transmission investment have lagged behind because of regulatory uncertainty, siting problems and insufficient incentives. There is a need to ensure that transmission rates create incentives for adequate investment in the transmission system, especially as restructuring leads to the creation of transmission companies whose only business is the operation of transmission facilities.

However, a new set of companies such as TransLink and ITC are coming into the market as transmission-only companies. The concept of an independent transmission company is attractive because it provides both the regional awareness of investment benefits and the level of regulatory incentives necessary to achieve FERC’s goals of a more efficient and regionally integrated transmission system.
Chapter 2

Economic Characteristics of Transmission Business

2.0 Electricity as a Regulated Industry

Electricity has traditionally been regulated for reasons of social equity, economic growth and economic efficiency. Among social equity concerns, the issues of distribution and concentration of economic power are paramount. As Posner argues, electricity has been considered to be a service that must be provided on the broadest possible basis (39). Electricity together with transportation and communications make up the infrastructure of economic growth. Posner points out that the conventional orthodoxy has been that these services

must be in place before the development of modern industry is possible, and most countries, including this one (i.e.: US) at various periods, have undertaken to subsidize these services or to provide them directly in the hope thereby of attracting industrial developers (39).12

Without adequate power supply, a region, a community or an individual is cut off from economic development. Everybody needs to have access to this infrastructure, but in a free market it might not be offered in sufficient quantities or at affordable price points. Therefore, historically it has been the utilities' obligation to provide universal service even to unprofitable customers. Such universal service has been made possible by high-profit margin customers subsidizing the loss-making ones. Posner concludes that such internal subsidization is essentially a form of tax shifting value from lucrative customer segments to those who would not be able to afford services in a free market (41).13

The economic efficiency argument points to the market failures that plague the electricity industry. Specifically, it is the industry's natural monopoly tendencies and the existence of network externalities in the transmission sector that have traditionally been argued as necessitating regulation.
Every step in the provision of electricity exhibits natural monopoly characteristics. Given the presence of strong economies of scale in generation, transmission and distribution, economic efficiency is realized with a single firm as average costs decline over relevant area of demand (Dyck, 5).\textsuperscript{14} The electricity infrastructure includes a nationwide power grid of long-distance transmission lines that move electricity from region to region, along with the local distribution lines that carry electricity to homes and businesses. Electricity originates at power plants, which are primarily fueled by coal, nuclear energy, natural gas, water and, to a lesser extent, oil. The high coordination need among these three segments of the value chain and the locational nature of production and distribution lead to the emergence of economies of scope, resulting in vertical integration.

The problem with the resulting monopoly is that, if left unregulated, instead of increasing production to where price equals incremental cost, it will choose to reduce output in order to raise prices. True, higher prices lead to less demand - but the monopolist can simply increase the price of the units still sold (Breyer, 15).\textsuperscript{15}

In addition to the natural monopoly feature of the electricity industry, the network externalities present in the transmission sector also push away from free competition to regulation. Network externalities arise from the tight physical linkages of the components of a power system and, as such, are associated with the flow of power across constrained transmissions systems (Hogan, 82).\textsuperscript{16} Overloading the electric network system causes serious damage to the transmission lines. When the generation facility and transmission line is owned by the same entity, overloading is avoided by adjusting generation. However, when multiple actors have access to the same line and the generation facilities are owned by different independent entities, it is impossible to identify which network user is overloading the line. Since it is only the transmission line owner who ends up internalizing the costs of overloading, the transmission users have no economic incentive to use the system efficiently.
2.1 Electricity Industry Value Chain and Dynamics

In order to understand how and why the industry has come to be restructured, it is first important to define in more detail the parts and characteristics of the industry value chain and elucidate the resulting industry dynamics.

An electric power system consists of four basic elements: 1) generation resources that produce electricity, 2) transmission system that transports power over high-voltage lines, 3) distribution that breaks down the power into smaller voltage and 4) load centers that consume power. Because electric power cannot be easily stored, the total generation must equal total load plus losses at any given time. This feature makes it necessary to produce electricity and transport it instantaneously to the point of demand. Figure 2.1 helps visualize the value chain.

![Electric Power Value Chain Diagram](image)

**Figure 2.1 : Electric Power Value Chain**

The most complex part of this value chain is the transmission segment. The electricity flows through the transmission system in accordance with physical laws and
cannot be directed to flow through specific lines. Given the physical nature of electricity, it is impossible to follow a given generator's 'product' traveling through the transmission lines. The system must be designed with reserve capacity in generation and transmission to allow for uninterrupted service when contingencies occur (Rotger and Felder, 10). Reliability is the number one system requirement in this industry. While these requirements make central coordination of transmission particularly challenging, they also bestow transmission line owners with significant market power over actors in the other segments.

Consequently, having the appropriate transmission regulations are crucial to the functioning of the entire system. Hogan concludes, "The rules for access to the limited capacity of the transmission system stand at the core of all other issues" (96). Rotger and Felder claim that "transmission reform is the key to an efficient allocation of investment resources not only among new transmission projects, but among all available methods of providing electric power to end-users – including transmission projects, large-scale generation, distributed small-scale generation, and load management technologies" (iv).

2.2 Why Restructure the Power Business?

If the power business is indeed an economic-growth infrastructure characterized by a natural monopoly nature and the presence of network externalities, why has restructuring become the new paradigm? When contemplating restructuring, it is pertinent to keep the distinct parts of the value chain in mind. Restructuring started with generation, which was the component of the value chain that most easily lent itself to free competition. Increased demand and reduction in efficient plant size made profitable entry possible in this segment by the end of the 1960s, thus eliminating its natural monopoly characteristics. However, as typical of many infrastructure sectors, while the possibility of competition opened up in one branch of infrastructure provision, natural monopoly conditions persisted in other branches (World Bank, 152).
What pushed legislatures to recognize that the electricity industry had changed over time were the macroeconomic shocks of the 1970s. While in Great Britain, Norway and New Zealand, political considerations motivated deregulation, here in the US, it was technical innovation coupled with increased demand against the backdrop of macroeconomic turmoil that led to the profound rethinking of the electricity industry model (Hogan, 81).21

The pre-1970s model was one of "vertically integrated monopoly with a regulated franchise" (Hogan, 81).22 Regulated utilities operated under cost plus pricing. At the bulk power purchase level, FERC regulated the price of each transaction.

For firm transmission service, a utility could charge rates designed to yield annual revenues that equaled the embedded cost of the utility's transmission facilities – that is, a fair rate of return on the original cost (less depreciation and including operation and maintenance expenses and taxes). For non-firm transmission service, a utility could charge rates to reflect, in addition to the variable cost of providing the service, a charge as high as the full amount of the fixed costs of providing the service (Rotger and Felder, 10).23

At the retail level, cost plus pricing meant that increased costs were passed on to consumers after regulatory approval. Consequently, utilities were not motivated to focus on efficiency. Nevertheless, in the 1960s, gains from realizing economies of scale outweighed the costs of inefficiency. The regulated electricity system was able to offer declining prices.

The macroeconomic developments of the 1970s, however, reversed this positive trend. The increase in oil prices resulting from the oil crisis, combined with higher inflation, led to an increase in the cost of electricity production. In addition, the renewed interest in the environment led to investment in new, more expensive technologies. Consequently, nominal and real electricity prices increased, shifting much of the burden to consumers (Hogan, 81).24

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2.3 History of Restructuring

It was this increase in prices that spurred the legislative action leading to the Public Utilities Regulatory Policies Act (PURPA) of 1978. PURPA was drafted to address the problem of American generation plants operating at the low generation efficiency of 33%. It created a special class of non-utility generators that could construct small power plants and co-generation facilities called qualifying facilities (QF). The condition was that QFs had to achieve 42% generation efficiency. Traditional utilities were obliged to purchase electricity from QFs at prices set at administrative estimates of the utilities' avoided costs. PURPA did not intend to start a deregulation process. But as many states came up with high administrative estimates, QFs flooded the market. Consequently, QFs became an important interest group with powerful lobbying capabilities that could effectively block legislators' efforts to lower administrative cost estimates (Hogan 82). The success of QFs was taken as an indication that a fully competitive electricity generation industry was, indeed feasible. The conventional wisdom that independent power producers could not be cost-effective or reliable had been proven wrong.

At the same time that on the legislative front changed macroeconomic conditions led to new solutions, FERC was gaining experience in deregulation. The passage of the Natural Gas Policy Act of 1978 allowed competition at the wellhead. More importantly, it reflected a regulatory willingness to replace the natural monopoly argument with regulation focused on encouraging competition (Rotger and Felder, 5)

The breakthrough Energy Policy Act (EPAct) of 1992 created a competitive wholesale market and the accompanying trading activities by ordering utilities to give third-party access to their transmission systems. This decision carved the transmission sector out of incumbent utilities. At this time, utilities were still vertically integrated, owning their generation facilities. The EPAct forced utilities to provide their competitors with transmission access. These competitors, referred to as independent power producers (IPP), did not have to meet efficiency requirements.
It was not the transmission access per se that had a price: utilities negotiated the price of the power with the IPPs and then allowed access to their transmission lines. The negotiated power price was determined according to strict regulatory guidelines. The drafters of the EPAct were hoping for competition at the margin. Non-utilities provided less than 10% of the total production volume at the time. But once competition was introduced and the financial payoff was enticing, pressure to introduce more competition followed. The EPAct stayed away from extending the open market notion to retail customers (Hogan, 83).27

At the same time that FERC was diligently implementing the EPAct, many initiatives were taken at the state level. The California Public Utility Commission (CPUC), for example, sought to introduce more competition and rely more heavily on the IPPs. CPUC went so far as splitting up the vertically integrated structure into generation, transmission and distribution, and created new regulatory institutions. It even contemplated opening the retail markets to competition (Hogan 84).28

During the mid-1990s the IPPs' customers changed. Immediately after the passage of EPAct, the IPPs served utilities exclusively. However, as the regulator's pricing policies lead to an outrage among utilities, prices to be paid by utilities to IPPs were lowered. Thus, IPPs commenced to look for new customers and started serving municipalities and other large wholesale loads. It was at this point that access to transmission lines became critical, since the new customers did not have their own lines. IPPs had to negotiate with the utilities to arrive at a price for the transmission access rights. The basic framework for pricing was cost plus with a one-year time lag. Utilities were obliged to post their available capacity and give it to the IPPs on a first come, first serve basis. However, they were allowed to price discriminate and hence could exert their market power at the expense of the IPPs.

By 1996, legislative and regulatory activism, combined with state initiatives, created the necessary momentum for a profound restructuring of the electricity industry.
Order 888 called for the unbundling of the vertically integrated utilities into generation, transmission and distribution activities. FERC concluded that the generation and retail supply sectors could be treated as competitive industries. Distribution, on the other hand, was to remain under monopoly franchise regulation.

The core of the industry restructuring continued to be ensuring that "the essential facility in between transmission would be available on an open access basis" (Hogan 85). Order 888 reflects FERC’s commitment to the provision of such free access to the transmission grid. FERC adopted the principle of non discrimination through the requirement of comparability of service. In order to ensure non discrimination, some states required utilities to divest their generation assets so that independent generators could not be considered direct competitors (Rotger and Felder, 12).

Despite Order 888’s recognition of the importance of managing the complex externalities associated with network usage, FERC did not modify the principle of contract path scheduling introduced in the ‘QF times’ when independent generation made up an inconsequential volume. The contract path approach stated that the power that an independent generation facility sent over the transmission line would follow a contractual path. However, in reality, power flows over every parallel path. As a result, incentives to overload the electric network system lead to a large increase in damages to the network (Hogan, 86).

Order 888 had mixed results. The generation sector saw an increase in generation facility investment, and many utilities sold off their generation assets. In the transmission sector, however, the results were less encouraging. The lack of operating experience led to an increase in the number of transmission line loading reliefs when the load threatened to become too high for the transmission line to handle. The North American Electric Reliability Council (NERC) had to initiate transmission loading relief protocols in order to avoid damage to the system during peak usage. In essence, "NERC created an administrative unscheduling system to counteract the effects of FERC-mandated scheduling system" (Hogan, 86). Despite NERC’s efforts, problems of overloading
persisted. NERC also noted a widening gap between transmission expansion need and the proposed investment in transmission. Transmission operations in general were poor. Also, Independent System Operators (ISO) did not emerge as swiftly as expected (Rotger and Felder, 14).32

To correct for the coordination failures, Order 2000 called for the creation of Regional Transmission Organizations (RTO). While in some areas, RTOs already existed, FERC wanted the RTOs to cover larger regions. There is a need for RTOs given the complex network interactions of the electricity industry. Thus, there must be an entity that provides coordinating services. In practice,

(re)al-time balancing is usually achieved through the direct control of select generators (and in some cases loads) who increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator (Hogan, 89).33

RTOs were to become the system operator, planning and controlling regional transmission systems. To define the RTO's design and role, the Millennium RTO Order attempted to define market institutions that would serve the public interest (Hogan 89).34

RTOs had eight critical transmission management functions: 1) tariff administration and design, 2) congestion management, 3) manage parallel path flow, 4) ancillary services, 5) OASIS management, 6) market monitoring, 7) planning and expansion, and 8) interregional coordination. "RTOs must have the following characteristics: independence, scope and regional configuration, operational authority and short-term reliability" (Rotger and Felder, 14).35

Otherwise, Order 2000 left the design of RTOs rather vague. Two useful distinctions between potential RTO structures refer to Transcos versus Hybrid GridCos/ISOs. Transcos are independent companies that own the grids and are responsible for system planning and operations. Hybrid GridCos/ISOs separate ownership from management of the grid. The Hybrid GridCos own the transmission
lines while the ISO manages the transmission operations and coordinates the spot market (Rotger and Felder, 15).^{36}

Another important recognition in Order 2000 calls attention to the importance of pricing signals as underlying both efficient operating and investment decisions. Hence, FERC attempted to reform transmission pricing. While it set out some guidelines as to what the new pricing must achieve, it did not put forward specific ‘hows’.

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking (NOPR), which, if finally issued as an order, would substantially change the regulations governing the nation’s wholesale electricity markets by establishing a common set of rules, called Standard market Design (SMD) that would apply to all public utilities that own, operate or control transmission facilities. FERC claims that these changes are necessary to rectify the undue discrimination that still exists inspite of Orders 888 and 889. However, FERC is soliciting input from the industry on many aspects of the SMD.

As part of the SMD, FERC intends to establish a uniform, non-discriminatory transmission tariff that provides for a single type of transmission service for all users of the interstate transmission grid, including bundled retail transmission customers. This assertion of jurisdiction over the transmission component of bundled retail transmission marks a sharp departure from Order No. 888 and reflects more recent judicial guidance to FERC’s jurisdiction over the transmission component of bundled retail service. FERC proposes a single access charge to recover embedded transmission costs based on a customer’s load ratio share of the Independent Transmission Providers (ITP) costs. This access charge would be paid by any customer taking power from the grid.

In this NOPR, FERC expects that most of the transmission owners will join an RTO, which would provide network access. Transmission owners that do not join an RTO must either qualify as an ITP or contract with an ITP to operate their transmission facilities and provide network access. ITPs are defined as any independent public utility that owns, controls or operate facilities used for transmission of electric energy in
interstate commerce, and that administers day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission service pursuant to SMD tariff.

With regard to SMD, FERC requires that all TPs use locational marginal pricing (LMP) for pricing energy at designated nodes and as the system for transmission congestion management. FERC proposes providing tradable financial rights or congestion revenue rights (CRR) as a means of locking in a fixed price for transmission service by shielding CRR holders from congestion costs. FERC has a preference for auctioning the CRRs, but initially would allow regional flexibility for a four-year transition period in determining whether to allocate CRRs to existing customers or to auction these rights.

The final outcome of deregulation is far from clear. For now, though, the generation sector is fully competitive, transmission and distribution are regulated and retail supply is in various stages of deregulation in half the states.

2.4 The Role of the Regulator in the Electricity Industry

The history of the most controversial issues of restructuring power utilities rings familiar. Legislatures and regulators working on the deregulation of other infrastructure sectors faced the same challenges:

- Historically economies of scale and scope led to vertical integration.
- Technological and demand changes had put an end to such scale and scope economies in some branches of the industry, while natural monopolies persisted in others.

Consequently, the regulatory challenge became ensuring competition in some branches while regulating the remaining monopolies, even though the success of the competitive branch depended on it. These issues decided the very success of deregulation of the railway system in the UK, the telecommunications industry in New Zealand, and the electricity industry in Germany.
In order to ensure competition, the part of the value chain that remains a monopoly needs to be opened up to new entrants. These new entrants must have access to the transmission line in the case of electricity, to rail tracks in the railway, and to phone lines in telecommunications. Therefore, an institutional framework must be put in place to regulate the monopoly and an actual price must be put on the access to, and usage of, the infrastructure. The choice of regulatory system influences the way such prices are set, and hence the emergence of a competitive market.

The US has had an independent regulatory agency, the FERC, overseeing the electricity and gas industries. This regulatory body enjoys considerable independence from political institutions as recent developments prove. The California blackout and the Enron bankruptcy greatly decreased the political--both legislative and executive--commitment to moving forward with the restructuring. Yet, FERC is expected to march ahead with market-based restructuring in its upcoming directive (interview with Professor Hogan). In its recent ruling, the Supreme Court reinforced FERC's autonomy from the legislative process.

The UK adopted a similar approach to regulatory design. There, the Office of Rail Regulator was created at the time of the privatization of the railway system. The secretary of state appointed a single regulator for five years. The regulator is free from direction from the secretary and guided mainly by statutory obligations (Office of the Rail Regulator, 3).

From the results of deregulation, it is unclear whether the American or British system works better. Given that FERC had existed prior to and actually brought about the restructuring, legislatures would have had to fight an uphill battle arguing for the creation of a new regulatory institution. FERC does benefit from having built up a body of knowledge and coterie of experts. Nevertheless, it is also more captive of its own legacy of being the regulator of an integrated monopoly. This tradition might cause FERC to be less open to new ideas and slower to react to the changed industry conditions.
The countries that chose a light-handed regulation model seem to have fared less well. For example, in the 1990s, New Zealand did away with its industry specific regulators and instead decided to enforce competition law through the court system. The World Bank report concludes that this experiment failed because the proceedings for determining the new entrant's interconnection fees in the telecommunication sector, for example, often took up to five years (159).\textsuperscript{39} A bitter legal battle between Telecom and Clear Communications demonstrates the difficulties of placing faith in a monopoly to open up competition without having close oversight over it (HBS case, 10-14).\textsuperscript{40}

Germany's Energy Act did not create an industry-specific regulator either. The industry as such was entrusted with the task of developing a general framework for network usage. Three trade associations worked together to develop the framework. Nevertheless, there was an emergency plan: had the industry failed to agree on a framework, the commerce department would have stepped in. Once the industry established general guidelines for the tariffs, the oversight of the infrastructure providers was left to the anti-trust agency. The result of this approach to regulation was access charges that varied by more than a factor of two. The incumbent utilities applied widely differing access charges to the new entrants. As they shifted their costs to distribution in order to be able to charge more for the access, the proportion of the cost of transmission in the total electricity bill shot up. After some spectacular bankruptcies, the Bundeskartellamt looked into what went wrong, admitting at the same time that it did not have the resources to do a thorough enough analysis (RWE, 10-15).\textsuperscript{41}

In the light handed regulation countries, negotiation was left to the market actors. In the case of Germany, this meant that a new independent power provider had to negotiate a separate contract for each of the thousand distribution networks (RWE, 3).\textsuperscript{42} In New Zealand, the new telecommunications entrant, Clear Communications, tried to get fair terms from a monopoly that knew that litigation to prove that it abused its monopoly powers would take years.
Determining the form of the regulatory system is challenging enough, but coming up with the price tag is even more difficult. The access fee must compensate the incumbent not only for its marginal costs, but also for the investments it will need to make in the infrastructure going forward. The monopoly will have to make investments to renew its infrastructure as well as to enhance it. As these sectors are characterized by network externalities and free-rider problems, underinvestment can occur. The UK rail case proves that enforcing the monopoly’s promise to invest is virtually impossible, especially when such monopoly is privatized. Railtrack was more interested in returning the access fees in the form of dividends to its shareholders than in investing it in infrastructure (Office of the Rail Regulator, 14-17). The second factor complicating the determination of access fees is the information asymmetry between the monopoly and the regulator. The regulator has to come up with a number working from the data provided by the monopoly. The monopoly is interested in presenting data that will ensure the highest access fees, which, in turn, stifles competition.

2.5 Conclusions

Electric utilities traditionally have been a regulated monopoly because of the economies of scale and scope and the characteristics of the industry value chain and the resulting industry dynamics. The Public Utility Regulatory Policies Act of 1978 started the deregulation process in the generation sector. By 1996, federal and state regulations created the necessary momentum for a profound restructuring of the electric industry. While the new regulations were successful in creating active generation and wholesale competition in the marketplace, they failed to give the appropriate pricing signal to stimulate investment in the transmission sector.

With the advent of the wholesale electricity markets, the transmission system is used for interstate commerce across regional markets, and thus, the use of the transmission lines has changed dramatically. The increased use of transmission lines led to an increase in the number of transmission line loading reliefs.
To ensure competition, the part of the value chain, transmission, that remains a monopoly needs to be opened up to new entrants. New entrants must have equal and non-discriminatory access to the transmission lines. Such access must be priced in such a way so that the infrastructure owners will have the necessary and sufficient incentives to invest in the maintenance and upgrade of the system. The choice of regulatory system affects the way such prices are set and hence, the emergence of a competitive market.
Chapter 3
Physical Characteristics of a Transmission System

3.0 Functions of a Transmission System

A strong transmission network allows utilities to provide a reliable source of power as economically as possible. The advantages of a strong network include:

1. Less installed generating capacity required for a given level of delivered reliability,
2. Greater transfers of power within and between regions, thus allowing for the most economic source of supply,
3. Larger generating units can be built, thereby allowing for greater economies of scale, and
4. Generating units can be located at sites far from the load centers.

These advantages are why the U.S. has an extensive extra high voltage (EHV; 230kV and above) transmission system—approximately 150,000 circuit miles. This system experienced explosive growth in the 1960s and 1970s. In the past few decades, though, the system has grown very little because of regulatory uncertainties as well as siting restrictions and delays.

Meanwhile, the existing facilities have become increasingly loaded. System loads continue to increase each year and utilities have increased coordination (pooling and power contracts) among themselves. If each company were to dispatch its own generation to serve its own load, inter-company interface limits would not come into play. However, in order to realize the economic benefit of pooling resources, many companies today choose to operate as a single control area, sharing among themselves the economic benefit of a single dispatch. This is referred to as Economic Dispatch, where a control area dispatches the cheapest available generators to serve the total load.
The key issue in transmission congestion is to identify bottlenecks on the system and to quantify their impact on system operation and costs. Not only must the limiting interfaces be identified, the magnitude and frequency of the limitations at these interfaces need to be evaluated. Also, the interrelations between several interfaces in a power system must be examined. With this knowledge in hand, the industry is better able to allocate responsibilities and costs, and to make sound engineering and economic decisions.

3.1 Transmission Interface

A line or group of lines capable of transferring power from one area to another is called an interface. The interface limit is the maximum amount of power that can be securely transferred over that interface. This value can be limited by thermal, voltage and stability constraints. Native load levels, generation dispatch, network topology and weather can all affect the interface limits. Obviously then, an interface limit is a range of values which vary as system conditions vary, but with one specific value at any given instant. An interface can be limiting because one of the elements on that interface reaches its limit. An interface can also be limiting because an element other than the ones constituting that interface reaches its limit.44

Electrical interfaces are adopted by system operators as a tool to evaluate concerns over the unrestricted transfer of power through a free-flowing system. Power flows redistribute over remaining transmission lines when generators or transmission lines are intentionally or unintentionally removed from service. Because power flow to load seeks alternate paths of least resistance under these contingency conditions, the result can be overloaded lines and an adverse impact on local or neighboring systems. One method for evaluating transmission system performance and setting limits to protect against wide area interruption involves establishing electrical interfaces for monitoring purposes. These interfaces are defined as specific transmission facilities used to transfer power from one area to another. Power flows across the monitored transmission facilities are aggregated to determine the instantaneous transfer across each interface.
The power-transfer capability over an electrical interface is not the sum of the individual line capabilities. Interface limits are determined by computer simulations that calculate maximum allowable power transfer levels across a set of pre-defined transmission facilities that will not violate prescribed limits of machine stability, equipment current carrying capabilities, and permissible ranges of voltage and frequency within an area. These calculations are performed in accordance with local, regional and national criteria.

Power that flows through a transmission network follows Kirchhoff’s Laws, which are network laws pertaining to the interconnection of elements rather than to individual elements. In contrast, Ohm’s Law is an element law that describes a particular element irrespective of how it is connected to other elements. Kirchhoff’s Current Law, which describes current relations at the nodes in a network, states, the net sum of the currents into any node equals zero at each and every instant of time. Kirchhoff’s Voltage Law expresses the principle of conservation of energy in terms of the voltage around a loop: the net sum of the voltages around any loop equals zero at each and every instant of time.

Power flows through a transmission line mainly dependent on the electrical characteristics of the network and the location of generation and load on the system. Because the electrical characteristics and the load cannot be easily changed in most cases, flows through lines and interfaces are generally controlled by adjusting generation on both sides of the interfaces.

To better understand the interface limits, consider the following simple 3 bus power system as shown in Figure 3.1. Let G1, G2 and G3 be three generators connected to an electrical network of buses A, B and C respectively as shown in Figure 3.1. For simplicity, assume the following: 1) A and B are connected by a line having a capacity of 100 MW and a reactance of 0.1 (assume zero resistance); 2) B and C are connected by a line having a capacity of 100 MW and a reactance of 0.1; and 3) A and C are connected by
a line having a capacity of 50 MW and a reactance of 0.2. Further assume that the loads connected to busses A, B and C are 50 MW, 0 MW and 200 MW, respectively. Also assume that G1, G2 and G3 each has a capacity of 200 MW each and that G1 is the least expensive to operate and G2 is the most expensive.

Figure 3.1: Three Bus Power System

In a transportation model, the maximum power that can be transferred from A to C is the sum of the capacity of the line from A to C and A to B (or B to C, which ever is lower). In this case, it would be 150MW. However, in an electrical circuit, the current flows through the lines will be dictated by their corresponding reactances (Kirchoff’s Law). In the 3 bus system, the reactance of the line from A to C (0.2) equals the sum of the reactance of the lines A to B (0.1) and B to C (0.1). Therefore, for every MW flow from A to C, there will be an equal amount of flow from A to B and B to C. Since the capacity of the line from A to C is 50 MW, the maximum power that can be transferred
from A to C is 100 MW. If effort is made to transfer any more power, flow through line AC will exceed its capacity.

### 3.2 Security Dispatch

The electric transmission system is comprised of tens of thousands of electrical and mechanical devices and components that are interconnected. The predominant and most widely known components are the electric generators, transmission lines and protection components such as circuit breakers and relays. A reliable transmission system is designed to withstand the planned and unplanned outage of virtually any component that may be out of service as a result of the component failure or planned maintenance. These outages are referred to as contingencies. In the event of a contingency, the flows through the lines would redistribute instantly, depending on the locations of the load and generators and the reactance of the remaining elements of the transmission system.

In the US, the North American Electric Reliability Council (NERC) is charged with developing the fundamental requirements for planning a reliable interconnected bulk electric system. NERC carries out its reliability mission by:

- Establishing reliability policies, standards, principles, and guides
- Measuring performance relative to NERC policies, standards, principles, and guides
- Ensuring conformance to, and compliance, with NERC policies, standards, principles, and guides

NERC has developed national standards that contain the minimum acceptable design criteria that each regional council across the US can adopt. Regional councils can develop more stringent criteria to meet unique regional needs.

These transmission reliability standards determine the adequacy and security of the nation’s transmission grid. The framework for a reliable national transmission grid is based on contingency analyses of predictable and probable events. The consistent use of
contingency planning that is applied across an area ensures that such design contingency events do not cascade outside of the area and adversely impact neighboring electric systems. Design contingencies are simulated using computer models developed to represent actual and future system conditions. The system performance under such contingencies must fall within predefined thermal, voltage and stability limits. If the simulation shows that transmission line power flows exceed emergency ratings, or that voltages fall outside of acceptable criteria, corrective action must be implemented to ensure that the integrity of the transmission grid is maintained.

Utilities evaluate the adequacy and security of the transmission network to meet varying load demands under reasonably foreseeable generation and transmission system conditions. Certain scenarios assume that all system generation resources and transmission lines are available, while other scenarios assume that certain generation and transmission facilities are unavailable due either to bid dispatch, scheduled maintenance or unplanned outages. The purpose is to demonstrate that the electrical network is sufficiently robust to withstand a reasonable level of facility outages and still reliably and economically serve the electrical needs of customers. Thus, the basic notion of a security-constrained dispatch is to identify a set of possible contingencies, such as loss of a line or a major facility, and to limit the normal dispatch so that the system would still remain within the emergency rating of all components for the period required to take remedial actions if the contingency occurs.

Most electric utilities have developed a standard procedure for rating transmission equipment. Each electrical component has both normal and emergency ratings. The normal rating is defined as the amount of current which, under specified ambient and load cycle conditions, will not cause equipment loss-of-life above design criteria. Emergency ratings are greater than normal ratings. Currents above normal ratings can cause a greater rate of equipment loss-of-life, loss of conductor tensile strength, and increased conductor sag that can pose both an operating and safety problems. The emergency ratings allow utilities to operate electrical equipment above a manufacturer's standard nameplate rating, recognizing the inherent capabilities of this equipment to
operate at higher current levels for short periods of time with acceptable loss-of-life. Thus, the use of emergency ratings in planning studies recognizes the limited switching and dispatch options available to operations.

Hence, a single line may have a normal limit of 100 MW and an emergency limit of 110 MW. The actual flow on the line at a particular moment might be only 90 MW, and the corresponding dispatch might appear to be unconstrained. However, this dispatch may actually be constrained because of the need to protect against a contingency. The binding constraints on transmission generally are on the level of flows or voltage in post-contingency conditions, and flows in the actual dispatch are limited to ensure that the system can sustain a contingency.

To understand the transfer limits considering a contingency (security constrained), assume that the lines from A to B and B to C are, in fact, two lines each with a normal capacity of 50MW and a reactance of 0.2, similar to the line from A to C as shown in figure 3.2. Similarly, assume that all these lines have an emergency rating (under contingency) of 55MW each. Further assume that one of the lines from B to C is tripped and is shown by the dotted line. Because of the reactance of the lines, for every MW of flow through the line from A to B, 1.5 MW will flow through the line from A to C. In other words, if 1MW of generation at A is increased to serve 1MW of load at C, 0.6MW will flow through the line from A to C and 0.4MW will flow from A to B. This increase in flow through AB and AC is generally referred to as the generation shift factor. The generation shift factor of a line with respect to a generator bus is defined as the change in flow over that line for a 1MW increase in generation at that generator bus to serve an increase in load of 1MW at the reference bus. Since the capacity of the line from A to C is 55 MW, the maximum power that can be transferred from A to C is now 92 MW. If the transfer of any more power is attempted, the flow through line AC will exceed its emergency capacity.
Transmission congestion is said to occur when there is a need to operate uneconomical generation to serve load because of transmission restrictions. To understand this phenomenon, consider the simple power system in Figure 3.3. Assume that the Generator G1 bids at $30/MW and the Generator G2 bids at $40/MW, and the loads at bus A and B are 50MW each. The flow through line AC will be 25MW and line AB will be 25 MW, which are below their thermal ratings. In this case, all the load at busses A and C can be served from the lowest cost generator G1. In this case, there is no transmission congestion.
Now consider the power system in Figure 3.4. Assume that the load on bus C is now increased to 150 MWs. Even though generator G1 has the capacity to serve the total load on A and C, the maximum power that can be transferred from A to C is 92 MWs (see Figure 3.2). In this case, the least cost generation at G1 cannot be used to serve the load and the higher cost generation G3 at C has to be operated out of merit because of transmission restrictions. This is a case of transmission congestion.
3.4 Transfer capability Considering Several interfaces

In the simple interconnected power system shown in Figure 3.5 with four companies, A, B, C and D, define five interfaces: AB, AC, CB, CD and BD. These interfaces, in general, will have different capabilities to transfer power in each direction. In order to achieve a better understanding of how these interfaces are interrelated in the power transfer problem, assume that power is transferred in the general direction from A to D. Suppose that for a specific generation pattern and load distribution, the interface BD reaches its limit. Upgrading the capability of this interface may lead to another interface being limiting, e.g., interface AC. But upgrading the capability of interface AC may lead to a third interface being limiting, e.g., CB. It is thus obvious that increasing the limits of one interface by 100 MW may not necessarily increase the transfer capacity from A to D by 100 MW.
Wheeling of power from one company to another can aggravate the flow through an interface. For example, a contractual arrangement to wheel power from A to D without due consideration to power flow path could lead to overloading the interface CB, even though companies C and B are non participants in the arrangement.

Interface limitations can be critical or trivial. Sometimes, interface overloads can be mitigated simply by re-dispatching generation output nearby, entailing minimal cost penalties. At other times, interface overloads can simply be eliminated by disconnecting one element on the interface. Often times, though, interface limitations can substantially hinder the transfer of power from one part to another, with heavy cost penalties compared to what might be accomplished in the absence of such limits.

Another issue is the simultaneous transfer capability of the network to deliver power to an area over several interfaces. For example, the sum of the interface limits BD
and CD may be greater than the actual ability of the system to move power to company D.

To assess the economic feasibility of reinforcing an interface, the frequency and magnitude of problems caused by the restriction must be determined. The cost penalties associated—either the cost of generation re-dispatch or loss of load—associated with the restrictions must also be determined. Still another factor to determine is the amount of increased transfer capability obtainable by reinforcing the interface and the cost associated with such reinforcement.

One of the commonly used methods to determine the interface limits involves the application of a combination of linear analysis and load flow techniques. Normally, linear analysis programs such as the contingency analysis program and transmission interchange limit analysis are used as screening mechanisms to approximate the transfer limits and to identify the limiting contingencies. Load flow techniques are then used with various representative generation dispatches and representative load levels to more accurately evaluate the transfer limits. This method has two principle deficiencies. First, it is difficult, if not impossible, to evaluate transfer limits considering all possible combinations of generation dispatch and load level, using linear analysis and load flow techniques. This is so because the interface limitations are dependent on the many conditions of generation dispatch and the geographic distribution of hourly load levels. Second, these techniques do not indicate the timing, frequency or magnitude of the limitations. Thus, it is difficult to determine whether the limitation is significant or trivial.

In a deregulated environment, the way the need for transmission investment is evaluated needs to be changed. For this transmission system in Figure 3.5, assume that interface BD has been found to be a bottleneck for the transfer of power from A to D and that an additional 500 MW of economic generation is to be sited in company A. Using computer models, the hourly system operation can be simulated. Programs such as General electric’s Multi Area Production Simulation (MAPS) can simulate the economic
generation dispatch (secure) recognizing the transmission limitations and can identify the hours and the critical elements for those situations where the generation needs to be redispatched because of a transmission limitation. The program can also calculate the magnitude of the restriction, i.e., how much power must be redispatched for each of these restricted occurrences.

In the scenario in which 500 MW of generation are added in company A, assume that the system generation has to be redispatched 300 hours a year because one of the lines on interface BD was limiting. Also, the generation has to be redispatched 20 hours a year because a line on interface AB is limiting, 50 hours because a line on interface AC is limiting, and 30 hours because a line on interface CD is limiting. If the level of interface flows across interface BD is plotted against the number of hours of occurrence, a histogram can be created that illustrates the distribution of flows as revealed in Figure 3.6. The largest curve shows the flows across the interface BD.

![Histogram of Power Flows on Interface BD](image)

**Figure 3.6 : Histogram of Power Flows on Interface BD**

The hours when one or more of the lines in the system were limiting (in the present scenario, it is 500 hours). If the interface flows are plotted against the number of
hours of restrictions, another histogram can be created — a sub-histogram as presented in Figure 3.6. This small curve shows the number of hours there was some transmission restrictions in the system for the specific level of flow across the interface.

Similarly, the flows across all five interfaces for the same year can be plotted for the same generation patterns and load levels. Together, they show the simultaneous transfer limits considering many interfaces in a transmission system.

Using computer models such as MAPS, the operation of the transmission system can be simulated and the magnitude of these restrictions can be identified. If these restrictions are plotted from the largest to the smallest, a duration curve is derived as shown in Figure 3.7. This plot gives the magnitude of the transmission restrictions. The area under this curve shows the energy restriction due to transmission limitations. A thorough analysis of this curve and the system conditions prevailing at the time restrictions occurred will provide insight into the problem and the economic value of potential transmission upgrades.

![Duration Curve of Limitations](image)

**Figure 3.7 : Duration Curve of Limitations on Interface BD**

It is possible to run a second scenario assuming that all transmission upgrades have been completed on Interface BD. This will generate a second set of plots
identifying the next most critical interface and its limitations. Such analysis will clearly help to evaluate the effectiveness of each transmission interface upgrade.

### 3.5 Conclusions

A line or group of lines capable of transferring power from one area to another is termed as an interface. The interface limit is the maximum amount of power that can be securely transferred over that interface. Power flows through transmission lines and hence, an interface is mainly dependent on the electrical characteristics of the network and the location of generation and load on the system. Because the electrical characteristics and the load cannot be easily changed in most cases, flows through lines and interfaces are generally controlled by adjusting generation on both sides of the interfaces.

Transmission congestion is said to occur when there is a need to operate uneconomical generation to serve load because of transmission restrictions. Interface limitations can be critical or trivial. Sometimes, interface overloads can be mitigated simply by redispaching generation output nearby, entailing minimal cost penalties. Often times, though, interface limitations can substantially hinder the transfer of power from one part to another, with heavy cost penalties compared to what might be accomplished in the absence of such limits.

To assess the economic feasibility of reinforcing an interface, the frequency and magnitude of problems caused by the restriction must be determined. The cost penalties associated (either the cost of generation re-dispatch or loss of load) with the restrictions must also be determined. Still another factor to determine is the amount of increased transfer capability obtainable by reinforcing the interface and the cost associated with such reinforcement. These analyses will provide insight into the problem and the economic value of potential transmission upgrades.
Chapter 4

Alternatives to New Transmission Lines

4.0 Transmission Upgrades

There are several alternatives to building new transmission lines to mitigate congestion or enhance reliability. Public perception about the environmental impact of new transmission construction continue to be very negative as evidenced by the continued public resistance to the siting and construction of new transmission facilities. Consequently, other methods must be considered for increasing transmission capacity by better utilization of the existing transmission facilities. Many of these alternatives can result in additional transmission capacity without the need for additional right-of-way acquisition and can delay or even completely eliminate a new transmission line project.

One alternative is to reconductor the existing lines with higher capacity conductors. High temperature superconducting cables can carry much more current than standard wires of the same size, with extremely low resistance, allowing more power to flow in existing right-of-ways. Also, advanced composite conductors are lighter and have greater current carrying capacity, allowing more power to flow in existing right-of-ways.

A second alternative is to use Flexible AC Transmission System (FACTS) devices. FACTS devices are used for the dynamic control of voltage, impedance and phase angle of high voltage AC lines. They provide strategic benefits for improved transmission system management through better utilization of existing transmission assets, increased transmission system reliability and availability, increased dynamic and transient grid stability increased quality of supply for sensitive industries (e.g. computer chip manufacture) and enabling environmental benefits.46

Some examples of FACTS devices are as follows:

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• Static Var Compensators (SVCs), the most important of the FACTS devices, have been used for a number of years to improve transmission line economics by resolving dynamic voltage problems. Their accuracy, availability and fast response enable SVCs to provide high performance steady-state and transient voltage control, compared with classical shunt compensation.

• Thyristor-controlled series compensators (TCSCs) are an extension of conventional series capacitors. This is accomplished by adding a thyristor-controlled reactor. Placing a controlled reactor in parallel with a series capacitor enables a continuous and rapidly variable series compensation system.

• STATCOMs are gate turn-off type thyristor based SVCs. Compared with conventional SVCs, they do not require large inductive and capacitive components to provide inductive or capacitive reactive power to high voltage transmission systems. This results in smaller land requirements.

• Unified power flow controller (UPFC) are shunt-connected devices, that are connected with series branches in the transmission line via its DC circuit results. They are comparable to a phase shifting transformers but can apply a series voltage with the required phase angle instead of a voltage with a fixed phase angle.

The transmission owner can accrue many financial benefits by using FACTS devices. This includes additional sales due to increased transmission capability and savings by avoiding or delaying investments in new high voltage transmission lines. Further, the construction period for FACTS devices is considerably shorter than that for new transmission lines -- 12 to 18 months from contract signing through commissioning.

A third alternative is energy storage devices, which permit the use of lower cost, off-peak energy during higher cost peak consumption periods. Some specialized energy storage devices can be used to improve power system control. Technologies include
pumped hydro, compressed air, superconducting magnetic energy storage (SMES), flywheels, and batteries.

In areas where the interface is limited by voltage constraints, additional transmission capacity may be added by providing voltage support with capacitor banks in existing substations. New technologies such as SVCs or STATCOMs can also accomplish voltage support to a constrained area.

High voltage direct current (HVDC) transmission provides an economic and controllable alternative to AC for long distance power transmission. DC can also be used to link asynchronous systems and for long-distance transmission under ground and under water. Conversion costs from AC to DC and then back to AC also has limited usage. Currently, there are several thousand miles of HVDC in North America.

4.1 Demand Response

Effective demand responsiveness (DR) programs targeting transmission limitations can have a profound influence in delaying the need for new transmission additions. A properly designed demand responsiveness program that targets load curtailments in a transmission constrained area can alleviate transmission loading during peak periods and under contingency conditions. While the residential and small commercial customers individually may not have any noticeable effect on the transmission system, large industrial customers can contribute significantly by reducing their load and unloading the transmission system. Such integration of the demand side response to manage transmission constraints are effective alternatives to transmission construction as the transmission system becomes increasingly stressed.

With the vertically integrated monopolistic structure, utilities have embraced the operating philosophy that “all customers must be served at all times at any cost.” This was in line with their “obligation to serve.” More importantly, under the rate-of-return regulation, utilities maximized their profit by maximizing their capital investment and,
as Averch and Johnson argued, had a strong incentive to overinvest in capital. Relaxing this principle is fundamental to achieving reliable and affordable electricity services. Allowing the demand side to effectively interact with the supply side will greatly enable a fully competitive and efficient market. With the proper economic incentive and price signals, a number of customers can be encouraged to voluntarily reduce their loads. Thus, improving the ability of electricity demand to respond to wholesale spot prices will reduce the total costs of reliably meeting demand, and can reduce the level and volatility of spot prices at critical periods.

Some economists argue that regulated prices below the costs of incremental supplies give consumers too little incentive to conserve and makes it unprofitable to expand supply. Utilities can improve consumer incentives and reduce its own full-cost-recovery prices by paying for demand reductions, as long as such payments do not exceed the difference between marginal costs and retail prices.

However, it is important to be careful to understand the cost-benefit ratio of the demand Side response programs. Just increasing DR by forcing or subsidizing demand reductions that cost more than they save will increase total costs for society and ultimately for consumers. The appropriate way to improve DR is by providing better price signals, technology, and information and then allowing market participants to respond to these. Improving DR may require some socialized investment in infrastructure, technology and transition costs, but will both increase DR and—if the socialized investments are well targeted and limited—reduce total costs.

4.2 Distributed Generation

Small, distributed generators (DG), including conventional (e.g., diesel generators) and newer technologies (e.g., PV, fuel cells and micro turbines), allow generation to be located close to the load, thus decreasing the need for reliance on the transmission system. There are many potential benefits for using DG: 1) increased efficiency of the electricity system, especially in combined heat and power applications; 2) improved
power quality, particularly for the customers who install the DG; 3) increased reliability for both host customers and others; and 4) reduced delivery infrastructure needs because they are located closer to load.

The benefits and costs of DG vary, depending on the technology deployed. DG technologies include reciprocating engines (diesels), combustion turbines, microturbines, fuel cells, photovoltaic and wind. Diesel and combustion turbine technologies are fully commercialized and have been used in distributed generation applications for many years. Their capital costs are low; but they have high levels of air emissions (NOx, SOx and CO2), which may limit future installations and operations. They are also relatively inefficient.

There are a number of emerging new technologies in distributed generation, as described below.49

4.2.1 Microturbines

Microturbines are miniature versions of the conventional base load machines used to generate power from natural gas. They evolved from aircraft engines and automotive turbochargers. In the US, microturbines are already being employed as on site power generators in a number of industries. Proponents claim that this technology can provide reliable, high quality power at the site of generation at a cost that is becoming comparable to the delivered price of peak electricity. As with other forms of distributed energy, microturbines have the potential to reduce loads on transmission and distribution networks and have the benefit that any waste heat produced can be used to provide heating or cooling, further reducing energy costs.

4.2.2 Fuel cells

Fuel cells are a group of technologies that produce electricity from the chemical interaction between hydrogen and oxygen. Fuel cells can use pure hydrogen or, if fitted
with a fuel reforming device, hydrocarbon fuels such as natural gas. Various fuel cell technologies are under development and are generally classified by the type of electrolyte used in the cells, including:

- Alkaline fuel cells (AFC)
- Protein exchange membrane fuel cells (PEMFC)
- Phosphoric acid fuel cells (PAFC)
- Molten carbonate fuel cells (MCFC)
- Solid oxide fuel cells (SOFC)
- Direct methanol fuel cells (DMFC)

The operating environment is a critical factor in selecting an appropriate fuel cell technology because each technology has various characteristics and applications. Significant research and development is being directed toward PEMFC technology because it is most promising for mobile applications. PAFC is a first generation technology and has the largest commercial penetration in stationary power generation applications. Many technological and commercial barriers remain for widespread fuel cell applications including storage and transport of hydrogen and the high cost of materials used in construction of fuel cells. However, fuel cells have many potential advantages over conventional energy sources, including a lack of emissions, energy conversion efficiency, and reliability. These factors provide significant advantages in applications such as transport and on-site electricity generation.

4.2.3 Wind turbines

Over the last decade, wind power has been the world’s fastest growing energy source and is now considered to be one of the most cost-competitive renewable energy sources. Small scale turbines (generally rated less than 10kW) can be used as remote area power systems. Technological advances in materials used in modern wind turbines are helping to reduce costs and improve design and construction of large generators. The greatest challenge to the economic use of wind power is the need for further significant
cost reduction, the variability of the wind resource, and in some areas, community acceptance. Very few areas have fairly constant wind throughout the day and throughout the year. Energy storage, or backup systems, are required for windless or extremely windy periods, and also to level the supply even when the wind is blowing. Environmental issues such as visual, noise and flora/fauna impacts are becoming an increasing concern for proponents of large scale wind farms.

4.2.4 Photovoltaics

Photovoltaic (PV) technology is a semiconductor-based technology in which light energy (photons) is converted into direct current (DC) electricity. PV’s differ from solar collectors such as water heaters and some electricity generators that convert the light energy into heat. There are particular opportunities for this technology where the consumer has a need for DC power. PV’s include a range of different technologies and approaches including silicon wafer-based technology and more recent approaches such as ‘thin film’ technologies. PV’s first practical uses were in space applications, and where alternative (conventional) forms of generation are not viable such as in remote areas. However, increasingly PV’s are being used in grid connected applications as the efficiency of the units are improving and construction costs are reducing. A potential application is the integration of PV cells into rooftop material to generate electricity for household and commercial use.

4.2.5 Biomass

Biomass energy is derived from plant and animal material, such as wood, residues from agricultural and forestry processes, and industrial, human and animal wastes. Large-scale energy production from biomass, which can substitute for conventional fossil fuel energy sources, generally rely on fuels such as forest wood and agricultural residues, urban wastes and biogas and energy crops. A range of technologies exist to convert
biomass into large scale energy production, which can substitute for conventional fossil fuel energy sources.

Biomass as an energy source benefits from the fact that the fuels are renewable and some biomass energy sources can reduce greenhouse gas emission. However, biomass has relatively low energy density and the need to transport large volumes of the fuel can significantly reduce net energy production.

4.2.6 Geothermal generation - Hot Dry Rocks

Geothermal resources come in five forms: hydrothermal fluids, hot dry rock, geopressed brines, magma, and ambient ground heat. Of these, only hydrothermal fluids have been developed commercially for power generation, with about 9000 MWe installed capacity in place worldwide. Hydrothermal electricity is generated from naturally occurring hot water and steam in rocks near volcanic centers, providing steam for conventional steam turbines and generators. The geological conditions necessary for hydrothermal energy are relatively uncommon, and only New Zealand, Indonesia, the Philippines, Iceland, Japan, Italy, the US and Mexico have commercial scale hydrothermal systems.

However, hot dry rock resources are generally more widespread. This energy is stored in rock heated by the earth’s core and close enough to the surface for conventional drilling to access. Much of the resource data information comes from oil and gas industry drilling. Hot dry rock geothermal energy is converted into electricity by circulating water through the hot rock and using the heated water to generate steam for standard geothermal power stations. The extraction process relies on existing technologies and engineering processes such as drilling and hydraulic fracturing, techniques established by the oil and gas industry.
4.2.7 Carbon sequestration

Carbon sequestration includes capturing CO2 gas from combustion flue gas and other point sources and storing it, as well as reducing atmospheric concentrations by enhancing the uptake of CO2 through natural ecological systems generally referred to as sinks (e.g. forests, oceans microorganisms). Carbon dioxide capture is estimated to represent a significant proportion of the total cost of a carbon capture, storage, transport, and sequestration systems. Options currently identified for CO2 separation and capture, include the following:

- Absorption (chemical and physical)
- Adsorption (chemical and physical)
- Low-temperature distillation
- Gas separation membranes
- Mineralization and bio-mineralization.

4.2.8 Coal Gasification

Coal gasification is one of a range of clean coal technologies. When coal is brought into contact with steam and oxygen, thermochemical reactions produce a fuel gas, primarily carbon monoxide and hydrogen, which, when combusted can be used to power gas turbines. Integrated coal gasification combined cycle (IGCC) power generating systems provide improved efficiency by using waste heat from the product gas to produce steam to drive a steam turbine, in addition to a gas turbine. The cost of CO2 capture is also reduced by the isolation of this gas during the gasification process.

4.3 Transmission Operation and Planning

As the power industry transitions into an unregulated environment, proper transmission operations procedures can greatly enhance the future competitive marketplace. In order for the transmission system operations to respond efficiently and fairly to market forces, the right price signals must be provided to transmission owners.
and operators to improve operations. Efficient transmission operations in response to accurate price signals can delay or even eliminate some construction of new transmission facilities. Further, if and when new transmission additions are needed, proper price signals will encourage market participants to select the most economically efficient solution to transmission constraints.

Most utilities have established the present operational rules and procedures based on experiences developed at a time when they were vertically integrated and when electricity transactions were smaller in volume, involved fewer participants, and did not routinely span multiple regions. These rules and procedures embody a central-planning approach that gives little consideration to either the commercial value of electricity trade and the cost to consumers of lost trading opportunities, or to customers' willingness to accept compensation voluntarily for interruptions of electricity service. Again, this philosophy was in line with their “obligation to serve” and more importantly, was influenced by a strong incentive to over invest in capital under the rate-of-return regulation.

For the future marketplace, a reliable transmission system is required that supports fair and efficient competitive regional wholesale markets that endeavors to lower the cost of electricity to all consumers. There must be reliance on market forces to improve transmission system operations. There are several measures utilities can undertake to increase the present transfer limits by improving their operations. One that approach is to use dynamic measurement of transmission lines.

4.3.1 Dynamic Measurement of Transmission Lines

Historically, utilities have employed a very conservative approach to rating lines and calculating interface limits. Transmission line ratings are a function of ambient conditions such as air temperature and wind speed, conductor loading profile, ground clearance and other factors. Presently, utilities assume conservative values for all these variables. Further, total transfer capability (TTC) has traditionally been determined by a
static analysis of acceptable system conditions. This practice was acceptable in the past because of the lack of measurement, communication, and analysis tools to determine the real-time status of the electric system. In addition, it was easier to conduct a static analysis and overbuild the transmission system than to conduct a dynamic analysis so that the system could be operated more efficiently.

In order to increase the efficiency of the transmission assets, the limits of safe and reliable transmission system operation must be understood. As ambient conditions change, transmission line rating and the transfer capability of the interfaces will likewise change. A dynamic system analysis that uses real-time data instead of the conservative proxies used in a static analysis provides a better estimate of TTC and would allow operators to safely move more power across existing lines. The overall consequence of using dynamic transmission system analysis could be a substantial increase in TTC, a reduction in transmission congestion, and a more efficient use of the transmission system. Recent advancements in measurement, communication, and analysis tools now make dynamic analysis a possibility. In some cases, a change from a static transmission system analysis to a dynamic analysis may be the most cost-effective means to reduce a transmission bottleneck.  

4.3.2 Value of Reliability

Value of reliability is not completely understood by consumers and the utilities. While reliable electric service is important, the price of marginal reliability to consumers must be communicated. Utilities assume that consumers demand extremely high reliability “at any cost”. In fact, some contend that utilities are using ‘reliability’ as an excuse to ‘gold plate’ their system. In the future competitive energy market, the costs of reliability to consumers should be explicitly accounted for when reviewing reliability rules. Also, consumers should be allowed to pay for a higher level of reliability than that provided by the current electricity system.
However, some changes are emerging to better utilize existing transmission facilities. Some transmission owners are employing techniques, such as real-time operation using state estimation, security analysis, and dynamic ratings, to get more use out of transmission facilities. Transmission planners are more closely analyzing the system utilizing special protection systems (SPS) or remedial action schemes (RAS) in lieu of building new transmission lines and substations. SPS or RAS is designed to detect abnormal system conditions and to take pre-planned, corrective action (in addition to the isolation of faulted elements) in order to provide acceptable system performance. SPS and RAS actions include changes in demand (e.g., load shedding), generation or system configuration to maintain system stability, acceptable voltages, and acceptable facility loadings. However, as the number of SPSs and RASs increase, the complexity of operating the system also increases.\textsuperscript{51}

4.3.3 Transmission Planning

For the continued development of competitive electricity markets, transmission planning must balance traditional reliability considerations with economic efficiency. Taking the economic efficiency attributes of electricity markets into account requires adopting a regional perspective because these markets span across regions. This is in sharp contrast to most current transmission plans, which, because of the limited geographic scope and the mandate of today’s transmission owners, focus primarily or solely on local considerations.

Today, most utilities use a deterministic approach as planning criteria. Utilities evaluate the adequacy and security of the transmission network to meet varying load demands under reasonably foreseeable generation and transmission system conditions. They assess scenarios that assume that certain generation and transmission facilities are unavailable due to bid dispatch, scheduled maintenance or unplanned outages without assessing the probability of such occurrences. The intent is to demonstrate that the electrical network is sufficiently robust to withstand a reasonable level of facility outages and still reliably and economically serve the electrical needs of customers.
As market forces change, it must be concluded that such a deterministic approach is too costly and difficult to justify in competitive markets. Generation planning is decentralized and is subject to competitive forces, and the transmission owners may have no control of its location. The most efficient means to achieve reliability under these uncertain circumstances may be to use a probabilistic approach to transmission planning, which can provide a superior measure of relative strengths of various options. Probabilistic evaluation can also give a better estimation of the price of reliability for the customers. It will help to identify and assess the tradeoffs among planning options such as reliability versus economic efficiency and local impacts versus regional benefits.

4.4 Transmission Efficiency

4.4.1 Transmission losses

Losses during the transmission of power depend on a variety of factors, including the physical properties of transmission facilities, the distance the electricity must travel, and the voltage of the transmission system. The costs of system losses are mostly socialized and sometimes included in uplift charges borne equally by all transmission system users. There is no accurate price signal to indicate who is causing what proportion of the losses, which leads to an inefficient use of the transmission system. Because the transmission owners in general pay for the losses, the loads and the generators have no incentive to locate in the most desirable location or for the efficient use of the transmission system. More accurate pricing and allocation of transmission losses will lead to more efficient markets because participants can see and respond to the true costs of using the transmission system.

4.5 Conclusions

There are several alternatives to building new transmission lines to mitigate congestion and enhance reliability. Some of these methods such as reconductoring of the existing lines with high capacity lines, using flexible AC transmission system devices and
using energy storage devices may, in fact, increase the transfer capacity of the transmission system using the existing footprint.

Enabling customers to reduce load on the transmission system through DR programs and reliance on DG are important but are currently underutilized approaches that could do much to address transmission bottlenecks today and delay the need for new transmission facilities. Policies and programs that improve DR and DG by providing more efficient incentives will produce real, lasting benefits for society and for consumers. However, it is critical to understand the cost-benefit ratio of these programs. Just increasing DR by forcing or subsidizing demand reductions that cost more than they save, will increase total costs for consumers.

As the power industry moves to an unregulated environment, efficient transmission operations in response to accurate price signals can delay or even eliminate some construction of new transmission facilities. For the continued development of competitive electricity markets, transmission planning must balance traditional reliability considerations with economic efficiency. Further, better pricing signals to allocate transmission losses more accurately to those who cause it will lead to more efficient markets because participants can see and respond to the true costs of using the transmission system.
Chapter 5

Role of Transmission in a Power System

5.0 Changing Role of Transmission

The electric transmission system in the US was built over the past 100 years by vertically integrated utilities (regulated monopolies) that produced, transmitted and distributed electricity to their local customers. Interconnections among neighboring utility systems were constructed over a period of time to exchange power, to increase reliability, and to share excess generation during certain times of the year. Today, over 150,000 miles of high-voltage transmission lines link generators to load centers through interconnected transmission systems that span utility service territories, states, regions, and the borders of Mexico and Canada.

While this industry structure remains largely intact in some areas of the country (e.g., the Southeastern US) and continues to function effectively, others have experienced dramatic changes in the electric power sector. As shown in Figure 5.1, nearly half the states are in some phase of restructuring of the electric industry. Today, more than half of the electricity generated in the US is traded in regional wholesale markets before being delivered to the end-use customer. In this new landscape, generation and transmission are increasingly provided by different companies.

Over the past 10 years, U.S. has introduced competition into wholesale electricity markets in order to lower costs to consumers by spurring needed investments in generation and increasing the efficiency of operations. Currently, the transmission system acts as an interstate highway system for wholesale electricity commerce. The growth of wholesale markets has altered how the nation’s transmission infrastructure is used. Spurred by federal and state regulatory changes in the past decade, utilities, independent producers, and marketers now use these interconnected transmission systems
to buy and sell wholesale power in robust regional wholesale markets. The transmission system was not designed for this new and critical use.

![Figure 5.1: Status of State Electric Industry Restructuring Activity -- as of December 2002 --](image)

Source: U.S. Department of Energy

**Figure 5.1 : Status of State Electric Industry Restructuring Activity**

-- as of December 2002 --

The system planning and decision making function has also changed, from integrated planning to a decentralization. Historically, utilities have performed generation and transmission planning to serve the needs of their own customers within a defined service territory. These regulated monopolies not only had the information (electricity trends and forecasts), but the assets (generation, transmission and distribution facilities) to manage transmission constraints. Centralized decision-making by vertically
integrated utilities, alone, now, no longer determines electricity production. Instead, competitive market forces involving a number of new market participants, increasingly determine what produces electricity and where it will be consumed. This lack of coordination (or lack of integrated planning) between generation construction and transmission planning has substantially contributed to electric power system congestion.

Load growth has also contributed to transmission congestion. As a percentage of total energy use, electricity use is growing in the US. In 1970, electricity in this country accounted for 8 percent of total US energy use. However, in 2000, electricity accounted for 16 percent of total US energy use. This substantial increase in electricity use reflects the transformation of the economy in an increasingly sophisticated, information-based economy. However, the transmission expansion has not kept pace with the growth in demand. Figure 5.2 illustrates the gap between the demand growth and transmission capacity expansion. Figure 5.3 shows the declining tendency in transmission investments for the past 25 years. Figure 5.4 shows the percentage of new generation additions during 1998 to 2007 as a percentage of 1998 total installed generation.

NERC reports that near-term (2002–2006) generation adequacy is deemed satisfactory throughout North America, provided that new generating facilities are constructed as anticipated. Projected near-term, NERC-wide capacity margins will continue to experience increases over projections from previous years, peaking at more than 24% in 2005. Although electricity demand is expected to grow by about 71,000 MW in the near-term, new resource additions totaling 159,000 to 263,000 MW are projected for the same period, depending on the number of merchant plants assumed in service.
Despite the success of the wholesale electricity markets and the ability of new participants to address the nation's needs for new generation capacity, there is growing evidence that the US transmission system is under stress. Growth in electricity demand and new generation, a lack of investment in new transmission facilities, and the incomplete transition to fully efficient and competitive wholesale markets, have allowed transmission bottlenecks to emerge.
Investment in new transmission facilities has declined steadily for the last 25 years.


Figure 5.3: Transmission Investment 1975 - 2000


Figure 5.4: Projected New Generation Additions
Transmission problems have been compounded by the incomplete transition to fair and efficient competitive wholesale electricity markets. Because the existing transmission system was not designed to meet present demand, daily transmission constraints or “bottlenecks” increase electricity costs to consumers as well as increase the risk of blackouts. Eliminating transmission bottlenecks is essential to ensuring reliable and affordable electricity now and in the future. Figure 5.6 illustrates the transmission constraints in the US.

These bottlenecks increase electricity costs to consumers and increase the risks of blackouts. The growth of electricity demand during the 1990s, coupled with new generation resulting from the emergence of competitive wholesale electricity markets, has led to electricity flows that are greater in size and go in different directions than those that were anticipated when the transmission system was first designed. NERC reports that there is minimal operating experience for handling these conditions. The increased
use of the system has led to transmission congestion and less operating flexibility to respond to system problems or component failures. This lack of flexibility has increased the risk of blackouts. Today, power failures, close calls, and near misses are much more common than in the past. Figure 5.7 illustrates the steady increase in the number of level five and higher TLRs per year.
5.1 Congestion

The cost of transmission accounts for approximately 6 percent of the final delivered cost of electricity in what is today a $224 billion electricity industry. By increasing the transmission capacity by a relatively small investment in transmission can help consumers enjoy the reliable and affordable electricity service that properly managed competitive forces will deliver. According to DOE, today’s wholesale electricity markets save consumers nearly $13 billion per year in electricity costs. In other words, the nation’s current $224 billion annual electricity bill would be $13 billion higher without these wholesale shipments of electricity. Figure 5.8 illustrates the projected average wholesale prices with and without wholesale trade.
Costs to add new transmission are relatively small for the average retail bill. However, the benefits in overall energy bills are potentially quite large. Figure 5.9 illustrates the price increase on an average retail bill because of a 20% increase in transmission infrastructure costs. Figure 5.10 illustrates the potential savings in generation prices on an average retail bill because of the same transmission additions.

Source: U.S. Department of Energy

Figure 5.8: Projected Average Wholesale Electricity Prices
Large Transmission Investments Have Very Small Retail Bill Impacts

Source: FERC Electric Transmission Constraint Study

Figure 5.9: Impact of Transmission Investment on Retail Bill

Increased Transmission Enables Generation Cost Savings In Retail Bills

Source: FERC Electric Transmission Constraint Study

Figure 5.10: Transmission Investment Enables Cost Savings
Successfully addressing transmission bottlenecks requires careful analysis and consideration of their impacts on both market operations and system reliability, as well as analysis of the costs of transmission and non-transmission alternatives. As discussed in Chapter 3, removing bottlenecks is not simply a matter of finding congested transmission paths and then reinforcing existing transmission facilities along those paths or constructing new facilities. Because the system is a network, reducing congestion in one part of the system may shift it to another (the next most vulnerable) part. Congestion also tends to move around the system from year to year and in response to weather and other seasonal factors.

In addition, solving the problem of transmission constraints in the US will also require cooperation with Canada. Many scheduled power transactions in the US, particularly east-to-west transactions in the Eastern Interconnection, flow over transmission lines located in Canada before reaching loads in the US. This is a particular problem at points in the upper Midwest, where the transmission systems of the US and Canada interconnect. These unintended flows, or “loop flows”, frequently require transmission service curtailments in the U.S.\(^2\)

The benefit of increasing transmission capability to increase economic trade depends on relative electricity prices in the regions linked by the additional capacity and on the additional amount of electricity that would be traded on the new lines. If price differences are small and the added transmission capacity would be used during only a small percentage of the hours during the year, then the cost of a new transmission line may not be justifiable. Some level of transmission congestion may be desirable because it gives signals for future transmission upgrades. Figure 5.11 illustrates the optimum level of transmission constraint.
Some Level of Congestion Is Economically Efficient

Figure 5.11: Cost of Congestion vs Cost of Congestion Mitigation

5.3 Reliability

The benefits of increasing transmission capability to ensure reliability, even if this insurance is used only once to prevent a system-wide blackout, would be enormous and could far outweigh any potential gains from increased trade. Similarly, increasing transmission capability to reduce the ability of a competitor to exert market power could lead to benefits far in excess of those gained from increased trade. Assessing these issues will involve tradeoffs, e.g., commerce versus reliability and local versus regional benefits.
The Cost of Reliability—August 10, 1996, Power Outages in the Western State

The blackout in the western states on August 10, 1996, was a complex and dramatic reminder of the importance our modern society places on reliable electricity service. Ultimately, power was interrupted to approximately 7.5 million customers, for periods ranging from a few minutes to about nine hours. Immediate costs to the region’s economy were estimated at $2 billion. The August 10 outages were caused by multiple transmission line failures over a period of several hours. A single transmission line failure is a contingency that is routinely considered in reliability planning. However, the failure of several lines, combined with the day’s pattern of operation, caused the system to become unstable (which had not been anticipated by reliability planners), causing automatic controls to open the California Oregon Intertie, a major link between the northern (Pacific Northwest) and southern (California) portions of the western system. Opening the Intertie produced a power surge from the Pacific Northwest through the eastern portion of the grid toward Arizona and southern California, causing many lines to disconnect automatically and eventually fracturing the western grid into four separate electrical “islands.” Within each island, large blocks of customers lost power when their electricity demands suddenly exceeded available local generation. The situation was worst in the southern island where automatic controls disconnected over 90 generators to prevent them from being further damaged. Some of the larger units were out of service for several days.


5.4 Transmission Pricing

The debate over transmission pricing has been intense in the last two decades. Recent FERC orders and rulemaking processes have brought this issue into focus. The pricing implications, coupled with state rate caps, have affected transmission owners positions on planning and expansion processes. These positions are often self-serving and counterproductive to the SMD NOPR objectives.

Further complicating this issue is the fact that recovering the cost of transmission becomes a local responsibility, while the benefits of increased market efficiency and reliability are regional. The key to spurring new transmission investments lies in ensuring that the rewards offered by this system of regulation are commensurate with the
risks of undertaking these investments and identifying innovative approaches to align costs and benefits.

Transmission lines have direct economic costs and indirect or external costs. While the direct costs may be easy to understand and calculate, the indirect costs such as land use and environmental burdens may be more difficult to assess.

5.4.1 Direct Economic Costs

In the traditional vertically integrated industry structure, state regulators were responsible for monitoring and granting the proper rate relief for prudent transmission investments. The utility typically studied the need for transmission improvements and proposes a construction plan. The state regulators would evaluate this proposal in terms of considering the economic costs of a new transmission line against its projected benefits, to determine if the proposal would be in the best interest of the ratepayer. If the regulators concluded that the proposal was prudent, the state would allow these costs to be recovered in the rate base.

However, the use of the transmission line has changed dramatically over the past few years. With the advent of the wholesale electricity markets, the transmission system is used for interstate commerce across regional markets. This new use makes it difficult to pinpoint the beneficiary of each transmission line. The principal defect in implementing a beneficiary test is that an electric system works based on the laws of physics not according to state borders or service territories. A cost causation policy would dictate a nodal to nodal review of facility beneficiaries over the life of a facility. The integrated transmission grid with free flowing electricity relates to a simple concept — all the people benefit from the use of all of the lines all the time. Further, as the system configuration changes as a result of load growth, new or retired generation, or change in relative fuel prices, the function of a transmission facility can change dramatically over its life. The initial justification for a new facility may have no relationship to its long-
term use. Hence, the benefits of new interstate transmission lines are likely to be more
diffuse than those conferred to ratepayers within the vertically integrated structure

Collectively, through the National Association of Regulatory Utility
Commissioners (NARUC), the states have urged FERC to establish a pricing policy that
provides for costs to be borne by the “cost-causer” in those instances in which the
upgrade or expansion does not benefit the public interest as defined by the state
regulatory body. More broadly, state regulators, industry, and FERC are evaluating
alternative approaches to transmission cost recovery. There are five primary alternatives
as follows.\textsuperscript{53}

1) Merchant Direct Current (DC) Transmission Projects
A developer builds a DC line with its own capital, and sells or leases shares of the line’s
capacity to interested parties, either distributors or generators.

2) Merchant Alternative Current (AC) Transmission Projects Using Location Marginal
Pricing
This approach builds upon the location marginal pricing, or LMP system currently in use
in the Pennsylvania-New Jersey-Maryland Interconnection (PJM). LMP informs market
participants how much electricity will cost at a particular location at a given time. By
studying LMP trends, market participants can determine where transmission congestion
is driving up the price of wholesale power and where new transmission lines or upgrades
can effectively reduce costs. Companies that build new lines or perform upgrades to
reduce congestion and costs would acquire financial transmission rights (FTR). They
could hold the FTRs for their own use or sell them to other market participants.

3) Traditional Cost Recovery Using Rolled-In Allocation
Recognizing that the benefits of new transmission lines can often be diffuse, this
approach seeks to distribute associated costs across all users in a given market. The
approach has been used in the New England regional power pool (NEPOOL).
Specifically, the costs of regionally significant transmission lines have been rolled in, or allocated, to the rate base of consumers across the New England region.

4) Traditional Cost Recovery Using Cost-Causation Allocation
In contrast to the rolled-in allocation described above, cost-causation allocation seeks to narrowly assign costs to a specific group. This approach might be applied in cases where a new transmission line or upgrade clearly confers a majority of the benefits to a specific set of consumers and/or generators.

5) Traditional Cost Recovery Using a combination of Rolled-In and Cost-Causation Allocation
The rolled-in and cost-causation allocation approaches speak to different cost-benefit scenarios. The rolled-in approach seeks to socialize costs when benefits are diffuse. The cost-causation approach aims to narrowly assign costs when benefits accrue to a distinct set of market participants. Some may therefore support both approaches, with the use of one over the other being dependent on the context of the line or upgrade.

5.4.2 Indirect Costs

Similar to the direct costs of a transmission line, the indirect costs such as land use, social, and environmental burdens associated with the siting of a new interstate transmission facility may be distributed inequitably across states. In cases where a transmission line passes through several states, it is possible that one state may not get any direct benefit locally out of the new line and yet get burdened with the indirect costs. Determination of the right beneficiary and proper allocation of costs within a regional market represents a major policy challenge for the state and federal regulators.
5.5 Regulatory Paradigms

5.5.1 Cost-of Service Regulation (COSR)

Cost-of-service regulation has been used in the US for some time and has proven to be fair and workable. Under the traditional cost of service regulation, utilities are allowed to recover prudently-incurred costs plus a return. As the generation side of the power industry is becoming competitive, it may be time to revisit the regulatory structure for the transmission business. The regulated firm under cost-plus regulation has no incentive to reduce costs, since it is authorized to recover its costs plus a fair return on its capital.

Economic theory predicts that profit-maximizing firms will operate on the technologically efficient production frontier. They always wish to minimize its costs, regardless of how much competition it faces. But a regulated firm is in a different situation. Although regulated firms can choose their technologies and operating practices, these choices are subject to the state’s control over prices, entry and exit, and without the challenges posed by unrestricted competition from incumbent firms and new entrants. Hence, managers and employees face a rather different set of incentives in searching for greater efficiency. In a seminal paper, Averch and Johnson (1962) demonstrated that a hypothetical form of regulation, rate-of-return regulation, forced regulated firms to select their inputs in an inefficient manner, because the regulators determined a firm’s profits as a percentage of the firm’s capital investment (or “rate base”), firms had a strong incentive to overinvest in capital. An industry’s adjustment to deregulation will, in theory, be shaped by intensified competition and increased operating freedoms that will cause the industry to become more technologically advanced, to adopt more efficient operating and marketing practices, and to respond more effectively to external shocks.34

Also, profit shifting can occur through misattribution of costs incurred by a firm’s unregulated businesses to the regulated business. This is sometimes referred to as cross-
subsidization. Under cost-based regulation, shifting costs to the regulated business allows the firm to argue for higher regulated rates. In principle, cross-subsidization may be problematic whenever a regulated firm also operates in unregulated markets, but it is more likely to escape regulatory detection when the markets are related.

5.5.2 Performance Based Regulation

Performance-based regulation (PBR), an alternative to COSR, injects competitive market incentives into monopoly markets. PBR results in reduced cost of regulation, reduced cost of power owing to sharing of utility cost reductions between utilities and consumers, and improved risk allocation between utilities and consumers.

Most PBR schemes institute a revenue or price cap that is adjusted annually to account for input price increases and offset by productivity improvements to ensure that customers share in any benefits derived by the utility. The incentive to cut costs under PBR leads to reliability and service quality concerns from consumers. Accordingly, PBR generally includes performance indicators related to reliability, market efficiency, customer service, and, less frequently, employee and public safety.

More closely aligning the incentives of transmission owners with those of the public and consumers should be another element of eliminating regulatory uncertainty and sharpening the focus of regulatory decisions. For example, one approach that should be considered is shifting some responsibility for congestion - both its costs and the benefits from investment to reduce these costs - to transmission owners so that they have an incentive to address transmission bottlenecks. The current form of rate-of-return regulation is based on investment costs. Simply passing costs of congestion through to consumers disconnects the decision to invest from the benefit to the consumer of the investment, and thus offers no incentive to transmission owners to address bottlenecks.

Rate-of-return regulation, therefore, may be inconsistent with newer forms of regulation that seek to emulate the role of competitive market forces in eliciting efficient
behavior from regulated firms. A basic tenet of competitive markets is that investors are rewarded based on the value and innovativeness of their actions. Examples of PBR can be found in the telecommunications industry in the US and in regulated utility industries around the world, most notably the UK.

The objectives of PBR are to:

- Improve cost and price performance,
- Maintain and improve service quality,
- Encourage effective expansion (i.e., maximize the gains to the market from network expansion or enhancement),
- Provide the service provider with an opportunity to improve its profits, and
- Ensure environmental protection.

5.6 Conclusions

Today, more than half of the electricity generated in the US is traded in regional wholesale markets before being delivered to end-use customer. In this new landscape, generation and transmission are increasingly provided by different companies. The transmission system acts as an interstate highway for wholesale electricity commerce. Spurred by federal and state regulatory changes in the past decade, utilities, independent producers, and marketers now use these interconnected transmission systems to buy and sell wholesale power in robust regional wholesale markets. Growth in electricity demand and new generation, lack of investment in new transmission facilities, and the incomplete transition to fully efficient and competitive wholesale markets, have allowed transmission bottlenecks to emerge.

Costs to add new transmission are a relatively small part of the average retail bill. Increasing the transmission capacity by a relatively small investment in transmission can help consumers enjoy the reliable and affordable electricity service that properly managed competitive forces will deliver to our nation. However, the tradeoffs between the cost of operation with transmission constraints and the transmission investment to fix
the constrains must be evaluated in order to arrive at the proper economically desirable level of constrints.

Cost-of-service regulation has been used in the US for some time and has proven to be fair and workable. However this type of regulation may be inconsistent with newer forms of regulation that seek to emulate the role of competitive market forces in eliciting efficient behavior from regulated firms. Performance-based regulation (PBR) is an alternative to cost of service regulation that injects competitive market incentives into monopoly markets. PBR results in reduced cost of regulation, reduced cost of power owing to sharing of utility cost reductions between utilities and consumers, and improved risk allocation between utilities and consumers.
Chapter 6

Regulatory Paradigms

6.0 Regulatory Authority

The major challenge to the transmission infrastructure expansion is regulatory uncertainty. Because transmission assets are long-lived, regulatory uncertainty increases the risks to investors and this in turn increases the cost of capital they need for transmission system investments. Many factors contribute to this uncertainty. First, there are too many regulators with overlapping responsibility, which leads to inconsistencies between rules in different states and federal agencies. Second, transmission benefit is regional in nature, whereas the impact of new construction is local. Third, although the costs of transmission are authorized by federal regulators, they are mostly collected through retail rates authorized by state regulators.

The optimal way to provide the needed environment for transmission expansion is to transfer all siting, permitting and ratemaking responsibility of transmission to the federal regulators. Electricity transmission is a vested public interest and most new transmission facilities will typically cross state boundaries, and hence, FERC must have the appropriate authority to ensure that the public interest is served. Transmission use has changed dramatically over the past decade and today transmission systems are regional in scope and their benefits are generally regional in nature. Hence, the siting authorities need to take a regional perspective and, therefore, must be transferred to federal regulators.

6.1 Planning Process

The transmission planning process clearly becomes more challenging and uncertain when the generation market is competitive and evolves in response to price signals rather than regulatory directives. As observed in chapter 3, the planning process must balance reliability considerations with economic efficiency and should take a
probabilistic approach. The planning principles and practices should also facilitate new investment in transmission facilities as well as non-transmission alternatives. To provide a leveled playing field for all network providers (wire and non-wire solution providers), it is necessary to publish accurate, timely and detailed information on the nature and physical performance of the interconnected network. Because the individual transmission providers may not share this information with others, the RTO should publish this information in order to mitigate the information asymmetry. This would facilitate more timely and appropriate investment responses from generators, demand response programs, and other technology solutions prior to initiating a regulated transmission response.

6.2 Need for Change in Regulation

The electric industry is in the midst of unprecedented change. Deregulation of the electricity supply side, along with the decentralized decision-making by separate generators and retailers responding to commercial incentives, have fundamentally changed the environment in which transmission systems operate. Accordingly, the incentive structure for the transmission owners and operators must likewise be changed to reflect this reality. To attract new transmission investments, the new regulatory framework should ensure that the rewards offered by this system of regulation are matched with the risks of these investments, and should find innovative ways to align costs and benefits.

In addition to transporting power, transmission owners provide a number of functions in the electric industry value chain such as grid reliability, loss management, voltage support, line loading relief cooperation, congestion management, loop flows, ancillary services and grid expansion. The traditional cost-of-service regulation (COSR) is not designed to compensate for these kinds of value-added services. As such, the transmission owners do not have any market incentives to invest in capacity expansions and service enhancements that increase competition and lower energy costs. Therefore, a
new regulatory structure will be essential to motivate transmission owners to fulfill their role effectively in the new competitive environment.

In designing the incentive structure, the interrelationship between the various components of the value chain in the electric industry should be recognized. For example, the short-term and real-time transmission service complements generation and distribution, while long-term transmission investment can be a substitute for local generation and demand-side resources even as it complements remote generation. Targeted energy efficiency programs, voluntary customer load-reduction programs, and distributed generation are complementary strategies for alleviating bottlenecks, and delay the need for construction of new facilities. Consequently, the regulatory structure should have the right incentives for the transmission to provide efficient short-term service, and to optimally expand the system while not unfairly discriminating against other transmission owners, generation, and demand management. Thus, the new regulatory structure should take a holistic view, and transmission system expansion must be one of the strategies to address transmission bottlenecks in a portfolio that also includes generation additions in a congested area, demand response programs, and targeting energy efficiency and distributed generation.

The objective of the incentive structure should not be to remove congestion altogether, rather it should be to arrive at the optimum economically desirable level of constraints. Some variation in locational price is appropriate because it sends signals for new investment. In fact, a gradual increase in average price levels may provide a smoother investment signal to transmission, as well as to other competing alternatives.

6.3 Performance Based Regulation

Performance Based Regulation (PBR) is an attractive alternative to the present cost-of-service regulation (COSR) because it provides incentives for regulated firms to achieve specific objectives. The PBR should be designed to encourage the transmission provider to maximize the market surplus. On the supply side, the difference between the
market price and the cost of production adds to the market surplus, while on the demand
side, the difference between the consumers’ willingness to pay and the market price adds
to the market surplus.

In this form of regulation, in contrast to more traditional regulation that controls
the utilities earnings, a price ceiling based on indices of price and technological change,
is imposed. Below this price ceiling, the regulated utility has full or partial pricing
freedom.

The basic forms of PBR include benchmarking, performance targeting, earnings
sharing mechanisms and price caps. Frequently, a PBR program combines several of the
basic forms to customize it for the best performance, recognizing the characteristics of
the particular industry.

There are four elements to standard PBR models.

1) Price Caps. Unlike COSR, which ties prices that the transmission owner may charge
to cost of service, PBR simply caps the price that the transmission owner may charge.
The transmission owners allowed rate of return is neither determined nor guaranteed by
regulation. Any cost-savings programs and other efficiency improvements that the
transmission owners can institute will benefit them. Conversely, inefficient operation,
waste and cost-overruns will penalize them.

2) Constraints. In order to have a link between prices and cost, PBR usually have
various rate of return constraints. Normally, it follows a formula called RPI-X. RPI
denotes Retail Price Index and the X factor denotes efficiency improvements. The RPI
component tends to increase the price and the X factor tends to decrease the price. Note
that the objective of the X factor is for consumers and producers to share in the technical
improvements/technological advances that are anticipated as there is increased system
efficiency.

3) Performance Targets. PBR adds an additional twist to the price cap model. In
addition to cost targets and, possibly, rate of return limits, quality of service targets is
established. This is because a price cap model may encourage a firm to meet its revenue
targets by cutting back on service quality. Service levels are benchmarked on a quality index, if the firm exceeds particular benchmark levels, it can recover additional amounts from customer. If it fails to meet certain levels, penalties are levied and the maximum price it may charge customer is reduced. Quality of service indices may be established for many areas of service and increases in quality of service in any one may be rewarded differently from increases in others.

4) Periodic Reviews. Most PBR models are adjusted periodically. This adjustment can be made every few years as a result of cost and service quality performance reviews.

6.3.1 Price Cap Regulation

Price cap regulation is designed to overcome the drawbacks of the traditional COSR. In a typical price cap scheme, the maximum price a regulated firm can charge is fixed for a period of time. The initial price is fixed normally at an existing rate and then adjusted at a rate of decrease/increase over time, taking into consideration the expected gain in efficiency, and then adjusted for inflation.

My conclusion is that a price cap regulatory structure with a two-part tariff that includes a variable cost component and a fixed cost component is the best form of regulation for transmission. Such a tariff, if properly designed, separates recovery of fixed costs from recovery of variable costs associated with the use of the transmission system in real time. If the variable cost component is tied to transmission efficiency, operating efficiency, congestion costs and ancillary services costs, then the fixed cost component can be recovered from the transmission access fees. Such a properly structured price cap regulation can gives the regulated transmission firm the appropriate incentives to balance the trade-offs between variable costs and fixed costs.

In order for the price cap regulation to be effective, some responsibility for congestion - both its costs and the benefits from investment to reduce these costs - must be shifted to transmission owners so that they have an incentive to address transmission bottlenecks. This will make congestion costly to the transmission owners. In the two-
part tariff, the transmission owner is subject to a price cap constraint on an average index of prices, including short-run usage fees and connection fees. If congestion or ancillary service costs rise, fixed-cost fees must be adjusted downward to satisfy the price cap constraint. Thus, whenever congestion or ancillary service costs increase, the transmission owner will be penalized. Conversely, whenever these costs decrease, they will be rewarded. Because the transmission owners want to reduce the variable costs to maximize their profit, they will seek to solve the problem of transmission congestion either with wires over non-wires solutions, whichever is the most economically efficient one. During the price cap period, the transmission owners maximize their profit by lowering the variable costs to improve recovery of the fixed costs. Thus, the two-part tariff ties the recovery of fixed costs through the transmission access fee to the variable price. This type of regulation can harness the transmission owners profit motive in socially beneficial ways.55

In one paper, the author Vogelsang60 argues that the most efficient price cap for a transmission provider would be based on a two-part tariff involving a variable price component and fixed price component. The author concludes that all suggestions have in common that variable prices for transmission and ancillary services are traded off against fixed fees, in order to stabilize revenues to cover transmission capacity costs and to allow for variable prices to approach marginal costs or congestion prices. The average price will then be a weighted combination of a variable price and a fixed price. The model says that the current average price cannot exceed the average price in the previous period, adjusted for increases in input costs and for decreases in costs due to productivity improvements.

The design of a price cap program based on a two-part tariff is consistent with the newer forms of regulation that seek efficient behavior from regulated firms. Properly designed price caps can possess strong incentive properties to promote efficient operations and grid expansion that would enhance the future competitive marketplace and public policy goals.
6.3.1.1 Fixed Cost Driver: New Transmission Investments

In a deregulated environment, it is necessary to change the way in which the need for transmission investments are evaluated. As stated earlier, reliability considerations and economic efficiency need to be balanced when planning transmission upgrades. To assess the economic feasibility of reinforcing an interface, it is necessary to determine the frequency and magnitude of problems caused by the restriction. Also, it is necessary to determine the cost penalties - either the cost of generation re-dispatch or loss of load - associated with the restrictions. Another factor to determine is the amount of increased transfer capability obtainable by reinforcing the interface and the cost associated with such reinforcement. These analyses will yield the insight into the problem and the economic value of potential transmission upgrades. Clear investment signals are required that more accurately reflect the value of new transmission investment to the market and the community, along with greater consistency in decision-making relating to new regulated investment.

ITP should publish information regarding potential problems and their associated benefits well in advance and should request for solutions which would allow market and cost-based alternatives to compete. This process will give both the market participants and existing transmission owners an opportunity to offer proposals to meet the identified transmission needs. Solutions can include cost-based transmission, merchant transmission, generation or demand response projects. ITP can then publicly evaluate the various proposals on an equal basis, without favoring market-based or cost-based solutions. If needed, a stakeholder advisory committee may be established to help the ITP with the evaluation and the decision process.

There are many who advocate that locational marginal pricing (LMP) should be the basis for new transmission additions. While LMP can form the basis for marginal pricing of transmission use and can send the necessary signals to the market for potential transmission investments, it cannot provide sufficient signals to ensure appropriate levels of transmission investment. The physics of electricity networks translate to mean that physical changes within any part of an interconnected network can have significant
implications on the operation of any other part of the network. Network externalities, such as loop flows, congestion and classic free-rider problems are unavoidable features of bulk-power AC transmission system and they limit the ability of LMP to send a clear signal for transmission investments. These characteristics of the transmission system make it necessary to take a balanced approach to its expansion that involves many parties including regulated entities and other market participants that may respond to congestion cost signals.

The proponents of LMP based price signals claim that the value of Congestion Revenue Rights (CRR) is sufficient for transmission expansion. However, expansion of the grid will lower or eliminate the CRR which in turn undermines the value a potential investor could capture. This dilemma of potential investors will lead to underinvestment or delay in investment.

After four years of LMP at PJM Interconnection, the Cambridge Energy Research Associates (CERA) found little empirical evidence that LMP result in significant transmission investment or generation investment at the expected locations. CERA believes that LMP provides an efficient means of allocating scarce transfer capability in the short run. However, PJM’s experience demonstrates that LMP alone will not stimulate the kind of investment in transmission infrastructure that many hope for.

6.3.1.2 Variable Cost Drivers

- Transmission Efficiency

For the efficient use and development of the transmission system, it is important to give market participants the price signals that reflect the true cost of the network use. Presently, most utilities socialize the losses over the transmission system and cross-subsidize different users on the network, thus distorting the real cost of network services. Similarly, uplift charges, in which costs are recovered from all transmission users on an equivalent basis, also distort the true cost of transmission use. These practices undermine
otherwise efficient alternatives to traditional generation, such as DG, demand-side solutions, and transmission technologies. Also, any new generator who does not see the true transmission costs may distort efficient investment decisions between remote locations and locations closer to load, thereby undermining the competitiveness of the embedded generation. Similarly, an energy intensive new load does not currently have the right price signal to locate in an area with surplus generation, even though it would be beneficial to all parties.

Many assert that if market participants pay the true costs of transmission services, they will buy and use these services efficiently. Thus, several aspects of transmission operations, including congestion and losses, could be effectively addressed by proper pricing. A study conducted by Analysis Group/Economics concluded that it costs much more to transport electricity than it does to transport input fuels, and that this differential increases as the distance from the fuel source increases. So, they argue, it is, in fact, economical to construct generation near load. The right pricing signal should encourage the location of new generation in congested areas and closer to load rather than in remote locations.

Traditional electricity transmission pricing procedures of “rolling-in” the cost and applying a “postage stamp” rate for all customers may be problematic in the future. Transmission pricing principles that encourage market participants to move electricity long distances will substantially increase the traffic on the existing lines and could lead to transmission congestion. FERC’s SMD NOPR, proposing to eliminate rate pancaking may further exacerbate this problem. Transmission systems do not have infinite capacity and the distance of transportation is an important driver for electricity transmission costs. In the case of a postage stamp, a person in Kentucky does not have an incentive to send a piece of mail to California that he/she would have send to Ohio just because the price of stamp is the same. Similarly, in the case of a license plate, a person in Kentucky who wants to go to Ohio does not have the incentive to drive to California just to get more ‘bang for the buck’out of the license plate fees. However, in the case of an indifferent transmission tariff, a Generator in Kentucky will have an incentive to send the power to
California if the price of energy there is more than that in Kentucky. The speed at which the Generator can transport the power to California (instantaneous) further enhances the incentive. Also, transmission pricing principles that are indifferent to the location of new generation and load additions could increase costs to maintain reliability if it leads to voltage, stability or other reliability problems.  

- **Demand Side Participation**

Demand side participation is an underused resource to mitigate congestion and improve reliability. One of the primary reasons is that the customers willing to shed load - or more critically to reschedule load - do not see the price signal. Also, because of the current market mechanism, demand side participants cannot gain the full value of what they bring to the market.

In order to stimulate demand side participation, real-time pricing is essential so that customers can decide for themselves how much power they want to use based on the actual price of electricity at any point in time. Further, a market mechanism should be put in place that would allow demand reduction to bid into the RTO for dispatch and payment in competition with generation bids.

- **Distributed Generation**

Proponents of distributed generation (DG) claim that there are a number of barriers to entry that still exist. These include difficulties in negotiating network connection agreements and costs, demand charges that include minimum chargeable demand, lack of buy back rates, and network pricing structures. However, both FERC and state regulators are working to standardize interconnection procedures to reduce costs and clarify requirements. State and federal regulators should review the current regulatory practices to ascertain that proper incentives are in place and that they are consistent with the public interest in ensuring cost-effective consumer investments in distributed generation and energy efficiency.
• **Advanced Technology**

Even though advanced transmission technologies have many advantages, their development and deployment has been waning during the past 10 years. The present utility regulation favors capital-intensive new infrastructure additions over smart engineering solutions using advanced technologies. A proper incentive structure has to be in place so that transmission owners will choose the most economically efficient solution for congestion and reliability.

• **Operational Efficiency**

Transmission owners provide a variety of network services to various customers, including generators, wholesale traders and load serving entities. However, many claim that the transmission owners are relatively unresponsive to market requirements saying that this leads to inefficient market operation and development. Transmission owners are not directly exposed to the market consequences of their operational and maintenance activities and hence they have no incentives to respond to high-priced events in the spot market.

In order to make the transmission operation responsive to the future market demands, transmission owners should receive bonuses or penalties, depending on the performance of their transmission assets. Such bonuses and penalties should set as an addition or subtraction from the allowed rate of return at a rate that provides a clear incentive for proper behavior and should be paid according to whether transmission system operation is above or below a target level. It should also afford the transmission owner with the necessary flexibility to efficiently manage the commercial risks resulting from greater exposure to the financial consequences of their operational performance.58
6.4 Conclusions

Electric utilities in the US have traditionally been regulated according to a vertically integrated monopoly model. However, in some parts of the country, recent regulatory changes have led to a divestiture of assets by the electric utilities and to a deregulation of the generation sector of the industry. While generation additions and load demands have increased over the past decades, transmission investments have lagged behind because of regulatory uncertainty, siting problems and insufficient incentives. However, a new set of transmission only companies are entering the market. This concept of an independent transmission company is attractive because it provides both the regional awareness of investment benefits and the level of regulatory incentives necessary to achieve FERC’s goals of a more efficient and regionally integrated transmission system.

With the advent of wholesale electricity markets, the transmission system is used for interstate commerce across regional markets and thus the use of the transmission line has changed dramatically. While the new regulations of the 90’s were successful in creating active generation and wholesale competition in the marketplace, they nonetheless failed to give the right pricing signal to stimulate investment in the transmission sector. To do that, transmission must be priced in such a way that infrastructure owners will have the necessary and sufficient incentives to invest in new transmission expansions as well as the maintenance and upgrade of the existing system. The choice of regulatory system influences the way in which such prices are established and hence, the emergence of a competitive market.

Transmission congestion is said to occur when there is a need to operate uneconomical generation to serve load because of transmission restrictions. Examining the transmission restrictions from an engineering perspective, power flows through transmission lines and hence, an interface mainly dependent on the electrical characteristics of the network and the location of generation and load on the system. To
assess the economic feasibility of reinforcing an interface, the cost penalties - either the cost of generation re-dispatch or loss of load – associated with the restrictions and the cost associated with such reinforcement must be able to be determined. These analyses will provide insight into the problem and the economic value of potential transmission upgrades.

There are several alternatives to building new transmission lines to mitigate congestion or enhance reliability. Some of these methods, such as reconductoring of the existing lines with high capacity lines, using flexible AC transmission system devices, using superconducting cables (in the future) and using energy storage devices may, in fact, increase the transfer capacity of the transmission system using the existing footprint. Other means of mitigation are demand response programs, distributed generation, and efficient transmission operations. For the continued development of competitive electricity markets, transmission planning must balance traditional reliability considerations with economic efficiency. Also, better pricing signals to allocate transmission losses more accurately to those that cause it, will lead to more efficient markets because participants can see and respond to the true costs of using the transmission system.

The role of transmission in the electric energy value chain has changed considerably in the last decade. Today, the transmission system acts as an interstate highway for wholesale electricity commerce. Growth in electricity demand and new generation, lack of investment in new transmission facilities, and the incomplete transition to fully efficient and competitive wholesale markets, have allowed transmission bottlenecks to emerge. Because costs to add new transmission are a relatively small part of the average retail bill, increasing the transmission capacity with a relatively small investment in transmission can help consumers enjoy the reliable and affordable electricity service that properly managed competitive forces will deliver to the nation.

Cost-of-service regulation (COSR) has been used in the US for some time and has proven to be fair and workable. However this type of regulation may be inconsistent with
newer forms of regulation that seek to emulate the role of competitive market forces in eliciting efficient behavior from regulated firms. Performance-based regulation (PBR) is an alternative to COSR that injects competitive market incentives into monopoly markets. PBR results in reduced cost of regulation, reduced cost of power owing to sharing of utility cost reductions between utilities and consumers, and improved risk allocation between utilities and consumers.

A properly structured price cap with a two-part tariff for a transmission with a variable cost fee and a fixed cost fee can create a balance between efficient operation and recovery of fixed costs. Such a tariff separates the recovery of fixed costs from the recovery of variable costs associated with the use of the transmission system in real time and give the regulated transmission firm the correct incentives to balance the trade-offs between variable costs and fixed costs. This type of regulation can harness the transmission owners profit motive in socially beneficial ways.
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